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3R14 Condition Monitoring and Operational Assessment of Indian Point 3 Steam Generators

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Revision Summary

Rev.	Description	Changes
0	Original Issue	n/a

1. Purpose

The purpose of this report is to evaluate the fourteenth refueling outage (3R14) inspection results and ensure the performance criteria contained in the Nuclear Energy Institute's "Steam Generator Program Guidelines" (NEI 97-06) are satisfied. This includes evaluating any detected degradation for structural and leakage integrity. Consideration is mainly given to the previous cycle 13/14 operational assessment to determine the accuracy of the assessment based on the results to the 3R14 inspection findings. Additionally, the results are used to project the condition of the steam generators at the next scheduled inspection in 3R17 (2013) and demonstrate that the performance criteria will continue to be satisfied until that inspection.

A steam generator integrity program, which provides reasonable assurance that the steam generator tubes are capable of performing their intended safety function, has been developed by Entergy, using guidance from NEI. This includes establishing performance criteria commensurate with adequate tube integrity, programmatic considerations for providing reasonable assurance that the performance criteria will be met during plant operation, and guidelines for condition monitoring of the SG tubing to confirm that the performance criteria are met.

2. Background

The Indian Point 3 steam generators (SGs) were replaced in 1989 with Westinghouse Model 44F SGs. At the time of the 3R14 inspection, the SGs had accumulated 150 effective full power months (EFPM) of service since replacement and 137 EFPM since the first in service inspection (ISI) in September 1990. The SG tubing material is Alloy 690TT and 3R14 marked the refueling outage nearest the end point of the first inspection period (144 EFPM) as defined in the PWR SG examination guidelines (Reference 10) and reiterated in the current IP3 Technical Specifications. Primary to secondary leakage during the previous operating period was less than 0.3 gallons per day (gpd). The next SG inspection is scheduled for 3R17 in 2013 which will be the refueling outage nearest the mid-point of the second inspection period. The second inspection period is 108 EFPM and the mid-point is 54 EFPM. Refueling outage 3R17 will occur at 59 EFPM.

3. Summary of Results

Only two tubes were found with degradation during the 3R14 eddy current inspection. This degradation was sized at less than the condition monitoring limit. There was no detectable leakage during the previous operating period (<0.3 gallons per day). Therefore, all of the steam generator performance criteria were met for two previous operating cycles (13 & 14). Because the tube degradation found was sized less than the condition monitoring limit, in-situ pressure testing was not required.

From the operational assessment, the steam generators were evaluated and it was concluded that tube integrity will be maintained while operating until the next scheduled inspection during (3RF17) in the spring of 2013. All performance criteria are anticipated to be maintained with added margin for the next 3 operating cycles.

4. 3R14 Steam Generator Workscope

4.1. Eddy Current Testing

Eddy current testing was performed on the steam generators (SGs) during the 3R14 outage. The eddy current examination techniques used were demonstrated to be equivalent with the Electric Power Research Institute (EPRI) PWR Steam Generator Inspection Guidelines (6) for detecting inactive, active, and potential modes of degradation. The inspection scope is summarized below and is applicable to all 4 steam generators 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 consisting of every other pair of columns.
   a) In addition, those tubes in 33 and 34 SGs not inspected since the first ISI in 1990 and not captured in this pattern were added to the inspection plan. This added 340 tubes in 33 SG and 121 tubes in 34 SG.
   b) In addition, those tubes in row 45, columns 44 through 49 were added to the inspection plan to identify any tube damage from maintenance equipment inserted in the 90-degree handholes.
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 to identify any undetected wear from the sludge lance equipment used in 2001.
   b) In addition, those tubes in row 45 from columns 44 to 49 not captured in this pattern were added to the inspection plan to identify any degradation that may have resulted from contact with sludge lance equipment inserted at the 90-degree hand holes.
3) Plus-point inspection of the U-bend sections of those row 1 and 2 tubes inspected in (2) above but not (2a) (about 92 tubes/SG) plus any row 3 tubes that could not pass a nominal size bobbin probe. This inspection was performed on rows 1 & 2 because the bobbin probe does not produce data of adequate quality in such a tight radius. The purpose of this inspection was to look for general degradation and not SCC which is considered a non-relevant degradation mechanism in 3R14.
   a) In addition, those row 1 and 2 U-bend sections that have not previously been inspected in 31 and 32 SGs were added to the inspection program. This added 19 and 21 tubes in 31 and 32 SGs 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 captures tubes not previously inspected in prior patterns to the extent practical. The purpose of this inspection was to continue capturing baseline conditions of the expansion transition before the onset of corrosion degradation and to enhance the detection of possible loose part/wear. Plus and minus 3 inches was selected because it is the industry norm to ensure the expansion transition region and areas below the top of any sludge pile are captured.
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.

