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NL-03-020

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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SUBJECT: Indian Point Nuclear Generating Units No. 2 and 3
Docket No. 50-247 and 50-286
Response to Request for Additional Information
Regarding the 60-day Response to NRC Bulletin 2002-01.

References
1. NRC letter to Entergy Nuclear Operations, Inc; Request for Additional Information Regarding 60-day Response to Bulletin 2002-01 for Indian Point Units 2 and 3 (TAC No. MB4550 and MB4551), dated November 21, 2002.
2. Entergy letter NL-02-074 / IPN-02-039 to NRC; "Submittal of 60-day Response to NRC Bulletin 2002-01," dated May 15, 2002.

Dear Sir:

This letter provides additional information requested by the NRC in Reference 1 regarding the 60-day response to NRC Bulletin 2002-01, previously provided by Entergy Nuclear Operations, Inc (ENO) for Indian Point Units 2 (IP2) and 3 (IP3), in Reference 2. The requested information, is provided in Attachment I.

ENO has a number of programs in place at the Indian Point Energy Center to ensure that boric acid leaks and the potential for resultant wastage is detected and appropriate corrective actions are taken. ENO is in the process of integrating various programs that were developed separately by the previous licensees for IP2 and IP3. This integration effort will include the programs that implement boric acid corrosion control requirements.

There are no new commitments identified in this letter. If you have any questions or require additional information, please contact Mr. Kevin Kingsley at 914-734-5581.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 1/27/03.

Very truly yours,

Fred Dacimo
Site Vice President
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cc: next page

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ATTACHMENT I TO NL-03-020

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

REGARDING 60-DAY RESPONSE TO NRC BULLETIN 2002-01

FOR INDIAN POINT UNITS 2 AND 3

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNITS NO. 2 AND 3
DOCKET NO. 50-247 AND 50-286

INTRODUCTION

This document provides responses to the NRC Request for Additional Information (Reference 1) regarding the previously submitted 60-day response (Reference 2) to NRC Bulletin 2002-01. This document contains responses for Indian Point 2 (IP2) and Indian Point 3 (IP3). Because the boric acid inspection programs for these two units were developed when these plants were operated by the previous licensees (ConEd for IP2 and New York Power Authority for IP3), there are some differences in the details of the respective programs. Entergy Nuclear Operations, Inc (ENO), the current licensee, is in the process of integrating organizations, programs, and processes for the two units. This integration effort will include development of a boric acid inspection program and implementing procedures, which are common to both units. Since there is now a single management team in place for both units, portions of the following responses are the same for IP2 and IP3, reflecting that single philosophy. In addition, integration efforts have resulted in the implementation of some common programs, such as the corrective action program and the industry events / operating experience program which are relevant to the subject matter in this letter. Portions of the following responses contain unit specific information where needed, to reflect existing differences in programs / procedures and inspection plans/schedules.

NRC QUESTION 1:

Provide detailed information on, and the technical basis for, the inspection techniques, scope, extent of coverage, and frequency of inspections, personnel qualifications, and degree of insulation removal for examination of Alloy 600 pressure Boundary material and dissimilar metal Alloy 82/182 welds and connections in the reactor coolant pressure boundary (RCPB). Include specific discussion of inspection of locations where reactor coolant leaks have the potential to come in contact with and degrade the subject material (e.g. reactor pressure vessel (RPV) bottom head).

RESPONSE:

Indian Point Units 2 and 3 are 4-loop Westinghouse nuclear steam supply systems and the Alloy 600/82/182 components and dissimilar metal welds are limited to the following locations:

- Reactor Vessel Upper Head; Alloy 600 vessel head penetrations (VHPs) with Alloy 82/182 welds for control rod drive mechanisms and thermocouple instrumentation (97 penetrations for IP2 and 78 for IP3) and the head vent.

- Reactor Vessel Lower Head; Alloy 600 penetrations with Alloy 82/182 welds for incore detector flux detectors (58 penetrations for IP2 and IP3)

- Other Alloy 82/182 welds are limited to the eight reactor vessel inlet and outlet nozzle to piping welds.

All other RCS components / welds are either low alloy carbon steel (with stainless steel cladding) or stainless steel.

