United States Nuclear Regulatory Commission Official Hearing Exhibit
In the Matter of: Entergy Nuclear Operations, Inc. (Indian Point Nuclear Generating Units 2 and 3)
ASLBP #: 07-858-03-LR-BD01
Docket #: 05000247 | 05000286
Exhibit #: ENT000082-00-BD01 Identified: 10/15/2012
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Rejected: Stricken:
Other:

ENT000082
Submitted: March 28, 2012

Entergy

Entergy Nuclear Northeast
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Fred Dacimo
Vice President
License Renewal

January 4, 2008

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

NL-08-004

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

SUBJECT: **Reply to Request for Additional Information Regarding License Renewal Application – (Steam Generator Tube Integrity and Chemistry)**

Reference: NRC letter dated December 7, 2007; "Requests for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application"

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment I, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application for Indian Point 2 and Indian Point 3. The additional information provided in this transmittal addresses staff questions regarding Steam Generator Tube Integrity and Chemistry.

There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. R. Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 1-4-08.

Sincerely,

Patric W. Conroy for
Fred R. Dacimo per telecon
Vice President
License Renewal

cc: next page

A128
NRR

cc: Mr. Bo M. Pham, NRC Environmental Project Manager
Ms. Kimberly Green, NRC Safety Project Manager
Mr. John P. Boska, NRC NRR Senior Project Manager
Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Mark Cox, NRC Senior Resident Inspector, IP2
Mr. Paul Cataldo, NRC Senior Resident Inspector, IP3
Mr. Paul D. Tonko, President, NYSERDA
Mr. Paul Eddy, New York State Dept. of Public Service

ATTACHMENT I TO NL-08-004

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING

LICENSE RENEWAL APPLICATION

(Steam Generator Tube Integrity and Chemistry)

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

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION (LRA)
REQUESTS FOR ADDITIONAL INFORMATION (RAI)

The U.S. Nuclear Regulatory Commission (NRC or staff) has reviewed the information related to Steam Generator Tube Integrity and Chemistry provided by the applicant in the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) LRA. The staff has identified that additional information is needed to complete the review as addressed below.

RAI 3.1.2.2.14-1

LRA Table 3.1.1, Item 3.1.1-32, and LRA Section 3.1.2.2.14 "Wall Thinning due to Flow Accelerated Corrosion" state that: "Wall thinning due to flow-accelerated corrosion could occur in steel feedwater inlet rings and supports and the Steam Generator Integrity Program manages loss of material due to flow-accelerated corrosion in the feedwater inlet ring using periodic visual inspections." LRA Section B.1.35 contains a description of the Steam Generator Integrity Program but does not mention monitoring flow accelerated corrosion (FAC) in the feedwater inlet ring.

- What is the frequency of these secondary side inspections of the feedwater inlet ring?
- When was the last inspection completed?
- What were the acceptance criteria?
- What were the results of the last inspection?

Response for RAI 3.1.2.2.14-1

As stated in the Steam Generator Integrity Program description, the program includes processes for monitoring and maintaining secondary side components. Visual inspections of feedwater rings are performed by qualified personnel using approved NDE processes and procedures. The inspection frequency is based on the results of degradation, condition monitoring and operational assessments. These assessments consider the age of the steam generators, prior inspection results and industry experience with comparable steam generators in determining the frequency and extent of steam generator inspections.

Feedwater ring inspections have not been performed in the IP2 steam generators (SG) since their replacement in 2000. Inspections are scheduled for two steam generators in 2010.

The feedwater rings were inspected in the IP3 SGs in 1992 (all 4), 1997 (34 SG), 1999 (33 SG), 2001 (32 SG) & 2007 (31 & 32 SGs). The inspections performed in 1997 through 2007 consisted of a visual exam of the OD of the ring and a fiberscope inspection of the ID of 5 selected J-nozzles (of 36 total) and the feedwater ring tee. The next feedwater ring inspection for IP3 is planned for two SGs in 2013.

The acceptance criterion for the inspection is the absence of any anomalous conditions. Any anomalous conditions require further evaluation.

No anomalies were noted in the inspections other than the appearance of minor washed out areas on the exterior of the feedwater ring beneath the outlets of the J-nozzles. The feedwater entering the steam generators exits the J-nozzles welded to the feedwater ring such that the discharge is directed downward towards the exterior of the feedwater ring. The feedwater ring is a carbon steel pipe that has a thin oxide film on the exterior surface. The flow from the J-nozzles prevents this oxide buildup giving the appearance of washed out areas where this feedwater impact occurs. Visual inspections of these washed out areas have not identified loss of material on the feedwater ring.

RAI B.1.15-1

LRA Table 3.1.2-4-IP2, the last component on page 3.1-152, is blowdown pipe connection (nozzle). The interior surface aging management program (AMP) credited for monitoring degradation is Water Chemistry Control-Primary and Secondary, and refers to NUREG-1801, Vol. 2, Rev. 1, "Generic Aging Lessons Learned (GALL) Report," Table IV, Item IV.D2-8.

- Since the component is a nozzle, explain why Item IV.D2-8. is cited here, rather than GALL Item IV.D2-7 which lists FAC as the AMP.
- Is the steam generator blowdown nozzle in the FAC program?

Response for RAI B.1.15-1

The blowdown system piping external to the steam generators is susceptible to loss of material due to flow accelerated corrosion and is managed by the Flow Accelerated Corrosion Program. The steam generator blowdown nozzles are part of the blowdown system piping and are included in the FAC program. The LRA is clarified to add the following line item to LRA tables 3.1.2-4-IP2 and 3.1.2-4-IP3.