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.
7) Plus-point inspection of previous possible loose part (PLP) indications at the top of the tubesheet to verify absence of degradation.
8) Plus-point inspection of all dents/dings ≥ 5 volts from the secondary tube sheet face hot to the secondary tube sheet cold and all dents/dings 2.00 – 4.99 volts at support structures from the secondary tube sheet hot to the secondary tube sheet cold. Dents/dings previously inspected with plus point were not reinspected unless the bobbin signal changed by >10 degrees on phase in the positive direction.
9) Special interest inspections as necessary to disposition possible degradation signals from the routine inspections.

4.2. Secondary Side Work Scope

In 3R14, all four steam generators were sludge lanced using a combination of passes with a 2-nozzle, high flow lance head and a conventional 8-nozzle lance head. Following the sludge lancing, the tubesheets of each SG were visually inspected down the tube lane, in the annulus and about every fifth column in-bundle. Any foreign objects observed, with the exception of short pieces of MSR wire, were catalogued and prioritized for retrieval.

In addition, the steam drums and top support plates ("G") of 31 and 32 steam generators were inspected visually to look for evidence of degradation.

5. 3R14 Results

5.1. Eddy Current Testing

The table below summarizes the number of indications found during the 3R14 eddy current inspection. Only two tubes were found with degradation during the 3R14 eddy current inspection. The indications were classified as volumetric and were located in 31 SG at row 1, column 8 and row 1 column 27 on the cold leg about 16 inches above the top of the tubesheet. This degradation was attributed to wear from contact with sludge lancing equipment used in 3R11 in 2001 and not considered service related. It was sized at 29 and 26% through wall (TW) using qualified eddy current technique ETSS 21998.1 the tubes were left in service. This technique oversized the wear scars because of the difference in the geometries between the calibration standard and wear scars themselves. They were more realisitically sized at 13 and 11% TW using a technique discussed in the condition monitoring section.

3R14 Eddy Current Indication Summary

Code	Description	31 SG	32 SG	33 SG	34 SG
DNG	Ding	32	20	11	117
FSA	Freespan Signal Absolute	90	34	32	71

FSD	Freespan Signal Differential	20	10	11	5
PLP	Possible Loose Part	20	2	0	3
PVN	Permeability Variation	2	2	2	0
VOL	Volumetric	2	0	0	0

5.2. Permeability Variation

Permeability describes the intrinsic willingness of material to conduct magnetic flux lines. Signals due to permeability variations (PVN) typically do not show the same phase correlation between the different frequencies as actual degradation. There were six permeability variation (PVN) indications identified in 3 tubes during 3R14. Four of them were in the freespan where degradation is not a concern and had limited extents. The remaining two were at the same location at the expansion transition on the cold leg side of the SG. These two PVNs were seen with the plug point coil over the length of the test from TTS+3 inches to TTS-3 inches. The tube was re-inspected with a mag-bias probe that did little to reduce the signal, however the pancake coil did significantly reduce the signal to the point where significant degradation would not be masked. This same tube did not exhibit a PVN with the bobbin probe. Given that corrosion degradation has not be observed in the IP3 replacement SGs, cracking at the expansion transition is currently not a potential damage mechanism, the two significant PVNs are on the cold leg and the signal with the rotating coil is small enough to see significant degradation, the decision was made to leave these indications in service until such time that degradation is observed in comparable locations in other tubes.