The reactor vessel insulation is mirror insulation installed during initial plant construction. The only exception to this is the upper vessel head insulation, which has recently been modified for IP2 and will be modified for IP3 during the upcoming refueling outage 3R12, scheduled to begin in March 2003. The new head insulation is mirror insulation, which is offset from the vessel head to allow for visual inspection of the head outer surface.

Reactor Vessel Upper Head

ENO performed an inspection of the IP2 reactor vessel upper head during refueling outage 2R15, completed in November 2002. A similar effort is planned for the IP3 head during the upcoming refueling outage. Detailed information regarding these inspections has been submitted in accordance with NRC Bulletins 2001-01, 2002-01, and 2002-02. The inspection for IP2 included removal of the asbestos insulation, which was replaced with a mirror insulation package, which will allow for future visual inspections of the outside surface of the reactor vessel head. These inspections were performed with video and robotic assistance and provided coverage of 100% of the CRDM nozzle to outer vessel head surface junctions by VT-2 certified personnel. Additional surface and volumetric inspections were also performed, the results of which confirmed the absence of SCC. No leakage was detected as a result of these inspections, as documented in the inspection results report (Reference 3). This description is representative of the effort planned for IP3 as described in the previously submitted inspection plan (Reference 4).

Reactor Vessel Lower Head

During 2R15, ENO also performed a visual inspection of the lower reactor vessel head including the lower instrumentation penetrations for IP2. This inspection was performed under both cold, static pressure conditions and at full system operating pressure and temperature without insulation removal. The individuals performing these inspections included a VT-2 certified individual and an individual familiar with boric acid corrosion mechanisms. Although this inspection detected signs of refueling cavity wall leakage on the outside surface of the lower vessel head mirror insulation, there were no signs of active or past leakage emanating from the incore instrumentation to lower head penetration junction. In addition, there are no carbon steel reactor coolant pressure boundary components located under the lower reactor vessel head. The Alloy 600 incore instrumentation tubes extend below the lower head. A similar inspection is planned for the upcoming IP3 refueling outage, 3R12. ENO is evaluating the feasibility of other approaches to this inspection.

Reactor Vessel Inlet / Outlet Nozzles

During 2R15, ENO performed a supplemental inspection, using a VT-2 certified individual, which included the Alloy 82/182 bimetallic welds (i.e. reactor vessel nozzle-to-piping welds) and other RCS, small bore penetrations such as stainless steel instrumentation and the pressurizer heater sleeves. Because of radiation dose considerations and resource requirements, these inspections were performed without insulation removal. The vessel nozzle-to-pipe welds are covered with mirror / blanket insulation located inside the biological shield wall. Signs of pressure boundary leakage associated with these locations would be investigated and corrected after insulation removal. However, since no boron deposits were detected in the areas below these nozzles, no insulation was removed during these inspections. Although extremely small amounts of leakage may be difficult to detect without insulation removal, experience has shown that even small amounts of leakage over a fuel cycle will result in visible amounts of boron deposits well in advance of the leakage challenging the structural integrity of the affected component. This was confirmed by the V. C. Summer Hot leg nozzle cracking and other industry leakage resulting from fatigue loads on small-bore penetrations. The fact that no visible signs of leakage (i.e., boron deposits) were detected during these inspections provides reasonable assurance of nozzle structural integrity. A similar inspection effort is planned for IP3 during 3R12.

In addition, the ASME Section XI Inservice Inspection Plan (ISI) involves inspection of the vessel nozzle to piping welds once during each ISI interval (typically 10 years). The eight vessel nozzle-to-piping welds were last inspected in 1995 for IP2 and 1999 for IP3 using a qualified ultrasonic inspection technique to detect flaws at both the inside and the outside surfaces. These inspections did not identify any crack-like indications at any of these locations.

NRC QUESTION 2:

Provide the technical basis for determining whether or not insulation is removed to examine all locations where conditions exist that could cause high concentrations of boric acid on pressure boundary surfaces or locations that are susceptible to primary water stress corrosion cracking (Alloy 600 base metal and dissimilar metal Alloy 82/182 welds). Identify the type of insulation for each component examined, as well as any limitations to removal of insulation. Also include in your response actions involving removal of insulation required by your procedures to identify the source of leakage when relevant conditions (e.g. rust stains, boric acid stains, or boric acid deposits) are found.

