August 23, 2006

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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION, UNIT 3 - SUMMARY OF CONFERENCE CALL REGARDING 2006 STEAM GENERATOR TUBE INSPECTION RESULTS (TAC NO. MD1240)

Dear Mr. Levine:

On April 21, 2006, the Nuclear Regulatory Commission (NRC) staff participated in a conference call with representatives from Arizona Public Service (the licensee) regarding the 2006 steam generator (SG) tube inspection activities for Palo Verde Nuclear Generating Station (Palo Verde), Unit 3.

To facilitate the discussion, the licensee provided to the NRC staff a preliminary briefing paper, which is attached to the enclosed summary of the conference call. Based on the information provided during the call, the NRC staff did not identify any issues that warrant follow-up action at this time.

The NRC will review the Palo Verde Unit 3 2006 SG inspection summary report when submitted in accordance with the plant's technical specification requirements. These summary reports are typically submitted within one year of the completion of the SG inspections.

Sincerely,

Mel B. Fields, Senior Project Manager
Plant Licensing Branch IV ***/RA/***
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. STN 50-530

Enclosure: Summary of Conference Call

cc: See next page

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ACCESSION NO: ML062130435 **NRR-106**

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SUMMARY OF CONFERENCE CALL

REGARDING 2006 STEAM GENERATOR TUBE INSPECTION RESULTS

PALO VERDE NUCLEAR GENERATING STATION, UNIT 3

DOCKET NO. 50-530

On April 21, 2006, the Nuclear Regulatory Commission (NRC) staff participated in a conference call with representatives from Arizona Public Service (the licensee) regarding the 2006 steam generator (SG) tube inspection activities for Palo Verde Nuclear Generating Station (Palo Verde), Unit 3. To facilitate the discussion, the licensee provided to the NRC staff a preliminary briefing paper, which is attached to this summary. In addition to the written material provided by the licensee, the following additional clarifying information was discussed during the conference call.

Several possible loose part indications were identified during the review of the eddy current data. There was no tube wear associated with these indications. At the time of the call, Foreign Object Search and Retrieval (FOSAR) was ongoing. Visual inspections in SG 31 were finished and revealed sludge rocks and a flexitallic gasket. The licensee stated that in the previous outage, an effort was made to remove the flexitallic gasket with no success. The licensee will attempt to remove the gasket as part of their FOSAR activities. No set screws were identified in either SG.

The following tubes were scheduled to be plugged in SG 31 during the refueling outage:

1. Eight tubes with single axial indications (SAI) in the ARC region (an area of the tube bundle with an increased potential for SG tube deposits and where axially oriented outside diameter stress corrosion cracking has been observed).
2. Two tubes with axial indications at the expansion-transition region.
3. One tube with an axial indication at the flow distribution baffle (FDB).
4. Five tubes with circumferential crack-like indications at the expansion-transition region.
5. Five tubes with wear indications greater than 40-percent throughwall.
6. Two tubes with wear indications at the batwing stay cylinder (21 and 24 percent throughwall).
7. Three tubes with single volumetric indications (SVI): two were caused by tube-to-tube wear and the other one was a pit-like indication.
8. One tube with a geometric anomaly in the U-bend.
9. One tube due to poor eddy current data quality.

The total number of tubes scheduled to be plugged in SG 31 is 28.

The following tubes were scheduled to be plugged in SG 32 during the refueling outage:

1. Nine tubes with an SAI in the ARC region.
2. Sixteen tubes with axial indications in the expansion-transition region.
3. Six tubes with axial indications below the expansion-transition region.
4. Fourteen tubes with an SAI at an eggcrate support.
5. Ten tubes with an SAI at the FDB.
6. Six tubes with circumferential crack-like indications in the expansion-transition region.
7. Thirteen tubes with circumferential crack-like indications below the expansion-transition region.
8. Three tubes with wear indications greater than 40% throughwall.
9. One tube with an SVI caused by tube-to-tube wear (24% throughwall).
10. Four tubes with geometric anomalies.
11. Two tubes with manufacturing-induced groove indications (one above the 2nd hot-leg tube support and one above the 1st cold-leg tube support).
12. One tube in row 14 with an axial crack-like indication in the U-bend.
13. One tube with an indication in a vertical strap.
14. One tube with an indication in the cold-leg ARC region.