Blowdown pipe connection (nozzle)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Flow Accelerated Corrosion	IV.D2-7 (R-38)	3.1.1-59	C

LRA Table 3.1.1, Item 3.1.1-59, Discussion column is revised to add the following sentence.

> "The carbon steel steam generator blowdown pipe connection is susceptible to flow accelerated corrosion."

RAI B.1.15-2

It is noted that both units have been approved for stretch power uprates within the past three years – Unit 2 in 2004 and Unit 3 in 2005.

- Provide details on any changes made to the FAC program to account for changes to process variables resulting from the power uprates.
- Which piping systems/components are the most susceptible to FAC?
- How accurately has the CHECWORKS™ model predicted changes in FAC wear rates for the top four most susceptible systems/components for each unit since the power uprates were implemented?

Response for RAI B.1.15-2

- Inputs to the Flow Accelerated Corrosion Program include operating parameters such as flow rates and operating temperatures, in addition to the results of previous wall thickness measurements. The Unit 2 and Unit 3 programs were updated to reflect the changes to plant operating parameters due to the stretch power uprates (SPU). The revised programs determine inspection locations based on the SPU operating parameters.

- Many of the previously most susceptible locations have been replaced with FAC-resistant materials. The IP2 system most susceptible to FAC is the extraction steam system with the most susceptible component being the 3rd point extraction steam line from the LP turbine to the 23 feedwater heaters. This piping is non safety-related piping that is included in the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2). The IP3 system most susceptible to FAC is the extraction steam system with the most susceptible component being the 5th point extraction steam line from the pre-separators to the 35 feedwater heaters. This piping is non safety-related piping that is included in the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2).

- The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC Program components. This input, in conjunction with the CHECWORKS predictive algorithm, is used to predict the rate of wall thinning and remaining service life on a component-by-component basis. The value of the model lies in its ability to predict wear rates based on changing parameters, such as flow rate, without having to have actual measured wall thickness values. The predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants. CHECWORKS was designed, and has been shown, to handle large changes in chemistry, flow rate and or other operating conditions. In its use throughout the industry, the CHECWORKS model has been benchmarked against measurements of wall thinning for components operating over a wide range of flow rates. Consequently, the validity of the model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions. In addition, by the time IPEC enters the period of extended operation (in the year 2013), inspection data under SPU conditions will have been obtained. These additional data sets, when added to the CHECWORKS database, will result in more refined wear rate predictions. Since the previously most susceptible locations have been replaced, wear rates are low. Due to the low wear rates, the small changes in operating parameters due to SPU, and the relatively short time since SPU, changes to wear rates since SPU will be very small. The accuracy of the model is not expected to change significantly due to the SPU.

RAI B.1.4-1

LRA Section B.1.4 states that the Boral Surveillance Program acceptance criteria for measurements are as follows: Neutron attenuation testing and B-10 areal density is equal to or greater than the B-10 gm/cm² nominal density assumed in the criticality analysis.

- What was the subcritical margin used in the criticality analysis?
- How does this acceptance criterion account for potential degradation between surveillance periods?

- Please confirm that Indian Point Unit 3 has sufficient boral coupon samples to maintain the sampling frequency through the period of extended operation.

Response for RAI B.1.4-1

Keff <0.95 is the margin to criticality used in the criticality analyses.

Use of Keff <0.95 as the margin to criticality acceptance criteria is consistent with NUREG 0800. IP3 boral coupon surveillance results to date have not identified any loss of neutron absorption capability between surveillance periods such that the current criterion remains acceptable for use. This is consistent with industry experience.

IP3 has sufficient boral coupon samples to maintain the sampling frequency through the period of extended operation.

RAI B.1.8-1

LRA Section B.1.8, Containment Inservice Inspection Program, is the program credited for condition monitoring of protective coatings in containment. However, the description of this program only addresses the containment liner, integral attachments on the liner and the concrete surfaces. It does not address other steel surfaces in containment with protective coatings.

- How is the condition of the protective coatings on other metal surfaces, other than the containment liner, monitored?
- Describe the frequency and scope of the inspections, acceptance criteria, and the qualification of personnel who perform containment coatings inspections.

Response for RAI B.1.8-1

The condition of the protective coatings on metal surfaces at IP, other than the containment liner, is monitored by Structures Monitoring Program (SMP). The SMP governs monitoring the condition of structures or components of structures, including the condition of their protective coatings, as required by 10 CFR 50.65, the maintenance rule.

The structures are inspected every 5 years and normally inaccessible areas are inspected every 10 years.

Scope of the inspections includes visual inspection of the coated surfaces for signs of degradation (blistering, peeling, flaking, pinhole, rusting, splitting, and discoloration). The degradation observed during the inspections is evaluated to determine if the current condition is acceptable or further monitoring or corrective actions are necessary. Industry codes and standards including the maintenance rule, ASME section XI, and building codes are used to perform these evaluations and make determinations as to whether or not the structures are capable of performing their intended functions. A structure is classified as acceptable if it is capable of performing its structural functions, including protection or support of safety-related equipment.

The inspections are performed by inspection engineers (IR) under the direction of the responsible engineer (RE). The RE is a degreed civil/structural engineer with at least 10 years of related experience and a registered professional engineer. The RE and IR must be knowledgeable in the design, evaluation, and performance requirements of structures. The IR must be qualified to perform visual examination either directly or remotely to detect evidence of degradation.

Additionally, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance", the Civil/Structural group visually inspects coatings in the vapor containment building during refueling outages. The frequency of the inspection will be at least once every two (2) years or every cycle during the refueling outage. Adverse conditions will be resolved or evaluated as acceptable prior to exiting the refueling outage.