PVN Indications reported in 3R14

SG	Row	Col	Volts	Deg	Ind	Loca	Inch
31	33	72	1.58	92	PVN	TSC	0.00
31	33	72	1.33	86	PVN	TSC	0.00
32	28	47	2.19	9	PVN	4H	48.62
32	28	47	1.11	8	PVN	BPH	4.85
33	2	18	2.21	4	PVN	5C	34.01
33	2	18	2.33	5	PVN	5C	32.11

5.3. Wear Scars from Sludge Lance Equipment

There were eight tubes identified with wear scars 3R12 in 2003 that were attributed to contact with sludge lance equipment used in the previous outage. One tube had indications on both hot and cold legs. One tube required plugging because it exceeded the repair limit and the other seven were plugged administratively. In 3R14, two additional tubes in 31 SG were identified as having similar wear scars. The tubes were row 1 column 8 and row 1 column 27 and the depths of the scars were 26 and 29% TW respectively using a qualified sizing technique. The affected tubes are consistent with those identified in a letter from the vendor as potential affected by the sludge lancing equipment. These tubes were left in service because the wear was attributed to maintenance activities, no growth is anticipated.

5.4. 3R14 Repairs

There were a total of 2 tubes plugged during 3RF14. The tubes were plugged administratively due to a wedged foreign object between the two tubes on the hot leg of 31 SG. Although there was no wear observed, the location is near the annulus where the flow velocities are the highest so it is difficult to predict the potential wear that could occur during future operating cycles. The tubes plugged are listed below.

RF14 Plugging List

SG	Tube	Location	Indication	Percent TW
31	R29 C79	HL TTS +0.57	PLP	0%
31	R29 C80	HL TTS +0.26	PLP	0%

5.5. Tube Plugging History

The table below lists the number of the tubes plugged from pre-service to the present. There are no sleeves installed in the IP3 steam generators.

Tube Repair History - Number of Tubes Plugged

Year	Outage	SG31	SG32	SG33	SG34	Total
1988	Fabrication	0	0	0	2	2
1989	Pre-service	0	0	0	0	0
1990	3RF07	0	0	0	0	0
1992	3RF08	0	0	0	0	0
1997	3RF09	0	0	0	0	0
1999	3RF10	0	0	0	0	0
2001	3RF11	0	0	0	0	0
2003	3RF12	1	6	3	2	12
2005	3RF13	0	0	0	0	0
2007	3RF14	2	0	0	0	0
Totals		1	6	3	4	14

5.6. Secondary Side Maintenance & Inspection Results

Sludge lancing was successful in removing loose deposits from the tubesheets of the steam generators with the exception of SG 31 and to a lesser extent SG 32. In those two SGs, there were small piles of scale and MSR (moisture separator reheater) wire near the annulus of the longer columns. A total of 223 pound of sludge was removed via lancing with a removal distribution as follows: 56.25 lbs from 31, 81.5 lbs from 32, 43.5 lbs from 33 and 41.5 lbs from 34 SGs. In addition to sludge, numerous small foreign objects were removed via sludge lancing. These objects were collected in a screen above the grit tank and included MSR wire and pieces of gasket.

The steam drum inspections performed in 31 and 32 SGs identified no anomolies but washout areas on the feedring below the nozzles were noted. There appeared to be negligible wall loss in these areas of the one-half inch wall carbon steel feedring. No anomolies were noted were noted on the top support plate inspections in either 31 or 32 SGs. The only observation was a slight dusting of deposits that is typically seen in this area. There were no indications of deposit buildup in the broach holes surrounding the tubes.

During the visual inspections of the tubesheet, numerous foreign objects were observed in SG31 and to a lesser extent in the remaining 3 SGs. The foreign objects were prioritized for retrieval attempts. Below are tables listing the foreign objects that remain in the SGs following the retrieval attempts. As mentioned in the eddy current section, one metallic foreign object was found wedged between two tubes and could not be retrieved despite several attempts. The two tubes were plugged preventively to prevent a possible tube leak should the part cause tube wear.