The total number of tubes scheduled to be plugged in SG 32 is 86.

The licensee also provided a description of its different ARC inspection regions: main, lower, mini, and cold-leg ARC. The main ARC region of the SGs consists of approximately 2700 tubes, with a buffer zone of approximately 900 tubes. The lower ARC region consists of tubes in lower rows and columns that are in the main ARC.

The mini ARC is considered random and is used to confirm that freespan ARC-like indications are not occurring outside the main ARC. The cold-leg ARC is used to detect the onset of freespan cracking in the cold leg.

During the mini ARC cold-leg inspection, the licensee found a small freespan outside-diameter stress-corrosion cracking indication in tube R48C159. The flaw measured 24-percent throughwall and was crescent shaped. The licensee stated that the flaw may be associated with a nick/groove. In reviewing historical eddy current data for this tube, an anomaly can be seen at this location as early as 1994. Although there appears to be some change in this signal on the 100 KHz absolute bobbin channel, some of the change may be a result of using a more advanced inspection technique. There was no evidence of deposits or bowing at this location. The inspections were expanded to bound the region where this flaw and another flaw in the Unit 1 SG was found (i.e., a box-like pattern bonding the two flaws was inspected with the box being biased toward the higher rows).

SG 32 has more sludge than SG 31 and the flaws detected at the expansion transition region in SG 32 generally follow the trends in the sludge pile.

No sludge lancing was performed during the last outage or this (2006) outage.

The indication in tube R14C59 was determined to have a burst pressure at 5525 pounds per square inch at a 95-percent probability level with 95-percent confidence.

No flaws exceeded the in-situ pressure test criteria.

All dents between the hot-leg tubesheet and Batwing 1 were inspected with a rotating probe in both SGs.

Two support related indications were identified during the cold-leg ARC inspections in SG 32 that were not detected by the bobbin. The flaw in the tube in row 100, column 161, in SG 32 at the support (vertical strap) measured approximately 51-percent throughwall.

Due to these indications and the scope of past inspections in this region, the licensee decided to inspect an additional nine tubes. These nine tubes had not been inspected in prior outages.

At the time of the conference call, the licensee was still finalizing some of their analysis and indicated that if there were significant changes, they would inform the NRC staff.

Based on the information provided during the call, the NRC staff did not identify any issues that warrant follow-up action at this time.

<u>Steam Generator Tube Inspection Discussion Points – Briefing Paper</u>

1. **Discuss whether any primary to secondary leakage existed in this unit prior to shutdown.**

   PVNGS met the requirements and limits of the EPRI *PWR Primary to Secondary Leak (PSL) Guidelines* during Unit 3 Cycle 12. Leakage monitoring prior to shutdown indicated very small primary to secondary leakage (0.46 gpd) existed prior to Unit 3 shutdown on 04/01/2006. It should be noted that the PVNGS PSL Shutdown limit is administratively controlled at 50 gpd. No special actions (e.g., secondary pressure tests) are employed for pre-outage leak rates less than 1 gpd.

2. **Discuss the results of secondary side hydrostatic tests.**

   PVNGS conducts secondary side hydrostatic tests if

   - There is evidence of sustained PSL (> 1 gpd) prior to shutdown of the affected unit. This threshold is significantly less than the EPRI PWR Steam Generator Examination Guidelines (Section 3.7 – 5 GPD).

   - If it has been determined that physical work has damaged the RCS pressure boundary in the steam generators (e.g., plug drilling, welded tube plugs etc).

   These conditions did/do not exist. As such, no secondary pressure test has been performed. PVNGS has conducted a visual examination of the tubesheet to determine if evidence of leakage from plugs and/or tubes exists. The visual examination is performed per procedure 73TI-9ZZ78 and PVNGS utilizes a library of historical examples in the training and application of the visual exams. The visual exam performed during U3R12 revealed no evidence of leakage.

