IP3 STEAM GENERATOR PROGRAM

APPLICABLE SITES

All Sites: ☐

Specific Sites: ANO ☐ **GGNS** ☐ **IPEC** ☒ **JAF** ☐ **PLP** ☐ **PNPS** ☐ **RBS** ☐ **VY** ☐ **W3** ☐ **HQN** ☐

Safety Related: ☒ Yes

☐ No

Change	PCN

REVIEW AND CONCURRENCE SHEET

Program Section Title: *IP3 STEAM GENERATOR PROGRAM*

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REVISION STATUS SHEET

REVISION SUMMARY

REVISION	ISSUE DATE	DESCRIPTION
0	9/19/12	Initial Issue
1	4/22/14	General update to include miscellaneous editorial items throughout the document. Additionally, updated to include 3R17 information and WT-WTHQN-2013-00387 CA0014 enhancement.

PAGE REVISION STATUS

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APPENDIX/ATTACHMENT REVISION STATUS

Appendix.	REVISION NO.	Attachment	REVISION NO.

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1.0 PROGRAM DESCRIPTION

1.1 Purpose

1.1.1 The purpose of this SEP is to provide the site specific programmatic details necessary to implement the steam generator integrity program as outlined in EN-DC-317, CEP-SG-001, CEP-SG-002, and CEP-SG-003.

1.1.2 The IP3 steam generator integrity program ensures compliance with the IP3 Technical Specifications 3.4.17, 5.5.8, and 5.6.8.

1.2 Scope

1.2.1 This SEP applies to the IP3 Steam Generators.

1.3 Organization of Program

1.3.1 Program responsibilities are defined in EN-DC-317.

1.3.2 This procedure provides IP3 specific steam generator information, IP3 steam generator program bases to include unique technical specification requirements and site commitments, IP3 component specific inspection history, and the current condition of the steam generators at IP3.

1.3.3 Long term strategic planning for the IPEC steam generators is documented utilizing the Engineering Change (EC) system.

1.3.4 EN-DC-317 provides details on the following:

a. Programmatic requirements implemented to ensure compliance with NEI 97-06 and Steam Generator Management Project (SGMP) Administrative Procedures.

b. Roles and responsibilities within the steam generator program organization.

c. Interfaces with other departments and programs.

d. Program document hierarchy.

1.3.5 CEP-SG-001 addresses primary side steam generator examinations and maintenance by providing Entergy wide programmatic requirements in the following areas:

a. Compliance with the EPRI Steam Generator Examination Guidelines for primary side inspections.

b. Compliance with the EPRI In-Situ Pressure Test Guidelines

c. Generic tube plugging and stabilization.

d. Generic requirements for Site Specific Performance Demonstrations (SSPD).

1.3.6 CEP-SG-002 addresses secondary side steam generator examinations and maintenance by providing Entergy wide programmatic requirements in the following areas:

a. Compliance with the EPRI Steam Generator Examination Guidelines for secondary side inspections.

b. Foreign Object Search and Retrieval (FOSAR)

c. Loose Parts

d. Sludge management

1.3.7 CEP-SG-003 addresses steam generator integrity assessments by providing Entergy wide programmatic requirements for the following areas:

a. Compliance with the EPRI Steam Generator Integrity Assessment Guidelines.

b. Reporting templates.

1.3.8 Specific site requirements for data analysis and equivalency are documented utilizing the EC system and referenced in the degradation assessment.

1.3.9 Chemistry Documents

a. Primary – The IPEC chemistry department is responsible for the primary-side water chemistry program at IPEC. 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. IPEC chemistry has also developed a site-specific "Primary Strategic Water Chemistry Plan (Document ID PSWCP)"

The upper tier chemistry procedures at IPEC are 0-CY-2310, "Reactor Coolant System Specifications and Frequencies" and EN-CY-101 which reiterates the chemistry commitment to NEI 97-06.

b. Secondary – The IPEC chemistry department is responsible for the secondary-side water chemistry program at IPEC. 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. IPEC chemistry has also developed a site-specific "Secondary Strategic Water Chemistry Plan" (Document ID SSWCP).

The upper tier chemistry procedures at IPEC are 0-CY-2410, "Secondary Chemistry Specifications" and EN-CY-101, "Chemistry Activities", which reiterate the chemistry commitment to NEI 97-06.

c. Chemistry Transients – Chemistry transients can stress 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. The following is a list of all SOP-SG-02 Action Level 2 chemistry transients. There have not been any action level 3 chemistry transients since SG replacement. A brief description of each transient has also been included. More detailed information is available in the source documents.

On January 5, 1991, the cation conductivity in steam generators 32 and 34 increased to 2.04 and 2.08 μS/cm respectively immediately after placing 31 heater drain pump into service following maintenance.

December 18, 1992, Steam generator cation conductivity increased rapidly to 4.9 μS/cm immediately after placing condensate polisher E vessel into service following maintenance. The contamination was organic and did not have significant levels of chloride or sulfate. Organic acids are considered benign with respect to SG corrosion.

On April 1, 2007 during power ascension (47% power) SG Chloride & Sodium exceeded Action Level 2. SG Chloride peaked at 85.6 ppb and exceeded the Action Level 2 threshold of 50 ppb for 4 hours 30 minutes. SG Sodium peaked at 67.9 ppb and exceeded the Action Level 2 threshold of 50 ppb for 3 hours 20 minutes. The cause of the excursion was a leak of 33 condenser circulating water from 1 loose and 1 missing plug on previously plugged tubes (CR-IP3-2007-1756).

Since that time there have been no Action Level 2 steam generator chemistry excursions.

1.3.10 Primary to Secondary Leakage

a. Primary-to-secondary leak monitoring is conducted in accordance with IPEC procedures 2-AOP-SG-1, 3-AOP-SG-1 and 0-CY-2450. These procedures follow the guidance contained in the EPRI PWR Primary-to-Secondary Leak Guidelines. A plant shutdown is 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. To date, primary-to-secondary leakage has not been observed in the replacement steam generators.

1.3.11 Foreign Material Exclusion – EN-MA-118 "Foreign Material Exclusion" provides the requirements for foreign material control during maintenance activities at IPEC.

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 the parts remaining. A listing of the loose parts left in the IP3 replacement SGs is provided in Attachment 5.

During plant operations, the steam generators are monitored for loose parts via the metal impact monitoring system (MIMS). 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.

Since steam generator replacement in 1989, IP3 has conducted foreign object search and retrieval (FOSAR) inspections in all four SGs at each refueling outage that sludge lancing is performed. This inspection is performed after sludge lance operations and encompasses a visual inspection at the tube sheet level around the annulus of the steam generator.

Another inspection typically performed after sludge lancing is a visual in-bundle at the tubesheet level 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. Periodically the support plates are inspected in selected SGs. 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 top of the uppermost support plate cannot be inspected using SID so the top support plate in selected 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 are typically inspected on a rotating basis.

Lastly, starting with 3R09, the steam drum area in one SG was inspected on a rotating basis each refueling outage through 3R11. 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, and primary and secondary separators. Based on the positive results of previous steam drum inspections, the steam drum inspection planned for 3R12 was deferred to 3R14. In 3R14 the steam drums in 31

and 32 SGs were inspected and no anomalies noted. In 3R17 the steam drums in 33 and 34 SGs were inspected and no anomalies noted.

1.3.12 Thermal Performance will be monitored by the site Performance Engineer in accordance with EN-DC-181.

2.0 REFERENCES

2.1 Regulatory

2.1.1 IP3 Technical Specifications 3.4.17, 5.5.8 and 5.6.8.

2.2 Industry

2.2.1 ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition addendum 2003

2.2.2 EPRI Steam Generator Management Program Administrative Procedures

2.2.3 EPRI PWR Steam Generator Examination Guidelines

2.2.4 EPRI Steam Generator Integrity Assessment Guidelines

2.2.5 EPRI Steam Generator In Situ Pressure Test Guidelines

2.2.6 EPRI Flaw Handbook

2.2.7 EPRI Primary Chemistry Guidelines

2.2.8 EPRI Secondary Chemistry Guidelines

2.2.9 EPRI Primary to Secondary Leakage Guidelines

2.2.10 NEI 97-06, Steam Generator Program Guidelines

2.2.11 NEI 03-08, Guideline for Management of Materials Issues

2.3 Vendor Communication

2.3.1 IP3 SG Technical Manual 1440-C350

2.4 Plant/Corporate Manuals and Procedures

2.4.1 EN-DC-317, Steam Generator Program

2.4.2 CEP-SG-001, Steam Generator Primary Side Examinations and Maintenance

2.4.3 CEP-SG-002, Steam Generator Secondary Side Examinations and Maintenance

2.4.4 CEP-SG-003, Steam Generator Integrity Assessment

2.4.5 EN-DC-203, Maintenance Rule Program

3.0 DEFINITIONS

3.1 None

4.0 COMMITMENTS

4.1 NEI 97-06, Steam Generator Program Guidelines

4.2 IPEC-LO-LAR-2011-174 CA-17

4.3 IPEC-LO-LAR-2011-174 CA-61

4.4 IPEC-LO-LAR-2011-174 CA-59

5.0 SITE STEAM GENERATOR DESIGN

5.1 Steam Generator Design Information

The original Westinghouse Model 44 steam generators (SGs) at IP3 were replaced in 1989 with Westinghouse Model 44F SGs, with a nominal 43,467 square feet of heat transfer area. Each steam generator contains 3214 thermally treated U-tubes fabricated from Alloy 690 (ASME-SB-163 Alloy UNS N06690 to Code Case N-20). There are 46 fewer tubes than the 3260 in the original SGs for two reasons. The tube support stay rods were relocated from the periphery to the middle of the tube bundle and quatrefoil tube openings in the tube support plates required elimination of some peripheral tubes to maintain a minimum ligament thickness around the holes.

The nominal OD of each tube is 0.875 in. and the nominal tube wall is 0.050 in. thick. During assembly, the ends of the tubes were expanded in the tubesheet with a urethane plug and then seal welded to the cladding on the primary side of the tubesheet. The seal welds were checked with helium, reworked if necessary and then the tubes were hydraulically expanded the full depth of the tubesheet to within 0.25 inches of the secondary face.

The U-bend bending process was tightly controlled to maintain very tight tube ovality specifications of less than 3 percent. The low ovality specification allowed for thicker anti vibration bars (AVBs) and tighter gaps between the tubes and the AVBs than the original SGs. The tube centerline radii of the U-bends range from 2.19 to 56.50 inches for rows 1 and 45 respectively. The first eight rows of tubes were heat treated after the tube bending process to relieve residual stresses in the tubing.

The tubes are supported on the primary side by the tubesheet. The tubesheet is a low alloy steel (ASME-SA-508 Class 3) forging with a minimum thickness of 21.81 inches. 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) to a minimum depth of 0.150 inches.