Visual examinations of the tubes at the annulus near the 90-degree handhole did not identify any marks on the tubes. There is no reason to believe that sludge lance equipment used at the 90-degree handholes made any contact with the tubes in this or prior outages.

SG 31 Foreign Object List

Item No.	Foreign Object Location	Foreign Object Description And Dimensions (inches)
31018	R29 C79 HL	Gasket 0.5 x 0.125 x 0.125
31001	R28 C11 HL	Slag 0.25 x 0.125 x 0.125
31016	R42 C67 HL	MSR wire 1.0 x 0.016 x 0.016
31026	R38 C23 CL	Metal Object 0.25 x 0.125 x 0.125
31032	R39 C27 CL	Slag 0.125 x 0.125 x 0.125
31033	R40 C27 CL	Slag 0.375 x 0.125 x 0.125
31002	R27 C12 HL	MSR wire 0.25 x 0.016 x 0.016
31003	R34 C17 HL	Scale pile 0.36 x 0.125 x0.312
31004	R36 C19 HL	Scale pile 0.36 x 0.125 x 0.312
31005	R37 C20 HL	Scale pile & MSR wire 0.36 x 0.125 x 0.312
31007	R36 C21 HL	Sludge rock pile 0.36 x 0.125 x 0.312
31008	R38 C22 HL	Sludge rock pile 0.36 x 0.125 x 0.36
31009	R38 C23 HL	Sludge & scale pile 0.36 x 0.125 x 0.36
31010	R39 C24 HL	Sludge & scale pile 0.36 x 0.125 x 0.36
31011	R40 C25 HL	Sludge & scale pile 0.36 x 0.125 x 0.36
31012	R40 C26 HL	Sludge & scale pile 0.36 x 0.125 x 0.36
31013	R40 C28 HL	Sludge rock 0.36 x 0.125 x 0.36
31014	R42 C30 HL	Sludge rock 0.36 x 0.125 x 0.125
31017	R38 C70 HL	Sludge rock 0.36 x 0.125 x 0.125
31025	R38 C22 CL	Gasket 0.25 x 0.125 x 0.125
31037	R44 C53 CL	Sludge rock 0.25 x 0.125 x 0.125
31040	R27 C15 HL	Gasket 0.25 x 0.125 x 0.125
31041	R36 C20 HL	MSR wire pile 0.12 x 0.015 x 0.015

SG 32 Foreign Object List

Item No.	Foreign Object Location	Foreign Object Description And Dimensions (inches)
32007	R44 C40 CL	Scale & MSR wire pile 0.33 x 0.33 x 0.33
32008	R42 C55 HL	MSR wire pile 0.2 x 0.2 x 0.2

SG 33 Foreign Object List

Item No.	Foreign Object Location	Foreign Object Description And Dimensions (inches)
n/a	n/a	**None Found**

SG 34 Foreign Object List

Item No.	Foreign Object Location	Foreign Object Description And Dimensions (inches)
34008	R15 C39	Sludge rock 0.3 x 0.3 x 0.3

6. Condition Monitoring Assessment

Condition monitoring is the assessment of the current state of the steam generator tubing, and is performed at the conclusion of each steam generator inspection. The purpose of condition monitoring is to confirm that both the structural integrity and accident-induced leakage performance criteria were satisfied during the past inspection interval. The assessment involves a comparison of the as-found inspection results against the performance acceptance standards for structural integrity and accident leakage. Because the detected indications, in terms of the distribution of either indication voltages or measured flaw sizes, reflect a conservative estimate of the in-service population of flaws at the end of the cycle, monitoring the as-found condition will provide a conservative evaluation of the current condition of the tube bundle, including the flaws that remain undetected after inspection. In this situation, the performance acceptance standard can be applied to the detected population to verify the steam generators met the Structural Integrity Performance Criteria (SIPC) during the previous inspection interval. Condition monitoring therefore requires that the detected flaws, as determined by in-service inspection, do not exceed the appropriate condition monitoring limit for each degradation mechanism.