3. **For each steam generator, provided a general description of the areas examined, including expansion criteria and type of probe used in each area. Also be prepared to discuss your inspection of the tube within the tubesheet, particularly the portion of the tube below the expansion/transition region.**

   The PVNGS inspection and test scope is attached.

4. **Discuss any exceptions taken to the industry guidelines.**

   APS meets all the requirements of Rev 06 of the EPRI *PWR Steam Generator Examination Guidelines* with the following documented exceptions

   - Calibration notches – EPRI GL requires notch length of 0.375” – APS uses 0.250” to accommodate all PVNGS calibration standard items. Study indicates that shorter length has no impact.

- Analyst Feedback – APS takes exception to review requirements on overcalls. APS conservatively excludes a review that may desensitize the analyst.

- Site Specific Performance Demonstration – APS excludes Level III analysts that prepare SSPD test from taking the test. Excluded analyst(s) is considered qualified.

No exceptions are taken to the other NEI 97-06 EPRI Guidelines.

5. Provide a summary of the number of indications identified to-date of each degradation mode and SG tube location (e.g., tube support plated, top-of-tubesheet, etc.). Also provide information, such as voltages, and estimated depths and lengths of the most significant indications.

To be discussed during briefing.

6. Describe repair/plugging plans for SG tubes that meet repair/plugging criteria.

The PVNGS Administrative Plugging Criteria is attached. The criteria meet/exceeds the PVNGS Technical Specifications and commitments per Generic Letter 97-05.

7. Discuss the previous history of SG tube inspection results, including any "look backs" performed. Specifically for significant indications or indications where look backs are used in support of disposition (e.g., degradation mode or location of degradation new to this unit).

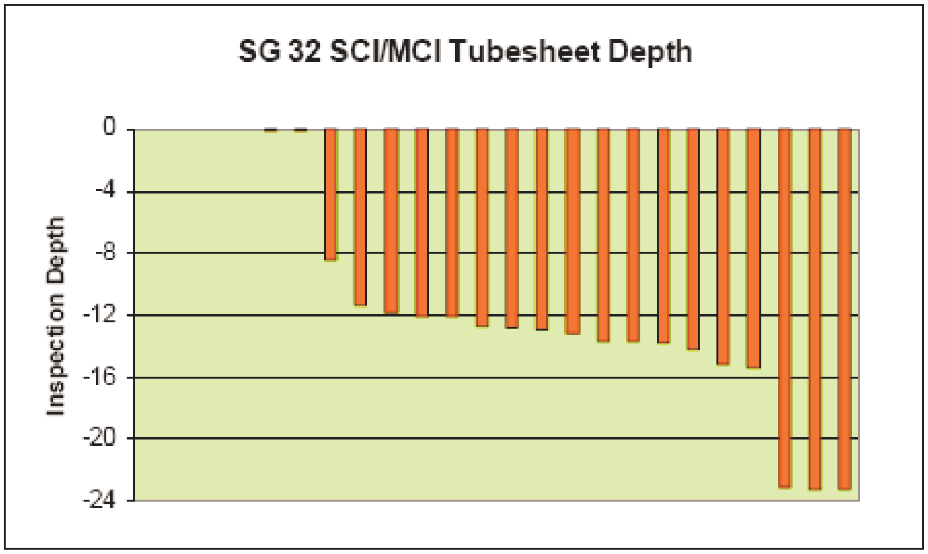
Historical "look backs" to be discussed during briefing and in discussion of Item 8 regarding expansions.

With regard to tubesheet inspections, which was the focus of a call between APS and the NRC on March 29, 2006 and RAIs with respect to C* criteria – The following update is provided.