The tubes are supported on the secondary side by six 1.125" thick tube support plates (TSP). The tube support plate material is stainless steel (ASME-SA-240 Type 405). The holes where the tubes pass through the tube support plates are quatrefoil shaped produced by broaching. The lower 5 TSPs have 6 flow slots down the tube lane 14.22 inches long by 1.75 inches wide. These slots are narrower than the original SGs. The top TSP has two rows of 90 circular holes 0.883 inches in diameter down the tube lane to

provide additional stiffness to the TSP.

A flow distribution baffle (FDB), located between the lowest tube support plate and the tubesheet, was designed to minimize the number of tubes exposed to low velocity flow in the vicinity of the tubesheet. The FDB material is stainless steel (ASME-SA-240 Type 405) 0.75" thick and has a circular cutout in the center approximately 34 inches in diameter. 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. The holes where the tubes pass through the FDB are octafoil shaped. The octafoil shape was chosen to minimize the deposition of corrosion products between the FDB and the tubing. Earlier Model 44F replacement steam generators (RSGs) used drilled holes in the FDB and the cutout was about 60 inches in diameter.

Three sets of anti-vibration bar (AVB) assemblies stiffen the tube bundle in the U-bend region and restrain tube vibration. This is one more set than previous Model 44 F RSGs and provides shorter distances between AVB/tube contact points. The V-shaped AVB assemblies also maintain proper tube spacing and alignment in the U-bend region. The first set of AVB assemblies is installed into the U-bend to a depth supporting the apex of the U-bend centerline of the ninth row U-tubes and has an included angle of 147 degrees. U-tubes 1 through 8 do not require AVB support. The remaining two sets of AVB assemblies are installed to depths supporting the U-bend apexes of the fourteenth and twenty-fifth row U-tubes with included angles of 111 and 67 degrees respectively. The AVB material is 405 stainless steel with a cross-section of 0.690 by 0.354 inches. Stainless steel provides lower tube wear rates than the chrome plated Alloy 600 square bars used in earlier model 44F replacement SGs. The design specifications are detailed in D-Spec 408A21, Rev. 4, "Model 44F Replacement Steam Generator provided by Westinghouse".

These units were constructed in accordance with the 1983 ASME Boiler and Pressure Vessel Code, Section III, through the Summer 1984 addenda. The code stress report for the replacement steam generators is documented in Westinghouse report WNEP-8805 and conforms with the 1965 ASME Code, through the Summer 1966 Addenda which was the design code.

5.2 Degradation Assessments

5.2.1 There are no current active degradation mechanisms at IP3.

Degradation Assessments are documented in the Merlin records management system.

5.3 Condition Monitoring and Operational Assessments are documented in the Merlin records management system.

5.3.1 A comparison of the condition monitoring (CM) results to the previous cycle operational assessment (OA) predictions shall be performed. If the previous cycle OA did not bound the CM results, an evaluation shall be performed in accordance with the corrective action program.

5.4 Thermal Hydraulic Analysis

5.4.1 Currently the SGs have excess thermal capacity on the order of 10%.

5.5 Plant History

Indian Point 3 started commercial operation in August 1976. The original steam generators had numerous degradation issues and in 1989 the replacement steam generators were installed. Activities that are significant with regard to the maintenance of the steam generators are outlined below. Since the steam generators were replaced in 1989, all information previous to that date is given for historical information only. Any mention made in this report to steam generators refers to the replacement generators unless the term original steam generator is used.

1976	Began commercial operation utilizing AVT chemistry (ammonia/hydrazine). Phosphate chemistry was never used at IP3.
1982	The MSR tubing was replaced with stainless steel tubing. 2971 steam generator tubes were sleeved due to sludge pile pitting.
1985	The brass feedwater heater tubing was replaced with stainless steel tubing. The brass tubing in the main condenser was replaced with titanium tubing and a titanium tube sheet.
1986	Installed a full flow condensate polishing facility.
1987	Installed a blowdown recovery system with demineralization rated at 250 gpm total flow. Installed ultrafiltration system on the effluent of the water treatment system to reduce organics.
1989	Replaced the steam generators with Westinghouse Model 44Fs. SG blowdown pipe size for 31 and 34 SGs was increased to allow higher blowdown flowrates overboard (not utilized). Replaced the brass gland steam exhaust and air ejector condensers with stainless steel ones. Replaced ammonia chemistry with morpholine and increased hydrazine concentration to > 200 ppb. Boric acid added to secondary side as proactive measure against stress corrosion cracking. Condensate polisher operated in partial flow (about 30% of condensate flow) to support morpholine chemistry.
1990	Steam generator 34 hot leg channel head and tubesheet impacted by a fuel assembly alignment pin from the reactor upper internals (see Section 6.1.3 for a more detailed description of the event).
1998	Changed secondary chemistry from morpholine to

	ethanolamine (ETA) to further reduce iron transport to the SGs. Condensate polisher bypassed except during startups.
1999	Steam generator boric acid concentration reduced from a range of 5 to 10 ppm to 3 to 5 ppm.
1999	Nominal steam generator blowdown flow reduced from 200 to 150 gpm (total) to improve thermal efficiency.
1999	During 3R10 significant BOP pipe replacement was made to a more resistant material. This lead to a drop in feedwater iron concentration in the following cycles.
2000	Secondary chemistry changes were made in November. The feedwater hydrazine concentration was reduced to 100 to 150 ppb with a minimum of 40 times the condensate dissolved oxygen concentration. In addition, boric acid injection to the steam generators was terminated to evaluate effects on iron transport.
2000	A contractor water treatment system was installed that uses a combination of EDI, RO, IX and UF. The existing in-house system was retired in place.
2001	The steam generator tube inspection program was changed from prescriptive to performance based under revision 5 of the EPRI PWR SG Examination Guidelines. Based on this change, eddy current inspections were not required or performed in 3R11.
2002	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 and shifted the program from performance back to prescriptive based.
2005	The HP turbine and MSR internals were replaced to support a stretch power uprate of 4.8%.
2007	Implemented new Technical Specification requirements consistent with TSTF-449, Rev. 4, "Steam Generator Tube Integrity" License Amendment 233

5.6 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 in the Indian Point 3 Technical Specifications as listed below.

(1) Structural Integrity Performance Criterion: 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, and 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 5.5.8 b 1)

(2) Accident-Induced Leakage Performance Criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the Operational Leakage Performance Criterion 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 0.3 gpm per SG and 1 gpm through all SGs. (TS 5.5.8 b 2)

(3) The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE" which limits RCS operational leakage to: 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG). (TS LCO 3.4.13 d)

The primary-to-secondary leakage limit referred to in the performance criterion is 150 GPD at room temperature conditions from any one steam generator. 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 IP3 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.

6.0 INSPECTION AND TESTING

6.1 Primary Side Examinations and Inspections

6.1.1 Eddy current

a. Eddy current acquisition and analysis will be performed using approved vendor procedures.

b. Refer to Attachment 6 for historical and future scope related to the appropriate interval of operation.

c. An audit of the inspection or ECT process shall be performed during the outage. This will include validation of the setup parameters and analysis guidelines requirements.

6.1.2 In Situ Pressure Testing

a. No in-situ pressure tests of SG tubing have been performed since the replacement SGs were installed in 1989.

b. In-situ testing will be performed using approved vendor procedures.

c. Screening values will be predetermined and documented in the degradation assessment.

d. Testing may be performed utilizing the guidance in Attachment 1.

e. A site condition report shall be written if any tubes are found to not meet the defined structural or leakage performance criteria.

6.1.3 Steam Generator 34 Hot Leg: Impacted Channel Head and Tubeheet

During the 1990 refueling outage a foreign object was found partially lodged in a tube end at location Row 1 - Column 34 in the hot leg of steam generator 34. The object was removed and determined to be a fuel assembly alignment pin from the reactor upper internals. Visual examinations revealed that the foreign object had made numerous indentations on the channel head surfaces. An inspection was performed of all 3212 open tube ends, the tubesheet, tube to tubesheet welds, the divider plate, and all cladding. Some tube ends indicated minor deformation from the loose part impact. Indian Point staff and Westinghouse evaluated the tube ends from a thermal hydraulic and structural point of view and determined them to be acceptable as is. The channel head condition was also evaluated and determined that the structural integrity of the indented components was not degraded and that no repairs were required.

During the 1992 refueling outage a follow up visual inspection was performed on the hot leg channel head of steam generator 34 which had been subjected to impacting by the fuel assembly alignment pin. The visual inspection was performed with a high resolution video camera and observed by a person qualified in accordance with SNT-TC-1A, "Recommended Practice for NDT Personnel Qualification and Certification". A person familiar with weld design requirements participated in the review. The videotape of this inspection and the original inspection, performed in 1990, were comparatively reviewed using side-by-side viewing equipment. The inspection and comparative results showed no change in the channel head since the first inspection.

6.2 Secondary Side Examinations and Inspections

6.2.1 Visual Inspections and Sludge Lancing

a. Prior to each outage, an evaluation shall be performed to determine if an inspection/cleaning of the secondary side of the steam generator is required. A summary of the evaluation shall be documented in the degradation assessment.

b. If it is determined that a visual inspection is required, the degradation assessment will be revised to include the scope of the work. Since entry into the secondary side must be performed remotely, the appropriate opening will need to be removed so that the remote device (i.e. camera, fiber optics etc.) can be inserted. This work will be performed using an approved vendor procedure.

c. Documentation of the inspection shall be performed using video or comparable material.

d. The results of the inspection shall be documented in the Merlin records management system.

e. If anything is identified that is not expected, initiate a condition report.

f. If desired, utilize Attachment 2 – IPEC Visual Inspections

g. If desired, utilize Attachment 3 – IPEC Sludge Lancing

6.2.2 Sludge Loading Evaluation

a. Each cycle sludge loading will be calculated and documented in the Merlin records management system.

6.2.3 Sludge Lance History

Sludge lancing was performed on all four steam generators every refueling outage from replacement through 3R11 in 2001. 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.

In 3R11, a high volume bundle flush was performed in all 4 SGs prior to sludge lancing. This process recirculated demineralized water from the bottom of the SG and sprayed the water over the tubes and support plates at approximately 2000 GPM. This process washed loose deposits from the tubes and support plates down to the tubesheet where it was removed by sludge lancing. The sludge lance process was modified by using a rail mounted lance operating at 2500-3000 psig versus the historical 2000 psig and the suction return was taken from the 90 degree hand holes. When taking into account the reduction of iron transport to the SGs, the amount of sludge removed appeared to be about half from the tubesheet and half from the upper surfaces of the SGs.

Unfortunately, the rail lance used unknowingly rubbed against some row 1 tubes causing measurable wear in 8 of the tubes. This was not discovered until eddy current examinations performed in 3R12.

In-bundle top of tubesheet inspections over the course of time have revealed the gradual buildup up hard deposits at the base of some tubes. These deposits were predominantly under the cutout of the flow distribution baffle with the majority on the hot leg side. In 3R12 a new cleaning process was employed in 33 and 34 SGs in an attempt to reduce the buildup of hard sludge deposits in the central or "kidney" region of the SGs. The original plan was to soak the top of the tubesheet with an advanced scale-conditioning agent (ASCA) followed by an application of ultra sonic energy cleaning (UEC). After the UEC process the tubesheet was to be soaked with a copper rinse agent and then conventional sludge lancing would be performed to removed the weakened deposits. The UEC could not be performed due to unforeseen required plant conditions so that portion of the process was de-scoped. The schedule did not support cleaning of 31 and 32 SGs.

