June 23, 2004

Mr. Michael R. Kansler
President
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

SUBJECT: INDIAN POINT NUCLEAR GENERATING UNIT NO. 2 - AMENDMENT RE: ONE-TIME CHANGE TO STEAM GENERATOR TUBE INSPECTION INTERVAL (TAC NO. MC1260)

Dear Mr. Kansler:

The Commission has issued the enclosed Amendment No. 239 to Facility Operating License No. DPR-26 for the Indian Point Nuclear Generating Unit No. 2. The amendment consists of changes to the Technical Specifications (TSs) in response to your application transmitted by letter dated October 21, 2003, as supplemented on March 31, 2004.

The amendment revises TS 5.5.7.b.1 to allow a one-time change to the maximum time interval between steam generator (SG) inspections. The change allows the next SG inspection, which currently must be performed no later than November 17, 2004, to be deferred until June 17, 2006. In effect, the current inspection interval is extended from a maximum of 24 calendar months to 43 calendar months.

A copy of the related Safety Evaluation is enclosed. A Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,

/RA/

Patrick D. Milano, Sr. Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-247

Enclosures:
1. Amendment No. 239 to DPR-26
2. Safety Evaluation
3. Request for Additional Information

cc w/encls: See next page

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Accession Number: ML041750603

OFFICE	PDI-1	PDI-1\PM	PDI-1\LA	EMCB\SC	OGC	PDI-1\SC
NAME	JHardy	PMilano	SLittle	CLauron for LLund	GLongo	RLaufer
DATE	06/09/04	06/07/04	06/07/04	06/08/04	06/15/04	06/23/04

Official Record Copy

DATED: June 23, 2004

AMENDMENT NO. 239 TO FACILITY OPERATING LICENSE NO. DPR-26 INDIAN POINT UNIT 2

PUBLIC
PDI-1 Reading File
R. Laufer
L. Lund
P. Milano
E. Murphy
G. Hill (2)
C. Bixler, RGN-I
ACRS
OGC

cc: Plant Service list

cc:

Mr. Gary J. Taylor
Chief Executive Officer
Entergy Operations, Inc.
1340 Echelon Parkway
Jackson, MS 39213

Mr. John T. Herron
Senior Vice President and
Chief Operating Officer
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Fred Dacimo
Site Vice President
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 2
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Christopher Schwarz
General Manager, Plant Operations
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Danny L. Pace
Vice President Engineering
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Brian O'Grady
Vice President, Operations Support
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. John McCann
Director, Nuclear Safety Assurance
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Ms. Charlene D. Faison
Manager, Licensing
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Michael J. Colomb
Director of Oversight
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. James Comiotes
Director, Nuclear Safety Assurance
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Patric Conroy
Manager, Licensing
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P. O. Box 249
Buchanan, NY 10511-0249

Mr. John M. Fulton
Assistant General Counsel
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Senior Resident Inspector's Office
Indian Point 2
U. S. Nuclear Regulatory Commission
P.O. Box 59
Buchanan, NY 10511-0038

Indian Point Nuclear Generating Unit No. 2

cc:

Mr. Peter R. Smith, President
New York State Energy, Research, and
Development Authority
17 Columbia Circle
Albany, NY 12203-6399

Mr. Paul Eddy
Electric Division
New York State Department
of Public Service
3 Empire State Plaza, 10th Floor
Albany, NY 12223

Mr. Charles Donaldson, Esquire
Assistant Attorney General
New York Department of Law
120 Broadway
New York, NY 10271

Mayor, Village of Buchanan
236 Tate Avenue
Buchanan, NY 10511

Mr. Ray Albanese
Executive Chair
Four County Nuclear Safety Committee
Westchester County Fire Training Center
4 Dana Road
Valhalla, NY 10592

Ms. Stacey Lousteau
Treasury Department
Entergy Services, Inc.
639 Loyola Avenue
Mail Stop: L-ENT-15E
New Orleans, LA 70113

Mr. William DiProfio
PWR SRC Consultant
139 Depot Road
East Kingston, NH 03827

Mr. Dan C. Poole
PWR SRC Consultant
20 Captains Cove Road
Inglis, FL 34449

Mr. William T. Russell
PWR SRC Consultant
400 Plantation Lane
Stevensville, MD 21666-3232

Mr. Alex Matthiessen
Executive Director
Riverkeeper, Inc.
25 Wing & Wing
Garrison, NY 10524

Mr. Paul Leventhal
The Nuclear Control Institute
1000 Connecticut Avenue NW
Suite 410
Washington, DC, 20036

Mr. Karl Coplan
Pace Environmental Litigation Clinic
78 No. Broadway
White Plains, NY 10603

Mr. Jim Riccio
Greenpeace
702 H Street, NW
Suite 300
Washington, DC 20001

Mr. Robert D. Snook
Assistant Attorney General
State of Connecticut
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120

Indian Point Nuclear Generating Unit No. 2

cc:

Mr. David Lochbaum
Nuclear Safety Engineer
Union of Concerned Scientists
1707 H Street NW, Suite 600
Washington, DC 20006

ENTERGY NUCLEAR INDIAN POINT 2, LLC

ENTERGY NUCLEAR OPERATIONS, INC.