Only two tubes were found with degradation during the 3R14 eddy current inspection. This degradation was the result of contact with sludge lancing equipment used in 3R11 in 2001 and not service related. The degradation was sized at 29 and 26% through wall (TW) using qualified eddy current technique ETSS 21998.1 which supports leaving the tubes in service. This technique is overly conservative because it utilizes a standard with small, flat bottom holes that do not match the geometry of the actual wear scars on the tubes. Using an ASME based technique developed by Westinghouse that has not been formerly peer reviewed the tube degradation was sized at 13 and 11% TW for the purpose of condition monitoring. The condition monitoring limit for this degradation is geometry dependent but bounded at 40.45% TW. Therefore, the burst performance criterion was met for the previous two operating cycles.

There was no detectable primary to secondary leakage during the two previous operating cycles. The nominal detectable limit was 0.3 gallons per day (gpd). This satisfied the operational leakage limit performance criterion. In addition, in the absence of any corrosion degradation and primary to secondary leakage, the accident induced leakage limits were satisfied for the previous operating period.

Because the tube degradation found was sized less than the condition monitoring limit, in-situ pressure testing was not required.

7. Operational Assessment

An operational assessment is a forward-looking prediction of the steam generator tube conditions at the next inspection. Operational assessments require that the projected sizes of the undetected

population of flaws, or detected flaws intentionally left in service as determined by analysis, do not exceed the operational assessment limit. The operational assessment limit is the value of the degradation parameter such that a tube with greater degradation would not meet the SIPC at the next SG inspection. The determination of the operational assessment limit considers factors such as measurement uncertainty, probability of detection (POD), and growth rate.

The tube integrity performance criteria have been incorporated into the Indian Point 3 Technical Specifications and are as follows:

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, operations 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 operations 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 load contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do not significantly affect burst or collapse shall be determined and addressed 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.

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 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.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE.

Based on the results of Eddy Current Testing (ECT) examinations and analysis described in this report, detection capabilities and predicted growth rates, future steam generator tube performance can be evaluated. The intent of this assessment is to evaluate approximately three full-cycles of operation until the next scheduled inspection. Steam generator replacement was performed during the (RF06) refueling outage (June 1989).

There are currently degradation mechanisms (as defined by EPRI) in the replacement steam generators. Using industry experience, the only potential issues that the IP3 replacement steam generators would experience is mechanical wear, either at structural supports or from contact with loose parts. Thermally treated Inconel 690 tubing has been in-service for greater than 12 years at several plants. To date, there has been no degradation identified associated with PWSCC or ODSCC. Mechanical wear will be evaluated assuming detection capabilities and growth for

seven cycles of operation. This is the amount of time that a given tube will be in-service without being inspected.

A run time of 14 EFPY was used to determine the end of cycle conditions for anti-vibration bar (AVB) wear. This was based on tubes not inspected since 3R08 in 1992 operating until the next scheduled inspection in 3R17. Three cycles of operation were assumed for operation with the existing foreign objects and possible loose part indications.

The degradation mechanisms reviewed in this assessment are structural wear at the anti-vibration bars, loose part wear and stress corrosion cracking (SCC). This operational assessment was developed using the deterministic methodology.

7.1. Steam Generator Design Information

IP3 is a four-loop plant with Model 44F steam generators. Operation with the new Model 44F Replacement Steam Generators (RSG) began with startup for cycle 7 on June 24th, 1989. These steam generators include Alloy 690 thermally treated (A690TT) tubing, full-depth hydraulically expanded tubesheet joints, and broached-hole quatrefoil tube support plates constructed of stainless steel. The tubes are 7/8ths outside diameter by 0.050 inch wall thickness. The tubing pattern is on a square pitch. IP3 has just completed 14 cycles of operation and 8 cycles with the replacement steam generators.

7.2. Tubing Structural Limits

The structural limits for the steam generator tube wear were calculated using the methodology outlined in draft Regulatory Guide 1.121. Those limits were updated for the more limiting proposed uprate conditions calculated in 2004 (Reference 5) for operation in cycle 14 and are listed below. Structural limits were not developed for cracks because they are geometry dependent and stress corrosion cracking is considered a non-relevant degradation mechanism in the IP3 replacement steam generators.