The chemical soak followed by sludge lancing in 3R12 had very little effect on the hard deposits. The chemicals did have the effect of dissolving about 1 pound of copper per SG from the sludge.

No secondary side cleanings or visual inspections were performed in 3R13. In preparation for SG maintenance activities scheduled for 3R14, different secondary cleaning methods were evaluated. In addition to the hard sludge previously observed, there was a concern for large numbers of small foreign objects on the tubesheet as a result of the major modifications performed on balance of plant equipment to support the stretch power uprate. This material was observed in the IP2 replacement SGs the year before following a similar uprate. Due to budget constraints, the use of the CECIL high pressure lance was not possible so the SG management team decided to allot additional sludge lancing time for each SG. In addition, a new sludge lance nozzle block was used that had two jets (aka scale buster) in combination with the conventional nozzle block featuring eight water jets. This was successful in removing most of the foreign objects and all of the loose sludge. This combination of lancing was not successful at removing the hard sludge. The flow distribution baffle was not lanced because there has historically been very little deposits at this location.

The number of sludge lance 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)
3R07	1990	6	6
3R08	1992	4	6
3R09	1997	4	6
3R10	1999	2	6
3R11	2001	2	6
3R12	2003	Not performed	6 (33/34 SGs only)
3R13	2005	Not Performed	Not Performed
3R14	2007	Not Performed	6 (31 SG) 8 (32-34 SGs)[2]
3R17	2013	Not Performed	10
Notes: (1) The sludge lance equipment can not 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) Two of the passes utilized a two-nozzle lance head (scale buster) in each SG to facilitate foreign object removal			

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 31	SG 32	SG 33	SG 34	Total
3R07	1990	42	43	31	39	155
3R08	1992	56	76	74	76	282
3R09	1997	50	63	55	55	223
3R10	1999	62	56	70	57	245
3R11	2001	106		103		209
3R12	2003	Not performed		55	25	80
3R13	2005	Not Performed		Not Performed		n/a
3R14	2007	56.2	81.5	43.5	41.5	222.7
3R17	2013	40	42	41	34	157

During sludge lancing, samples of the sludge from each steam generator are collected and analyzed for form and content. The samples collected during 3RFO12 in 2003 were not analyzed because the deposits were treated with chemicals that dissolved some of the iron and copper so the results would not be comparable with previous samples. Detailed results are presented in the individual sludge analysis reports. Of primary concern to IP3 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 31	SG 32	SG 33	SG 34	Avg
7	1990	68	76	51	77	68
8	1992	87	58	66	50	65
9	1997	57	44	60	57	55
10	1999	93	91	88	92	91
11	2001	91.75		83.86		88
12	2003	Sludge lancing not performed – no samples taken		Not analyzed due to application of ASCA chemical agents		n/a
14	2007	94	97	100	97	97
17	2013	86	87	75	77	81

Percent of Elemental Copper Removed from the SGs						
RFO	Year	SG 31	SG 32	SG 33	SG 34	Avg
7	1990	28.5	20.2	45.0	19.0	28
8	1992	10.5	38.3	31.2	46.3	32
9	1997	32	41	28	33	34
10	1999	5.9	8.4	11	7.2	8
11	2001	6.54		14.46		11
12	2003	Sludge lancing not performed – no samples		Not analyzed due to application of ASCA chemical agents		n/a
14	2007	6	3	0	3	3
17	2013	3	7	14	6	8

Steam Generator Sludge Analysis Summary

	3R07	3R08	3R09	3R 10	3R11	3R12	3R14	3R17
Powder Magnetite (% Fe3O4)	68	65	55	91	88	Analyses not performed	97	81
Powder Copper (%)	28	32	34	8	11		3	8
Powder Copper Oxide (%)	ND	ND	6	ND	ND		ND	ND
Powder Lead (%)				.006	0.02		.02	.03
Sludge Collar Magnetite (%)				75	26			41
Sludge Collar Copper (%)				25	14			12
Sludge Collar Lead (%)				.08	.07			.9
Scale Magnetite (%)				99	92			79
Scale Copper (%)				<1	.9			4

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. Copper was 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 was expected to drop with each succeeding outage but this trend was not seen until the fourth outage after replacement. The experience is comparable to experience at the H.B. Robinson plant. The copper in the sludge has been in the elemental state each refueling outage except for a small amount of copper oxide found in 3R09 samples as described in the next paragraph. IP3 maintains a reducing environment in the steam generators by using hydrazine concentrations at least 20 times greater than the condensate dissolved oxygen concentration during plant operation and by minimizing the time the steam generator secondary side is exposed to oxygen during maintenance conditions.

Sludge samples taken during 3R09 did have measurable copper oxide concentrations in the range of 3 to 6 w%. The reason for the copper oxide is unknown. One possibility is the oxidation of the copper during the extended shutdown that occurred during cycle 9. Sludge samples from 3R10 and 3R11 had no detectable copper oxide so results from 3R09 are considered an anomaly.

To further quantify the extent of copper in the steam generators, the samples from 3R10 were segregated into powder, tube scale and tube collars. It was determined that the copper in the tube scale was less than 1 percent by weight. Sludge collars are hard deposits covering about 20% of the top of tube sheet. The sludge collars contained about 20 to 30% copper. The copper was in the elemental form and not considered a concern because of the reducing environment maintained in the steam generators.

Lead has been implicated as an initiator of stress corrosion cracking in alloy 600TT in the field and alloy 690TT in the laboratory. Analysis of lead in sludge samples is difficult and the results are frequently suspect. Typically, lead levels in the powdered sludge are about 100 ppm. During the sludge collar analysis on 3R10 samples lead was found at concentrations ranging from 800 to 1600 ppm. During the analysis on 3R14 samples lead was found at concentrations ranging from 180 to 190 ppm. During the analysis on 3R17 samples lead was found at concentrations ranging from 213 to 257 ppm. Lead concentrations will be monitored in future deposit samples.

6.2.4 Steam Generator Secondary Side In-Bundle Inspection

There have been secondary-side in-bundle remote video inspections performed on the steam generators during all refuel outages since the steam generators were replaced when secondary side SG work was performed. 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 typically covers the annulus and tube lane. Retrieval is attempted on all foreign objects that are considered detrimental to SG tube integrity. If retrieval is not successful, an evaluation is performed to justify operation with the object left in the SG. The third inspection is in-bundle where typically every 5th column is examined for the buildup of hard deposits.

Additional inspections are periodically performed on selected steam generators. An inspection is done of the tops and bottoms of the tube support plates (TSP) in the vicinity of the flow slots. The purpose of this inspection is 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.

6.2.5 Steam Generator Secondary Side Upper Internals Inspection

In November 1993 an inspection was performed on the upper internals portion of all four steam generators. This inspection was performed to meet the recommendation contained in the steam generator owners manual 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 examined consisted 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 NRC Information Notices 96-09 and 96-09, Supplement 1, identified several modes of degradation in the secondary side of pressurized water reactor (PWR) steam generators (SGs) operated in Europe by Electricite de France (EDF). During R09 in June 1997, a comprehensive inspection of secondary side internals was performed in 34 SG. The inspection looked at the following areas: primary separator/swirl vanes, transition cone to upper shell weld, secondary separator, J-nozzle and feedwater ring, top support plate ligament cracking, anti-vibration bars

(AVBs), upper wrapper supports, upper wrapper support anti-rotation keys and wedges, lower wrapper support keys and the wrapper weld seam. The results are reported in Field Service Report INT-20 and summarized as follows:
"From the collective observations ..., these steam generators, to the extent inspected during this outage by procedure NSD-FP-1997-7966, do not exhibit any advance degradation, and only exhibit the possible initiation of some deterioration modes that should be observed in the future to establish the rate of progression. These possible initiations of deterioration include:
(1) Upper tube support plate "G" tube hole blockage in select areas that are only now beginning to show as scale build-up between the tube support plate quatrefoil hole lands and the tube.
(2) Feedwater ring J-tube discharge impingement on the feedring pipe outer diameter surface and/or on the primary separator riser barrels, now observed as only a "washed" areas void of magnetite build-up and having no discernible depth of base material.
(3) J-tube to feedwater ring inner diameter surface joint erosion-corrosion of the feedwater pipe base material, only identified during this outage as possibly starting for the J-tube closest to the feedwater nozzle and "T" section.
(4) Sludge collection on the lower deck plate where washing off is prevented by the lower deck skirt attached at the periphery of the deck; now showing as a uniform sludge depth of approximately $^{1}/_{16}$ inch and a few local piles up to ½ inch deep."

In December 1998, Westinghouse evaluated the susceptibility of model 44F steam generators to the internals degradation exhibited in the French steam generators and determined that the IP3 replacement steam generators were not susceptible. This was documented in a report prepared for the Westinghouse Owners Group (WOG).

During 3R10 in 1999, the steam drum in 33 SG was visually inspected. The steam drum was in good shape with the only anomaly being some streaks on the inside diameter of the feedring indicative of J-nozzle discharge impacting on the feedring surface. The maximum estimate of wear is 10 mils on a 0.500" thick pipe so there is currently no concern.

A steam drum inspection was performed in 32 SG during 3R11 in 2001. No anomalies were noted and the steam drum was noted to appear cleaner than previous steam drum inspections in the other steam generators. Based on the positive results of the previous steam drum inspections, the inspection of the 31 SG steam drum scheduled for 3R12 was deferred to 3R14.

In 3R14, the steam drums of 31 and 32 steam generators were inspected. Both steam drums looked very good with no anomalies

noted. There were washed out areas on the feedring below the outlet of the J-nozzles comparable to what was observed in 34 SG in 1997 with negligible loss of base material from the carbon steel feed ring. The primary and secondary separators were clean with no buildup of deposits and no structural issues were identified.

In 3R17, the steam drums and top support plates (TSP) of 33 and 34 steam generators were inspected. Both steam drums and TSP's looked very good with no anomalies or abnormal wear noted. The primary and secondary separators were clean with no buildup of deposits and no structural issues were identified. For more details see the 3R17 secondary side inspection final report.

6.2.6 Inspection History

a. Inspection results are kept in the vendor database.

b. Copies of the inspection results are kept in the IPEC records management system.

6.3 Examination Scheduling

6.3.1 Refer to Attachment 6 for historic and future Inspection Plans. Attachment 6 contains a table outlining the past maintenance and inspection work that has been performed on the replacement SGs at IP3 along with tentative future plans. The frequency of future eddy current inspections is driven by technical specifications. The number of tests is driven by both technical specifications and the need to acquire enough information to support the operating interval between inspections. The inspection plans are the results of degradation assessments performed prior to each SG eddy current inspection.