DOCKET NO. 50-247

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 239
License No. DPR-26

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Entergy Nuclear Operations, Inc. (the licensee) dated October 21, 2003, as supplemented on March 31, 2004, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-26 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 239, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Richard J. Laufer, Chief, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 23, 2004

ATTACHMENT TO LICENSE AMENDMENT NO. 239

FACILITY OPERATING LICENSE NO. DPR-26

DOCKET NO. 50-247

Replace the following page of the Appendix A Technical Specifications with the attached revised page. The revised page is identified by amendment number and contain marginal lines indicating the areas of change.

Remove Page	Insert Page
5.5-7	5.5-7

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 239 TO FACILITY OPERATING LICENSE NO. DPR-26

ENTERGY NUCLEAR OPERATIONS, INC.

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

DOCKET NO. 50-247

1.0 INTRODUCTION

By letter dated October 21, 2003, as supplemented on March 31, 2004, Entergy Nuclear Operations, Inc. (the licensee) submitted a request for changes to the Indian Point Nuclear Generating Unit No. 2 (IP2) Technical Specifications (TSs). The requested change would revise TS 5.5.7, "Steam Generator (SG) Tube Surveillance Program." Specifically, TS 5.5.7.b.1 would be revised to allow a one-time change to the maximum time interval between SG tube inspections such that the next SG inspection, which currently must be performed no later than November 17, 2004, would be deferred until June 17, 2006. In effect, the current inspection interval is extended from a maximum of 24 calendar months to 43 calendar months.

The supplement dated March 31, 2004, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on December 9, 2003 (68 FR 68663).

2.0 REGULATORY EVALUATION

TS 5.5.7 defines the required SG tube surveillance program that governs the scope, frequency, and repair of the SG tubing. In particular, TS 5.5.7.b.1 specifies that "steam generator examinations shall be conducted not less than 12 months nor later than twenty four calendar months after the previous examination." The IP2 SGs were last inspected during the fall 2002 refueling outage (RFO 2R15) and, thus, TS 5.5.7.b.1 requires that the next examinations be conducted no later than November 17, 2004.

The TSs governing the frequency of SG examination for IP2 are different from those for other pressurized-water reactors (PWRs). In general, the TSs for other PWRs, which are similar to the standard TSs (STS) in Reference 4, permit the inspection intervals to be extended from 24 to 40 calendar months "if two consecutive inspections, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred." A C-1 category is defined as less than 5% of the total tubes inspected are degraded (i.e., contain defects greater than 20 percent through wall (TW)) and none of the affected tubes are defective (i.e., contain defects greater than or equal to 40% TW).

The IP2 SGs are replacement SGs which were installed during RFO 2R14 in 2000. The replacement SGs are Westinghouse Model 44F, incorporating significant design improvements, including thermally treated Alloy 600 tubing, as compared to the originally installed Model 44 SGs. The SG examinations performed during RFO 2R15 in 2002 were the first inservice inspections of the replacement SGs. The licensee reported the results of these examinations by letter dated December 19, 2002 (Reference 3). The licensee states that very few tubes were found with measurable indications (consistent with C-1 category as defined in the STS) and all of these were removed from service.

The licensee is requesting that TS 5.5.7.b.1 be modified by adding a footnote (asterisk) which would read as follows:

> *Except that the surveillance related to the steam generator tube inspection due no later than November 17, 2004, may be deferred until June 17, 2006.

This request would effectively extend, on a one-time basis, the maximum allowed inspection interval from 24 calendar months to 43 calendar months after one inservice inspection with results consistent with Category C-1 results in the STS. This will allow SG examinations which would otherwise be required to be performed by RFO 2R16 to be deferred to RFO 2R17, thereby reducing radiation dose by about 8 person-rem and cost by about $3,000,000.

The licensee states that several plants that have recently replaced their SGs (Braidwood 1, Farley 1 and 2, South Texas Project, and Arkansas Nuclear One - Unit 2) have requested and received NRC approval for extensions on their SG inspection intervals from 24 to 40 calendar months after just one inspection with Category C-1 results. Given that the licensee is proposing to extend the current interval beyond 40 calendar months, the licensee has committed to increasing its steam jet ejector sampling to twice a week while the plant is operating for the portion of cycle 17, beginning March 17, 2006, which is 40 calendar months after completion of the RFO 2R15 outage inspection, until June 17, 2006.

The licensee states that this one-time change to the maximum inspection interval requirement is justified on the basis of the significant design improvements in the IP2 replacement SGs, the favorable industry experience with these design improvements, the minimal number of tubes found with measurable indications during RFO 2R15, and that the licensee is operating and maintaining the SGs in accordance with Nuclear Energy Institute (NEI) 97-06, “Steam Generator Program Guidelines,” and EPRI guideline documents referenced by NEI 97-06.

The staff’s regulatory basis for evaluating TS amendment requests of this nature is that tube structural and leakage integrity will continue to be maintained consistent with the plant design and licensing basis. This involves maintaining structural margins consistent with the stress limits in the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III, and limiting potential primary-to-secondary leakage during design-basis accidents to values consistent with what is assumed in the plant licensing basis safety analyses and which do not unacceptably increase risk.

