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Engineering Report Cover Sheet

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Indian Point 2 Steam Generator Program

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*: For ASME Section XI Code Program plans per ENN-DC-120, if required

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Revision Summary

Rev.	Description	Changes
0	Supercedes Calculation FMX-00331-00	Adds statements in various sections that SGMP interim guidance letters will be followed in addition to EPRI guidelines Adds current interim guidance letters to References section
1	1. Revised to incorporate "Results of INPO's Steam Generator Review Visit at IPEC during Sept. 21-23, 2004" (ref. 57).	Section 1.0 Updated references. Section 2.2 Updated Plant History Section 2.3 Updated Sludge Lance History Section 2.4.1 Updated IP2 Plugging Limit Section 2.5 Updated History of Tube Leakage/Tube Rupture Events Section 3.0 Revised Steam Generator Performance Criteria Section 4.3.1 Added 4.7% Stretch Power Uprate (SPU) Section 4.5 Added revision 3 of the EPRI PWR Primary-to-Secondary Leak Guidelines Section 4.11 Updated latest Self Assessment Section 9.0 Updated references. Attachment 4 Revised 2R15 Outage Summary Attachment 5 Revised Steam Generator Work Scope Chart
2	2. Major revision	Entire document effected.

1. Purpose

This document describes Entergy's steam generator program implemented at the Indian Point 2 Nuclear Power Plant (IP2). The purpose of the steam generator program is to maintain the steam generator tube integrity to assure their continued operation until the end of plant life and to support plant life extension. The program formalizes and integrates the various inspections, maintenance, chemistry and operational activities performed on the steam generators and provides the basis for making strategic decisions to optimize steam generator reliability and performance.

The elements of the steam generator program consist of the following: inspections, maintenance and repairs, tube integrity assessments, chemistry control and initiatives and reporting. This program is structured following the guidance given in the Nuclear Energy Institute's Steam Generator Program Guidelines (NEI-97-06) and its referenced documents. This program report is updated as necessary to remain current with inspection information and as required by Steam Generator Management Project (SGMP) administrative documents.

Entergy will modify its Steam Generator Program as described in EN-DC-317, Entergy Steam Generator Administrative Procedure, as required by Steam Generator Management Project (SGMP) transmittal letters. When an EPRI Guideline is revised, Entergy will modify any affected documents and procedures as required by the EPRI SG Management Project (SGMP) transmittal letter. When an EPRI Guideline is revised, the EPRI SGMP notifies its members. The SGMP notification transmittal letter, or guideline document, is required by NEI 97-06 to provide a listing of the revised sections of the guideline and the technical basis for each revision to the document's mandatory elements. Licensees will modify their SG programs as directed by EPRI SGMP.

2. Background

2.1. Steam Generator Design Information

The original Westinghouse Model 44 steam generators at IP2 were replaced in 2000 with Westinghouse Model 44F's, with a nominal 43,467 square feet of heat transfer area. Each steam generator contains 3214 thermally treated U-tubes fabricated from Alloy 600 (ASME-SB-163 Alloy UNS N06600 to Code Case N-20). This is 46 fewer tubes than the original SGs to accommodate the broached tube support plates and the relocation of the stay rods. The nominal OD of each tube is 0.875 in. and the nominal tube wall is 0.050 in. thick. The ends of the tubes are hydraulically expanded the full depth of the tubesheet and seal welded to the cladding on the primary side. In addition, the first eight rows of tubes were heat treated after the tube bending process to relieve residual stresses.

The tubes are supported on the primary side by the tubesheet. The tubesheet is a low alloy steel (ASME-SA-508 Class 3) forging. That portion of the tubesheet primary side in direct contact with the primary coolant is clad with weld deposited Ni-Cr-Fe alloy (SFA5.14 Cl. ERNiCr-3/SFA 5.11 Cl. ENiFe-3).
The tubes are supported on the secondary side by six tube support plates. The tube support plate material is stainless steel (ASME-SA-240 Type 405). The holes where the tubes pass through the tube support plate are quatrefoil shaped holes produced by broaching.

A flow distribution baffle (FDB), located between the lowest tube support plate and the tubesheet, is designed to minimize the number of tubes exposed to low velocity flow in the vicinity of the tube plate. The FDB material is stainless steel (ASME-SA-240 Type 405) and the center portion of the FDB has a circular cut out about 31" in diameter. The FDB has round rather than quatrefoil tube holes. This FDB design controls the cross-flow velocity so that the low velocity region (and sludge deposition zone) is located at the center of the tube bundle, near the blowdown intake.

Two sets of anti-vibration bar (AVB) assemblies stiffen the tube bundle in the U-bend region and restrain tube vibration. The AVB assemblies also maintain proper tube spacing and alignment in the U-bend region. The AVB's are installed between the tube columns in the U-bend to a specified insertion depth to provide support for tube rows 10 and 13 and higher. The smaller 45° AVB's provide support tubes rows 13 through 45, while the larger 141° AVB's provide support for tube rows 10 through 45. U-tubes 1 through 9 do not require AVB support. The design specifications are detailed in D-Spec 405A08, Rev. 5, Model 44F Replacement Steam Generator provided by Westinghouse.

These units were constructed in accordance with the 1980 ASME Boiler and Pressure Vessel Code, Section III, through the Winter 1981 addenda. The code stress report for the replacement steam generators is in Westinghouse reports WNEP-8732 and WCAP-15598. The stress report is in accordance with the 1965 ASME BPVC Code, through Summer 1966 Addenda.

2.2. Plant History

Indian Point 2 started commercial operation in August 1974. The original steam generators had a number of problems and in 2000 replacement steam generators were installed following a steam generator tube rupture event. Activities that are significant with regard to the maintenance of the steam generators are outlined below. Since the steam generators were replaced in 2000, all information previous to that date is given for historical information only. Any mention made in this report to steam generators means the replacement generators unless the term original steam generator is used.

1974	Began commercial operation utilizing phosphate chemistry (phosphate/hydrazine).
1975	Began utilizing AVT chemistry (ammonia/hydrazine).
1978	Boric acid added to secondary as proactive measure against stress corrosion cracking. (ammonia/hydrazine/boric acid)
1978	A sludge-lancing program was initiated. Since then sludge lancing has been performed during each outage.
1982	The tube bundles in the six moisture separator reheaters and three high-pressure feedwater heaters were replaced. The replacement tubing material for moisture separator reheaters and feedwater heaters was Type 439 stainless steel and Type 304L stainless steel, respectively.
1987	Nine additional feedwater heaters were replaced.
1991	Admiralty tubed Condenser 21 was replaced with titanium tubed modular unit during the 1991 outage
1993	Admiralty tubed Condenser 22 was replaced with titanium tubed modular unit during the 1993 outage
1995	Admiralty tubed Condenser 23 was replaced with titanium tubed modular unit during the 1995 outage
1995	Added ethanolamine (ETA) to secondary chemistry to lower iron transport to the SGs. (ammonia/hydrazine/boric acid/ETA)
2000	During the 2000 outage, the six remaining low-pressure feedwater heaters, with admiralty brass tubes and located in the condenser neck, were replaced with units that have 304L stainless steel tubes. In addition the gland steam condenser, with 90/10 copper/nickel tubes, was replaced with a titanium tube unit.
2000	Replaced the steam generators with Westinghouse Model 44Fs.

2000	A decision was made to perform an in-house cleaning of the feedtrain by dissolving accessible copper in a high pH/high ammonia content solution prior to restart in the 2000 outage. Copper removal from the Feedwater and Condensate Systems was performed by recirculating an aerated pH >10 solution of ammonia and ETA (100 part per million (ppm) and 15 ppm, respectively) at 3000 gallons per minute (gpm) through an iron and copper specific filter system for a minimum of 24 hours. The filter proved ineffective in removing copper from the system. The cause of the filter not removing copper was attributed to the high percentage of copper that was soluble versus particulate. Following the dissolution step, condenser vacuum was established and hydrazine was added to the condensate hydrazine concentration to approximately 35 ppm. After this initial exposure to the reducing environment established by the condenser vacuum and hydrazine there was a large release of copper. Approximately 1500 gpm of feed water was diverted through portable demineralizers and the system cleaned up. In all approximately 5 pounds of copper was removed from the condensate and feed water systems.
2000	Prior to plant startup and initial operation with the replacement steam generators efforts were made to remove tramp copper that has deposited on plant piping during approximately 27 year of operation. Subsequent to these actions an optimized pH program was implemented that will benefit both the new steam generators, which have thermally treated alloy 600 tubes, and the all-ferrous material Secondary System.
2003	The plant output was uprated by 1.4% with virtually no change in operating temperatures.
2003	The steam generator inspection program adopted revision 6 of the EPRI PWR SG examination guidelines.
2004	On 6/23/04 IP2 received approval from the NRC of a license amendment to TS 5.5.7.b.1 for a one-time change to SG tube inspection interval. The change allows the next SG inspection, which was to 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.
2004	During 2R16 the plant output was uprated by 4.7% with virtually no change in operating temperatures. Note the demister pads in all the MSRs, which were a source of most of the loose parts in the SGs were replaced with chevrons as part of this uprate.
2007	On 2/13/07 the NRC issued Amendment No. 251 for IP2. The amendment consist of changes to the Technical Specifications (TSs) in response to Entergy application dated May 31, 2006, as supplemented by letter dated August 30, 2006. The amendment revises the TSs associated with steam generator (SG) tube integrity consistent with Revision 4 to TSTF Standard Technical Specification Change Document TSTF-449,"Steam Generator Tube Integrity."

2.3. Sludge Lance History

Sludge lancing has been performed on all four steam generators every refueling outage in which there was a primary inspection since replacement. The objective is to remove as much sludge as possible to minimize the potential for corrosion in the sludge pile. Historically, both the flow distribution baffle and the tubesheet in each steam generator have been sludge lanced. The number of passes made each outage is listed in the table below.