Secondary side maintenance and inspections are performed as needed in a balance between the cost and perceived benefits of those activities. Periodic cleaning reduces sludge deposits that could support corrosion and it enhances the ability to perform visual inspections. Visual inspections are most valuable in their ability to monitor the buildup of sludge and to detect foreign objects not detectable by eddy current that could challenge tube integrity during the operating interval.

7.0 MAINTENANCE AND REPAIR

7.1 Primary Side

7.1.1 Plugging

a. Current accident analyses assume SG plugging levels of 10% to support implementation of the 4.8% stretch power uprate. Therefore the current tube plugging limit is 10%.

b. Plugging specification

i. A plugging specification shall be developed in accordance with the ASME code requirements.

c. The Indian Point 3 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%, the structural limits for the steam generator tubing were calculated in accordance with draft regulatory guide 1.121. The results are documented in WCAP-15920.

In 2005, a stretch power uprate SPU of 4.8% was implemented. The structural limits for the steam generator tubing were recalculated in Calculation Note Number CN-SGDA-03-147. Two operating conditions were evaluated, high Tave and low Tave corresponding to steam pressures of 715 and 650 psia respectively. IP3 currently operates with a steam generator steam pressure of 730 psig which corresponds to the high T_{ave} operating conditions.

The table below summarizes the IP3 RSG tube structural limits.

Structural Limits for IP3 Replacement Steam Generators

Location / Wear Scar Length	Structural Limit (%)(1)		
	1.4% Uprate	4.8% SPU high T_{ave}	4.8% SPU low T_{ave}
Straight Leg and Anti-Vibration Bar(2) / ≥1.50" (Tube Rows 9-16 and 25-27)	56.00	**54.00**	52.00
Anti-Vibration Bar(2) / 0.9" (Tube Rows 17-24 and 28-45)	62.00	**60.20**	58.20
Flow Distribution Baffle / 0.75"	64.60	**62.80**	61.00
Tube Support Plate / 1.125"	59.00	**57.00**	55.20

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

(2)For tube / AVB tangent points, straight leg structural limits apply. Tube / AVB tangent point correspond to Row 9 for the inner set of AVBs, Row 14 for the intermediate set of AVBs, and Row 25 for the outer set of AVBs. For tube / AVB intersections that are not tangent points, but exceed the 0.9" wear scar length, straight leg structural limits also apply.

d. Plugging and repair methods shall be developed, qualified, and implemented in accordance with the applicable provisions of the

ASME Code and 10CFR50, Appendices A and B. Plugs are to be procured in accordance with the appropriate specification

e. The vendor performing plugging shall submit their applicable procedures for installation of plugs for approval.

f. Each primary side SG inspection, a visual inspection of all installed plugs shall be performed. Any evidence of unexpected leakage or abnormal conditions shall be documented by the initiation of a condition report. The inspection will be documented by a type of optical media.

g. Following each primary side SG inspection, an EC documenting the number of tubes plugged, as well as their row-line designation, shall be performed and provided to Safety Analysis to update their records on available RCS volume and flow.

h. The tubes plugged shall be tracked for future reference.

i. A 100% pre-service examination shall be performed on all plug installations. This can be in the form of a visual verification and process verification such as torque traces or mandrel travel distance. All verifications shall be reviewed by the Utility and documented.

j. History of Tube Plugging

During SG fabrication two tubes were plugged in 34 SG due to ding indications at row 44, col 57 and row 45, col 52. Both ends of each of these tubes were plugged with a welded tapered tube plug fabricated from Alloy 600 material that was given an additional special heat treat by Westinghouse to optimize the plug material microstructure.
No inservice tube plugging was performed until 3R12 in 2003 when 13 tubes were administratively plugged for one of 3 reasons. One tube had a permeability variation that reduced the sensitivity of eddy current to identify potential degradation. Three tubes had small volumetric indications between 15 and 23% through wall (TW) at the top of the tubesheet that were attributed to loose part wear when identified in 1999. However no foreign objects were found that could be linked to the degradation so the tubes were administratively plugged in 2003 because the cause could not be reasonably ascertained. The remaining 9 tubes were plugged administratively after detecting wear scars that were attributed to contact with the sludge lance rail system used for the first and only time in 2001. The wear scars had lengths ranging from 0.6 to 2.45 inches and depths initially ranging from 20 to 47% that were later re-evaluated to be 8 to 26% TW. The tubes were plugged because the degradation was not anticipated and the appropriateness of the sizing technique was in question at the time of the inspection. The tubes plugged in 3R12 are listed in the table below.

In 3R14, two tubes were preventatively plugged due to the presence of a wedged metallic object in 31 SG. The tubes were evaluated for potential stabilization which was determined as unnecessary due to the limited circumferential contact with the foreign object.
In 3R17 no tubes were plugged.
No tube sleeving has been performed or planned until the advent of a degradation mechanism that affects numerous tubes that makes the process economical or plugging would force the plant to derate its output capacity. Currently, the SGs have excess thermal capacity on the order of 10%.

Tube Plugging List from 3R12

SG	Tube	Location	Indication	Degradation Depth Percent TW
31	R28 C29	-4.96 to 5.04	PVN	n/a
32	R41 C28	TSH +0.15	VOL	34%
32	R40 C29	TSH +0.0	VOL	32%
32	R41 C29	TSH +0.05	VOL	24%
32	R1 C85	TSH +16.70	VOL	11%*
32	R1 C9	TSC +16.01	VOL	8%*
32	R1 C66	TSC +18.16	VOL	13%*
33	R1 C66	TSH +15.62	VOL	26%*
33	R1 C27	TSH +18.04	VOL	16%*
		TSC +17.86	VOL	12%*
33	R1 C8	TSC +16.51	VOL	9%*
34	R1 C8	TSH +16.69	VOL	10%*
34	R1 C84	TSC +16.92	VOL	11%*

*These volumetric indications were attributed to wear from sludge lance equipment and were evaluated using an amplitute based curve constructed from as built depths developed using the ASME flat bottom hole standard.

Tube Plugging List from 3R14

SG	Tube	Location	Indication	Degradation Depth Percent TW
31	R29 C79	TSH	PLP	0%
31	R29 C80	TSH	PLP	0%

Tube Repair Summary for IP3

	SG 31	SG 32	SG 33	SG 34	Total
Total Number of Tubes	3214	3214	3214	3214	12856
Number of Sleeved Tubes	0	0	0	0	0
Number of Plugged Tubes	3	6	3	4	16

% of Tubes Plugged to Date	0.09%	0.19%	0.09%	0.12%	0.12%
Effective Tube Plugging %	0.09%	0.19%	0.09%	0.12%	0.12%

Note: Since there are no sleeves installed and the safety analyses credit plugged tubes with the same value regardless of location, the effective tube plugging is equivalent to the percentage of tubes plugged.

Tube Plugging History for IP3

Year	Outage	SG31	SG32	SG33	SG34	Total
1988	Pre-service	0	0	0	**2**	**2**
1990	3RO7	0	0	0	0	0
1992	3R08	0	0	0	0	0
1997	3R09	0	0	0	0	0
1999	3R10	0	0	0	0	0
2001	3R11	0	0	0	0	0
2003	3R12	**1**	**6**	**3**	**2**	**12**
2005	3R13	0	0	0	0	0
2007	3R14	**2**	0	0	0	**2**
2013	3R17	0	0	0	0	0
Total Plugged		3	6	3	4	16
Percent Plugged		0.16%	0.19%	0.09%	0.12%	0.12%

7.1.2 Stabilization

a. Stabilization, or staking, of SG tubes may be required when plugged to prevent impact and damage to adjacent tubes.

b. Stabilizers are to be procured in accordance with the appropriate specification.

7.1.3 Sleeving

a. IP3 does not have any sleeved tubes.

7.1.4 Summary of Pulled Tube Test Results

a. IP3 has not pulled any tubes from the steam generators.

7.1.5 Alternate Repair Criteria

a. IP3 does not utilize an alternate repair criteria.

7.2 Secondary Side

7.2.1 Sludge lancing

a. Lancing will be performed using a vendor approved procedure.

8.0 PROGRAM IMPLEMENTATION

8.1 Pre-Outage

8.1.1 A pre-outage and outage checklist should be used to identify all actions needed with responsible person and due dates.

8.1.2 Proposals will be requested for the scope of work and contracts initiated.

8.1.3 Vent Path may be evaluated pre-outage if required.

8.2 Outage

8.2.1 The condition monitoring assessment and the interim operational assessment will be completed prior to mode 4.

8.3 Post-Outage

8.3.1 The outage checklist will be utilized to validate that all task have been completed.

8.3.2 The NRC required 180 day report will be completed and submitted prior to the due date.

8.3.3 The EPRI SGDD will be updated within 120 days

8.3.4 The final operational assessment will be complete within 90 days unless it is considered complicated which will allow for it to be completed with adequate documentation.

8.3.5 Records will be submitted within 60 days of final signatures.

8.4 Vendor Documents

8.4.1 Review and approval of vendor procedures will be performed utilizing the PAD initially and documented in the Merlin records management system.

8.5 Document Cross-references

8.5.1 See Attachment 4 for a list of where various program documents are documented. Documents prior to 3R17 are not included.

9.0 DEVIATIONS

9.1 Deviations are developed and controlled in accordance with EN-DC-202 and EN-DC-317

9.2 Listing of site deviations

9.2.1 Active - None

9.2.2 Historical - None

10.0 ATTACHMENTS

10.1 Attachment 1 In-Situ Testing

10.2 Attachment 2 Steam Generator Visual Inspection

10.3 Attachment 3 Steam Generator Sludge Lancing

10.4 Attachment 4 Steam Generator IP3 Document Cross Reference

10.5 Attachment 5 IP3 Steam Generator Loose Parts Inventory

10.6 Attachment 6 IP3 Steam Generator Work Scope Chart

10.7 Attachment 7 IP3 Steam Generator Evaluations

10.8 Attachment 8 IP3 Steam Generator Outage Inspection Summary

ATTACHMENT 1
In-situ Testing

1.0 LIMITS AND PRECAUTIONS

1.1 Items removed from the primary side of the steam generators may be highly radioactive. Failure to properly evaluate radiological hazards associated with such items can result in doses in excess of regulatory limits of administrative dose control levels. Additionally, such items can be a source of area dose rates higher than indicated by area radiological postings.

1.2 Shield doors/ventilation equipment is to be installed as soon as the diaphragms are removed. The doors are to remain closed at all times except when work is being performed.

1.3 Radiation Protection coverage is required for the steam generator work. A Radiation Protection representative will be present at the platform at the discretion of Radiation Protection.

1.4 When communication is lost with Radiation Protection no work is to be performed inside the generator without coverage at the platform, or communications must be restored.

1.5 Notify Operations prior to starting In-Situ testing.

1.6 Upon completion of the in-situ testing, the tube shall be removed from service by plugging. Based on the type and location of the flaw, stabilization will be reviewed and performed in accordance with the degradation assessment.

1.7 Prior to testing, containment closure should be addressed with Operations due to the possibility that the tube could burst.