As indicated in the 3/29/06 call, additional analysis performed by Westinghouse to accommodate "first slip" resulted in a change to the minimum inspection depth to 12.6 inches below the Bottom of the Expansion Transition (BET). APS indicated an intention to change the minimum inspection depth to 13 inches. For U3R12, the inspection was conducted at a 14 inch depth to provide additional margin. As such, the acquisition and data management personnel verify that at least 14 inches of inspection length below the

BET is acquired. As a figure of merit, the average inspection depth (from TTS) is 15.31 inches in SG 31 and 15.41 inches in SG 32.

As reported previously, in general, tubesheet SCC is not a progressing damage mechanism. That is, most of the defects detected are outside previously inspected elevations. Additionally, in the case of SG 31, no circumferential SCC was found outside the tubesheet transition region. For SG 32, the distribution of circumferential SCC indicates that most of the detected flaws are beyond the inspection depth performed in U3R11 (i.e., 12 inches). See below.



8. Discuss, in general, the new inspection findings (e.g., degradation mode or location of degradation new to this unit).

APS elected to expand the inspection program discussed in Item 3 to address four (4) findings

- As indicated in the attached inspection plan, APS planned and conducted a 20% plus point sample program of the Row 6-18 U-bends. The inspection program was based primarily on industry experience identified in the Degradation Assessment. In SG 32, a long (13.18 inch) but shallow axial ODSCC flaw was found in R14C59. Per the pre-outage expansion plan, APS expanded the program to inspect with plus point, 100% of all U-bends in both steam generators. No other U-bend flaws were identified. The integrity evaluation of the flaw found in R14C59 will be discussed in Items 10 and 12.

- Based on findings in U1R10 of upper bundle cold leg support ODSCC, APS has conducted a cold leg upper bundle region sample inspection to assist in identifying the potential for freespan axial ODSCC. The basis for this program had been previously communicated to the NRC Staff in Letter 102-05240-CDM/TNW/JAP dated March 25, 2005, *Unit 3, Refueling 10, Outage (U3R10) Steam Generator Tube Inspection Request For Additional Information (RAI) Response.* The U3R12 expansion criteria calls for a 100% CA inspection, if a freespan indication is identified within this region. Two (2) support-related indications were identified in SG 32 at the VS5 and VS6 supports. Neither flaw was detected by bobbin coil. The flaw in tube R100C161 was considered to be marginally detectable by bobbin and as such, APS reviewed the basis for the expansion criteria and current and historical inspections in the location of R100C61. Based on the collective inspection results and

inspection program for U3R11and U3R12 (90 tubes), APS conducted an additional sample (9 tubes) to assess whether the flaw had a regional disposition. No additional flaws were identified.

- The Hot Leg ARC region has successfully employed a five (5) tube buffer zone inspection since 1994. Based on discovering a flaw in tube R112C113, a five (5) tube buffer zone expansion was employed. No additional flaws were identified.

- A small freespan ODSCC indication was found in tube R48C159 adjacent to the VS4 support. The indication was identified as part of APS's "mini-ARC program. This program requires plus point inspection of the entire bend if programmatically inspecting a NQI/DSI at the batwing. The flaw measures 24% and was not detectable by bobbin coil. There is some evidence that the flaw may be associated with a nick/groove. APS reviewed the incidence of flaws in this region (radially and vertically). Although no other freespan indications have been identified in Units 1 or 3, a VS4 indication was found in U1R10 at tube R51C152. APS elected to conduct a 58 tube bounding inspection to include the locations of both indications.

9. Discuss your use or reliance on inspection probes (eddy current or ultrasonic) other than bobbin and typical rotating probes, if applicable.

PVNGS is currently using standard bobbin and Plus Point probes for Unit 3 tube inspection. The small radius U-bend inspections are being supplemented with high frequency Plus Point. PVNGS also employs the GHENT probe to inspect tubes with permeability calls to ensure permeability does not mask flaw signals.