Number of Sludge Lance Passes[1] by Outage			
RFO	Year	Passes on flow distribution baffle (FDB)	Passes on tubesheet (TS)
15	2002	6	6
17	2006	2[2](SG23 & SG24)	9[3](SG21) 6(SG22, SG23 & SG24)

Notes: (1) The sludge lance equipment cannot go past the center of the steam generator because of the center stay rod. A sludge lance pass covers the area from the handhole to the center of the SG and a coverage is defined as completion of two passes.
(2) SG23 & SG24 only
(3) 9 passes on SG21 due to damming of scale and debris.

The amount of sludge removed each outage is quantified and the results are tabulated below. More detailed information is contained in the Westinghouse outage reports.

Historical Sludge Removal Data (pounds) by Outage						
RFO	Year	SG 21	SG 22	SG 23	SG 24	Total
15	2002	13	8	10	11	42
17	2006	27.5	24.5	18	25.5	95.5

Each outage, samples of the sludge from each steam generator are removed and analyzed for form and content. Detailed results are presented in the individual sludge analysis reports listed in the reference section. Of primary concern to IP2 is the amount of copper and iron present in the sludge so those results are tabulated below.

Percent of Iron Oxide in Sludge Removed from the SGs						
RFO	Year	SG 21	SG 22	SG 23	SG 24	Avg
15	2002	57.1	65.1	62.3	54.5	59.8
17	2006	tbd	tbd	tbd	tbd	tbd

Percent of Elemental Copper Removed from the SGs						
RFO	Year	SG 21	SG 22	SG 23	SG 24	Avg
15	2002	12	9.2	9.9	12.2	10.8
17	tbd	tbd	tbd	tbd	tbd	tbd

	RFO 15	RFO 17
Powder Magnetite (% Fe3O4))	69.2	tbd
Powder Copper (%)	27.5	tbd
Powder Copper Oxide (%)	3.7	tbd
Powder Lead (ppm)	320 ppm	tbd
Sludge Collar Magnetite (%)	NA	NA
Sludge Collar Copper (%)	NA	NA
Sludge Collar Lead (%)	NA	NA
Scale Magnetite (%)	NA	NA
Scale Copper (%)	NA	NA

Copper oxide has been shown to increase the risk of corrosion in steam generators. Prior to SG replacement all the copper bearing components in the secondary system were replaced with ferrous materials. Additionally, a copper cleaning was performed in an attempt to remove copper from feedwater piping with minimal success. Copper is expected in the steam generators in the outages following SG replacement with the source being the piping surfaces that were plated with copper from years of exposure to corrosion products from the copper bearing components. The copper concentration in the sludge is expected to drop with each succeeding outage.

Lead has been implicated as an initiator of stress corrosion cracking in alloy 600TT in the field. Analysis of lead in sludge samples is difficult and the results frequently suspect. Typically, lead levels in sludge are about 100 ppm. Based on industry experience, these levels are not considered detrimental to the steam generator tubing.

2.4. History of Tube Plugging and Tube Sleeving

During the manufacture of the steam generators, Westinghouse plugged two tubes at locations Row 25 - Column 12 and Row 26 - Column 13 in steam generator 24 due to manufacturing defects. Both ends of each of these tubes were plugged with a welded tube plug fabricated from Alloy 690 material that was given an additional special heat treat by Westinghouse to optimize the plug material microstructure. A total of 16 tubes were administratively plugged during the 2R15 inspection with Westinghouse (W) mechanical plugs fabricated from Alloy 690. A total 13 tubes were plugged due to AVB wear and 3 tubes were plugged due to volumetric indications. None of the tubes plugged met EPRI Rev. 5 criteria for requiring repair. No crack-like indications were reported. Reports (reference 37, 38, & 39) of the Steam Generator Examination Program Results conducted at IP2 during the 2002 and 2006 refuel outages (2R15 and 2R17), were submitted to the NRC pursuant to Technical Specification. The only degradation detected during 2R17 was Anti-Vibration Bar (AVB) wear. There were 55 AVB wear indications in 23 tubes. All of the indications were new. Entergy administratively plugged all 7 tubes found with AVB wear indications ≥ 20% TW (through wall). The deepest indication was 28% TW. No crack-like indications were found in 2R17.

Table of Historical Tube Plugging Information						
Year	**Outage**	**SG21**	**SG22**	**SG23**	**SG24**	**Total**

IPEC00243517

1988	Fabrication	0	0	0	2	2
2000	Pre-service	0	0	0	0	0
2002	2R15	8	1	3	4	16
2004	2R16	0	0	0	0	0
2006	2R17	2	2	0	3	7
Totals		10	3	3	9	25
Percent Plugged		0.31%	0.09%	0.09%	0.28%	0.19%

2.4.1. IP2 Plugging Limit

The steam generators are required to allow a minimum amount of reactor coolant flow through the tubing as well as provide a minimum amount of heat transfer capability. The tube plugging limit has been reduced from the original 25% to 10% for the 4.7% uprate condition, which has a significant beneficial effect on tube wall dryout potential. Additional information is available in Reference 3.

2.5. History of Tube Leakage / Tube Rupture Events

To date there have been no forced outages due to tube leakage or tube rupture in the replacement steam generators. In December 2001 an extremely low level of secondary system activity was detected. As discussed in detail in Reference 38, a very small tube end weld imperfection in 22SG is considered the most likely source of this activity. Although the activity only has an associated volume of approximately 0.01 gallons per day (well below industry guidelines for steam generator leakage concern), it will continue to be closely monitored, and has not changed since it was first detected. A combination of fuel leaker and condenser tightness lowers the sensitivity that one could measure leakage. During 2R15 and 2R17 a primary side visual inspection of 22SG tube seal welds found no anomalies.

During 2R16, CR-IP2-2004-05239 was written to document finding trace levels of short lived isotopes (~8 days) in 21 and 23 steam generators. On resample of 23 steam generator no measurable activity was found. Finding trace quantities is not totally unexpected as the unit operated with the associated volume of ~0.02GPD for the cycle. Chemistry resampled all generators to confirm initial sample results. This CR documents the new evidence that more strongly suggest the small amount of inleakage is in 21 SG, not 22 SG as previously imagined. No changes in our primary to secondary leak rate program are needed, as there are adequate measures to increase monitoring should leak rate increase (per EPRI guidelines).

2.6. Chemistry Transients

Chemistry transients can impact corrosion of the steam generator materials and should be evaluated to determine if compensating actions should be taken. Transients greater than action level 2 are considered significant enough for evaluation. There have not been any action level 2 or 3 chemistry transients since SG replacement. During startup following 2R16 there was a chemistry transient of sodium due to the silica used to clean impurities in the MSRs, however action level 1 was not exceeded.

2.7. Summary of In-situ Pressure Test Results.

No in-situ pressure tests of steam generator tubing have been performed since the replacement steam generators were installed. Any required in-situ pressure tests would be performed in accordance with the

latest revision of EPRI Guidelines (EPRI TR-107620) "Steam Generator In-Situ Pressure Test Guidelines, and any Steam Generator Manage Project (SGMP) Interim Guidance.

2.8. Summary of Pulled Tube Test Results

No tubes have been pulled from the replacement steam generators.

2.9. Steam Generator Thermal Performance Monitoring

IP2 has a thermal performance monitoring program in place for the steam generators. The thermal performance of the steam generators is monitored on a weekly basis and there has been no loss of thermal performance since the steam generators were replaced in 2000.

2.10. Steam Generator Secondary Side In-Bundle Inspection

A secondary-side in-bundle remote video inspection was performed on all 4 steam generators during 2R15 and 2R17. Several inspections are performed after sludge lancing. The first is a cleanliness inspection to verify the adequacy of the sludge lancing. The second is a search for foreign objects that could detrimentally impact the operation of the steam generators. This inspection covers the annulus, tube lane and approximately 20% of columns in-bundle. Best efforts are made for retrieval on all foreign objects that could potentially affect tube integrity. Objects/loose parts found but remaining in the SGs were justified historically with a safety evaluation and more recently with Condition Reports (CR's) and engineering documents if the Nuclear Safety Evaluation (NSE) (reference 52) bound them.

Additional inspections are performed as needed on selected steam generators. A visual inspection of the Top Support Plate ("G" plate) was performed in 23 & 24 SGs in 2R17 including: the underside of the tube U-bends; the top of the plate the full length of the tube lane; and the length of 11 columns on both hot and cold legs from the tube lane to the wrapper The purpose of this inspection was to look for fouling of the broach holes and SG tubing. Another inspection is done at the top support plate. This inspection looks at the top of this support plate, the underside of the U-bends, ligament cracking and a sampling of the tubes in-bundle. These extensive inspections are performed to look for some of the corrosion product precursors to tube degradation and to get a feeling for the condition of the OD of the tubes. Copies of the videotape reports from previous in-bundle visual inspections are maintained by engineering programs.

2.11. Steam Generator Secondary Side Upper Internals Inspection

Inspections may be performed on the upper internals portion of all four steam generators in future outages. These inspections will be performed to meet the recommendation contained in the steam generator owners manual (reference 59) and because industry experience in the areas of erosion, corrosion, tube denting, sludge deposition, and loose parts monitoring have emphasized the prudence of visual inspection of steam generator internals as a means of preventive maintenance to preclude lost time due to failures. The equipment to be examined consists of the major internal components contained in the upper internals portion of the steam generator. Those components are the primary separators, the secondary separators, the feedring and the feedring J-nozzles. The steam drum inspection was deferred in 2R15 and will be performed in 2R19 as per CR-IP2-2002-10621.

3. Steam Generator Performance Criteria

The steam generator performance criteria described below identify the standards against which performance is to be measured. Meeting the performance criteria provides reasonable assurance that the steam generator tubing remains capable of fulfilling its specific safety function of maintaining reactor coolant pressure

boundary (RCPB) integrity. Performance criteria used for steam generators shall be based on tube structural integrity, accident induced leakage, and operational leakage as defined below.

3.1. Structural Integrity Performance Criterion

The structural integrity performance criterion is the following:

> **All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.** (TS 5.5.7)

The structural performance criterion is based on ensuring that there is reasonable assurance that a steam generator tube will not rupture during normal or postulated accident conditions. The tube integrity at IP2 is determined in accordance with the EPRI Steam Generator Tube Integrity Assessment Guideline and any SGMP interim guidance in effect.