RESPONSE:

The response to question 1 addresses all of the locations involving Alloy 600 base metal and dissimilar metal Alloy 82/182 welds.

ENO does have boric acid corrosion control programs in place at IP2 and IP3 to ensure that leakage of borated water does not result in structural challenges at other locations in the reactor coolant pressure boundary. There are multiple components of these programs covering ASME Section XI requirements for pressure boundary integrity leak tests and boric acid corrosion control requirements of Generic Letter 88-05. A summary description of these programs was provided under the original 60-day response to Bulletin 2002-01 (Reference 2).

In general, insulation is not removed to perform the various inspections, unless the inspection results identify the need for insulation removal. The basis for this is that any leakage, even leakage that is well below Technical Specification and leakage surveillance limits, would be expected to manifest itself during an operating cycle in the form of corrupted insulation and/or deposits of boric acid and fluid readily visible from outside the insulated surface. If an insulated component was leaking, the ability to visually inspect the insulated component is key so that the leaking condition can be identified and insulation removed to assess wastage and affect repairs. The type of insulation for these locations varies and includes bare blanket insulation, stainless steel lagged blanket insulation, and calcium silicate insulation.

There are certain exceptions with respect to insulation removal as it relates to performance of the inspections. The IP2 Bolted Connections Inspection Program performed each refueling outage for Class 1 components and every period for Class 2 components in accordance with ASME Section XI, IWA-5000, requires insulation removal as part of these inspections. IP3 has an ISI relief request related to this requirement and inspects these components after extended service with insulation installed. The basis of this relief request is that leakage would be expected to manifest itself during the operating cycle in the form of corrupted insulation and/or deposits of boric acid and fluid readily visible from outside the insulated surface. The discovery of evidence of leakage is entered into the Corrective Action Program for evaluation and resolution.

Determination as to whether insulation removal is deemed appropriate for a given location includes the following considerations:

(1) Plant specific and industry experience relative to leakage at the location under evaluation (i.e., Inconel 600, bolted connections, etc.)
(2) Plant operating conditions (i.e., operating temperature, chemistry, etc.)
(3) Inspection results of other plant specific locations with similar material but more aggressive operating environment.
(4) Personnel radiation exposure associated with insulation removal.
(5) Location accessibility based on plant conditions.

The philosophy applied at ENO is to repair identified active borated water leaks associated with the reactor coolant system prior to returning the unit to service following an outage.

NRC QUESTION 3:

Describe the technical basis for the extent and frequency of walkdowns and the method for evaluating the potential for leakage in inaccessible areas. In addition, describe the degree of inaccessibility, and identify any leakage detection systems that are being used to detect potential leakage from components in inaccessible areas.

RESPONSE:

Boric acid inspections for both IP2 and IP3 are performed in accordance with the respective programs summarized in the prior response to Bulletin 2002-01 (Reference 2). The extent of the walkdowns is based on those areas that are susceptible to boric acid degradation. These inspections are conducted at a refueling outage frequency, as a minimum. These inspections may also be conducted during planned or forced outages. Radiological access is the primary factor affecting the ability to perform these inspections, and is the reason these inspections are conducted with the reactor in a sub-critical condition.

Areas susceptible to boric acid degradation are accessible while the reactor is sub-critical, with varying degrees of difficulty. For example, the reactor vessel nozzle-to-pipe welds are restricted by the biological shield wall. Some areas require ladders and/or scaffolding. In addition insulation is typically installed and may not be removed to directly inspect the particular component of interest. However, even small amounts of leakage over a long period of time should result in visible boron accumulation or other evidence of leakage in the vicinity of the component, which would be detected during these inspections. The surrounding area, including the floor, equipment surfaces underneath the component, and other areas where leakage may be channeled, can be examined for evidence of component leakage.