10. Describe in situ pressure test plans and results, if applicable and available, including tube selection criteria.

No tubes currently require in situ pressure testing. APS conducts pre-screening based on criteria per the EPRI In Situ Guidelines and PVNGS tube pull results. Flaws that exceed pre-screening criteria are further interrogated using an Appendix B condition monitoring software (OPCON) developed for APS by APTECH. The indication found at R14C59 was evaluated with a lower bound probabilistic model (in use since 1996). The model accounts for uncertainties in sizing, material properties and burst correlation. Despite the long crack length the structurally significant crack depth and length was determined to be 40.63% and 1.42 inches respectively. Accounting for all uncertainties at 90/50, the burst pressure is calculated to be 5967.8 psi and the POL at MSLB is zero. The 3NODP basis for PVNGS is 3855 psia.

11. Describe tube pull plans and preliminary results, if applicable and available, include tube selection criteria.

PVNGS has no plans for tube pull during U3R12.

12. Discuss the assessment of tube integrity for the previous operating cycle (i.e., condition monitoring).

No flaws were identified that are structural or leakage integrity concerns.
The plugging projects for U3R12 were calculated to be 150 tubes per Steam Generator. The plugging in SG 31 is expected to be less than 30 tubes. In SG 32 the plugging totals are expected to be less than 100. As such, the Cycle 12 operational assessment is considered to be conservatively validated.

13. Provide the schedule for SG related activities during the remainder of the current outage.

To be discussed during briefing.

ASSESSMENT OF STEAM GENERATOR TUBE DEGRADATION MECHANISMS
RECOMMENDED SG INSPECTION, TESTING & REPAIR SCOPE – U3R12

Scope	Inspection Method	Extent	SG 3-1	SG 3-2	Comments
100% Full Length Bobbin Program	Bobbin	Full Length	~10,100	~10,000	Standard Refueling Outage Bobbin Program (Ref. memo 323-00258-DFG/ECS 1/25/93)
Bobbin Straight Leg	Bobbin	07C-TEC 07H-TEH	~280	~280	Full Length of vertical leg of low row U-bends. Bend Region inspected by Plus Point.
ARC Region Inspection plus Buffer Sample	RC (Plus Point)	07H- VS3	~3600	~3800	100% of Critical Area (CA) for ARC Region axial defects, based on Degradation Assessment and 99-ENGINEERING-TJ-006. Definition of CA.
100% Top of Tubesheet Hot Leg Program	RC (Plus Point)	TSH (+2 –14)	~10,400	~10,400	Inspection for circumferential indications per GL 95-03. Critical Area (Extent) based on Preliminary WCAP 16208 report for Unit 3.
U-bend Row 1 through 5	RC (Plus Point)	07H-07C	~280	~280	Short Radius U-bend cracking Reference CRDR 97-1350
20% Cold Leg Tubesheet Program	RC (Plus Point	TSC (+2 -14)	~2150	~2150	20% sample program based on Section 4.2 of PVNGS SG Degradation Assessment
Lower Hot Leg Dents (DNT), > 2volts	RC (Plus Point)	02H-09H	150	170	100% all DNT indications Reference CRDR 2499573, U2 new damage mechanism found at Axial PWSCC at dented tube supports.
Manufacturing Buff Marks (MBM) and Bulge (BLG) Indications	RC (Plus Point)	Various	50	50	Exploratory sample to determine presence of corrosion indications. PVNGS SG Degradation Assessment (Section 4.1) indicates likely initiation sites in lower Hot Leg Region.
Row 6-18 U-Bends, 20% sample program	RC (Plus Point)	07H-07C U-Bends	~180	~180	100% of all APA indications, PVNGS program, based on Apex anomalies findings in Unit 3. CRDR 2600042, inspection includes 100% of all APA indications.
Previous Wear Calls or DSH calls & I-Codes	RC (Plus Point)	Various	~1600	~1300	100% CA Inspection Program to verify defect characterization based on observed SCC indications in Unit 2
100% of bobbin indications at support locations (DSI)	RC (Plus Point)	Support Locations	~150	~150	100% CA Inspection Program to verify defect characterization based on observed SCC indications in Unit 2 per Section 3.2.2 of PVNGS SG Degradation Assessment.
Lower ARC	RC (Plus Point)	7h to 2nd VS	~250	~100	CRDR 2755877
Mini ARC HOT LEG COLD LEG	RC (Plus Point)	BW1-VS3 BW2-VS5	~450 ~60	~330 120	Program to determine if free span ARC-like indications occur outside ARC CA.
20% cold leg ARC region	RC (Plus Point)	VS5-07C	~600	~600	PVNGS sampling program to detect onset of free span cracking in cold leg, first observed in U1R10.