3.0 TECHNICAL EVALUATION

The Nuclear Regulatory Commission (NRC) staff's evaluation herein addresses: (a) the improved design features of the replacement SGs, (b) related industry operating experience, (c) the SG inspection scope implemented during RFO 2R15 and the results of these inspections, and (d) the licensee's operational assessment demonstrating that SG tube integrity will be maintained for the period of the proposed extension of the current inspection interval from the currently allowed 24 calendar months, ending November 17, 2004, to June 17, 2006 (i.e., for 43 calendar months).

3.1. SG Design Improvements

The replacement SGs incorporate both design and material improvements to address problems the industry experienced with the original SG design features. Several examples of these improvements are discussed below.

- The replacement SG tubing at IP2 is made of thermally-treated Alloy 600 (Alloy 600TT) material which has increased resistance to stress corrosion cracking (SCC) compared to the mill annealed Alloy 600 SG tubing used in the original SGs. This has been demonstrated by laboratory testing and by operating experience. Operating experience is discussed in more detail in Section 3.1.2 of this evaluation. Alloy 600TT tubing basically is mill annealed Alloy 600 tubing that has undergone an additional thermal treatment process to relieve fabrication stresses and to improve the tube metal microstructure. This process promotes carbide precipitation at the grain boundaries for improved primary water SCC (PWSCC) resistance and promotes diffusion of chromium to regions adjacent to the grain boundaries for improved resistance to outer diameter SCC (ODSCC).

- Subsequent to bending to form the tube U-bends, the first eight rows of tubes, which contain the smallest radius bends (i.e., those with the highest residual stresses), are given a thermal stress relief to minimize the residual stresses and, thus, reduce the potential for SCC. The small radius U-bends in the original IP2 SGs were not stress relieved.

- The replacement SGs employ a tighter fit of the U-bends with the anti-vibration (AVB) supports to provide a more stable tube bundle, reducing the potential for wear and high cycle fatigue relative to the original SGs at IP2.

- The tubes in the replacement SGs are supported by tube support plates made of Type 405 stainless steel. This material is more resistant to corrosion and magnetite formation (causing tube denting) than the carbon steel support plates used in the original IP2 SGs. Denting was a major degradation mechanism affecting the original IP2 SGs.

- The tube support plates in the replacement SGs contain quatrefoil shaped tube support holes. This design reduces tube dryout and chemical concentration at the tube-to-tube support plate intersections.

- The upper support plate in the replacement SGs employ two rows of flow holes rather than the rectangular flow slots in the original SGs. This reduces the potential for deformation of the upper support plate even if denting should occur. This further reduces the likelihood of producing a service-induced deformation of the small radius U-bends such as occurred with the original SGs leading to failure in the U-bend of a row 2 tube in 2000.

- A flow distribution baffle plate (made from Type 405 stainless steel) has been added in the replacement SGs that promotes a secondary side flow pattern that minimizes the size of the zone at the top of the tubesheet where sludge can accumulate.

- The tubes in the replacement SGs are hydraulically expanded over the full depth of the tubesheet. The use of hydraulic expansion significantly reduces the residual stresses and cold working associated with the hard roll expansions used for the original SGs. The full-depth expansion eliminates the tube-to-tubesheet crevice where contaminants can accumulate, which reduces the potential for ODSCC at the expansion transition zone.

Although not installed in the plant until RFO 2R14 in 2000, the replacement SGs were fabricated during the mid to late 1980s and, thus, reflect the SG state of the art at that time period. Nevertheless, the NRC staff finds that the replacement SG's design and materials will significantly enhance the SG tubing's resistance to service induced degradation of the type experienced with the original SGs, especially during the first several cycles of operation.

3.2 <u>Related Industry Operating Experience</u>

The licensee states that the Westinghouse Model 44F SGs at IP2 are nearly identical to replacement Model 44F SGs at Turkey Point Units 3 and 4, Point Beach Unit 1, and H. B. Robinson Unit 2. These four units have a total of 11 SGs that have been in service from 13.25 to 14.70 effective full-power years (EFPY). The replacement Model 51F SGs, which are similar in design but have a larger tube bundle, at Surry Units 1 and 2 have operated in excess of 15 EFPY as of 2001 and 2000, respectively. In comparison, the IP2 SGs will have accumulated only 4.8 EFPY as of June 17, 2006, when the next scheduled inspection would be performed under the requested amendment, well within the envelope of comparable industry experience.

The licensee states there has been minimal degradation exhibited in the Model 44F SGs, with minor wear at the AVB supports having been found at some of these units. The licensee also states that other Westinghouse model SGs with Alloy 600TT tubing and similar AVB designs have seen very few corrosion indications and minor AVB wear with declining growth rates over time.