Leakage detection systems used at both IP2 and IP3 include containment atmosphere particulate and gaseous radioactivity monitors, the containment Fan Cooler Unit condensate collection system, the containment sump pump-outs, Containment humidity detectors, and sump level instrumentation/alarms, including the reactor sump. Certain of these systems are required by the Technical Specifications of both units, which are consistent with Regulatory Guide 1.45.

NRC QUESTION 4:

Describe the evaluations that would be conducted upon discovery of leakage from mechanical joints (e.g. bolted connections) to demonstrate that continued operation with the observed leakage is acceptable. Also describe the acceptance criteria that were established to make such a determination. Provide the technical basis used to establish the acceptance criteria. In addition,

a. If observed leakage is determined to be acceptable for continued operation, describe what inspection/monitoring actions are taken to trend/evaluate changes in leakage, or

b. If observed leakage is not determined to be acceptable, describe what corrective actions are taken to address the leakage.

RESPONSE 4a:

Leakage detected at mechanical joints at IP2 or at IP3 is characterized as either active or non-active depending on whether coolant is observed flowing out of the joint (or wetness) or whether only dry boron residue is present. Active leakage is evaluated and corrective actions taken, including adjusting plant conditions to support the corrective action if needed based on the evaluation. Actions taken can include correcting the leakage and inspecting and repairing the affected components if degradation is evident. Non-active leakage (i.e. boron residue) is cleaned and the affected components are inspected. Detected degradation, which exceeds the limits of ASME Section XI requirements, is corrected prior to returning the component to service. Heavy boron deposits are also evaluated to determine if additional corrective measures are required to prevent future leakage with corrective measures implemented as required. If active leakage cannot be readily corrected, then an inspection of the affected components, including those components that can be impacted by the leakage, is performed and the conditions evaluated to ensure that the leakage does not result in unacceptable reactor coolant pressure boundary degradation. This evaluation is performed using the guidance provided in EPRI Technical Report TR-114761, "Establishing an Effective Fluid Leak Management Program", for categorization, prioritization and development of corrective action. Parameters evaluated include the current condition of the component, the expected time until the leakage can be corrected, corrosion resistance of the materials contacted by the leakage, leakage rate, chemistry of the leaking fluid, safety consequences of potentially unacceptable structural degradation, etc. Supplemental inspection/monitoring actions may be implemented if they are considered necessary to ensure that the appropriate structural margins are not exceeded. In all cases, leakage conditions will be corrected prior to the predicted structural margins decreasing below those required by ASME, Section XI consistent with the requirements of 10CFR50, Appendix B.

RESPONSE 4b:

As discussed above, any observed leakage of borated coolant determined to be unacceptable is corrected consistent with the requirements of 10CFR50, Appendix B. These actions include identifying and correcting the sources of leakage and evaluating any degradation, which might have resulted from the leaking fluid. Structural degradation, which exceeds the limits of the AMSE, Section XI IWX-3000 requirements, is repaired or the affected component is replaced as required.

NRC QUESTION 5:

Explain the capabilities of your program to detect low levels of reactor coolant pressure boundary leakage that may result from through-wall cracking in the bottom reactor pressure vessel head incore instrumentation nozzles. Low levels of leakage may call into question reliance on visual detection techniques or installed leakage detection instrumentation, but has the potential for causing boric acid corrosion. The NRC has had concern with the bottom reactor pressure vessel head incore instrumentation nozzles because of the high consequences associated with loss of integrity of the bottom head nozzles. Describe how your program would evaluate evidence of possible leakage in this instance. In addition, explain how your program addresses leakage that may impact components that are in the leak path.

RESPONSE:

The programs implemented at IP2 and IP3 rely on above-insulation visual inspection of the lower reactor vessel head during refueling outages. The design of the insulation (reflective metal) and the interference from incore instrument tubing makes insulation removal difficult. However, ENO believes that the configuration of the insulation around the instrumentation nozzles permits detection of accumulated boron that would result, even for low levels of leakage. The inspection was recently completed for IP2 (November 2002) during refueling outage 2R15 and a similar inspection, as previously stated in the response to question 1will be performed at IP3 during refueling outage 3R12 (beginning March 2003).