3.2. Accident-Induced Leakage Performance Criterion

The accident-induced leakage performance criterion is the following:

> **The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 150 gpd per SG. (TS 5.5.7)**

3.3. Operational Leakage Performance Criterion

The operational leakage performance criterion is the following:

> **The RCS operational primary to secondary leakage through any one steam generator (SG) shall be limited to 150 gallons per day. (TS 3.4.13)**

IP2 technical specifications limit is the same as the NEI 97-06 performance criterion. With any steam generator leakage greater than this limit the reactor shall be brought to hot shutdown within 6 hours, and cold shutdown within 36 hours. The primary-to-secondary leakage limit referred to in the performance criterion is 150 gallons per day (GPD) at room temperature conditions from any one steam generator (NEI 97-06). The EPRI Primary to Secondary Leak Guidelines require a plant to enter Mode 3 (hot shutdown) within certain timeframes if a leak equals or exceeds 75 GPD in a single steam generator depending on nature of the leak. The IP2 Operations procedures have adopted the most conservative guideline shutdown period of 3 hours should a leak equal or exceed 75 GPD to simplify operator actions.

During a DBA, the leak rate may increase above what was present during normal operation. Therefore, it may be necessary to ensure that the operational leak rate is kept below its limit in order to meet the accident limit. An increase in leakage during a DBA can be a result of either: (1) the higher differential pressure between the primary coolant system and the secondary system associated with a DBA thus causing the leak rate from flaws that leak during normal operation to leak at higher rates; or (2) the higher stress loadings associated with a DBA causing a flaw that was not leaking during normal operation to leak during the DBA.

IP2 will administratively limit the amount of primary-to-secondary leakage to 75 gpd. This administrative limit is intended to provide margin between the operating and accident induced leakage limit consistent with TSTF-449. The NRC staff notes that although there may be margin between these limits, the staff's approval of TSTF-449 (and this amendment) was not intended to ensure that satisfying the operating leakage limit would result in the accident induced leakage limit being met. Rather, the NRC staff reviewed the adequacy of the proposed TS criteria for operational and accident-induced leakage based on the technical basis associated with each limit. Namely, that the operating leakage limit is effective at limiting the frequency of tube ruptures and the accident induced leakage limit is consistent with the plant's design and licensing basis. Since the TS criteria on operational leakage at IP2 is consistent with TSTF-449 and the accident-induced leakage limit is consistent with the licensee's accident analysis, the NRC staff finds the licensee's proposed TS criteria on these values acceptable.

4. Steam Generator Program

4.1. Assessment of Potential Degradation Mechanisms

Entergy Nuclear Northeast prepares a steam generator degradation assessment prior to each scheduled steam generator inspection as required by NEI 97-06. The purpose of this assessment is to identify both existing and potential degradation mechanisms, identify inspection techniques for those mechanisms, establish the number of tubes to be inspected, establish the structural limits for the tubing flaws and establish flaw growth rates. More details on the performance of this assessment and the results of the most current assessment are provided in Reference 47.

4.2. Steam Generator Tubing Inspection

Following the preparation of a degradation assessment, an inspection plan is prepared in accordance with the latest applicable revision of the EPRI PWR Steam Generator Examination Guidelines and any SGMP interim guidance in effect. This inspection plan also takes into account the requirements of plant technical specifications (TS). A summary of the 2R17 Steam Generator examination program is presented in Attachment 6 of this report. The most recent inspection plan is documented in Reference 48.

4.3. Tube Integrity Assessment

After each steam generator inspection, Entergy Nuclear Northeast prepares an assessment of the steam generator tubing integrity. This is a two-part assessment that ensures the performance criteria have been met for the pervious operating period (condition monitoring) and will continue to be met for the next period (operational assessment). A preliminary assessment is performed prior to closeout of the steam generators and the final assessment must be completed within 90 days after startup. More details on the performance of this assessment are provided in Reference 48.

4.3.1. Repair Limits

The Indian Point 2 Technical Specifications specifies a tube repair limit of 40% through-wall (TW). Any tube degradation greater than 40% TW must be plugged or repaired. Any degradation that cannot be sized must also be plugged or repaired.

As part of the Appendix K power uprate of 1.4%, and the 4.7% Stretch Power Uprate (SPU) the structural limits for the steam generator tubing were calculated in accordance with draft regulatory guide 1.121. The results are documented in WCAP-15909. The table below summarizes the RSG tube structural limits.

Structural Limits for IP2 Replacement Steam Generators

Location / Wear Scar Length	Minimum Wall Thickness (inch)	Structural Limit (%)
Straight Leg	0.024	52.0
Anti-Vibration Bar / 0.5" (tubes rows 14-45)	0.016	67.8
Anti-Vibration Bar / 0.75" (tube rows 1-13)	0.020	61.0
Flow Distribution Baffle / 0.75"	0.020	61.0
Tube Support Plate / 1.125"	0.022	55.2

(1) Structural Limit = $[(t_{nom} - t_{min})/t_{nom}] \times 100\%$ where $t_{nom} = 0.050$ inches

(2) The tube structural limits and minimum thickness specified for AVB applies only for rows 14 and higher. For tube/AVB intersections for tube rows 1 to 13, the structural limits and minimum thickness for the FDB locations are to be used.

4.4. Maintenance and Repairs

Prior to any repairs on steam generator tubing, IP2 must qualify and implement the repair method in accordance with industry standards. After a repair is made a baseline inspection of the repair must be performed in accordance with the latest revision of the EPRI PWR Steam Generator Examination Guidelines and any SGMP interim guidance in effect. Additional guidance is also available in the EPRI PWR Steam Generator Tube Plug Assessment Document and the EPRI PWR Sleeving Assessment Document.

4.5. Primary-to-Secondary Leakage Monitoring

Primary-to-secondary leak monitoring is conducted in accordance with IP2 procedures 2-AOP-SG-1 and IPC-A-110-S. These procedures follow the guidance contained in revision 3 of the EPRI PWR Primary-to-Secondary Leak Guidelines. A plant shutdown is procedurally required when leakage exceeds 75 gallons per day (GPD). This limit is more conservative than the EPRI guidelines so that operators do not have to monitor the rate of change in observable leakage.

4.6. Secondary Side Water Chemistry

The IP2 chemistry department is responsible for the secondary-side water chemistry program at IP2. Procedures have been established for monitoring and controlling secondary-side water chemistry that follow the guidance contained in the EPRI PWR Secondary Water Chemistry Guidelines. IP2 chemistry has also developed a site-specific secondary chemistry optimization plan that is documented in report Secondary Strategic Water Chemistry Plan, Rev 0, June 2006 DOC ID SSWCPR00 (reference 36). These plans are reviewed each cycle, and when the EPRI PWR Secondary Water Chemistry Guidelines are revised any deviations are noted. The upper tier chemistry procedure at IP2 is CH-SQ-13.018, "Chemistry Program for Sampling, Analysis and Control of Secondary Systems" (reference 32). EN-CY-101, "Chemistry

Activities" (reference 29) is the upper tier fleetwide Entergy chemistry procedure that references the commitment to NEI-97-06 for compliance with the chemistry guidelines both primary and secondary.

4.7. Primary Side Water Chemistry

The IPEC chemistry department is responsible for the primary-side water chemistry program at IP2. Procedures have been established for monitoring and controlling primary-side water chemistry that follow the guidance contained in the EPRI PWR Primary Water Chemistry Guidelines. IP2 chemistry has also developed a site-specific primary chemistry optimization plan that is documented in report Strategic Primary Strategic Water Chemistry Plan, Rev 0, June 2006 DOC ID PSWCPR00 (reference 32). These plans are reviewed each cycle, and when the EPRI PWR Primary Water Chemistry Guidelines are revised any deviations are noted in the above Strategic Plan. The upper tier chemistry procedure at IP2 is CH-SQ-13.017, "Chemistry Program for Sampling, Analysis and Control of the Reactor Coolant System" (reference 33).

4.8. Foreign Material Exclusion

4.8.1. Secondary-Side Visual Inspections

Since steam generator replacement in 2000, IP2 has conducted foreign object search and retrieval (FOSAR) inspections during 2R15 and 2R17 which included all four SGs. The FOSAR inspection is controlled under Specification MM-02-104, "Visual Inspection of Steam Generators". This inspection is performed after sludge lance operations (if performed) and encompasses a visual inspection at the tube sheet level around the annulus of the steam generator.

Another inspection that is performed in all four SGs is a visual in-bundle at the tubesheet level approximately every 5th column of both the hot and cold legs. The purpose of this inspection is to monitor for the buildup of sludge not removed by sludge lancing. Typically in two SGs a support plate inspection is performed. In this inspection a camera is inserted in the SG handhole and sent up through a flow slot. The tool used is called the support plate inspection device or SID. The tops and bottoms of the support plates are inspected for sludge buildup on the tubes, on the tube support plates (TSP) and in the quatrefoil openings of the TSPs. The two SGs are rotated each outage for this inspection.
The top of the uppermost support plate cannot be inspected using SID so the top support plate in two SGs is inspected from the three inch inspection port located just above the TSP. This inspection looks at sludge buildup on the support plate and on the underside of the tubing at the U-bend. In addition, the camera probe is sent in-bundle at selected locations to look at the weld attachments of the wrapper to the TSP and to look for ligament cracking. The SGs inspected are rotated each outage.

The Westinghouse Technical Manual (reference 59) recommends a thorough inspection of each steam generator upper internals during the second and fifth years of operations. Subsequently, a detailed visual inspection should be performed at least once every five (5) years. The purpose of this inspection is to look for degradation that might affect the integrity of the SG tubing or impact the overall operation of the SG. This inspection is performed by personnel entering the steam drum area with camera equipment to look at components such as the J-nozzles, feed ring, primary and secondary separators. Based on the engineering judgment the steam drum inspection planned for 2R15 (CR-IP2-2002-10621) was deferred to 2R19.