1.8 If a flaw requires proof testing, leak testing is also required. If the indication is axially oriented, if it requires leak testing, proof testing is also required.

1.9 All flaws will be screened for testing.

1.10 Hold times will be a minimum of 2 minutes.

1.11 Pressurization rates will be $\leq$ 200 psi/second.

1.12 If leakage is observed at or below MSLB, a bladder shall be used to go above MSLB pressure.

ATTACHMENT 1
In-situ Testing

1.13 Screening of flaws will be performed in accordance with the EPRI Steam Generator In-situ Pressure Test Guidelines

2.0 PREREQUISITES/INITIAL CONDITIONS

2.1 All required Vendor procedures shall be approved prior to starting work.

2.2 Trained personnel in accordance with the appropriate vendor procedures shall perform all equipment setups.

2.3 Trained personnel in accordance with the appropriate vendor procedures shall perform all tooling calibrations.

2.4 Ensure Confined Space Entry Permit obtained, as necessary.

2.5 Ensure personnel have completed any required mockup training and pre-job briefing as required.

2.6 Nozzle dams and/or covers should be installed prior to primary access unless actions are taken to prevent entry of foreign material into the steam generator.

2.7 Ensure Foreign Material Exclusion "FME" accountability in accordance withEN-MA-118.

2.8 Ensure that the required documentation listing the candidate tubes for in-situ testing have been authorized by an Engineering representative.

2.9 An Engineering representative shall notify the applicable Operations representative that work is about to commence and verify that containment closure is acceptable.

Name (Ops. contacted)	Date	Name (Engineering)

ATTACHMENT 1
In-situ Testing

2.10 The level of the secondary system should be evaluated based on the type and location of the flaw being tested. It is not always necessary to drain the secondary prior to testing. It is beneficial to leave the secondary in wet lay-up if possible. Both Operations and Outage Management should agree to this.

2.11 Prior to the start of In-situ testing verify that the vendor procedures being used in the field are consistent with those that have been reviewed and approved.

3.0 INSTRUCTIONS

Prior to the start of in-situ testing, an Entergy representative will verify that the field procedures being used by the vendor are consistent with those that have been reviewed and approved.

__________________ Entergy Rep.	__________________ Date and Time

3.3 Reporting

3.1 Documentation of the selection or exclusion of the identified flaws will be performed. This will be documented with an EC.

__________________ Code Programs Rep.	__________________ Date and Time

3.2 The data will be entered into the EPRI steam generator degradation database within 120 days of completion of the test.

__________________ Code Programs Rep.	__________________ Date and Time

3.3 If leakage or burst is experienced during testing, the information will be transmitted to the EPRI Engineering and Regulatory Issues Resolution Group within 15 days.

__________________ Code Programs Rep.	__________________ Date and Time

ATTACHMENT 1
In-situ Testing

3.4 Document the results of the testing with an EC. Typically this is part of the condition monitoring report.

____________________ ____________________
Code Programs Rep. Date and Time

4.0 RESTORATION AND CHECKOUT

4.1 Perform cleanup operations, as necessary, to remove equipment and debris from the primary heads of the steam generators and adjacent areas of the primary manways.

____________________ ____________________
Code Programs Rep. Date and Time

4.2 Notify Operations and Outage Management when the in-situ testing has been completed.

____________________ ____________________
Code Programs Rep. Date and Time

4.3 Verify that the tubes tested have been removed from service.

____________________ ____________________
Code Programs Rep. Date and Time

4.4 After completing this procedure, include in repair work order for permanent records.

____________________ ____________________
Code Programs Rep. Date and Time

Table 1 Historical In-Situ Test

Outage	Steam Generator	Row	Tube/Column	Pass/Fail	Reason for In-situ Test

ATTACHMENT 2
Steam Generator Visual Inspection

The inspection of the secondary side of the steam generator is broken down into distinct areas. They include:

Secondary Side Upper Internals

- Feedring and J-nozzles
- Primary and Secondary Moisture Separators

Secondary Side Lower Internals

- Annulus/Tube Lane
- Tube Support Structures/ Tube Bundle

1.0 Prerequisites

1.1 Verify water level in the secondary side is adjusted to the appropriate height. The water level should be maintained as high as possible to assist with shielding.

____________________________ ____________________________

Individual Date

1.2 Verify that the appropriate opening (secondary manway, inspection port or handholes) have been removed.

____________________________ ____________________________

Individual Date

1.3 Verify appropriate FME criteria are in place.

____________________________ ____________________________

Individual Date

1.4 Verify that a Confined Entry Permit has been processed. This will include the requirement for ventilation and heat stress. Also that if the internal hatches were open, testing of the environment was performed in the areas that will be entered. This may require a second testing with the first being for entry to remove the tack welds on the internal hatches.

____________________________ ____________________________

Individual Date

ATTACHMENT 2
Steam Generator Visual Inspection

1.5 Verify that the steam generator(s) have been isolated with Operations.

Individual	Date

1.6 Perform a pre-job brief to determine roles and responsibilities prior to performing the task to minimize exposure and limit the time the secondary sides are open.

Individual	Date

1.7 Ensure all tooling and equipment is lanyard off. This will include dosimitry. Dropping of material into the secondary side of the generator is forbidden. If something is lost, initiate a Condition Report.

Individual	Date

1.8 If inspecting the upper internals or access to the tube bundle is required, verify that the internal hatches have had the tack welds removed and are ready for access.

Individual	Date

1.9 Notify Operations and Radiation Protection prior to starting work.

Individual	Date

2.0 Instructions

2.1 Secondary Side Upper Internals Inspection

A thorough inspection of the steam generator upper internals should be performed.

ATTACHMENT 2
Steam Generator Visual Inspection

The purpose of inspection of the secondary side upper internals is to examine the condition of the:

- Primary and Secondary Moisture Separation Equipment
- Feedwater Ring and J-tube Assembly

The inspection should include but is not limited to:

- OD surface Erosion/Corrosion
- Mechanical Damage
- Any Unusual Conditions

If any of the above items are identified, a condition report shall be initiated.

Ultrasonic testing of the J-tubes may be required if evidence of erosion is found. Certified UT personnel should take thickness measurements and the values compared to the baseline/design data.

2.2 Secondary Side Lower Internals Inspection

If possible, an inspection should be performed in order to assess the amount of sludge deposition on the tubesheet and to check for loose parts as well as corrosion and other damage in the lower tube bundle region.

The scope of the inspections of the secondary side lower internals may include:

- Visual Inspection of the Annulus for Loose Parts
- Visual Inspection of the Groove in the Annulus for Loose Parts
- Visual Inspection of the Tube Lane and Row 1 Tubes
- Visual Inspection of the First Tube Support Plate

The inspection should include but is not limited to:

- OD surface Erosion/Corrosion

ATTACHMENT 2
Steam Generator Visual Inspection

- Unusual Sludge Deposition
- Loose Parts

If any of the above items are identified, a condition report shall be initiated.

ATTACHMENT 3
Steam Generator Sludge Lancing

The tubesheet secondary side should be cleaned regularly to minimize the buildup of solids deposits. Sludge accumulation control is an integral part of the preventative maintenance program for the steam generators.

The sludge lance system consists of both high and low pressure water systems. The high-pressure system is used to loosen and move the sludge from between the tubes to the periphery of the tube bundle. The low-pressure system provides a high volume flow of water from the handholes at one end of the tubelane, around the bundle periphery, to the handhole at the opposite end of the tubelane. The water and sludge are extracted by a suction manifold at the handhole.

Sludge lancing will be performed using approved vendor procedures.

1.0 Prerequisites

1.1 Verify water level in the secondary side has been drained and the nitrogen overpressure has been terminated.

____________________________ ________________________

Individual Date

1.2 Verify that the appropriate handholes have been removed.

____________________________ ________________________

Individual Date

1.3 Verify appropriate FME criteria are in place.

____________________________ ________________________

Individual Date

1.4 Verify that Safety has determined that the area that the individuals will be working is not oxygen deficient due to the nitrogen overpressure.

____________________________ ________________________

Individual Date

ATTACHMENT 3
Steam Generator Sludge Lancing

1.5 Verify that the steam generator(s) have been isolated with Operations.

_____________________ _____________________

Individual Date

1.6 Demineralized water has been sampled and the results meet or exceed the following criteria:

Sodium	< 1000 ppb
Chloride	< 1000 ppb
Sulfate	< 1000 ppb

_____________________ _____________________

Individual Date

1.7 Perform a pre-job brief to determine roles and responsibilities prior to performing the task to minimize exposure and limit the time the secondary sides are open.

_____________________ _____________________

Individual Date

1.8 Ensure all tooling and equipment is lanyard off. The loss of material into the secondary side of the generator is forbidden. If something is lost, initiate a Condition Report.

_____________________ _____________________

Individual Date

1.9 Notify Operations and Radiation Protection prior to starting work.

_____________________ _____________________

Individual Date

2.0 Instructions

ATTACHMENT 3
Steam Generator Sludge Lancing

2.1 Setup

2.1.1 Have the sludge lance trailer delivered prior to the start of the outage under normal circumstances.

2.1.2 Have temporary power connected to the trailer.

2.1.3 Notify Radiation Protection for posting area

2.1.4 Align de-mineralized water to the trailer

2.2 Sludge Lancing

2.2.1 Lancing is performed in accordance with the Vendor approved procedure.

2.2.2 Each time lancing is performed; two 1-liter samples will be taken from each generator lanced. One will be analyzed and one kept for archive purposes.

2.2.3 The sample that is sent off must be counted for activity prior to shipment.

2.2.4 As a minimum, the following species should be tested for:

Iron	Calcium	Chrome
Copper	Phosphate	Potassium
Nickel	Aluminum	Sulfur Species
Manganese	Magnesium	Zinc
Silica	Sodium	Lead

2.2.5 When analysis is complete, trend each species. Document the results and total weight removed using the EC system.

2.3 Close-out

2.3.1 Once lancing is complete, sample the bulk water for activity and solids.

2.3.2 Based on the results, coordinate with Operations and Chemistry for draining.

ATTACHMENT 3
Steam Generator Sludge Lancing

2.3.3 Notify Radiation Protection for de-posting of area.

2.3.4 Notify Rad-waste for delivery of drums and archived sample.

ATTACHMENT 4
IP3 Steam Generator Document Cross Reference

Outage	SG Condition Monitoring	SG Degradation Assessment	SG Operational Assessment	PLP/Sec Side Report	SG Equivalency	SG Analysis Guidelines	Training Manual	Hideout Return	Sludge Analysis	Notes
3R17	Note 1	Note 1	Note 1	Note 1	N/A	Note 1	Note 2	N/A	Note 1	

Note 1: These documents are part of the 3R17 Steam Generator Areva Final Report and are located in the Merlin records management system under General Records: Search *3R17*Steam*Generator*

Note 2: These documents are part of the 3R17 Steam Generator Final Level III Report and are located in the Merlin records management system under General Records: Search *3R17*Steam*Generator*

ATTACHMENT 5

IP3 Steam Generator Loose Parts Inventory

NOTE: The most recent outage list is considered the current loose part inventory because the same areas are inspected each outage. Any material from a previous outage is considered removed, most likely by sludge lancing activities.