ECT Program

Inspections to be conducted per procedure 73TI-9RC01. Technique selection per PVNGS Steam Generator Degradation Assessment.

ECT Expansion Criteria

- Axial ARC Region Indications:
    - Five (5) tube expansion zone (all directions)
    - Additional regions may be specified based on ARCRISK Software
    - Formal evaluation by Engineering.
    - Cold Leg Region, expansion – Expand to 100% of CA if free-span SAI is detected.

- Outside ARC region Indications
    - Additional regions may be specified based on ARCRISK Software
    - Formal evaluation by Engineering

- Short Radius U-bends
    - 100% of adjacent row if SAI is detected – expansions based on GEOs will be evaluated by Engineering.

- Row 6-18 U-bends
    - Evaluate CA and perform 100% if SAI is detected

- ARC Region Dents
    - 100% of all dents > 2 volts if dent-related SAI is detected

- RC Exam of any Bobbin indications that exceed PVNGS Plugging Criteria
- RC Exam PLP/PLI region as specified by APS Level III and Engineering
- RC Exam of all I codes and bobbin indications per 73TI-9RC01
- RC Exam all new Dents greater than 2 volts.
-

RC Exam of all:

MBM, BLG – 100% of critical size locations below elevation of detected defect

Circumferential Cracks (Cold Leg)
- Expand to 100% of tubesheet if cold leg SCI is detected
- Expand to 100% of Cold Leg if C-3 condition occurs in Hot Leg MRPC Program

Mixed Mode Indications
- Five (5) Tube buffer zone (all directions)

Plug Inspection

Per EPRI ISI Guidelines and Technical Justification 99-SGPG-TJ-001 - A plug visual inspection for structural and leakage integrity is required. The Inspection is to be performed per Procedure 73TI-9ZZ13.

Special Tests

The following equipment should be available on site:

In-Situ Pressure Equipment – Local and Full Length Tube Tooling

Sludge Lancing/ Chemical Cleaning

Following SGWG recommendation after chemical cleaning in U3R10 no sludge lancing will be performed.

FOSAR

Required for both Steam Generators per 81DP-9RC01, Hot and Cold leg top of tubesheet annulus and outer periphery tubes.

Upper Bundle Flush

Since chemical cleaning has been completed successfully in U3R10 the need for an upper bundle flush has not be established and will not be performed.