4.9. Control and Monitoring of Foreign Objects and Loose Parts

Station procedure IP-SMM-MA-118 provides the requirements for foreign material control during maintenance activities at IP2. In general, retrieval is attempted on all foreign objects identified during SG inspections unless the objects are considered so small that they do not challenge the integrity of the tubing. Any loose parts left in the SG are evaluated to support plant operation with parts remaining. A listing of the

loose parts left in the replacement SGs is provided in Attachment 5. During plant operations, the steam generators are monitored for loose parts via the digital metal impact monitoring system (DMIMS). Any alarms from this system should be evaluated to determine if any special inspections should be performed when the steam generator is opened for maintenance.

4.10. Maintenance of Steam Generator Secondary-Side Integrity

Routine preventative maintenance of the steam generator secondary-side is essential for maximizing the operating life of the steam generators. Sludge accumulation can increase the risk of tubing corrosion. To that end, IP2 performs periodic maintenance of secondary side to remove sludge. Secondary-side steam generator components may have the capability to prevent the steam generator from fulfilling its intended safety-related function. The degradation assessment discussed in Reference 47 addresses potential secondary-side degradation that could affect the safety-related function of the steam generator and the appropriate inspections that should be performed. Currently, the only actions that need to be taken are to visually look for a drop in the wrapper if any hand hole covers are removed.

4.11. Self-Assessment

Entergy Nuclear Northeast is required to perform a periodic self-assessment of the steam generator program by NEI 97-06. The assessment must address all the program elements listed in sections 4.1 thru 4.8 above. The self-assessment should be performed in accordance with ENN-LI-104. The self-assessment must be performed by qualified personnel and may include industry peers. The latest self-assessment (LO-WPOLO-2004-00044) was performed by INPO Sept. 21-23, 2004 and is documented in Reference 57. Note that an INPO SG Review Visit can be credited as a self-assessment in accordance with NEI-97-06.

5. Reports to the NRC

Several reports associated with the steam generators are required to be filed with the NRC. In addition to IP2 Technical Specification reporting requirements, the following reports are required by NEI 97-06 and TS. Reports are also prepared in accordance with ASME Section XI.

Condition	Reports Required
Completion of an inspection performed in accordance with the Specification 5.5.7, Steam Generator (SG) Program.	A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection.
Failure to meet a performance criterion discovered during condition monitoring.	Submit an Operational Assessment establishing the basis for the next operating cycle. Assess to determine if a serious degradation of a safety barrier has occurred, if so, it is considered a reportable event – notify the NRC in accordance with the requirements of 50.72 and 50.73
Failure to implement a required plugging or repair discovered while operating.	Submit an Operational Assessment establishing the basis for the next operating cycle. Notify the NRC in accordance with the requirements of 50.72 and 50.73.

6. Summary of Results

This report provides a summary of the Indian Point 2 steam generator program following refueling outage (2R17) steam generator NDE inspection. The next inspection is planned for 2R19 in 2010, which is at the completion of two fuel cycles.

The most recent inspection, 2R17 occurred at the end of the third fuel cycle after the original steam generators were replaced; all four steam generators were inspected. A Condition Monitoring assessment was performed, on a defect specific basis, by demonstrating compliance with integrity criteria through a comparison of 2R17 NDE measurements with calculated burst and leakage integrity limits. Calculated integrity limits, including consideration for appropriate uncertainties, burst and leak analytical correlations, material properties, and NDE technique and analyst uncertainties were provided in the 2R17 degradation assessment report (Reference 47). All indications in this inspection were below the calculated integrity limits and therefore met integrity requirements without further testing. Based on the inspection results, all four steam generators were found in compliance with Condition Monitoring requirements provided in Reference 5 and 12.

An Operational Assessment for assumed operation duration of 4.0 EFPY for Cycle 17 and 18 confirms that the steam generator tube structural and leakage integrity will be maintained until the next planned steam generator inspection. The Indian Point 2 Steam Generator Program is in accordance with Nuclear

Energy Institute, Steam Generator Program Guidelines, NEI 97-06, (Rev.1, January 2001) and PWR Steam Generator Examination Guidelines, EPRI Report 1003138 (Rev. 6, October 2002).

7. Conclusions

The Indian Point 2 (IP2) steam generator program maintains the steam generators in optimal condition to assure their continued operation until the end of plant life and to support plant life extension. The program formalizes and integrates the various inspections, maintenance, chemistry and operational activities performed on the steam generators and provides the basis for making strategic decisions to optimize steam generator reliability and performance.

8. Recommendation

Westinghouse recommended installation of a cable dampener in tubes SG21-R45C45 and SG23-R41C46 during 2R15, but noted that the installation of the dampener was optional at that time. The criterion that is used by Westinghouse for stabilization recommendations is prevention of tube-to-tube contact. The potential for tube-to-tube contact from AVB wear was not expected to occur at IP2 during the next two operating cycles. The refuel outage in which the identified tubes would be stabilized was tracked in CR-IP2-2002-10501.

The conclusions from the "Analysis to Determine the Maximum Operating Time Before Stabilization of Previously Plugged Tubes is Required For Indian Point Unit 2", IP-RPT-06-00073, Revision 0 (Ref 51) performed to evaluate the need for, and timing of, stabilization of tubes currently plugged for AVB wear is as follows:

1. The operating time to reach the fatigue endurance limit presuming progressive wear is very long, on the order of 50 calendar years from 2R15. There are uncertainties inherent to the analysis, such as the potential for redistribution of wear, changing boundary conditions, etc. that may affect the predicted time to reach the critical wear time for the tubes. It is not anticipated that the wear will be more rapid than the condition analyzed, i.e. wear progressing at a single AVB intersection.

2. For all tubes considered (shortest and longest rows observed with wear at 2R15), the wear is predicted to progress very slowly. At the time that the worn tubes are predicted reach their critical section for fatigue separation (time is about 50 years), the wear is insufficient to result in contact with the adjacent tubes. Therefore, the original criterion utilized for a stabilization recommendation will not be achieved, and wear of the adjacent tubes is not an issue.

3. The new wear observed during 2R17 is bounded by the analysis for the previously observed wear; thus all conclusions apply to the newly observed wear also.

4. Since wear of adjacent, active tubes has been eliminated as a concern for the currently plugged tubes and tubes with newly reported wear, plugging of the adjacent tubes is not considered necessary at this time.

5. Inspection of tubes adjacent to tubes plugged for AVB wear should be performed at each inspection as a conservative measure to verify that contact with the plugged tube has not been achieved.

6. A follow-on effort should be completed to assess the wear progression of active tubes adjacent to currently plugged tubes, assuming that tube-to-tube contact occurs, notwithstanding the results of the current conservative analysis. The follow-on effort is scheduled for 2007 and is required for SG operation beyond 2R18 without inspection.

9. References

9.1. Regulatory Documents

3. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1983 Edition, Summer 1983 addenda

4. Indian Point 2 Technical Specifications, Section 5.5.7

5. Indian Point 2 Updated Final Safety Analysis Report (UFSAR), Chapter 14.2

6. 10CFR Part 50 Appendix A, General Design Criteria for Nuclear Power Plants, and Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.

7. 10CFR § 50.65, Maintenance Rule

8. 10CFR § 50.72, Immediate Notification Requirements for Operating Nuclear Power Reactors, and § 50.73, Licensee Event Report System

9.2. Industry Guidelines

9. Nuclear Energy Institute, Steam Generator Program Guidelines, NEI 97-06, Revision 2, May 2005

10. PWR Steam Generator Examination Guidelines, EPRI Report TR-107569 (Rev. 6, October 2002) and SGMP Interim Guidance Letters dated 4/22/2003 and 3/16/2004.

11. PWR Primary-to-Secondary Leak Guidelines, EPRI Report TR-1008219 (Rev.3, December 2004)

12. PWR Secondary Water Chemistry Guidelines, EPRI Report 1008224 (Rev. 6, December 2004)

13. PWR Primary Water Chemistry Guidelines, EPRI Report TR-1002884 (Rev. 5, October 2003)

14. Steam Generator Integrity Assessment Guidelines, EPRI Report 1012987, (Rev 2, July 2006)

15. Steam Generator In Situ Pressure Testing Guidelines, EPRI Report TR-1007904 (Rev. 2, August 2003) and SGMP Interim Guidance Letter dated 5/11/2004.

16. PWR Steam Generator Tube Plug Assessment Document, TR-109495 (Rev. 0, December 1997)

17. EPRI PWR Sleeving Assessment Document TR-105962, (Rev 0, December 1995)

18. "SGMP-IG-07-01, Interim Guidance Regarding EPRI Steam Generator Integrity Assessment Guidelines, Revision 2, 1012987, July 2006" transmittal letter dated April 23, 2007

19. "SGMP-IG-06-02, Interim Guidance Regarding Minimum Feedwater Hydrazine Concentration for Plants with Once-Through Steam Generators (RE: PWR Secondary Water Chemistry Guidelines - Revision 6, TR-1008224)", transmittal letter dated October 27, 2006

20. "SGMP-IG-06-01,lnterim Guidance to the Steam Generator Degradation Specific Management Flaw Handbook", transmittal letter dated October 18, 2006

21. "SGMP-IG-05-03, Interim Guidance on Identification of 'Mandatory', 'Shall' and 'Recommended' Elements for Revision 5 of the EPRI PWR Primary Water Chemistry Guidelines (1002884)", transmittal letter dated October 18, 2005

22. "SGMP-IG-05-02, NEI 97-06 Revision 2, 'Steam Generator Program Guidelines'", transmittal letter dated October 10, 2005

23. "Interim Guidance on EPRI Steam Generator In Situ Pressure Test Guidelines, Revision 2, Chapter 10", transmittal letter dated May 11, 2004

24. "Steam Generator Management Program (SGMP) Interim Guidance for EPRI Steam Generator Examination Guidelines, revision 6 Sections 6.2.4, 6.3.3.3, 6.5 and Appendix H Supplements H1 and H2", transmittal letter dated March 16, 2004

25. "Interim Guidance on Steam Generator Tube Leak at Comanche Peak Unit 1", transmittal letter dated April 22, 2003