SG Tube Wear Structural Limits

Location	Parameter	Limit
Straight Leg and Anti-Vibration Bar(1) (≥1.50" tube rows 9-16 and 25-27)	t_{min} (inch)	0.024
	Structural Limit (%)	52.0
Anti-Vibration Bar(1) (0.9"; tube rows 17-24 and 28-45)	t_{min} (inch)	0.021
	Structural Limit (%)	58.2
Flow Distribution Baffle (0.75")	t_{min} (inch)	0.020
	Structural Limit (%)	61.0
Tube Support Plate (1.125")	t_{min} (inch)	0.022
	Structural Limit (%)	55.2

(1) For tube / AVB tangent point, straight leg structural limits apply. Tube/AVB tangent points 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.

7.3. AVB Wear Assessment

The following are the inputs used to evaluate AVB wear through the end of Cycle 17:

Method Used:	Simplified Statistic
Structural Limit	1.121 analysis (52%TW)
Sizing Uncertainties	Mean of Regression Line + 1.645 sigma
Analyst Uncertainties	1.645 sigma
BOC Flaw Size	Estimate from field and ETSS results
Growth	Value from EPRI [2]

Structural Limit	52 % TW
Sizing Technique Uncertainty[7]	4.49 % TW x 1.645 = 7.39% TW (95/50)
Analyst Uncertainties[6]	0.86 % TW x 1.645 = 1.41 % TW (95/50)
BOC Flaw Size	10 % TW
Growth[2] (40 yrs)	12 % TW

The beginning of cycle depth of 10% was estimated based on experience at Indian Point 2 detecting AVB wear at 9% and the dataset for the ETSS had no missed calls all the way down to 5% through wall. No indications of AVB wear have been detected in the Indian Point 3 replacement steam generators from the time of initial service through the last tubing examination in RF14. Indian Point 3 is one of 6 units with Westinghouse model 44F steam generators but the only one with a more advanced AVB design. The design includes 3 sets of bars fabricated of stainless steel that have a contact point twice as long as the other 44F SGs. This means that estimating AVB wear rates based on the experience of the other 44F SGs is overly conservative.

To provide a more realistic estimate of potential AVB wear rates, thermal hydraulic models have been used to predict AVB wear over an assumed 40 year operating life. The initial Westinghouse stress report estimated a maximum wear of 1.3 mils over 40 years. Reference 8 estimates a 40-year post-uprate wear of 2.4 mils or 4.9% TW (through wall).

Reference 2 used a slightly different thermal hydraulic model and estimated a 40-year AVB wear at the most susceptible location to be 6 mils or 12% TW. This assumed a relative high tube to AVB bar clearance of 23 mils when the nominal clearance is about 5 mils resulting in a conservative estimate.

For the purpose of this assessment, the projected AVB growth over the inspection period is assumed to be the 40-year estimate of 12% TW from Reference 9.

To calculate the end of cycle (EOC) maximum depth, the following equation is used:

(BOC flaw) + (SQRT [Sizing^2 + Analyst^2]) + (Growth) = EOC flaw
(10 %) + (SQRT [7.39^2 + 1.41^2)] + (12 %) = Maximum Depth at EOC.
(10 %) + (7.5 %) + (12 %) = Maximum Depth at EOC
(10 %) + (7.5 %) + (12 %) = 29.5 % TW Maximum EOC Depth (95/50)

This result is much less than the lower AVB wear tube structural limit of 52% TW.

Since wear at the AVBs are typically self limiting, the above calculation should be conservative in nature. Since this value is below the structural limit of 52 %, tube integrity as a result of AVB wear will be maintained until the next scheduled inspection in 3R17.

Anticipated Number of AVB Indications at Next Inspection

Based on the lack of detectable AVB wear in the IP3 SGs with a service time of 12.5 EFPY, no AVB wear indications are anticipated at the next scheduled inspection in 3R17 in 2013.

