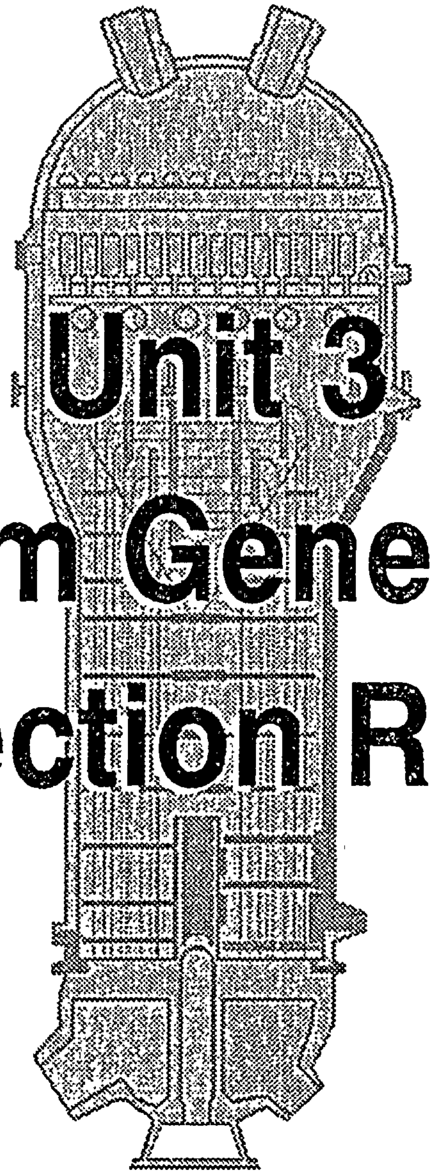
Palo Verde Nuclear Generating Station



Unit 3 Steam Generator Inspection Report

U3R4
July 1994

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I. EXECUTIVE SUMMARY

PVNGS Unit 3 was shutdown in March of 1994 for its fourth refueling outage. Extensive steam generator (SG) eddy current testing (ECT) was performed to determine the extent of axial and/or circumferential indications. While four circumferential indications were found in Unit 3 during the previous outage (U3M4), none were discovered during the U3R4 inspection process. Upper bundle axial indications (SAIs), similar to those found in Unit 2, were identified in Unit 3 for the first time. One tube was plugged in SG 31 and sixteen were plugged in SG 32 for upper bundle axial indications. A total of 7 tubes in SG 31 and 24 tubes in SG 32 were plugged in U3R4 (see Appendix A for a complete summary of tube plugging). A sampling of tubes was re-examined following chemical cleaning. No evidence of a shift in detectability was identified in any of these examinations.

Two tubes were removed from the secondary side of SG 32 to evaluate the nature of volumetric indications (SVI) seen on tube R152C73 (and others). The SVI was determined to be an area of general dissolution corrosion under a deposit on the tube OD. There were no wear or erosion indications. While the condition was verified to be neither intergranular stress corrosion cracking (IGSCC) nor intergranular attack (IGA), the chemistry conditions that caused this degradation could not be determined.

A full bundle chemical cleaning effort was successfully completed in both SGs during the U3R4 outage. The process was similar to that employed in Unit 2 (Reference 1). A total of 5387 and 5123 pounds of deposit were removed from SG 31 and 32, respectively. ECT analysis of the upper tube bundle indicates ridged deposits remaining on some tubes following the chemical cleaning process.

Following entry into Mode 3, leakage from a SG 32 instrument nozzle was discovered. The plant was cooled down to Mode 5 to effect repairs followed by a heatup to Mode 3. A second nozzle (downcomer sample) was found to be leaking. This required a second cooldown and repair effort. No root cause of failure was determined. The failure mechanism is believed to be weld porosity in the original weld. Porosity would not have been visible during the magnetic particle testing (MT) performed during nozzle manufacture. Cyclic stress can damage or destroy the ligaments between areas of weld porosity and eventually form a leakage path.

Short term corrective actions involve emphasizing (to control room personnel) the possible indications of a SG nozzle leak, visual inspection in the vicinity of the SGs during planned containment entries, and evaluation of the use of thermography during the visual inspections. Long term actions under evaluation include inspection of the nozzles during planned plant shutdowns and heatups and preplan, as much as possible, for repair of a failed nozzle so that the impact can be minimized and evaluation of preventative repair of all nozzles during a planned outage so as to minimize the schedule and cost impact.

II. STEAM GENERATOR INSPECTION

A. Tube Harvest

In an effort to ascertain the nature of SVIs discovered on tubes in Unit 3 SGs, a tube (R152C73) containing an SVI was removed. Additionally, an adjacent tube (R154C73)was removed to allow access to the tube of interest. The tube containing the SVI was inspected and removed from service via plugging during the midcycle outage in December, 1993.

These tube sections were removed from the secondary side of the SGs using the process employed in Unit 2 (U2M5). The process is described in detail in the "Unit 2 Steam Generator Inspection Report" to the NRC, dated March 1994 (Reference 1). After removal of the hot and coldleg plugs from tube R152C73, both tubes were cut approximately 3" above the 09H support using an ID whip cutter from the primary hotleg plenum. A tube gripping device was attached to the OD of the tubes to prevent damage to adjacent tubes during cutting and removal activities. The final cut was then made approximately 3" from the first vertical support (VS1) using the whip cutter from the primary coldleg plenum. The two L-shaped tube sections were then removed from the SG via the secondary manway.