26. Westinghouse Nuclear Services Division, "Steam Generator Secondary Side Maintenance Guidelines, July 1998

9.3. Entergy Nuclear Procedures & Reports

27. Inservice Inspection / Test Program, IP-SMM-DC-906, (IP Site Management Manual Procedure)

28. Self Assessment and Benchmark Process, EN-LI-104, (Entergy Nuclear Management Manual Procedure)

29. Chemistry Activities, EN-CY-101, (Entergy Nuclear Management Manual Procedure)

30. Entergy Steam Generator Administrative Procedure, EN-DC-317, (Entergy Nuclear Management Manual Procedure)

31. Foreign Material Exclusion and Control, IP-SMM-MA-118, (IP Site Management Manual Procedure)

32. Chemistry Program for Sampling, Analysis and Control of Secondary Systems, CH-SQ-13.018, (IP2 Chemistry Procedure)

33. Chemistry Program for Sampling, Analysis and Control of the Reactor Coolant System, CH-SQ-13.017, (IP2 Chemistry Procedure)

34. Primary to Secondary Leak Rate, IPC-A-110-S, (IP2 Chemistry Procedure)

35. Steam Generator Tube Leak, 2-AOP-SG-1, (IP2 Operations Procedure)

36. Secondary Strategic Water Chemistry Plan, Rev 0, June 2006 DOC ID SSWCPR00

37. Primary Strategic Water Chemistry Plan, Rev 0, June 2006 DOC ID PSWCPR00

38. Entergy Northeast Report, " Investigation of Low Level Radioactivity at the Steam Jet Air Ejector", February 7, 2002

39. Steam Generator Inservice Examination Program Results 2002 Refueling Outage (2R15), NL-02-161

40. Entergy letter NL-06-067 to NRC dated June 14, 2006; "Steam Generator Examination Program Results, 2006 Refueling Outage (2R17)."

41. Entergy Letter NL-06-116 to NRC dated November 16, 2005; "Reply to Request for Additional Information Regarding Steam Generator Examination Results for 2006 Refueling Outage"

9.4. Reports

42. Westinghouse Nuclear Services Division, "Evaluation of EDF Steam Generator Internals

Degradation – Impact of Casual Factors On the Westinghouse Models F, 44F, D and E2 Steam Generators", Revision 1, December 1998, WCAP-15093

43. Westinghouse Nuclear Projects Division, "Series 44F Steam Generator Study Prepared for Westinghouse Owners Group (WOG)", Revision 0, June 1998, Entergy Nuclear Northeast report number WNEP-9806

9.5. Degradation, Condition Monitoring & Operational Assessments

44. Entergy Nuclear Northeast, "Operational Assessment of IP2 Steam Generator Tubing for Cycle 15", July 30, 2002

45. Westinghouse Electric Company, "Steam Generator Degradation Assessment for Indian Point Unit 2 RFO-15", Report Number SG-SGDA-02-29, October 2002

46. Westinghouse Electric Company, "Indian Point 2 Condition Monitoring Assessment and Operational Assessment RFO-15", Report number SG-SGDA-02-45, January 2003

47. Steam Generator Pre-Outage Degradation Assessment and Repair Criteria for 2R17 ER-IP2-05-20801, IP-RPT-05-00408

48. Condition Monitoring and Operational Assessment of Indian Point 2 Steam Generator Tubing for Cycles 18 and 19, IP-RPT-06-00055

9.6. Chemistry and Sludge Related Reports / Memos

49. Evaluation of Westinghouse Chemical Analysis of the Indian Point 2R15 Steam Generator Deposits, LTR-CDME-03-175, November 2003

9.7. Inspection / Outage Reports

50. Westinghouse Steam Generator Primary Services, "Field Service Report MRS-FSR-1194-IPP for Indian Point Unit 2 – RO15, October 29, 2002 – November 18, 2002

51. R. Brooks Associates, Inc., "Brooks Field Service Report" (R15), October 31, 2002 – November 15, 2002 R. Brooks work order number J02-187, no Entergy Nuclear Northeast report number

9.8. Nuclear Safety Evaluations

52. Entergy Nuclear Northeast, "Evaluation of Foreign Objects in the SGs at IP2 RFO15", 02-0528-PR-00-RS, Revision 0, November 15, 2002

53. Entergy Nuclear Northeast, "Stabilization Recommendations to Address IP2 AVB Wear", 02-0532-MM-00-AD, Revision 0, November 18, 2002

54. NRC letter to Michael R. Kansler dated 6/23/04, "Indian Point Nuclear Generating Unit No. 2 – Amendment Re: One-Time Change to Steam Generator Tube Inspection Interval" (TAC No. MC1260)

9.9. Audit / Self-Assessment Reports

55. Entergy Nuclear Northeast, CR 20002049, October 26, 2001, Subject: Steam Generator Programs Assessment Plan

56. Entergy Nuclear Northeast, IP2 Nuclear Quality Assurance Independent Oversight Program, Assessment Plan Number 02-AP-29-EN, September 20, 2002, Subject: Steam Generator Program / Outage Preparation Tubing

57. INPO Letter to Chris Schwarz dated Oct. 28, 2004, "Results of INPO's Steam Generator Review

Visit at IPEC during Sept. 21-23, 2004".

9.10. Miscellaneous Steam Generator Related Reports

58. Steam Generator Progress Report Revision 15, EPRI, December 2000, Report #1000805.

59. Westinghouse Technical Manual Vertical Steam Generator for IP2, TM-1440-C348

60. Westinghouse, "Regulatory Guide 1.121 Analysis for the Indian Point 2 Model 44F Replacement Steam Generators", WCAP-15909, December 2003

61. Analysis to Determine the Maximum Operating Time Before Stabilization of Previously Plugged Tubes is Required For Indian Point Unit 2, IP-RPT-06-00073, Revision 0.

Attachment 1: List of Definitions

The following definitions are provided to ensure a uniform understanding of terms used in this Report.

Accident Induced Leakage: Primary-to-secondary leakage that occurs in a faulted steam generator as a result of a limiting accident.

Burst: the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.

Condition Monitoring: A comparison of the as-found inspection results against the performance criteria for structural integrity and accident leakage. Condition monitoring assessment is performed at the conclusion of each operating cycle.

Degradation-Specific Repair Criteria: Repair criteria developed for a specific degradation mechanism and/or location, e.g., a degradation specific repair criteria for ODSCC at tube support plates or for PWSCC at the tube sheet expansion.

Deterministic Approach: An approach that is based on the deterministic addition of parameter values to determine a limit.

Faulted: The state of the steam generator in which the secondary side has been depressurized due to a main steam line break such that protective system response such as main steam line isolation, reactor trip, safety injection, etc., has occurred.

Limiting Design Basis Accident: In the context of steam generator primary-to-secondary pressure boundary integrity, it is the accident that results in either the largest differential pressure across the steam generator tubes for structural considerations or the minimum margin to the applicable dose limits for accident leakage considerations.

Operational Assessment: Forward looking prediction of the steam generator tube conditions that is used to ensure that the structural integrity and accident leakage performance criteria will not be exceeded during the next cycle. The operational assessment needs to consider factors such as NDE uncertainty, indication growth, and degradation-specific repair limits.

Performance Criteria: Criteria to provide reasonable assurance that the steam generator tubing has adequate structural and leakage integrity such that it remains capable of sustaining the conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena.

Probabilistic Approach: An approach that uses probabilistic simulations, e.g., Monte Carlo simulations, to determine appropriate limits.

Probability of Burst (POB): The probability of burst of a steam generator tube if a limiting accident occurs.

Probability of Detection (POD): The probability of detecting a flaw during a steam generator inspection.

Repair Limit: An NDE parameter value at which steam generator tube repair is required. The repair limit will be determined by either subtracting margins for NDE uncertainty and growth from the structural limit or by conducting a probabilistic analysis.

Normal Makeup Capacity: The ability of the makeup system to maintain reactor coolant system inventory without the manual or automatic actuation of engineered safeguards features, e.g., safety injection. Manual starting of redundant or standby pumps may be credited as normal makeup capacity if the additional pumps are provided for in plant procedures.

Steam Generator Degradation-Specific Management (SGDSM): The use of inspection and/or repair criteria developed for a specific degradation mechanism, e.g., outside diameter stress corrosion cracking at tube support plates.

Steam Generator Tube Rupture (SGTR): A tube rupture or burst is a gross failure of the tube such that the formation of a primary-to-secondary opening with an area affiliated to that of a double-ended guillotine break occurs. For burst testing of limited length axial cracks, approximately two inches or less in length, the phenomenon requires extension of the crack tips. In most situations, extension of the degradation is necessary to achieve the level of opening needed.

Attachment 2: List of Acronyms

ARC .... Alternative Repair Criteria

ASME .... American Society of Mechanical Engineers

AVT .... All Volatile Treatment

CFR........... Code of Federal Regulations

EOC .... End of Cycle

EPRI.......... Electric Power Research Institute

GDC .... General Design Criteria

GPD .... Gallons Per Day

INPO .... Institute of Nuclear Power Operations

ISI............. In-service Inspection

MSLB........ Main Steam Line Break

MSLB-SGTR .... Main Steam Line Break-Steam Generator Tube Rupture

NDE .... Non-Destructive Examination

NEI .... Nuclear Energy Institute

NRC .... Nuclear Regulatory Commission

NSSS .... Nuclear Steam Supply System

ODSCC ..... Outer Diameter Stress Corrosion Cracking

POB........... Probability of Burst

POD .... Probability of Detection

PWR.......... Pressurized Water Reactor

PWSCC..... Pressurized Water Stress Corrosion Cracking

RCPB .... Reactor Coolant Pressure Boundary

SF .... Safety Factors

SG .... Steam Generator

SGDSM..... Steam Generator Degradation Specific Management

SGMP........ Steam Generator Management Project

SGTR .... Steam Generator Tube Rupture

SL.............. Structural Limit

SLB .... Steam Line Break

TR .... Technical Report

TSP............ Tube Support Plate

Attachment 3: SG Examination Program Results 2R15

1.0 Examination Program Description

Details of the Indian Point Unit 2 steam generator tube inservice examination program to be conducted during the fifteenth refueling outage were submitted to the NRC via Entergy Nuclear Operations, Inc (ENO) letter dated August 21, 2002. The original examination scope is described in Section 2 below. This original scope was subsequently expanded during the outage, to include 27% of periphery tubes in the hot leg inspection. This change was primarily due to finding two (2) confirmed loose parts with Rotating Pancake Coil (RPC) at the top of tubesheet (TTS) hot leg. The results and conclusions of the full examination scope are provided in Sections 3 and 4 respectively.