The NRC staff previously reviewed operating experience with Alloy 600TT tubing in NUREG-1771, "U.S. Operating Experience with Thermally Treated Alloy 600 Steam Generator Tubes," published in April 2003 (Reference 5). This review showed a total of 400 tubes plugged among the population of Model 44F and 51F replacement SGs, a very small number compared to the many thousands of tubes plugged in the original SGs after comparable operating time. The dominant degradation mechanisms affecting these 400 tubes were wear (109 tubes, mostly at the AVBs) and manufacturing flaws (131 tubes). In addition, a substantial fraction of the 400 tubes were plugged based on volumetric or linear indications of inconclusive origin, mainly near the top of the tubesheet. Subsequent investigations (after plugging) for many of these latter indications revealed that some of these indications were volumetric or pit-like indications (possibly due to manufacturing and installation) and that some were related to causes not involving flaws. Thirty-eight of the 400 tubes were plugged as a result of loose part or foreign object related degradation. The staff has no information indicating that SCC is a likely mechanism for any of the 400 indications found to date in the replacement Model 44F and 51F SGs, although the possibility that some of these indications may be SCC related cannot be entirely ruled out.

Looking beyond replacement Model 44F and 51F SGs, three U.S. plants with SGs employing Alloy 600TT tubing have observed ODSCC after at least 10 EFPY service. In May 2002 at Seabrook Unit 1, which has Westinghouse Model F SGs, axially-oriented ODSCC indications were detected in 42 tube-to-tube support plate intersections in 15 tubes. The staff reported on these indications in NRC Information Notice (IN) 2002-21, dated June 25, 2002, and supplemented on April 1, 2003. These indications were found after approximately 10 EFPY operation with a relatively high hot leg temperature of 618 degrees Fahrenheit (°F), and (based on tube pull examinations) represent the first confirmed instance of SCC in Alloy 600TT tubing in the US. Subsequent investigation revealed a high level of residual stress in the straight leg portions of the affected tubes. In addition, this investigation also revealed that tubes affected by these high residual stress levels exhibit a characteristic low frequency eddy current response. Non-optimal tube processing during SG manufacturing was strongly suspected of being the primary cause of the high residual stress and the principle factor increasing the susceptibility of the affected tubes to stress corrosion cracking. The precise processing steps responsible for the adverse stress state could not be conclusively determined from a review of the tube processing records. The licensee for IP2 reports that the IP2 SG tubing was fabricated from different heats of material by a different manufacturer than was the case for Seabrook. In addition, the licensee states that the characteristic eddy current response associated with the Seabrook tubes with high residual stress were not observed during the RFO 2R15 inservice inspection in 2002.

In fall 2003 at Braidwood Unit 2, which has Westinghouse Model D5 SGs with Alloy 600TT tubing, axial ODSCC indications were detected in 4 tube-to-tube support plate intersections in three tubes. These indications were found among a population of 77 tubes exhibiting the characteristic eddy current offset signal seen at Seabrook which was determined to be associated with high residual stress levels. These cracks were found after 12.7 EFPY operation with a hot leg temperature of 610 °F.

Just recently, in April 2004 at Vogtle Unit 2, which has Westinghouse Model F SGs with Alloy 600TT tubing, circumferential ODSCC indications were detected in nine tubes at the tube expansion transition at the top of the tubesheet. The licensee for Vogtle Unit 2 is continuing to investigate this occurrence. These indications were found after approximately 12 EFPY operation with a relatively high hot leg temperature of 618 °F. Tube samples covering two locations where these indications were found were removed from the SGs for laboratory examination, which will determine whether the indications are actually associated with cracks. This laboratory examination is still in progress.

As previously stated, the IP2 replacement SGs will have accumulated 4.8 EFPY operation at the conclusion of the current inspection interval (as proposed). The staff notes that this is considerably less than the operating time associated with the earliest known instances (i.e., 10 to 13 EFPY) of cracking affecting Alloy 600TT tubing in the U.S. In addition, IP2 operates with a relatively low hot leg temperature (590 °F), which tends to increase the time to crack initiation than is the case for plants operating at higher temperatures, everything else being equal.

Based on the above, the staff concludes that industry operating experience supports a high level of confidence that the improved design and materials in the IP2 replacement SGs will significantly enhance resistance to service induced degradation of the type experienced with the original SGs, especially during the first several cycles of operation. In addition, U.S. industry-wide experience indicates that SCC is not expected to be an issue for IP2 during the current inspection interval (as proposed).

3.3 SG Inspection Scope during RFO 2R15

The first and most recent inservice inspection of the IP2 replacement SGs was conducted during RFO 2R15 in fall 2002. The licensee states that the scope of the inspections exceeded both TSs requirements and the Electrical Power Research Institute (EPRI) SG Examination Guidelines, Revision 5. The initial inspection scope included:

- A full length bobbin coil inspection of 100% of the non-plugged tubes in all four SGs, with the exception of the U-bends of row 1 and row 2 tubes which were inspected with a mid-range +Point coil.

- A 3-coil rotating probe inspection of a random 20% sample of tubes on the hot leg side plus all peripheral tubes in a zone extending from 3 inches above the top of the tubesheet (TTS) to 3 inches below the TTS. The staff notes that these inspections were performed to identify any SCC indications and any loose parts related damage affecting the peripheral tubes.

- All dents found by bobbin with dings or dents with voltage responses equal to or exceeding 5 volts were subsequently inspected with the +Point coil. The staff notes that this was to ensure detection of any small amplitude crack indications which could be potentially masked by the ding or dent signals.