The inspection at IP2 was performed under cold static pressure conditions and again under full system pressure and temperature during plant heatup. There was no evidence of any leakage, active or otherwise emanating from the lower vessel head or head penetration locations, or any signs of lower vessel head degradation (i.e. rust, brown residue, etc.). In addition, there are no carbon steel components in the potential leak path from lower reactor vessel head leakage. The only reactor coolant pressure boundary components in the potential leak path would be the Alloy 600 incore instrumentation tubes, which are not susceptible to wastage from leaking coolant. Although this inspection was performed without insulation removal, the absence of any signs of lower head leakage provides reasonable assurance that the lower head is free of any active degradation mechanism. The bases for this conclusion are as follows:

1) There is no industry experience of cracking of the lower vessel head penetrations at any of the operating plants. Even those plants, which have experienced significant upper head cracking of Alloy 600/82/182, have not detected any signs of cracking in the lower head penetrations. The main reason for this, is believed to be the fact that the lower vessel head operates at cold leg temperatures while the upper head region operates close to the hot leg temperature which is approximately 55^0 F higher than the cold leg.

2) IP2 is a relatively low susceptibility plant with total accumulated Effective Degradation Years (EDY) for the upper vessel head, of approximately 8.0 EDY. In addition, IP2 has recently completed a visual, surface and volumetric inspection of the upper head penetrations and found no evidence of an active SCC degradation mechanism. Since the IP2 lower head penetrations operate at a temperature of approximately 535 ^{0}F which is significantly lower than the upper head temperature (i.e. 586.5 ^{0}F), the lower head penetrations would be expected to be free of any active SCC mechanism. Although the upper head EDY for IP3 is higher (estimated to be 11.2 years at the next outage), IP3 is still classified as a moderate susceptibility plant. The lower head penetrations are at a lower temperature and therefore have a corresponding lower susceptibility to SCC. The scope and results of the IP3 inspection of the lower head will be included in upper head inspection report that is required to be submitted within 30 days after startup.

NRC QUESTION 6:

Explain the capabilities of your program to detect the low levels of reactor coolant pressure boundary leakage that may result from through-wall cracking in certain components and configurations for other small diameter nozzles. Low levels of leakage may call into question reliance on visual detection techniques or installed leakage detection instrumentation, but has the potential for causing boric acid corrosion. Describe how your program would evaluate evidence of possible leakage in this instance. In addition, explain how your program addresses leakage that may impact components that are in the leak path.

RESPONSE:

The IP2 and IP3 NSSS design does not have Alloy 600/82/182 small diameter nozzles other than the bottom head ICI nozzles discussed in the response to question 5 and the vessel head penetrations discussed in the response to question 1. The scope of the boric acid inspection programs at IP2 and IP3, as previously discussed, does include inspection of locations and configurations other than those containing Alloy 600/82/182 components to ensure that other potential degradation mechanism (i.e., vibration fatigue) do not result in pressure boundary leakage. These small diameter nozzles are inspected for signs of leakage without insulation removal. Operating experience has demonstrated that even small amounts of leakage will result in visible boron deposits prior to challenging the structural integrity of the affected components.

NRC QUESTION 7:

Explain how any aspects of your program (e.g. insulation removal, inaccessible areas, low levels of leakage, evaluation of relevant conditions) make use of susceptibility models or consequence models.

RESPONSE:

ENO does not use susceptibility models or consequence models to determine which locations require inspections and/or insulation removal for IP2 or IP3. ENO does however consider the inspection results from higher susceptibility locations in evaluating if the personnel exposure and use of other resources associated with insulation removal is justifiable for the lower susceptibility locations (i.e. use of reactor vessel upper head inspection results to assess the susceptibility of the lower vessel head). For IP2, bolted connections, which fall under the requirements of ASME XI, IWA-5000 for borated systems are inspected with insulation removed as required by the ASME Code. For IP3, bolted connections, which fall under the requirements of ASME XI, IWA-5000 for borated systems are inspected with insulation installed in accordance with an approved ISI Relief Request. In the evaluation of an active or inactive leak, models may be developed using guidance contained in EPRI reports TR-114761, "Establishing an Effective Fluid Leak Management Program", and TR-104748, "Boric Acid Corrosion Guidebook", to characterize the leakage and wastage to assist in determining the appropriate corrective action.