2.0 Examination Scope

a. <u>Steam Generator Tube Eddy Current Examination</u>

The Indian Point Unit 2 Fall 2002 steam generator eddy current inspection was the first inservice inspection for the replacement steam generators, which were installed in December of 2000. All bobbin full length tests, TTS RPC, low row U-bend RPC, and hot leg special interest tests were collected on the hot legs first, and then the robots were moved to the cold legs to finish the straight section bobbin and special interest tests on the cold legs.

The planned inspection programs consisted of the following:

- Full-length bobbin coil test of 100% of the open tubes in all four steam generators, except for the U-bend sections of rows 1 and 2, which were tested with the rotating plus point coil.
- 3-Coil Rotating Probe inspection of approximately 26-27% (20% random plus all peripheral tubes) of the Top of Tubesheet (TTS) intersections in the Hot Leg of each SG. The extent of each TTS exam was -3" to +3" as a minimum.
- 100% row 1, and 2 U-bends were inspected with a mid-range +Point coil. Both primary and secondary analysts monitored noise values at the apex of each U-bend and were reviewed by lead analyst.
- 100% of dings and dents $\geq$ 5.0 volts from bobbin were inspected with +Pt RPC.

Additionally, a series of special interest +Point MRPC exams were planned, which included all "I" codes, and other codes of interest from the bobbin exam.

Additional testing (scope expansion) included the following:

- There were a total of 991 RPC special interest tests of bobbin signals. The actual number of bobbin "I" codes tested was 1074 (some tests covered multiple "I" code signals). An "I" code from bobbin was reported when either the signal was not present in the baseline or had changed from baseline history. The large number of signals that changed from history was due to the fact that this was the first operating cycle of the generators; therefore, the first time heat was applied to the tubes. Steam generators with thermal treated I600 tubing throughout

the industry are well known to contain many benign signals which change rapidly after the first cycle and not as much in subsequent cycles, so the large number of RPC tests which needed to be performed, was not unexpected.

- A total of 51 tubes were RPC tested at the top of tube sheet to bound all tubes with Possible Loose Parts.

- Due to finding two (2) confirmed loose parts with RPC at the top of tubesheet hot leg, ENO added all peripheral tubes on the cold leg side to the RPC top of tube sheet inspection program. This was a total of 1080 tubes.

b. Secondary Side Examination

The steam generator secondary side examination plan assesses steam generator internals, both in-bundle and steam drum, and top of tubesheet regions. Visual inspection is utilized to assess the presence of loose parts or other steam generator secondary side component conditions that could affect the structural integrity of the primary boundary and leak tightness.

The secondary side inspection incorporated sludge lancing and foreign object search and retrieval (FOSAR). In-bundle inspection was performed in approximately every fifth column. The upper bundle inspection was performed by looking up from the bottom on all four steam generators. Also for one steam generator, the inspection port located above the top support plate was removed, and an inspection looking downward was performed.

c. Steam Generator Sludge

The sludge removed from the steam generator tubesheets during 2R15 by lancing operations is being analyzed.

3.0 2002 Examination Results

a. Steam Generator Tube Eddy Current Examination

Inspection Results- Overall Summary

Anti vibration bar (AVB) wear was reported during the 2R15 inspection. Thirteen tubes contained AVB wear indications $\geq$ 9% with the highest percentage wear measured at 20% in 3 locations over 2 tubes.

3 Volumetric (VOL) indications were found in the free span of the tubes and measured using the EPRI qualified sizing technique #21998.1 for the Plus Point Probe. None measured >19%. It is theorized that transient loose parts fell from above causing the indications found in the free span of the tubes.

Steam generator inspections were performed in accordance with the EPRI PWR Steam Generator Examination Guidelines, Rev. 5, and all applicable requirements of Station Administrative Order (SAO)-180, "Administrative Steam Generator Program Plan," Rev. 4.

Table 1 summarizes the overall inspection results.

Inspection Results - Possible Loose Parts Indications

No wear was found on any tubes due to Possible Loose Parts (PLP). All PLP reported during the 2R15 inspections were detected by the +PT RPC and all were reported on top of the tube sheets. It is sometimes difficult to distinguish sludge from a loose part with eddy current, therefore reporting a PLP with eddy current indicates only the possibility of a loose part present and does not indicate that a loose part is present for certain.

In SG 24, four adjacent tubes were reported originally by RPC on the top of the tubesheet hot leg. The tubes were R37 C22, R38 C22, R37 C23, and R38 C24. As a result of these reported PLP calls, a 2.5" long piece of metal bracket was removed from that area. When the tubes were retested with +PT after the removal of the part, the indications were no longer present from eddy current.

All other PLP calls reported from eddy current were visually checked on the secondary side. As a result, one other loose part was found wedged between tubes in SG 21 on the hot leg Top of Tubesheet and in the periphery of the steam generator, however could not be removed. Westinghouse performed an evaluation to leave the tubes with PLP indications in service. None of the PLP locations showed any sign of tube wear from +PT testing. All tubes adjacent to PLP calls were tested with +PT RPC to bound all PLP indications.

Table 2 summarizes all PLP calls remaining in the database.

Inspection Results - Tubes Plugged

A total of 16 tubes were administratively plugged during the 2R15 inspection with Westinghouse (W) mechanical plugs fabricated from Alloy 690. A total 13 tubes were plugged due to AVB wear and 3 tubes were plugged due to volumetric indications. None of

the tubes plugged met EPRI Rev. 5 criteria for requiring repair. No crack-like indications were reported.

The qualified bobbin sizing standard contains only single sided wear. All three 20% bobbin indications at AVB locations were tested with +Pt RPC and confirmed as double sided wear. Therefore, the qualified bobbin sizing technique that was used overestimated the 20% calls. In addition, 2 other < 20% bobbin calls at the AVB's were tested with +Pt and confirmed as wear (single sided).

Table 3 summarizes the plugged tubes.

b. <u>Secondary Side Examination Results</u>

Foreign Object Search and Retrieval (FOSAR) procedures were conducted in the steam generators around the annulus and within the tube bundle during 2R15. Various loose objects were observed during FOSAR and eddy current of the tubesheet region of the steam generators. Some of these objects were removed; however, some were not removed due to the small size of the objects and the time and personnel exposure required to do so. Secondary side inspections after sludge lancing included a visual (by camera) inspection of the peripheral and tube lanes on the tubesheet. Objects found were removed in this area. Additionally a visual inspection was performed at every fifth column. This was where the remaining loose parts were located. The remaining items were evaluated for wear rates on adjacent tubes. The evaluation concluded that the Indian Point Unit 2 steam generators may be returned to service with the identified items, and that operation during Cycles 16 and 17 with these foreign objects would not involve a change to any Technical Specification, and would not represent an unreviewed safety question in accordance with 10CFR 50.59

c. <u>Steam Generator Sludge</u>

Sludge was removed from each of the steam generators by lancing. The sludge is being analyzed. The quantities are listed in Table 5.

4.0 Conclusions

This report provides a summary of the Indian Point Unit 2 steam generator tube integrity condition as determined during the 2R15 refueling outage by NDE inspection and a projection by analysis of the tube integrity until the next planned steam generator inspection. On 6/23/04 IP2 received approval from the NRC of a license amendment to TS 5.5.7.b.1 for a one-time change to SG tube inspection interval. The change allows the next SG inspection, which was to 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. The next inspection is planned for 2R17, which is following the completion of two fuel cycles. All of the activities reported in this report have been conducted in accordance with NEI 97-06 Revision 1 and associated guidelines.

The 2R15 represents the end of the first fuel cycle after steam generator replacement, consequently all four steam generators were inspected. A Condition Monitoring assessment was performed, on a defect specific basis, to demonstrate compliance with integrity criteria by the comparison of 2R15 NDE measurements with calculated burst and leakage integrity limits. Calculated integrity limits, including consideration for appropriate uncertainties, burst and leak

analytical correlations, material properties, and NDE technique and analyst uncertainties were provided in the degradation assessment report. All indications in this inspection were below the calculated integrity limits and therefore met integrity requirements without further testing. Based upon the inspection results, all four steam generators were found in compliance with Condition Monitoring requirements.

An Operational Assessment for assumed operation duration of 4.0 EFPY for Cycle 16 and 17 confirms that the steam generator tube structural and leakage integrity will be maintained until the next planned steam generator inspection.

The 2R15 steam generator tube inservice examination demonstrates that the Indian Point Unit 2 steam generators are acceptable for continued service at full power. A Conditioning Monitoring Assessment performed for Indian Point Unit 2 has established the end of cycle structural and leakage integrity of the steam generator tubing.