This initial inspection scope was expanded to include additional +Point coil “special interest” inspections based upon results from the bobbin coil as follows:

- +Point inspections were conducted at 1074 locations in 991 tubes where bobbin “I-Codes” were recorded. I-Codes were reported when bobbin signal responses or indications were found which were not present in the baseline inspection (performed on the replacement SGs prior to their initial service) or exhibited change relative to the baseline inspection. The licensee states that the large number of I-Codes found was due to the fact that this was the first operating cycle of the SGs and, thus, the first time heat was applied to the tubes. The licensee states that SGs throughout the industry with Alloy 600TT tubing are well known to contain many benign signals which change rapidly after the first cycle and not as much in subsequent cycles, so the need to perform a large number of +Point examinations (of I-Codes) was not unexpected.

- An additional 51 tubes with +Point inspected at the TTS to bound all tubes with possible loose parts (PLP) indications. In addition, the inspection was expanded to include +Point inspection of all peripheral tubes on the cold leg side.

In addition to eddy current inspections, the licensee conducted visual (video) inspections on the secondary side as part of its Foreign Object Search and Retrieval (FOSAR) program for loose parts or other conditions that could affect tube structural integrity or leak tightness.

The staff finds that the scope of inspection during RFO 2R15 significantly exceeded minimum TS requirements. The broad scope of these inspections coupled with extensive rotating coil inspections of locations with bobbin I-Code responses and of locations where bobbin may not be capable of detecting potential cracking mechanisms (e.g., small radius U-bends, tube expansion transitions at the TTS, locations with large amplitude dents or dings) provided for an effective approach for purposes of identifying active degradation mechanisms and flaws which could potentially challenge tube integrity.

3.4 RFO 2R15 SG Inspection Results

The licensee reports that the most significant indications found during the RFO 2R15 were wear indications at AVB supports of thirteen tubes with measured depths ranging from 9% to 20% of the initial wall thickness. The licensee elected to plug each of these tubes even though the indications were less than the repair limit of 40% of the initial wall thickness. This was done to support a two cycle inspection interval. The licensee elected not to stabilize these thirteen tubes at this time, prior to plugging. This is discussed further in Section 3.1.5, below.

Three freespan volumetric indications were also found, with measured depths ranging to a maximum of only 19%. Again, the licensee elected to plug each of these tubes even though the indications were less than the repair limit of 40% of the initial wall thickness. The cause of these indications is not definitively known. The licensee believes these indications could be manufacturing buff marks that became indications under the sustained heating of the replacement SG first operating cycle or perhaps be caused by a transient loose part.

Since December 2001, the licensee has reported extremely low levels of secondary system activity corresponding to a primary-to-secondary leakage rate of approximately 0.01 - 0.03 gallons per day (gpd). Eddy current examination during RFO 2R15 revealed no indications which could explain this activity. The licensee considers a very small tube end weld imperfection in SG 22 to be the most likely source of this activity. Approximately 200 tube ends in SG 22 had weld repairs during SG fabrication and while they were successfully tested for leak tightness, the licensee states that the possibility exists that a minor flaw was missed or that the thermal stress of operation could have opened a subsurface flaw. A primary side visual inspection of the SG 22 tubesheet to look for leaks or surface indications at the tube-to-tubesheet welds revealed no anomalies.

Although loose parts were found on the secondary side in all four SGs, no loose part wear was found by eddy current examination (other than citing transient loose parts as a potential contributor to the three volumetric indications discussed above). The loose parts found by inspection largely consisted of small pieces of wire bristle and sludge rock. A number of metallic objects were also found, mostly small in size. The licensee elected not to retrieve many of these loose parts which included sludge pebbles and rocks with diameters ranging from 1/8 to 3/8-inches and small wires/bristles with diameters of 1/64-inches and lengths ranging to 1.5-inches due to the limited size of these objects and the time and personnel exposure required to retrieve. In addition, the licensee states that an oval shaped metallic mass measuring 1/2 by 1/4-inches could not be retrieved. The licensee performed an analysis for each type of object remaining in the SGs and determined that the time required to wear a tube to the 40% tube repair limit is greater than two operating cycles, making the conservative assumption that such tubes contained 20% through wall wear during RFO 2R15. Eddy current examination did not reveal any indications of wear associated with these loose parts.

Based on these inspection results, the staff finds that active degradation at the time of RFO 2R15 was consistent with overall industry experience with replacement Model F SGs. This active degradation consists largely of a small number of wear indications at AVB supports plus, possibly, three volumetric flaws of undetermined cause. Each of the indications found were small relative to the flaw acceptance limits in the TSs (i.e., the 40% plugging limit) and, thus, the staff concludes that none of these indications degraded tube structural integrity margins or leak tightness to less than that assumed in the plant licensing and design basis. In view of the large number of loose parts which continue to be present in the SGs, the staff believes that loose parts related damage cannot be precluded as an active degradation mechanism. However, the small size of the loose parts coupled with the absence of any detectable flaw indications associated with these loose parts suggest that loose parts related flaws are likely to remain small prior to the next scheduled inspection in RFO 2R17. For the reasons cited by the licensee, the staff concurs that the cause of the small primary-to-secondary leak that has been present and unchanged since December 2001 is likely related to tube end weld fabrication rather than to a service induced flaw. The staff finds that such a fabrication flaw has negligible tube integrity implications. Such a flaw cannot cause a tube burst by virtue of the radial constraint provided by the tubesheet. Any significant growth of this flaw in the future would be expected to be accompanied by small, observable increases in leakage rate which can be easily managed relative to the TS limit on allowable primary-to-secondary leakage (150 gpd). The staff finds that the TS leakage limit provides reasonable assurance that leakage from such a fabrication flaw during design-basis accidents will be within that assumed in the licensing basis safety analyses.