NRC QUESTION 8:

Provide a summary of recommendations made by your reactor vendor on visual inspections of nozzles with Alloy 600/82/182 material, actions you have taken or plan to take regarding vendor recommendations, and basis for any recommendations that are not followed.

RESPONSE:

IP2 and IP3 are Westinghouse NSSS plants. Westinghouse conducted a review of its databases and communications to determine what recommendations have been made regarding visual inspections of Alloy 600/82/182 materials in the reactor coolant pressure boundary. The review included Nuclear Safety Advisory Letters, Technical Bulletins, Data Letters, and Infograms. This review did not identify any recommendations for inspections applicable to IP2 and IP3. Therefore, ENO is not taking exception to NSSS vendor inspection recommendations.

ENO is a member of the Westinghouse Owners Group, and the Materials Subcommittee is in the process of developing technical guidance and inspection guidelines that can be used to further enhance existing boric acid corrosion management programs. When available, ENO will evaluate the applicability of these new guidelines for implementation at IP2 and IP3. ENO is also a member of the EPRI Materials Reliability Program and applies technical guidance as applicable to IP2 and IP3.

NRC QUESTION 9:

Provide the basis for concluding that the inspections and evaluations described in your responses to the above questions comply with your plant Technical Specifications and Title 10 of the Code of Federal Regulations (10CFR), Section 50.55a that incorporates Section XI of the American Society of Mechanical Engineers (ASME) Code by reference. Specifically, address how your boric acid corrosion control program complies with ASME Section XI, paragraph IWA-5250(b) on corrective actions. Include a description of the procedures used to implement the corrective actions.

RESPONSE:

As discussed in the above responses, ENO has programs in place for Indian Point Units 2 and 3 to assure structural integrity of reactor coolant pressure boundary components susceptible to leakage of borated water and Alloy 600 components and Alloy 82/182 weld locations in the reactor coolant pressure boundaries. Inspections, which were completed for IP2 during the most recent refueling outage, (2R15, completed during November 2002) confirmed the absence of any active SCC in the Alloy 600/182/82 locations. During 2R15, ENO also completed a visual, surface and volumetric inspection of the reactor vessel upper head penetrations, which are the higher susceptibility locations in the RCS. These results coupled with the fact that IP2 is a relatively low susceptibility plant compared to the rest of the industry PWRs, confirms that SCC of Alloy 600/182/82 is not an active cracking mechanism at IP2, at this time. The inspections required by the programs currently in place at IP3, will be conducted in the upcoming refueling inspection, 3R12, scheduled to begin in March 2003.

The Alloy 600/182/82 locations are part of the reactor coolant pressure boundary and are therefore, subjected to the inspection requirements provided in IWB-2500 and the system pressure testing requirements provided in IWB-5200. Implementation of these requirements and confirmed absence of any currently active SCC mechanism forms the bases for demonstrating compliance with the requirements of 10CFR50.55a. As previously discussed, active leakage and/or visible component degradation detected during the program inspections is promptly evaluated and corrected as required by IWA-5250(b).

Boric Acid Corrosion inspections are performed for IP2 and IP3 in accordance with the programs and procedures as previously described in Reference 2. Corrective actions required as a result of these inspections are implemented through the ENO Corrective Actions Program.

REFERENCES:

1. NRC letter to Entergy Nuclear Operations, Inc; Request for Additional Information Regarding 60-day Response to Bulletin 2002-01 for Indian Point Units 2 and 3 (TAC No. MB4550 and MB4551), dated November 21, 2002.

2. Entergy letter NL-02-074 / IPN-02-039 to NRC; "Submittal of 60-day Response to NRC Bulletin 2002-01," dated May 15, 2002.

3. Entergy letter NL-02-162 to NRC; "Reactor Vessel Head Inspection Results – Indian Point 2, Fall 2002 Refueling Outage," dated December 18, 2002.

4. Entergy letter IPN-02-095 to NRC; "Reactor Pressure Vessel Head and Penetration Nozzles Inspection Plan for Spring 2003 Refueling Outage," dated December 19, 2002.