Table 1

Inspection Results- Overall Summary

Bobbin Coil Results					
Indication	**SG-21**	**SG-22**	**SG-23**	**SG-24**	**Total**
1-19%	11	1	4	7	23
20-39%	2	0	1	0	3
>=40%	0	0	0	0	0
NOI	2	0	1	0	3
PID	6	1	2	4	13
DNS	10	12	11	5	38
DSS	3	0	1	1	5
NOS	287	335	153	246	1021
Total "S" Codes	300	347	165	252	1064
BLG	1	1	1	0	3
DNG < 2.00 Volts	1	9	1	2	13
DNG 2.00 - 4.99 Volts	100	57	58	51	266
DNG >= 5.00 Volts	2	4	3	1	10
Total DNG	103	70	62	54	289
DNT < 2.00 Volts	0	0	0	0	0
DNT 2.00 - 4.99 Volts	75	8	65	13	161
DNT >= 5.00 Volts	3	1	15	2	21
Total DNT	78	9	80	15	182
FSA	31	44	30	49	154
FSD	288	250	225	245	1008
DNR	0	6	2	1	9
INR	155	60	120	81	416
INF	2	6	2	7	17
PVN	7	5	1	5	18
Total Bobbin Results	986	800	696	720	3202
+Point Inspection Results					
Indication	**SG-21**	**SG-22**	**SG-23**	**SG-24**	**Total**
1 - 19%	2	0	1	0	3
VOL	10	0	4	0	14
PID	2	0	1	0	3
PLP	6	1	1	0	8
PVN	4	0	1	0	5
DNT	0	1	0	0	1
TRA	2	1	0	0	3
NDF	310	371	188	262	1131
Total +Point Results	336	374	196	262	1168
All Probes	1322	1174	892	982	4370

Table 2
Summary of Possible Loose Part (PLP)

SG	ROW	COL	CODE	Location	Result of Visual Search
21	44	43	PLP	TSH +0.42”	No Part Visible
21	45	43	PLP	TSH +0.21”	No Part Visible
21	44	44	PLP	TSH +0.04”	No Part Visible
21	1	47	PLP	TSH +0.04”	No Part Visible, possible sludge deposits
21	42	59	PLP	TSH +0.07”	Part wedged between tubes. Removal not possible.
21	42	60	PLP	TSH +0.27”	Part wedged between tubes. Removal not possible.
22	1	47	PLP	TSC +0.12”	No Part Visible, possible sludge deposits
23	1	46	PLP	TSC +0.20”	No Part Visible, possible sludge deposits

Table 3
Locations of Indications Plugged

SG	ROW	COL	Location	Reason for Plugging
21	16	28	5H + 5.63”	18% Volumetric Indication (sized by +Pt)
21	44	43	AV3, AV4	WEAR 9% AV3, 10% AV4
21	45	45	AV1, AV2, AV3, AV4	WEAR 17% AV1, 20% AV2, 20% AV3, 14% AV4
21	38	47	AV2, AV3	WEAR 13% AV2, 16% AV3
21	45	47	AV1, AV2	WEAR 14% AV1, 18% AV2
21	28	50	AV3, AV4	WEAR 10% AV3, 14% AV4
21	21	56	TSH + 18.39”	18% Volumetric Indication (sized by +Pt)
21	28	79	AV3	WEAR 12% AV3
22	39	37	AV3	WEAR 10% AV3
23	27	33	5H + 37.98”	19% Volumetric Indication (sized by +Pt)
23	41	46	AV1, AV2, AV3, AV4	WEAR 12% AV1, 17% AV2, 20% AV3, 17% AV4
23	41	61	AV3	WEAR 13% AV3
24	41	41	AV2, AV3, AV4	WEAR 14% AV2, 15% AV3, 16% AV4
24	34	51	AV2	WEAR 12% AV2
24	36	64	AV3, AV4	WEAR 11% AV3, 12% AV4
24	36	66	AV1	WEAR 11% AV1

Table 4
Summary of Tubes Plugged

SG	Plugged in 2002	Previously Plugged	Total Plugged	Percent Plugged
21	8	0	8	0.25 %
22	1	0	1	0.03 %
23	3	0	3	0.09 %
24	4	2	6	0.19 %
Total	16	2	18	0.14 %

Notes:
All tubes were plugged on both the hot and cold legs.
All tubes plugged in 2002 used Westinghouse (W) mechanical plug fabricated from Alloy 690.
All tubes previously plugged used (W) welded plug fabricated from Alloy 690.

Table 5

Sludge Removed (November 2002)

SG	2002
21	13 lbs
22	8 lbs
23	10 lbs
24	11 lbs
Total	42 lbs

Table 6
Eddy Current Data Acronyms

3-Letter Code	Description
BLG	Bulge
DNG	Ding
DNR	Ding With Rotation
DNS	Ding Signal
DNT	Dent
DSS	Distorted Support Signal
FSA	Freespan Absolute Signal
FSD	Freespan Differential Signal
INF	Indication Not Found
INR	Indication Not Reportable
NDF	No Degradation Found
NQI	Non Quantifiable Indication
NQS	Non Quantifiable Signal
PID	Positive Identification
PLP	Possible Loose Part
PVN	Permeability Variation
TRA	Trackable Anomaly
VOL	Volumetric Signal

Attachment 4: SG Examination Program Results 2R17

1.0 Examination Program Description

Details of the Indian Point Unit 2 steam generator tube inservice examination program to be conducted during the seventeenth refueling outage (2R17) were submitted to the NRC via Entergy letter NL-06-008 dated February 13, 2006. The original examination scope is described in Section 2 below. The results and conclusions of the full examination scope are provided in Sections 3 and 4 respectively.

2.0 Original Examination Scope

a. Steam Generator Tube Eddy Current Examination

The Indian Point Unit 2 2R17 steam generator eddy current inspection was the second inservice inspection for the replacement steam generators, which were installed in December of 2000.

The inspection programs consisted of the following:

1) 50% Bobbin all 4 SGs full length except rows 1 & 2 (1515 tubes/SG)
2) 50% Bobbin all 4 SGs straight lengths hot and cold legs rows 1 & 2 (92 tubes/SG)
3) 50% Rotating Pancake Coil (RPC) of U-Bend all 4 SG's Rows 1 & 2 (92 tubes/SG)
4) RPC of tubes at top of tubesheet (TTS) $\pm$3" in 4 SG's:
   - 20% patterned sample of hot leg TTS ($\pm$3") in all 4 SG's (~648 tubes/SG)
   - Three tubes in from the annulus on the hot leg not covered in the 20% sample above. Purpose was for possible loose part (PLP) identification and loose part wear (~508 tubes)
   - All row 1 & 2 tubes on the hot leg not covered in two criteria above. Purpose was for PLP identification and loose part wear (~124 tubes)
   - Three tubes in from the annulus on the cold leg. Purpose was for PLP identification and loose part wear
   - All row 1 & 2 tubes on the cold leg not covered in the criteria above: Purpose was for PLP identification and loose part wear (~164 tubes)
5) RPC of selected dents/dings in the hot leg straight sections
   - 100% of dents/dings $\geq$5 volts identified in 2R15 (25 tubes total)
   - 20% sample of dents/dings $\geq$2 volts and <5 volts identified in 2R15 (46 tubes total)
   - Any new dents/dings $\geq$2 volts identified in 2R17
6) RPC of selected indications in hot leg tubesheet:
   - 20% sample of OXP, BLG and DNT indications
7) Special Interest Examinations:
   - Special interest exams of abnormal indications

b. Secondary Side Examination

The secondary side inspection program consisted of the following:

1) Sludge lanced the top of the tubesheet in all 4 SGs and the flow distribution baffle in 23 & 24 steam generators.
2) Performed foreign object search and retrieval (FOSAR) in all 4 SGs (annulus and tube lane) post lancing
3) Performed TTS In-bundle visual inspection of approximately every 5th column of both hot and cold legs in all 4 SGs post lancing
4) Visually inspected the Top Support Plate ("G" plate) visual inspection in 23 & 24 SGs including:
   - The underside of the tube U-bends
   - The top of the plate the full length of the tube lane
   - The length of 11 columns on both hot and cold legs from the tube lane to the wrapper

3.0 3.0 2006 Examination Results

d. Steam Generator Tube Eddy Current Examination

Inspection Results - Overall Summary

The only degradation detected during 2R17 was Anti-Vibration Bar (AVB) wear. There were 55 AVB wear indications in 23 tubes. All of the indications were new. Entergy administratively plugged all 7 tubes found with AVB wear indications $\geq$ 20% TW (through wall). The deepest indication was 28% TW. No crack-like indications were found in 2R17.

There were thirteen tubes identified with permeability variations (PVN). These tubes remain in service since no evidence of degradation has been identified in the area of interest in other tubes. Therefore, it is believed the PVN indications are not masking degradation.

Visual inspections were performed in all 4 SGs for foreign objects in the annulus and tube lane regions. Additionally, approximately every fifth column was inspected for cleanliness in all 4 SGs following sludge lancing. The presence of any foreign objects seen during the in-bundle inspections was documented as well. There was no evidence of tube wear attributable to foreign objects.

The steam generator inspections were performed in accordance with Revision 6 of the EPRI PWR Steam Generator Examination Guidelines and the Indian Point 2 Steam Generator Program.

Table 1 summarizes the overall inspection results.

Inspection Results - Possible Loose Parts Indications

No wear was found in any tubes with Possible Loose Part (PLP) indications. All PLP calls reported during the 2R17 inspections were detected by the Plus Point Rotating Pancake Coil (+PT RPC) and all were reported at or near the top of the tube sheet. All tubes adjacent to PLP calls were tested with +PT RPC to bound all PLP indications.

All PLP calls reported from eddy current were visually checked on the secondary side. Attempts were made to retrieve potential loose parts from locations identified with eddy current data. In many cases retrieval was successful; however, in other cases the part broke into pieces or was not found at the designated location. Any part found but not retrieved or that was unable to be retrieved was bounded by prior analysis based on mass, size and location. None of the PLP locations showed any sign of tube wear from +PT RPC testing.

Table 2 summarizes all PLP calls in the database.

Inspection Results - Tubes Plugged

A total of 7 tubes were administratively plugged during the 2R17 inspection with Westinghouse (W) mechanical plugs fabricated from Alloy 690. All 7 tubes were plugged due to AVB wear. None of the tubes plugged met EPRI Revision 6 criteria for requiring repair. No crack-like indications were reported.

The qualified bobbin sizing standard contains only single sided wear. The largest bobbin indication at an AVB location was 28% which was tested with +PT RPC and confirmed as single sided wear. Therefore, the qualified bobbin sizing technique that was used estimated the 28% call properly.

Based on engineering evaluation, it was determined that tube stabilization was not required for the 7 tubes plugged in 2R17 for AVB wear. The engineering evaluation also determined that the 13 tubes previously plugged for AVB wear in 2R15 do not require tube stabilization.

Table 3 summarizes the AVB wear and tubes plugged in RF17.

e. Secondary Side Examination Results

Foreign Object Search and Retrieval (FOSAR) procedures were conducted in the steam generators around the annulus and within the tube bundle during 2R17. Various loose objects were observed during FOSAR and eddy current of the tubesheet region of the steam generators. Any part found but not retrieved or that was unable to be retrieved was bounded by prior analysis based on mass, size and location.