3.5 Operational Assessment

The licensee performed an operational assessment with the objective of demonstrating that active degradation mechanisms observed during RFO 2R15 will not adversely affect tube structural or leakage integrity during Cycle 16 and 17, after which the licensee is proposing to perform its next scheduled inspection during RFO 2R17. As background, IP2 operated for 1.72 EFPY during Cycle 15 (the first post-SG replacement cycle). The interval to the proposed next inspection at RFO 2R17 is 3.1 EFPY or 43 calendar months.

The licensee states in Reference 1 that the AVB system has been designed to minimize the clearance between the AVBs and the tubing so as to minimize any wear as a result of flow induced vibration of the tubing. The licensee states that based on the design dimensions and tolerances, the calculated wear of the tubing over a 40-year lifetime of the SGs is about 2 mils or 4% of the initial tube wall thickness. This includes the effects of a total power uprate of

4.7%. In Reference 2, the licensee provided its explanation for why 13 tubes exhibited wear indications ranging to a maximum depth of 20% TW after just one operating cycle. The licensee states that anecdotal data indicate that the extremely tight tolerances of the design led to unanticipated difficulties during U-bend assembly. The licensee believes that local conditions exist where wear greater than predicted in the design performance predictions may occur. The licensee states that although a few additional tubes may yet be found to wear outside the predicted design performance, the wear conditions which have actually been observed are expected to be a worst case from an initiation and growth perspective.

Given that all 13 tubes with observed wear indications were plugged during RFO 2R15, the licensee assessed the potential growth of wear indications which may have been just below the eddy current detection threshold for AVB wear during RFO 2R15. This estimate considered an assumed constant volumetric growth rate corresponding to the growth rate observed for the worst indication found during RFO 2R15, allowing for an assumed 5% TW measurement error based on a Westinghouse test study of AVB wear sizing uncertainty. This growth estimate was factored up to reflect the total 4.7% power uprate, which was conservatively assumed to be in place throughout the current inspection interval. Based on the above, the licensee projects that a wear flaw that was below the detection threshold in RFO 2R15 could be as large as 55.8% TW following 43 calendar months operation at RFO 2R17. The staff finds this to be a conservative estimate, primarily because the staff would expect the wear rate for a currently undetected wear flaw to be less than that observed for the most limiting wear flaw observed during RFO 2R15. This estimate is less than the reported structural limit of 67.8% TW (Reference 6) corresponding to the maximum depth at which a wear scar will maintain a margin consistent with the plant design basis (i.e., ASME Code, Section III). (However, a tube with such a flaw would exceed the TS 40% plugging limit and would be required to be plugged at that time).

With respect to the 13 tubes found with wear indications during RFO 2R15, the licensee elected not to stabilize any of these tubes prior to plugging, although experience shows that wear activity will likely continue to occur after the tubes are plugged. The staff notes that it is industry practice to install stabilizing devices in tubes prior to plugging in cases where damage mechanisms may continue to be active after plugging and where such degradation may cause the plugged tube to ultimately damage adjacent tubes. For wear at the AVB supports, the licensee states (Reference 2) that the Westinghouse criterion for stabilization is prevention of tube-to-tube contact. Westinghouse states that prevention of tube-to-tube contact ensures that wear will not proceed sufficiently through the plugged tube section such as to permit the plugged tube to become severed by fatigue which in turn would permit the severed tube ends to propagate damage to adjacent live tubes. Reaching the point of tube-to-tube contact requires the plugged tube to wear not only entirely through-wall, but through approximately 35% of the cross-section of the tube. Assuming wear rates consistent with that observed during the initial operating cycle with the replacement SGs and adjusting for the power uprate conditions in effect during the current inspection interval, the licensee calculates the time needed to wear through the tube wall thickness to be well in excess of the length of the proposed 43-month inspection interval. The staff notes that this finding is also supported by operating experience with similar Model F SGs based on wear rates observed during inspections of de-plugged tubes up to six EFPY after they were plugged for AVB wear. Based on the above, the staff believes there is reasonable assurance that the 13 plugged tubes will remain intact, without stabilization, well beyond the proposed next inspection during RFO 2R17.

The licensee states that it plans to evaluate the need to install stabilizing devices in the most limiting two of the thirteen tubes (i.e., those exhibiting wear indications at all four AVB supports) prior to the next inspection. In addition, the licensee committed in Reference 2 to evaluating the other 11 tubes for future stabilization within 90-days of the next SG inspection outage (RFO 2R17).