Loose Parts Remaining after Refueling Outage 7

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1990	31	C			periphery between cols 59 & 71	weld slag	0.031	0.500	0.500	
1990	32	H			periphery between cols 59 & 71	congealed sludge	0.063	0.333	0.333	
1990	33	H			periphery between cols 53 & 59	congealed sludge	0.500	0.250		
1990	34	H			periphery between cols 58 & 59	congealed sludge	0.375	0.250		
1990	34	C			periphery between cols 45 & 58	congealed sludge	0.375	0.250		

Loose Parts Remaining after Refueling Outage 8

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1992	31	H	40	29		flexitallic gasket	0.500			
1992	31	H	29	26		flexitallic gasket	1.000			
1992	31	H	37	25		flexitallic gasket	1.000			
1992	31	H	32	17		flexitallic gasket	0.500			
1992	31	C	39	25		flexitallic gasket	3.000			
1992	31	C	42	45		flexitallic gasket	2.000			
1992	31	C	43	46		flexitallic gasket	1.500			
1992	31	C	43	47		flexitallic gasket	1.500			
1992	31	C	42	63		flexitallic gasket	1.000			
1992	32	H	42	46		wire	2.375	0.031	0.031	
1992	32	H	44	38		flexitallic gasket	2.000			
1992	32	H	42	53		flexitallic gasket	1.500	0.031		
1992	32	H	41	55		flexitallic gasket	3.000			
1992	32	H	40	56		flexitallic gasket	2.000			
1992	33	H	40	65		flexitallic gasket	4.500			
1992	33	H	43	56		flexitallic gasket	0.500			

ATTACHMENT 5

IP3 Steam Generator Loose Parts Inventory

1992	34	H	0	61	hot leg past 3rd blocking device	flexitallic gasket	1.250			length estimated as 1-1.5
1992	34	H	0	64	3 tube lanes from 3rd blocking device	flexitallic gasket	1.000			
1992	34	C	35	75		sludge formation	0.375	0.375		3/8 dia
1992	34	H	32	17		flexitallic gasket	3.000			
1992	34	H	23	85		flexitallic gasket	0.250			

Loose Parts Remaining after Refueling Outage 9

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1997	31	H	22	40		flexitallic gasket	0.375	0.250	0.125	
1997	31	C	19	44	C44/45	flexitallic gasket	3.000	0.250	0.125	length noted as 2.5-3.5
1997	31	C	38	43		flexitallic gasket	0.333	0.250	0.125	
1997	31	C	19	5	annulus	wire bristle	1.000	0.016	0.016	1/64 dia wire
1997	34	H	38	61		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	43	51		sludge rock (fixed in place)	0.333	0.125	0.125	
1997	34	H	37	40		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	37	45		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	30	44		flexitallic gasket	0.333	0.250	0.125	

Loose Parts Remaining in SGs after Refueling Outage 10

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1999	33	C	20	84	R20/21, C82/86	Flexitallic gasket	5.000	0.125	0.125	
1999	33	H	41	38	R41/42, C37/38	wire	1.000	0.031	0.031	1/32 dia wire
1999	34	C	28	25	R28/29	wire	0.750	0.031		1/32 dia
1999	34	C	27	25	R27/28	coiled metal chip	0.375	0.031	0.375	1/32 dia
1999	34	C	27	25	R27/28	wire	1.000	0.031	0.500	1/32 dia
1999	34	C	39	31	R39/40	sludge rock	0.750	0.250	0.250	
1999	34	C	37	31	R36/38,C30/31	wire	3.000	0.016		1/64 dia
1999	34	C	23	31	C30/31	wire	1.500	0.031		1/32 dia
1999	34	C	41	37	R41/42	sludge rock	0.375	0.375	0.375	

ATTACHMENT 5
IP3 Steam Generator Loose Parts Inventory

1999	34	C	40	37	R40/41,C37/38	sludge rock	0.750	0.188	0.188	
1999	34	C	39	37	R39/40	sludge rock	0.188	0.188	0.188	
1999	34	C	37	39	C39/40	metal chip	0.250	0.031	0.125	
1999	34	C	37	36	C36/37	wire	1.000	0.031		1/32 dia
1999	34	C	44	44	R44/45,C44/45	sludge rock	0.375	0.188	0.188	
1999	34	C	35	40	C40/41	wire	0.250	0.031		1/32 dia
1999	34	H	36	25	R36/37	wire	0.500	0.016		1/64 dia
1999	34	H	42	30	C30/31	wire	0.750	0.031	0.125	
1999	34	H	31	37	R31/32	wire	0.750	0.031		1/32 dia
1999	34	H	27	37	R27/28	wire	0.750	0.031		1/32 dia
1999	34	H	33	41	R33/34	sludge rock	0.063	0.188	0.063	
1999	34	H	36	41		wire	0.250	0.031		1/32 dia
1999	34	H	35	40	R35/36	sludge rock	0.375	0.375	0.375	
1999	34	H	32	40	R32/33,C40/41	wire	0.750	0.031		1/32 dia
1999	34	H	39	45	R39/40	sludge rock	0.750	0.375	0.375	
1999	34	H	36	45	R36/37	wire	0.750	0.031		1/32 dia
1999	34	H	34	56	R34/35	sludge rock	0.375	0.375	0.375	
1999	34	H	40	51	R40/41	metal wafer	0.375	0.031	0.375	

Note: No known loose parts were left in 31 and 32 steam generators during RF-10.

Loose Parts Remaining in SGs after Refueling Outage 11

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2001	31	H	32	20		Flexitallic gasket	.25	.25		
2001	31	C	39	40	R39-40	Wire	0.125	0.010		
2001	31	C	38	44	R39-39	Machine remnant	0.125	0.25		
2001	31	C	38	44	R38-39	Wire	0.25	0.010		
2001	31	C	34	44	R34-35	Wire	0.125	0.010		
2001	31	C	36	52		Wire	0.25	0.010		
2001	31	C	34	52		Wire	0.25	0.010		
2001	31	C	31	52		Wire	0.375	0.010		
2001	31	C	30	52		Wire	0.375	0.010		
2001	31	H	36	62	R36-37	Wire	0.375	0.010		
2001	31	H	20	62		Wire	0.062	0.010		
2001	31	H	18	62		Wire	0.062	0.010		

ATTACHMENT 5
IP3 Steam Generator Loose Parts Inventory

2001	31	H	18	57		Wire	0.300	0.010		
2001	32	C	21	10		Wire	0.125	0.010		
2001	33	C	30	53		Wire	0.125	0.010		
2001	33	C	19	53		Wire	0.125	0.010		
2001	33	C	38	36		Wire	0.125	0.010		
2001	33	C	18	53		Wire	0.310	0.020		
2001	34	H	10	5		Wire	0.125	0.010		
2001	34	H	18	10		Wire	0.750	0.010		
2001	34	H	28	24		Wire	0.125	0.010		
2001	34	H	31	31		Wire	0.125	0.010		
2001	34	C	7	15		Wire	0.125	0.010		
2001	34	C	31	21		Wire	0.125	0.010		
2001	34	C	34	21		Wire	0.125	0.010		
2001	34	C	12	21		Wire	0.125	0.010		
2001	34	C	38	40		Wire	0.125	0.010		
2001	34	C	32	40		Wire	0.125	0.010		
2001	34	C	5	44		Wire	0.125	0.010		
2001	34	TL		41		Wire	0.125	0.010		

Loose Parts Remaining in SGs after Refueling Outage 12

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2003	31	C	45	50		MSR wire	0.125	0.010		
2003	31	C	38	71		MSR wire	0.125	0.010		
2003	31	C	36	74		MSR wire	0.125	0.010		
2003	31	C	33	78		MSR wire	0.125	0.010		
2003	31	C	25	85		MSR wire	0.125	0.010		
2003	31	C	26	84		MSR wire	0.125	0.010		
2003	31	TL	01	84		MSR wire	0.50	0.010		
2003	31	H	29	26		MSR wire	0.125	0.010		
2003	33	TL		44		MSR wire	0.375	0.010		
2003	34	H	1	01	R1-5	MSR wire	0.125	0.010		
2003	34	H	27	10		MSR wire	0.125	0.010		
2003	34	H	38	21		MSR wire	0.50	0.010		
2003	34	H	40	31		MSR wire	0.125	0.010		
2003	34	H	08	40		MSR wire	0.125	0.010		
2003	34	C	16	05		MSR wire	0.125	0.010		

ATTACHMENT 5

IP3 Steam Generator Loose Parts Inventory

2003	34	C	35	31		MSR wire	0.125	0.010		
2003	34	C	39	44		MSR wire	0.125	0.010		
2003	34	C	37	44		MSR wire	0.25	0.010		
2003	34	C	21	44		MSR wire	0.25	0.010		
2003	34	C	33	74		MSR wire	0.25	0.010		
2003	34	C	39	65		MSR wire	0.25	0.010		
2003	34	C	38	56		MSR wire	0.25	0.010		
2003	34	C	37	56		MSR wire	0.25	0.010		
2003	34	C	36	56		MSR wire	0.25	0.010		
2003	34	C	42	48		MSR wire	0.25	0.010		
2003	34	C	38	48		MSR wire	0.25	0.010		
2003	34	C	38	48		MSR wire	0.25	0.010		
2003	34	C	34	48		MSR wire	0.375	0.010		

Loose Parts Remaining in SGs after Refueling Outage 14

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2007	31	H	28	11		Slag	0.25	0.125	0.125	
2007	31	H	27	12		MSR wire	0.25		0.16	
2007	31	H	34	17		Scale pile	0.36	0.312	0.125	
2007	31	H	36	19		Scale pile	0.36	0.312	0.125	
2007	31	H	37	20		Scale pile & MSR wire	0.36	0.312	0.125	
2007	31	H	36	21		Sludge rock pile	0.36	0.312	0.125	
2007	31	H	38	22		Sludge rock pile	0.36	0.36	0.125	
2007	31	H	38	23		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	39	24		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	25		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	26		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	28		Sludge rock	0.36	0.36	0.125	
2007	31	H	42	30		Sludge rock	0.36	0.125	0.125	
2007	31	H	42	67		MSR wire	1.0		0.016	
2007	31	H	38	70		Sludge rock	0.36	0.125	0.125	

ATTACHMENT 5
IP3 Steam Generator Loose Parts Inventory

2007	31	C	38	22		Gasket	0.25	0.125	0.125	
2007	31	C	38	23		Metal object	0.25	0.125	0.125	
2007	31	C	39	27		Slag	0.125	0.125	0.125	
2007	31	C	40	27		Slag	0.375	0.125	0.125	
2007	31	C	44	53		Sludge rock	0.25	0.125	0.125	
2007	31	H	27	15		Gasket	0.25	0.06	0.125	
2007	31	H	36	20		MSR wire pile	0.12	0.015		
2007	31	C		80	Annulus	Machine remnant	0.5	0.125	0.25	
2007	32	C	44	40		Scale & MSR wire pile	0.33	0.33	0.33	
2007	32	H	42	55		MSR wire pile	0.2	0.2	0.2	
2007	33				No objects found					
2007	34	H	13	15		Sludge rock	0.3	0.3	.3	