4.0 Conclusions

This report provides a summary of the Indian Point Unit 2 steam generator tube integrity condition as determined during the 2R17 refueling outage by NDE inspection and a projection by analysis of the tube integrity until the next planned steam generator inspection. The next inspection is planned for 2R19, which is following the completion of two fuel cycles. All of the activities reported in this report have been conducted in accordance with NEI 97-06 Revision 2 and associated guidelines.

The 2R17 refueling outage represents the end of the third fuel cycle after steam generator replacement, consequently, all four steam generators were inspected. A Condition Monitoring assessment was performed, on a defect-specific basis, to demonstrate compliance with integrity criteria by the comparison of 2R17 NDE measurements with calculated burst and leakage

integrity limits. Calculated integrity limits, including consideration for appropriate uncertainties, burst and leak analytical correlations, material properties, NDE technique, and analyst uncertainties were provided in the degradation assessment report. All indications in this inspection were below the calculated integrity limits and, therefore, met integrity requirements without further testing. Based upon the inspection results, all four steam generators were found to be in compliance with Condition Monitoring requirements.

The 2R17 steam generator tube inservice examination demonstrates that the Indian Point Unit 2 steam generators are acceptable for continued service at full power. A Condition Monitoring Assessment performed for Indian Point Unit 2 has established the end of cycle structural and leakage integrity of the steam generator tubing.

An Operational Assessment for an assumed inspection interval of 3.7 EFPY covering Cycles 18 and 19 concluded that the steam generator tube structural and leakage integrity will be maintained until the next planned steam generator inspection in 2R19.

Table 1
Inspection Results - Overall Summary

Identification Code	SG21	SG22	SG23	SG24
Final "I" Codes	0	0	0	0
>=20%	2	2	0	3
PCT	9	13	14	19
PVN	5	2	5	4
DNT	58	7	39	11
DNG	70	47	32	30
DNR	26	5	23	1
BLG	265	1	130	369
FSD	221	248	155	131
FSA	55	72	33	72
PLP	13	4	0	7
INR	114	54	73	139
Bobbin "S" Codes	1	0	0	2
NDD	3273	3520	3382	3247
Bobbin Coil Results				
Tubes with Indications <20%	4	5	6	8
Tubes with Indications 20-39%	2	2	0	3
Tubes with Indications ≥40%	0	0	0	0
Tubes with Bobbin "I" Codes	0	0	0	0
Tubes with 3-Letter Codes	463	267	336	457
+Point Inspection Results				
Number of Flaws	0	0	0	0
Number of Tubes with Flaws	0	0	0	0
Tube Repair and Engineering Evaluation				
Tubes Requiring Condition Monitoring Review	0	0	0	0
Tubes Requiring In-Situ Testing	0	0	0	0
Tubes Plugged	2	2	0	3

Table 2
Summary of Possible Loose Part (PLP)

	SG21	SG22	SG23	SG24
PLP Indications	13	4	0	7

Table 3

AVB Wear Identified in 2R17

SG	Tube Row	Tube Column	AV1 %TW	AV2 %TW	AV3 %TW	AV4 %TW	Tube Status
21	39	35	NR	21	NR	17	Plugged
	33	46	15	NR	NR	NR	In-Service
	34	60	13	13	NR	16	In-Service
	37	60	16	20	16	NR	Plugged
22	34	43	NR	20	15	NR	Plugged
	36	44	14	15, 16	NR	NR	In-Service
	23	54	13	11	13	18	In-Service
	40	59	13	15	25	NR	Plugged
	30	67	NR	11	NR	NR	In-Service
23	37	39	13	16	19	NR	In-Service
	41	40	NR	18	14	15	In-Service
	39	56	15	NR	16	NR	In-Service
	40	58	NR	16	15	NR	In-Service
	34	64	14	NR	16	13	In-Service
	41	64	NR	13	NR	NR	In-Service
24	38	57	22	25	28	16	Plugged
	33	63	NR	15	11	NR	In-Service
	33	64	NR	NR	15	14	In-Service
	38	64	NR	25	16	NR	Plugged
	33	71	12	15	14	NR	In-Service
	35	71	NR	16	23	NR	Plugged
	36	71	14	15	11	NR	In-Service
	35	73	NR	NR	12	NR	In-Service
NOTES: all wear identified in IP2-R17 is new wear; all wear identified during the previous inspection was plugged. NR represents no recorded wear.							

Table 4
Summary of Tubes Plugged

Year	Outage	SG21	SG22	SG23	SG24	Total
1988	Fabrication	0	0	0	2	2
2000	Pre-service	0	0	0	0	0
2002	2R15	8	1	3	4	16
2004	2R16	0	0	0	0	0
2006	2R17	2	2	0	3	7
Total Plugged		10	3	3	9	25
Percent Plugged		0.31%	0.09%	0.09%	0.28%	0.19%

Notes:
All tubes were plugged on both the hot and cold legs.
All tubes plugged in 2002 and 2006 used Westinghouse (W) mechanical plug fabricated from thermally treated Alloy 690.
All tubes plugged during fabrication used (W) welded plug fabricated from thermally treated Alloy 690.
There were no steam generator inspections in 2002 during 2R16.

Table 5
Eddy Current Data Acronyms

3-Letter Code	Description
BLG	Bulge
DNG	Ding
DNR	Ding With Rotation
DNT	Dent
DSS	Distorted Support Signal
FSA	Freespan Absolute Signal
FSD	Freespan Differential Signal
INR	Indication Not Reportable
NDD	No Detectable Degradation
PCT	AVB wear detected by bobbin
PLP	Possible Loose Part
PVN	Permeability Variation

Attachment 5: SG Secondary Loose Parts List 2R17

Table 5-1 SG 21 Foreign Object List

Object Number	Object Description	Object Location			Length	Height	Width/Dia.	Object Retrieved Yes/No
		Col.	Row	Leg				
21-007	Gasket	87	23	HL	0.5	0.125	0.125	No
21-016	Gasket	71	38	HL	0.375	0.125	0.125	No
21-018	Metal Object	46	44	HL	0.5	0.125	0.3	No
21-020	Metal Object	40	43	HL	0.5	0.125	0.125	No
21-021	Metal Object	20	34	HL	0.300	0.062	0.032	No
21-023	Metal Object	25	38	CL	0.300	0.125	0.100	No
21-024	Unknown	35	41	CL	0.250	0.250	0.250	No

Table 5-2 SG 22 Foreign Object List

Object Number	Object Description	Object Location			Length	Height	Width/Dia.	Object Retrieved Yes/No
		Col.	Row	Leg				
22-009	Gasket	40	12	HL	0.354	0.050	0.188	No
22-010	Metal Object	45	16	HL	0.354	0.000	0.031	No
22-013	Metal Object	80	22	HL	0.150	0.100	0.030	No

Table 5-3 SG 23 Foreign Object List

Object Number	Object Description	Object Location			Length	Height	Width/Dia.	Object Retrieved Yes/No
		Col.	Row	Leg				
23-001	Rock	40	31	HL	0.175	0.175	0.175	No

Table 5-4 SG 24 Foreign Object List

Object Number	Object Description	Object Location			Length	Height	Width/Dia.	Object Retrieved Yes/No
		Col.	Row	Leg				
24-003	Unknown/object	33	40	CL	0.250	0.250	0.125	No
24-004	Gasket	47	13	HL	1.000	0.125	0.050	No
24-007	Gasket	65	39	HL	0.500	0.125	0.125	No
24-008	Flake/Unknown	73	22	HL	0.300	0.125	0.125	No
24-009	Wire	80	28	HL	1.500	0.000	0.032	No
24-010	Gasket	55	41	HL	0.375	0.125	0.125	No
24-011	Metalic Object	55	25	HL	0.125	0.125	0.125	No
24-012	Gasket	23	32	HL	0.250	0.125	0.125	No

24-013	Gasket	30	39	HL	0.250	0.125	0.125	No

IPEC00243553

Attachment 6: Steam Generator Work Scope Charts

Long Term Maintenance and Inspection Plan for the Indian Point 2 Steam Generators

EFPM since SGR	20.9	43.3	60.0	85	108	131	154	177	200	223	246	269	292	315
EFPM since Period start	1st ISI	22.4	39.0	63	86	109	12	35	58	81	14	37	60	23
Year	2002	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028
Refueling Outage #	2R15	2R16	2R17	2R18	2R19	2R20	2R21	2R22	2R23	2R24	2R25	2R26	2R27	2R28
Secondary Cleanings														
Sludge Lance	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
Hi Vol Bundle Flush														
TTS ASCA/CU rinse														
TTS UEC														
CECIL Lansing														
Chemical Cleaning														
Lbs Sludge Removed	42		95.5											
Est. lbs Iron Xported	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Tube Scale (lbs/SG)														
Secondary Inspections														
FOSAR	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
20% TTS In-bundle	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
Top TSP (G)			, ,3 ,4		, , 3,4		1,2, ,		, , 3,4		1,2, ,		, , 3,4	
C-F TSP (SID)			, , ,		, , 3,4		1,2, ,		, , 3,4		1,2, ,		, , 3,4	
Steam Drum			,, ,		, , 3,4		1,2, ,		, , 3,4		1,2, ,		, , 3,4	
Primary Inspections														
Full length bobbin	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
% of tubes/SG	100		50		50		50		50		50		50	
R1&2 U-bend RPC	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
% of tubes/SG	100		20		20		50		50		50		50	
HL Tubesheet RPC	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
% of tubes/SG	27		50		50		50		50		50		50	
CL Tubesheet RPC	1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4		1,2,3,4	
% of tubes/SG	8		8		8		8		8		8		8	
Plugging														
SGs plugged	1,2,3,4		1,2,3,4											
# tubes plugged	8,1,3,4		2,2,0,3											

Legend: 1,2,3,4 represents work performed in 21, 22, 23 and 24 SGs
where there are two percentage numbers in a cell, it represents work performed in 21/22 and 23/24 SGs respectively