7.4. Loose Parts

A list of loose parts left in the steam generators was presented in the results section of this report. SG 31 has the majority of the loose parts remaining. SG 33 had no foreign objects found or remaining. SG 32 had only some scale and small MSR wire piles remaining and SG 34 had only a sludge rock remaining. The majority of the 23 foreign objects remaining in 31 SG consist of scale piles, MSR wire and sludge rocks. There were also 3 small pieces of weld slag and 2 small pieces of flexitallic gasket material with the largest being 0.375 inches long. This material is bounded by previous loose part evaluations and is not anticipated to initiate any wear on in-service tubes. There was one significant foreign object that could not be retrieved. Although, the tubes did not show any wear, the tubes were administratively plugged because of the difficulties predicting potential wear at this location.

Eddy current testing also identified numerous possible loose part (PLP) indications in SG31 and several others in 32 and 34 SGs. None of the PLP indications had any associated wear and there were no PLP calls made in 33 SG. The majority of the PLP calls in 31 SG were made in the annulus region where small piles of scale and MSR wire were also noted during visual inspections of the tubesheet. There was very little overlap between the SG secondary side visual inspections and the primary side eddy current. Therefore, the PLPs were evaluated by their location, history and proximity to the areas where visual inspections were performed. Based on this evaluation, none of the PLP indications were considered indications of significant foreign objects that could cause significant tube wear over the next three operating cycles. The table below lists all the PLP calls made during the 3R14 steam generator inspection along with a note as to how they were dispositioned.

List of Possible Loose Parts Eddy Current Indications for 3R14

No.	SG	Row	Col	Volts	Deg	Ind	Loc	Indl	Note
1	31	41	32	.35	87	PLP	TSC	0.14	1
2	31	2	42	.11	76	PLP	TSC	1.06	1
3	31	26	79	.29	86	PLP	TSC	0.07	1
4	31	26	80	.36	83	PLP	TSC	0.15	1
5	31	1	27	.20	84	PLP	TSH	0.10	1
6	31	2	27	.28	89	PLP	TSH	0.14	1
7	31	29	28	.30	79	PLP	TSH	2.06	2
8	31	30	28	.24	71	PLP	TSH	2.05	2
9	31	30	28	.34	78	PLP	TSH	2.09	2
10	31	42	33	.28	71	PLP	TSH	0.00	1
11	31	42	34	.42	84	PLP	TSH	.06	1
12	31	16	35	.13	77	PLP	TSH	.05	1
13	31	17	35	.18	74	PLP	TSH	.41	1
14	31	25	35	.37	82	PLP	TSH	.16	1,3
15	31	38	66	.10	76	PLP	TSH	.06	1
16	31	40	67	.27	92	PLP	TSH	.08	1
17	31	7	71	.40	87	PLP	TSH	.16	1
18	31	29	79	.31	83	PLP	TSH	.57	4
19	31	30	79	.30	86	PLP	TSH	.13	1
20	31	29	80	.31	80	PLP	TSH	.26	4
21	32	[illegible]	60	[illegible]	[illegible]	PLP	TSH	.25	1
22	34	[illegible]	37	[illegible]	78	PLP	TSH	.10	1
23	34	5	37	.26	83	PLP	TSH	.06	3
24	34	1	39	.18	83	PLP	TSH	.14	2
25	34	1	40	.34	87	PLP	TSH	.18	2

Notes: 1. Covered by visual inspection scope, no significant parts observed
2. Also, reported in previous outage, no wear indicated
3. Single indiction with no indications on neighboring tubes
4. Part confirmed, irritrievalable, tube plugged.

Based on a review of the foreign objects remaining and the PLP indications, none of these are anticipated to cause tube wear over the next three operating cycles.