Loose Parts Remaining in SGs after Refueling Outage 17

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2013	32	C	44	46		Sludge formation	0.3	0.5		
2013	34	H	13	15		Sludge rock	0.3	0.3	0.3	

ATTACHMENT 6
IP3 Steam Generator Work Scope Chart

Long Term Maintenance and Inspection Plan for the Indian Point 3 Steam Generators 5/29/2007

Cycle EFPD	394	413	565	654	541	661	669	686	682	661	687	684	684	684	684	684	684	684
Plant EFPY	7.84	8.97	10.52	12.31	13.79	15.60	17.43	19.31	21.17	22.98	24.87	26.74	28.61	30.48	32.36	34.23	36.10	37.97
EFPY since SGR	1.08	2.21	3.76	5.55	7.03	8.84	10.67	12.55	14.42	16.22	18.11	19.98	21.85	23.72	25.60	27.47	29.34	31.21
EFPM since SGR	12.9	26.5	45.1	66.6	84.3	106.1	128.0	150.6	173.0	194.7	217.3	239.7	262.2	284.7	307.2	329.6	352.1	374.6
Month/Year	09/90	04/92	05/97	09/99	04/01	03/03	03/05	03/07	03/09	03/11	03/13	03/15	03/17	03/19	03/21	03/23	03/25	03/27
Refueling Outage #	3R07	3R08	3R09	3R10	3R11	3R12	3R13	3R14	3R15	3R16	3R17	3R18	3R19	3R20	3R21	3R22	3R23	3R24
Secondary Cleanings																		
Sludge Lance	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	, ,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					1,2,3,4													
TTS ASCA/CU rinse						, ,3,4												
TTS UEC						aborted												
CECIL Lancing																1,2,3,4		
Chemical Cleaning?																		
Lbs Sludge Removed	156	283	223	245	209	80	0	223			157							
Est lbs Iron Xported	975	1035	1304	1288	555	372	467	338	350	350	350	350	350	350	350	350	350	350
tube scale (lbs/SG)			1700	1500														
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			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	, ,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	1,2, ,	, ,3,4	, ,3,4	1,2, ,			1,2 , ,			, ,3,4		1,2, ,			, ,3,4		1,2, ,
C-F TSP (SID)	, ,3,4	1,2, ,	, ,3,4	, ,3,4	1,2, ,													
Steam Drum		1,2,3,4	, , ,4	, ,3,	,2, ,			1,2, ,			, ,3,4		1,2, ,			, ,3,4		1,2, ,
Primary Inspections																		
Full length bobbin	1,2,3,4	1,2,3,4	, ,3,4	1,2, ,		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	1,2,3,4
% of tubes/SG	r20	r20	r60	100		25		50/55			50		50		50	50	50	50
R1&2 U-bend RPC			, ,3,4	1,2, ,		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	1,2,3,4
% of tubes/SG			r20	40		60/100		61/50			50		50		50	50	50	50
HL Tubesheet RPC			, ,3,4	1,2, ,		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	1,2,3,4
% of tubes/SG			r20	40		20/30		37			60		60		60	60	60	60
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	1,2,3,4
% of tubes/SG						8		22			22		22		22	22	22	22
Inspection Periods	12.9	13.6	32.1	53.6	***71.4***	93.1	115.1	***137.6***	**22.4**	**44.2**	***66.7***	**89.2**	***111.7***	26.1	***48.6***	***71.1***	***33.6***	***56.0***
Period Milestones	1st ISI				72			144			54		108		36	72	30	60
Plugging																		
SGs plugged (Note 1)						1,2,3,4		1,2,3,4			1,2,3,4							
# tubes plugged						1,6,3,2		2,0,0,0			0,0,0,0							
Rev & Sec of Exam GL	2	2	4	5/3	5/4	5/4	6/3	6/3										

Legend: 1,2,3,4 represents work performed in 31, 32, 33 and 34 SGs
where there are two percentage numbers in a cell, it represents inspections performed in 31/32 and 33/34 SGs respectively
Note 1: two tubes were plugged in 34 SG in the fabrication shop (1988) with specially heat treated Alloy 600 welded plugs.

ATTACHMENT 7

IP3 Steam Generator Evaluations

Sludge Lance Tube Wear

Westinghouse issued a nuclear safety advisory letter (NSAL-03-5) to notify users of its Series II sludge lance rail that the system could potentially cause wear in selected row 1 tubes. IP3 used this rail system in 2001 and identified tube wear during the 2003 eddy current inspection. The eddy current examination scope was increased to include the row one tubes adjacent to the rail latching mechanism. Additional wear indications were found during the scope expansion. In the NSAL, Westinghouse further identified four row 1 tubes that conservatively could have been contacted by Delrin guide blocks containing metal pins. Those columns for IP3 were 1, 3, 90 and 92. Columns 1 and 90 were inspected as part of the original bobbin scope at IP3 in 2003. No wear indications were found in those rows and Westinghouse reports that to date, there has been no reported wear among Series II rail users in the vicinity of the Delrin block. No wear was anticipated in columns 3 and 92 at IP3 but those tubes were included in the bobbin inspection scope for 3R14 as well as any row 1 tubes not inspected since 2001. In 3R14, there were no wear indications found in previously uninspected row 1 tubes. However two row 1 tubes previously inspected with no wear indications had wear identified in 3R14 at TTS+16" consistent with sludge lance rail wear scars. The indications were just above the detection threshold and not considered missed indications in the previous inspection. The wear was sized conservatively at 26 and 29% TW and the tubes were left in service.

Top of Tubesheet Volumetric Indications in 32 Steam Generator

In 1999, volumetric indications were found in three hot leg peripheral tubes in 32 SG at the secondary face of the tubesheet with plus point RPC eddy current probe. These indications were never identified with bobbin probes and this was the first inspection of those tubes with RPC. The depths of the indications were 15, 21 and 23% when sized against an ASME flat bottom hole standard. The cause could not be determined but the possibilities were manufacturing or wear from loose parts. No loose parts were found at the tube locations so the indications were not expected to increase in size so the tubes were left in service.

Prior to the 2003 eddy current inspection, the 1999 data for the three tubes was reviewed. It was determined that the indications in two of the tubes extended into the expansion transition. This extent makes it impossible for the indications to be due to contact with loose parts so the most likely cause is manufacturing. During the 2003 eddy current inspection the tubes were re-examined and found to be the same size as in 1999. A decision was made to administratively plug the three tubes.

ATTACHMENT 8

IP3 Steam Generator Outage Inspection Summary

SG Outage Inspection Summary

Technical specifications required different inspection scopes for the first 3 in-service inspections. The EPRI PWR SG Examination Guidelines have been revised several times since SG replacement and those revisions have changed the SG inspection requirements. A description of the requirements at the time of each refueling outage and the SG inspections performed to meet those requirements is presented below.

3R07 – September 1990

Requirements: This was the first refueling outage after SG replacement and the first in-service inspection (ISI) for the replacement steam generators (RSGs). The TS requirement was to perform an inspection between 12 and 24 calendar months since the last inspection. TS also required that at least 6% of the tubes in each of 2 SGs be inspected and the tubes to be inspected should be selected on a random basis. Revision 2 of the EPRI GL was in effect at the time and required that 20% of the tubes in all SGs be inspected.

Inspection: The 3R07 inspection was performed 17 calendar months after the post installation inspection performed in April 1989. Twenty percent of the tubes in each SG were selected on a random basis and inspected over their full length with a bobbin probe. No degradation was found and the inspection was classified C-1 per TS.

3R08 – May 1992

Requirements: This was the second refueling outage after SG replacement and the second ISI for the RSGs. The TS requirement was to inspect a minimum of 12% of the tubes in one of the 2 SGs not previously inspected between 12 and 24 months subsequent to the last inspection. Again the tubes to be inspected should be selected on a random basis. Revision 2 of the EPRI GL were still in effect requiring 20% of the tubes in all SGs to be inspected.

Inspection: The 3R08 inspection was performed 20 calendar months after the previous inspection. Twenty percent of the tubes in each SG were selected on a random basis and inspected over their full length with a bobbin probe. No degradation was found and the inspection was classified C-1 per TS. TS permits extending SG inspection intervals to 40 calendar months following two consecutive C-1 inspection results.

3R09 – May 1997

Requirements: This was the third refueling outage after SG replacement and the third ISI for the RSGs. The TS requirement was to inspect a minimum of 12% of the tubes in the SG not previously inspected within 40 calendar months since the last inspection since the previous two inspection results were classified C-1. Prior to reaching the end of the 40-

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month interval in September 1995, a license amendment request (LAR) was submitted to extend the inspection interval to the 3R09 refueling outage. The LAR tried to apply the 1.25 surveillance extension to the 40-month interval to reduce the amount of the extension. The NRC approved the request but called out that application of the 1.25 was not appropriate for SG inspections. Reference Tech Spec Amendment #166.

Prior to 3R09 there was an industry concern about using appropriate inspection techniques since the rotating pancake coil (RPC) probe was qualified to detect circumferential degradation that the bobbin probe could not. The NRC issued a letter requesting each utilities plans for using the relatively new RPC probe. It its letter to the NRC, IP3 staff committed to inspecting just 3% of the hot leg expansion transitions and row 1 and 2 U-bend regions with the RPC probe on a one-time basis at the next inspection (3R09).

Revision 4 of the EPRI GL was in effect prior to 3R09. The revision permitted inspection of just half the SGs provided the sample size was increased to 40% of the tubes in those SGs. Revision 4 also stipulated that no SG shall operate more than two cycles between inspections and that 100% of the tubes were inspected over their full length within 60 effective full power months (EFPM). This revision also permitted the selection of tubes to be inspected on either a random or systematic basis provided the selection was evenly distributed across the SG. Another requirement implemented in revision 3 and carried on in revision 4 was to inspect 100 percent of the tubes over their full length with a general purpose eddy current probe (bobbin) in the first ISI after replacement but this requirement was not retroactive to SGs already beyond the first ISI.

Inspection: IP3 decided to shift from inspecting 20% of the tubes in all 4 SGs to 40% of the tubes in two SGs each refueling outage as a more economical alternative to inspecting all 4 SGs each refueling outage.

In 3R09 IP3 began inspecting alternating pairs of generators and performed the following inspection on steam generators 33 and 34:

- 60% full-length bobbin (completing 100% inspection in both generators)
- 20% of the hot leg expansion transitions with plus point RPC probe- hot leg (selected on a random basis)
- 20% MRPC of rows 1 &2 U-Bend (selected on a random basis)
- ALL dings and dents greater than 5 volts with plus point
- ALL previously identified areas with loose parts left in those generators
- ALL partial length inspections performed previously were re-examined.