The licensee's operational assessment does not treat the three freespan volumetric indications as an active mechanism. As previously discussed, the licensee believes these indications to be related to fabrication or, perhaps, a transient loose part. Even if assumed to represent an active mechanism, the staff believes that these volumetric indications do not have any significant tube integrity implications during the current inspection interval (as proposed). This finding considers that each of the tubes with the three indications have been plugged and that the shallow depths of these indications (≤ 19% TW) after 24 months operation make it unlikely that any volumetric indications that were too small to be detected during RFO 2R15 could grow to the applicable structural limit depth (67.8% TW) during the current 43-calendar month interval (as proposed).

The licensee states that wear from secondary side loose parts or foreign objects represents a possible damage mechanism that may affect the tubes in the replacement SGs. However, known loose parts not retrieved from the SGs are relatively small, and the licensee's analysis of these objects (previously discussed) indicate that any wear damage from these objects will remain below the tube repair limit and structural limit throughout the current 43-calendar month inspection interval (as proposed). On this basis and in view of the absence of wear indications associated with identified loose parts during RFO 2R15 after 24 months of operation, the staff finds that extension of the current inspection interval from a maximum of 24-calendar months to 43-calendar months should not adversely impact SG tube integrity from a loose parts related wear perspective.

SCC was not identified as an active degradation mechanism at IP2 during RFO 2R15 after 24 months of operation. The staff finds it likely based on a number of considerations that SCC will continue to be identified as a non-active mechanism at through at least RFO 2R17 when the next scheduled inspection of the SGs will be performed (as proposed). This finding is based on the fact that IP2 will have accumulated a total of only 4.82 EFPY by RFO 2R17, which is well within the envelope of U.S. industry experience for the earliest onset of identified SCC; i.e., at Seabrook Unit 1 after approximately 10 EFPY, at Braidwood Unit 2 after 12.7 EFPY, and at Vogtle Unit 2 after approximately 12 EFPY. In addition, IP2 operates at a lower hot leg temperature (590 °F) than Seabrook Unit 1 (618 °F), Braidwood Unit 2 (610 °F), and Vogtle Unit 2 (618 °F). All other factors being equal, the lower operating temperature at IP2 can be expected to increase the time to crack initiation. In addition, the licensee has determined that the IP2 tubing does not contain the tell-tale eddy current offset signal characteristic evidenced at Seabrook Unit 2 and Braidwood Unit 2 which is indicative of abnormal residual stress believed to have contributed to the relatively early appearance of cracking at those units.

Finally, the staff finds that should a flaw of any type occur and unexpectedly grow entirely through the tube wall thickness during the proposed 43-calendar month operating interval, the likely consequence will be a small primary to secondary leak. The IP2 TSs limit the allowable primary-to-secondary leakage to 150 gpd, both for purposes of minimizing the likelihood of SG tube rupture and for ensuring that leakage is maintained consistent with values assumed to exist in the licensing basis accident analyses. Although not 100% effective for preventing tube ruptures, as evidenced by the SG tube failure at IP2 in 2000 (original SGs) following the occurrence of a small (approximately 4 gpd) primary-to-secondary leak, the staff finds that industry operating experience has shown that the leakage limits have been effective in minimizing the occurrence of SG tube ruptures through timely plant shutdown before rupture occurs.

3.6 Summary

The staff finds that the IP2 replacement SGs design and materials will significantly enhance the SG tubing's resistance to service induced degradation of the type experienced with the original SGs, especially during the first several cycles of operation. This is supported by extensive operating experience with SGs of similar design and materials. The results of the first inservice inspection of the replacement SGs during RFO 2R15 were consistent with this expectation of improved performance, with relatively minimal degradation and no evidence of SCC found. In addition, the IP2 replacement SGs will have accumulated a total of only 4.8 EFPY at the time of the next inspection during RFO 2R17 (as proposed), well within the earliest onset of SCC observed in the U.S. The staff finds that the observed degradation activity provide a high level of confidence that tube structural margins and leakage integrity will continue to be maintained in accordance with the design and licensing basis under the proposed extension to the SG inspection interval. Thus, the staff finds the amendment request to be acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. In a letter dated May 7, 2004, the State forwarded the following comments. The New York State Energy Research and Development Authority, in conjunction with the New York State Departments of Health and Public Service, objected to the granting of the inspection interval extension. The objection was based on the past history of the plant and insufficient inspection history. The State of New York further commented that if "... the NRC does cho[o]se to approve this exemption, then the commitment made by Entergy in its exemption request to increase the steam jet air ejector sampling from once to twice a week should begin immediately upon the end of the current inspection interval instead of March 17, 2006, as proposed."