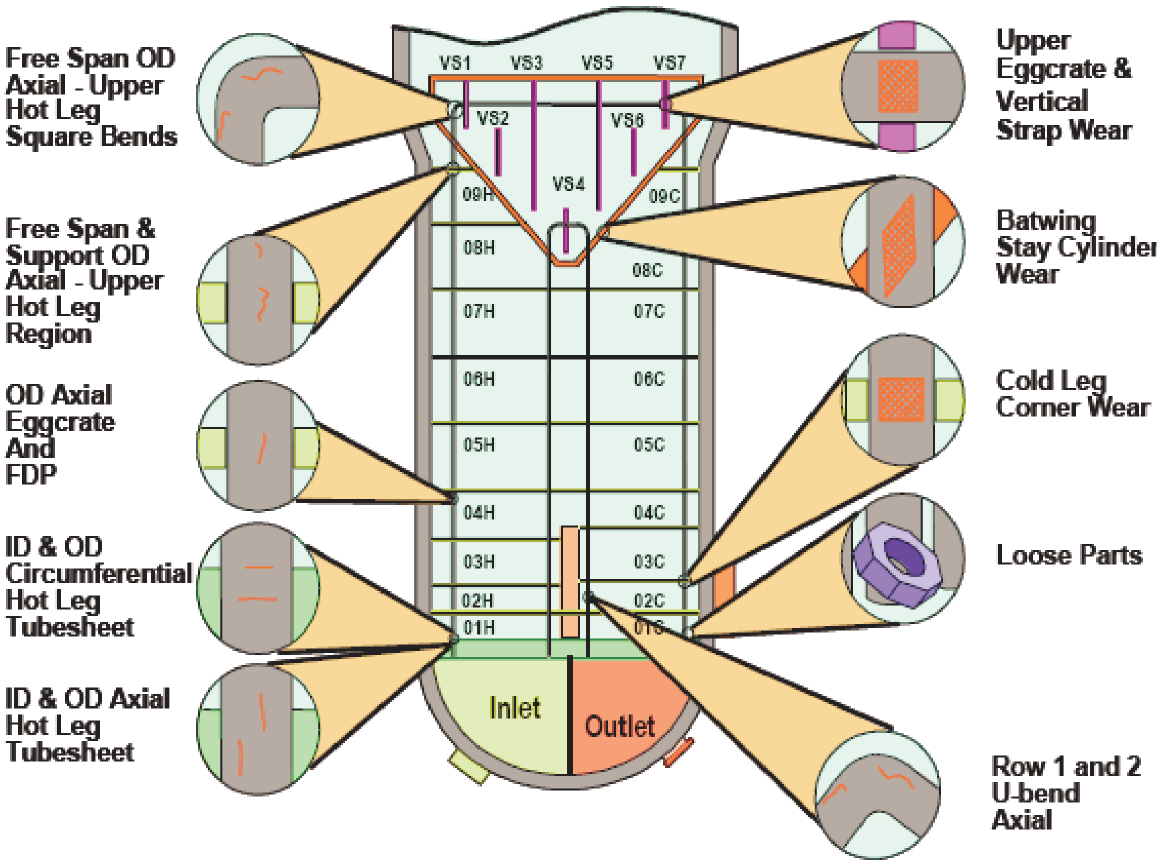
IN SITU Screening:

The initial screens for circumferential and axial cracks are evaluated in accordance with EPRI In Situ Pressure Testing Guidelines in conjunction with SG integrity engineer and Level III assessment as necessary.

Plugging Projections:

Based upon U3R11 results and the Unit 3 Cycle 12 Operational Assessment, plugging 150 tubes (2 long stakes and 10 short stakes) per SG is predicted.

Typical Damage Mechanisms – PVNGS Steam Generators



PVNGS Administrative Plugging Criteria

1. Wear indications $ the Technical Specification repair limit of 40% as called by either bobbin or RPC techniques. The highest call shall be the call of record.

2. Wear indications $ 20% (by bobbin) for Stay Cylinder Batwing Wear. The affected tube population is identified in 73TI-9RC01. Tubes may require stakes in accordance with the PVNGS Staking Guidelines N001-6.03-440.

3. Wear indications $ 20% (by bobbin) for Cold Leg Corner Wear. The affected tube population is identified in 73TI-9RC01. Tubes may require stakes in accordance with the PVNGS Staking Guidelines N001-6.03-440.

4. Batwing Wrapper Bar (BWW) indications $ 20% (by bobbin) wear. If the defect indicates a wear rate >40% per cycle, the tube shall be staked.

5. Repair wear indications $ 35% (by bobbin) for tubes with no previously identified wear. A historical review of the previous inspection results is permitted for this evaluation.

6. All detected loose parts (PLPs) with detectable wear. Tubes may require staking based on engineering evaluation and FOSAR results.

7. All detected cracks and mix mode indications. All detected circumferential cracks and mixed mode indications shall be staked as required.

8. GEO indications in Row 1-5 U-bends.

9. Volumetric indications (SVIs) which indicate corrosion behavior (SVI with change that is not attributable to ET process tolerances). Change shall be based on present data compared to a minimum of two (2) cycles earlier.

10. SVIs identified as tube-to-tube wear (TTW) indications (Reference V-PENG-TR-004 Examination of Palo Verde 3 Steam Generator Tubes During the 1994 Outage) which indicate $ 35% by RPC.

cc:

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