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The inspection results showed no degradation and were categorized as C-1 permitting the continuation of 40 calendar month inspection intervals.

3R10 – October 1999

Requirements: This was the fourth refueling outage after SG replacement and the fourth ISI. The TS requirement was to inspect 12% of the tubes in one SG on a rotating basis provided the previous inspections demonstrate that the SGs are performing in a like manner which was the case. Another option is to inspect 3% of the tubes in all 4 SGs. EPRI had released revision 5 of the examination guidelines one month prior to the outage was not required to be implemented until after the outage so the revision 4 requirements were in effect. This meant that SGs 31 and 32 had to be inspected such that 100% of the tubes would be inspected over 60 EFPM.

Inspections: In 3R10 SGs 31 and 32 were examined at 29 calendar months since the last inspection. The following inspections performed in those SGs:

- 100% full-length bobbin excluding the U-Bend areas
- 40% of the expansion transition with plus point RPC probe-hot leg
- 40% of rows 1 &2 U-Bend with plus point RPC probe-hot leg
- ALL dings and dents greater than 5 volts with plus point probe
- ALL previously identified areas with loose parts left in those generators were also inspected

The inspection identified 2 tubes with degradation (=>20% through wall) but the inspection results were still classified as C-1 maintaining 40-month inspection intervals. The two tubes were left in service because revision 4 of the EPRI GL did not require an Appendix H qualified sizing technique to leave degraded tubes in service.

3R11 – May 2001

Requirements: This was the fifth refueling outage after SG replacement but no ISI inspection was performed. The TS requirement was to inspect at least 12% of the tubes in one SG within 40 calendar month intervals. Another option is to inspect 3% of the tubes in all 4 SGs. The following outage (3R12) was scheduled 42 calendar months after the 3R10 inspection but implementation of improved technical specifications added a specific statement under the SG section that the surveillance margin of 1.25 applied to SG inspections. (TS amendment 205) The basis section for applying this margin states that it could be applied to extend surveillance intervals to be consistent with refueling intervals.

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Revision 5 of the EPRI GL was in effect at this time. Revision 5 presented two options for SG inspections; prescriptive and performance based. The prescriptive requirements were the same as in revision 4. The performance based approach was new and allowed the condition of the SGs to determine the inspection intervals provided no SG operated more than two cycles between inspections and all tubes were inspected on a rolling 60 EFPM basis.

Inspections: IP3 elected to adopt a performance based SG inspection program that determined that no inspections were required in 3R11. The 1.25 surveillance margin was applied to satisfy TS requirements and technical justifications for deviating from the two cycle and 60 EFPM requirements were prepared as well. The SG operational assessment supported deferring inspections until the next refueling outage.

3R12 – April 2003

Requirements: 3R12 was the sixth outage following SG replacement and the fifth ISI for the RSGs. The TS requirements were to inspect at least 12% of the tubes in one SG in a 40 calendar month interval. Another option is to inspect 3% of the tubes in all 4 SGs. The surveillance margin of 1.25 times the interval could be applied meaning the inspection could be performed at 50 months provided it was consistent with refueling intervals. 3R12 was 42 calendar months since the last SG inspection. TS also stated that the inspection population should be selected at random.

IP3 had adopted the requirements for performance based SG inspections under revision 5 of the EPRI GL. Evaluations determined that inspections were not required in 3R12 but IP3 opted to inspect all 4 SGs to be conservative while inspecting one SG to meet TS requirements. Revision 6 of the EPRI GL were issued prior to the 3R12 outage but implementation was not required until after the outage. Inspection requirements from the prescriptive based section in revision 6 were considered in the inspection scope recognizing that staying in a performance based program would require NRC approval.

Inspections: The following scope of inspections was performed in all four SGs unless otherwise noted:

25% of the tubes with bobbin along the full-length in a patterned inspection

20%/30% of the hot leg expansion transitions in 31/32 and 33/34 SG respectively with plus point RPC bringing the cumulative population examined to date to 50% in all 4 SGs.

80%/100% of the row 1 and 2 U-bends in 31/32 and 33/34 SGs respectively with plus point MRPC bringing the cumulative population examined to date to 100% in all 4 SGs.

8% of the cold leg expansion transitions in all 4 SGs comprising all the peripheral tubes of the annulus and tube lane with plus point RPC to provide low level detection capability for potential small volumetric indications attributable to loose part wear.

A sampling of hot leg dents and dings with plus point MRPC.

Some minor degradation was found in this degradation but the inspection results were still classified as C-1. The 25% patterned inspection with bobbin in all 4 SGs was considered to comply with the TS statement that the 3% TS sample "should be selected on a random basis". Nine indications of wear in 8 row 1 tubes attributed to contact with sludge lance equipment used in 3R11. One of the wear indications was initially sized conservatively at 47%. This is considered a defective tube by both technical specifications and the EPRI SG examination guidelines and prompted a sample expansion. Because the wear could positively be attributed to sludge lance equipment, the potential wear indications could be confined to just row 1 tubes. The initial inspection scope encompassed 25% of the row one tubes. TS required a minimum sample size of 3 percent and an expansion size of twice that so the TS requirement was considered met by the initial 25% sample. The EPRI guidelines recommended an expansion of 20% in the affected SGs so an additional 20 tubes or 22% of the row 1 tubes were inspected to meet the guideline requirement. Because the wear was due to a latching mechanism in two locations on each side of the SG, the tubes were systematically selected to ensure several tubes on each side of the latching mechanism were inspected.

3R13 – April 2005

Requirements: This is the seventh refueling outage since SG replacement and no inspections were performed during this outage. The TS requirements call for a minimum inspection of 12% of the tubes in one SG in a 40 calendar month interval. Other options include 6% of the tubes in two SGs or 3% of the tubes in all four SGs. 3R14 is scheduled for 48 calendar months after the 3R12 inspection. If necessary the 1.25 surveillance margin could be used to defer SG inspections until 3R14 but it is more likely that new technical specifications will be in place that are consistent with Revision 6 of the EPRI PWR Steam Generator Examination Guidelines. This TS change is TSTF-449 which the NRC made available to the industry on May 2, 2005 via the Consolidated Line Item Improvement Process (CLIIP).

Revision 6 of the EPRI GL were in effect at the time of this outage. Revision 6 permits SGs with Alloy 690TT tubing to operate as long as 96 EFPM between inspections provided the entire population of tubes is inspected at different intervals over the life of the SGs. 3R14 will be the outage nearest the end of the first inspection interval of 144 EFPM as measured from the first ISI.

Inspections: No SG inspections were performed for 3R13.

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3R14 – April 2007

Requirements: In February 2007, a license amendment was implemented incorporating the requirements of TSTF-449 Rev 4 on Steam Generator Tube Integrity The TS requirements for steam generator inspections during 3R14 were to inspect any tubes not previously inspected since the first ISI during 3R7 in 1990 for potential degradation as defined in the degradation assessment. This is because the SGs had accumulated 137 effective full power months (EFPM) of operation since the first ISI and 3R14 was the refueling outage closest to the end of the first inspection period of 144 EFPM.

The potential degradation mechanisms for the SGs at this time were wear at support structures and wear due to foreign objects. Prior to 3R14, 100% of the tubes in 31 & 32 SGs were inspected over the full length except for 19 and 21 low row U-bend sections in 31 and 32 SG respectively. In 33 & 34 SGs, 100% of the low row U-bend sections had been inspected but approximately 240 tubes in each SG had not had a full length bobbin inspection. To meet the TS requirement those tubes and sections had to be inspected along with a 20% minimum sample to meet EPRI guideline requirements.

Another consideration in determining the inspection scope was the need to assess potential AVB wear in the U-bend section since the prior operating cycle was under stretch power uprate conditions. A 50% full length bobbin sample was selected to provide enough information to support a planned 3 cycle operation following the inspection.

Inspections: The following SG inspection scope was performed on all 4 SGs except as noted:

1. Bobbin inspection over the full length of 50% of the tubes in rows 3-45 (about 1515 tubes/SG) in a patterned inspection of every other pair of columns.
    a. In addition, those tubes not inspected since the first ISI in 1990 and not captured in this pattern were added to the inspection plan. This added 324 and 117 tubes in 33 and 34 SGs respectively.
2. Bobbin inspection of the hot and cold straight leg sections of 50% of the tubes in rows 1 and 2 aligning with the same columns as the patterned inspection for full length bobbin. (about 92 tubes/SG)
    a. In addition, those tubes in row one on both hot and cold legs not inspected in 2003 and not captured in this pattern were added to the inspection plan.
3. Plus-point inspection of the U-bend sections of those row 1 and 2 tubes inspected in item 2 above but not item 2(a) (about 92 tubes/SG) plus any row 3 tubes that could not pass a nominal size bobbin probe. Plus-point probes were used in rows 1 and 2 because the tight radius of the bend does not permit quality data to be collected with the bobbin probe.

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a. In addition, those tubes whose row 1 and 2 U-bend sections were not inspected since the first ISI in 1990 were added to the inspection plan. This added 19 and 21 tubes to 31 and 32 SG respectively.

4. Plus-point inspection of the HOT leg expansion transitions from TTS+3 to TTS-3 inches of 20% of the tubes in a patterned inspection (about 643 tubes/SG) that captured tubes not previously inspected in prior patterns to the extent practical. The purpose of this inspection was to collect baseline information of the tube expansion transition region for comparison should this region be considered for potential degradation mechanisms.
5. Plus-point inspection of the HOT leg expansion transitions from TTS+3 to TTS-3 inches of all HOT leg peripheral tubes (defined as 3 tubes in from the annulus in column, row and diagonal directions and all row 1 and 2 tubes) (about 550 tubes/SG not covered by 20% patterned inspection). The purpose for this inspection was to identify possible loose parts and loose part wear in what are considered the most susceptible regions of the SG.
6. Plus-point inspection of the COLD leg expansion transitions from TTS+3 to TTS-3 inches of all COLD leg peripheral tubes (defined as 3 tubes in from the annulus in column, row and diagonal directions and all row 1 and 2 tubes) (about 700 tubes/SG). The purpose for this inspection was to identify possible loose parts and loose part wear in what are considered the most susceptible regions of the SG.

Special interest inspections as necessary to disposition possible degradation signals from the routine inspections including all dents/dings ≥ 5 volts and a 20% sample of dents/dings 2.00 – 4.99 volts in the HOT leg straight sections.

3R15, 3R16 – March 2009, March 2011

Requirements: As documented in the Condition Monitoring and Operational Assessment (CMOA) performed following 3R14 (IP-RPT-07-00031), the next scheduled inspection is not required to be performed until 2013 (3R17).

Inspections: No SG inspections were performed for 3R15 or 3R16.

3R17 – March 2013

Requirements: All steam generators were required to be inspected during 3R17. For a detailed description of the requirements, see the 3R17 documents referenced in Attachment 4.

Inspections: Inspections were performed in all SG's during 3R17. For a detailed description of the inspections performed, see the 3R17 documents referenced in Attachment 4.