The following represents the staff's response to specific concerns raised by the State:

4.1 Concerns About Wear at the AVB Supports

The licensee's March 1, 2004, application addressed the issue of why some tubes experience wear rates higher than nominal design predictions at the AVB supports, as acknowledged in the staff's safety evaluation (SE). The wear experience at IP2 is not unexpected and appears to be well within the envelope of industry experience. Approximately 93 tubes have been plugged due to AVB wear in the U.S. fleet of replacement Westinghouse Model F SGs (i.e., Model 44F and 51F). NUREG-1771 provides additional relevant statistics on this. It is also important to note that the wear depths at IP2 ranged to a maximum depth of 20% through wall. These measured flaw depths were well below the applicable 40% repair (plugging) limit in the TSs. Thus, all of the affected tubes were still acceptable for continued service without repair or plugging. The licensee elected to plug these tubes to support a two-cycle inspection interval. As noted in the SE, it is possible that there may have been additional tubes which contained small wear indications below the detection threshold during the RFO 2R15 inspection and some of these undetected flaws may grow sufficiently to be detectable at the next inspection. However, based on the licensee's operational assessment (discussed in the SE), the staff does not expect such wear indications to grow sufficiently to pose a tube integrity concern prior to the next inspection proposed for RFO 2R17.

4.2 Concerns About Power Uprate to be Implemented During Current Inspection Interval

The licensee's operational assessment conservatively considered the 3.26% stretch power uprate to be in effect throughout the 2-cycle inspection interval, rather than possibly commencing after RFO 2R16. This power uprate results in an increase in the tube cross flow velocities, increasing wear rates by an estimated 46% relative to the non-uprated conditions existing during the previous inspection interval. As discussed in the SE, the licensee's operational assessment considered maximum growth rates for the current inspection interval to be 46% higher than the maximum growth rates observed during the previous inspection interval.

4.3 Concerns About Steam Jet Sampling Frequency

The State recommended that the licensee increase the steam jet air ejector sampling frequency from once to twice a week for the entire period of the requested inspection interval extension (i.e., beyond November 17, 2004). The NRC staff does not believe this measure to be necessary to ensure the safe operation of the unit during the period of the requested extension. The licensee utilizes diverse methods for monitoring leakage including the use of continuous radiation monitors (e.g., N-16 and air ejector radiation monitors) and periodic analysis of chemistry samples from the steam jet air ejectors and SG blowdown. The N-16 monitor has a number of alarm set points beginning at 5 gpd (based on information provided to the staff in 2000) and ranging to the administrative leakage limit. The licensee's program includes administrative limits on allowable leakage which are more restrictive than the 150 gpd limiting condition for operation limit in the TSs. The administrative limits include a 75 gpd leak rate limit for a period of >1 hour, consistent with industry guidelines, after which the unit must be shut down.

Steam jet air ejector sampling is capable of detecting very small levels of leakage as evidenced by the licensee's ability to monitor a 0.01 to 0.03 gpd leak that has existed since 2001. The licensee estimates that the leakage detection threshold with the N-16 is about 1.0 gpd. The staff notes, however, that 1.0 gpd is well below levels at which industry guidelines recommend taking actions such as increasing the frequency of chemistry sampling or ultimately shutting down the plant. Thus, leakage will be detectable with the continuous N-16 radiation monitors well before actionable levels of leakage are reached.

Operating experience indicates that degraded SG tubes usually, but not always, exhibit leak before break behavior. Between 1975 and 2000, there were 188 unplanned or forced plant shutdowns in the U.S. due to SG tube leakage. These unplanned shutdowns typically involved maximum leak rates ranging from 50 to 1000 gpd. Only eight of these shutdowns (including IP2 in 2000) involved a tube rupture or failure event with leak rates exceeding 100 gpm. Effective leakage monitoring in conjunction with implementation of appropriate leakage limits has proven to be an effective approach for minimizing the incidence of tube failure and for providing added assurance of tube integrity. The current trend in the industry to adopt more and more restrictive administrative leakage limits such as those in place at IP2 which will further enhance their effectiveness in preventing tube ruptures. However, these programs can never provide complete assurance against tube rupture even if the leakage limits are reduced to zero. This is evidenced by the fact that two of eight tube failures in the U.S. occurred without precursor leakage prior to the event.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in *Title 10 of the Code of Federal Regulations* (10 CFR), Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (68 FR 68663). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

1. Entergy letter NL-03-165, "Proposed Change to Technical Specifications: One-Time Change to the Indian Point 2 Steam Generator Tube Inspection Requirements," dated October 21, 2003. (NRC Accession No. ML032960328).

2. Entergy letter NL-04-033, "Response to NRC Request for Additional Information Re: Proposed Change to Technical Specifications: One-Time Change to the Indian Point 2 Steam Generator Tube Inspection Requirements," dated March 31, 2004. (NRC Accession No. ML040930142).

3. Entergy letter NL-02-161, "Steam Generator Inservice Examination Program Results 2002 Refueling Outage (2R15)," dated December 19, 2002. (NRC Accession No. ML023580031).

4. NUREG-1431, Volume 1, Revision 2, "Standard Technical Specifications Westinghouse Plants," June 2001.

5. NUREG-1771, "U.S. Operating Experience with Thermally Treated Alloy 600 Steam Generator Tubes," April 2003.

6. Entergy letter NL-02-112, “Proposed Steam Generator Examination Program - 2002 Refueling Outage (2R15),” dated August 21, 2002. (NRC Accession No. ML022390064).

Principal Contributor: E. Murphy

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