7.5. Stress Corrosion Cracking

The experiences of other plants with A690TT tubes or with a similar design and with more extensive operating histories have been used to assess the potential for degradation to occur now or in the future at Indian Point 3. For corrosion mechanisms, IP3 is one of the lead plants worldwide with A690TT tubing. Ringhals 2 and Dampierre 1 have similar service times compared to IP3 but operate at significantly higher hot leg temperatures increasing the stress on the material. Corrosion degradation has not been found at either unit nor in any SG with A690TT

tubing. The SGs at Dampierre 1 had 12 effective full power years (EFPY) of service at the last SG inspection in 2005 with a hot leg temperature of 613F. The SGs at Ringhals 2 had 13.2 EFPY of service at the last SG inspection in 2006 with a hot leg temperature of 610F. If those service times were normalized to the 593F hot leg temperature for IP3, they would increase to 28 EFPY for Dampierre 1 and 26 EFPY Ringhals 2 (refer to table 5-6 in reference 9).

Since there has been no detected corrosion related degradation in A690TT, the next most relevant information we have to help predict the occurrence of degradation in A690TT is the limited corrosion degradation found in A600TT tubing. Axial outside diameter stress corrosion cracking (ODSCC) was found at Seabrook after 11 EFPY of service. Tube pulls at Seabrook verified the presence of cracks. This degradation as well as similar indications at Braidwood Unit 2 were attributed to poor material microstructure atypical of A600TT. All the tubes considered to have the poor microstructure were removed from service and no crack indications have been found in the remainder of the tubes. The tubing at these two units was made by a manufacture other than Sanvik and is not considered relevant to the IP3 SGs.

In the fall of 2006, Votgle unit 1 detected ODSCC indications at the expansion transition following 14.7 EFPY of service at a hot leg temperature of 617F. Although the cracking was not confirmed with a tube pull, there is a high confidence through the use of Ghent and delta eddy current probes. Assuming the indications are actual cracks this would be the first occurrence of ODSCC in a U.S. SG with A600TT tubing. In 2003 EPRI published a report [Ref. 9] that predicts the onset of degradation in U.S. SGs with A600TT and A690TT tubing. The report's best estimate for the onset of circumferential ODSCC in a Model F SG with A600TT tubing operating with a hot leg temperature of 618F is 41 EFPY. The actual occurrence at Votgle after 14.7 EFPY corresponds with the bounding prediction at 95% confidence limit.

If we apply the same bounding estimate to the predictions for ODSCC for the IP3 SGs, the onset is predicted to occur at 20 EFPY if operating with a hot leg temperature of 618F. Temperature correcting the operating time for the actual operating temperature at IP3 results in an onset time of about 60 EFPY. The most limiting prediction for corrosion degradation is the occurrence of hot leg tube support plate IGA/SCC at 14 EFPY at 618F (95% CL; see Table 6-23 in reference 30). Normalizing to the 593F conditions at IP3 increased the time to degradation to 41 EFPY.

Based on laboratory testing, A690TT tubing is considered immune to primary water SCC (PWSCC). Therefore, PWSCC is not considered a credible degradation mechanism for the IP3 SGs. This includes bulge locations within the tubesheet. Based on no indications of SCC in A690TT tubing in the U.S. and international experience and the limited indications in A600TT tubing, as well as the predictions in Reference 9, corrosion degradation is not anticipated in the IP3 SGs until after the next scheduled inspections in 2013.

7.6. Operational Assessment Conclusions

Entergy Nuclear Operations has performed an investigation into the potential degradation of the replacement steam generators at IP3. The investigation was based on guidance based on NEI 97-06 for determining end of cycle conditions. The only anticipated potential degradation mechanisms over the next three operating cycles are wear at the anti-vibration bars and wear due

to foreign objects. Using industry experience, it was evaluated that the IP3 steam generators will still meet their structural integrity requirements at the end cycle 17 (18 effective full power years). Therefore, IP3 is considered safe to operate for 3 consecutive cycles until the next scheduled steam generator inspection in 2013 (3R17).

8. References

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9. EPRI 1003589, "Pressurized Water Reactor Generic Tube Degradation Predictions, U.S. Recirculating Steam Generators with Alloy 600TT and Alloy 690TT Tubing", July 2003
10. EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6", October 2002
11. Indian Point 3 Technical Specifications, Amendment 233