Detailed analyses were performed to ensure that tube removal would not result in an unstable configuration of the upper tube bundle following the removal of the tube sections. Flow induced vibration (FIV) calculations were performed for the hotleg straight section of tubing, extending from the hotleg tubesheet to the 09H support, the long section of tubing from the coldleg tubesheet to VS1, and the unsupported length of batwing support left from the tube removal process. The FIV calculations show the as-left tube configuration to be more stable than the virgin tube. The relatively short unsupported length of bat wing is also not a stability concern for causing increased wear rates on adjacent tubes.

TABLE II.1: SG 32 Tube Pull Candidates

Row	Col	Elevation	93 Bobbin	93 MRPC	94 Bobbin	94 MRPC	Voltage	Extent
152	73	BW1+3.10 BW1-3.26 BW1-0.39	NQI NQI NQI	SVI PDP BOW	NQI NQI NQI	SVI PDP BOW	1.39 N/A N/A	1.40" 7.20" 3.27"
154	73	BW2+1.13 09H+23.6	<20%	NDD NDD	<20%	NDD PDP	0.26 N/A	N/A 12.35"

B. Original Eddy Current Scope

An examination plan was prepared and submitted to the NRC (Reference 2, dated March 2, 1994) to address the original scope and expansion plans. The original scope of ECT examinations planned for the U3R4 outage was largely based on the examination results of the U2M5 and U3M4 outages for axial indications, and the U1R4 outage for circumferential indications. The scope included 100% full length bobbin coil examination, 20% rotating pancake coil (MRPC) examination of the hotleg tubesheet area in SG 31, full MRPC examination of the hotleg sludge pile region in SG 32, and 20% MRPC examination of the arc area. This is illustrated in the following table:

TABLE II.2: EXAMINATION SUMMARY			
Exam Description	Extent	SG 31	SG 32
Full Length Bobbin	TEC-TEH	10891	10899
Tube Sheet MRPC	TSH-TSH	2220	553
U-Bend MRPC	08H-1st VS	388	391

C. Chemical Cleaning Expansion Scope

An examination plan was also prepared to address the examinations associated with the chemical cleaning schedule and related scope. This plan was prepared with the purpose of verifying the effectiveness of the chemical cleaning process to remove the ridge deposits and also to determine if a significant detectability shift occurred.

To summarize the plan; tubes with non-quantifiable bobbin coil indications detected prior to chemical cleaning were to be MRPC examined after cleaning. An additional 60 tubes (expansion 2) that contained deposit indications were also reexamined. No evidence of a shift in detectability was identified in these examinations.

D. Expansions

Several expansions were performed during this outage in each SG. The expansions are categorized in Table II.3. A short explanation of each expansion is provided below:

Expansion 1: Utilized to track the special interest MRPC performed to quantify or evaluate bobbin or previously called indications including NQI, ADR, DSI, DTI, PLP, and others.

Expansion 2: MRPC of various tubes after chemical cleaning to determine if a signal change due to chemical cleaning could be measured. The priority for this selection was on tubes with deposit calls prior to cleaning.

Expansion 3: Bobbin coil examination after sludge lance to aid in determination of effectiveness of sludge lance.

Expansion 4: Bobbin coil examination of a loose part believed to have moved after chemical cleaning.

Expansion 5: MRPC examinations bounding SAIs to aid in determination of additional SAIs in general area.

Expansion 6: MRPC examination of Rows 1 and 2 tubes in the U-bend area due to location of an SAI in a low row U-bend area of SG 32.

Expansion 7: MRPC examination of re-evaluated I-codes. Re-evaluation of bobbin data was performed due to an SAI having an NQI signal with a particular characteristic and location.

Expansion 8: Full length bobbin coil examination performed after chemical cleaning in SG 31. The area examined was a similar mirror-type image of the bounded SAIs (expansion 5) in SG 32.

Expansion 9: MRPC of non-quantifiable type indications found during expansion 8.

Expansion 10: Full length bobbin coil examination of the remaining region above row 90 after chemical cleaning. The combination of expansion 8 and expansion 10 resulted in all tubes in row 90 and above being full length bobbin coil examined after chemical cleaning.

Expansion 11: MRPC examinations bounding an SAI to aid in determination of additional SAIs in general area.

Expansion 12: MRPC of non-quantifiable type indications found during expansion 10.

TABLE II.3: EXPANSION SCOPE

Exam Description	Extents	SG 31	SG 32
Expansion 1	Various	189	215
Expansion 2	08H-1st VS	60	60
Expansion 3	TEC-TEH	256	205
Expansion 4	TEH-01H	N/A	241
Expansion 5	08H-2nd VS	N/A	1137
Expansion 6	07C-07H	114	110
Expansion 7	Various	N/A	39
Expansion 8	TEC-TEH	1142	N/A
Expansion 9	Various	28	N/A
Expansion 10	TEC-TEH	2171	N/A
Expansion 11	08H-2nd VS	59	N/A
Expansion 12	Various	42	N/A

III. CHEMICAL CLEANING

A. Process Objectives

A full bundle chemical cleaning effort was conducted on both Unit 3 SGs. The objectives of the process were identical to those of Unit 2:

1. To remove ridged deposits in the upper bundle regions which were identified by eddy current analysis and may have aggravated the axial cracking condition in that area.

2. To remove tube scale deposits which interfere with heat transfer and may contain undesirable contaminants..

3. To remove deposits from the surface of the tubesheet and the flow distribution plate (FDP).

4. To remove deposits from the drilled hole crevices in the FDP.

The EPRI/SGOG low temperature process was nearly identical to that employed in Unit 2 (Reference 1). Additionally, corrosion allowances and limits were the same as those employed in Unit 2. Details on the differences between the two units will be discussed in detail.

B. Process Application

The process, as applied to each SG in series, involved:

- A full volume rinse at ambient temperature. The solution contained 50-200 ppm hydrazine and enough ammonium hydroxide to adjust the pH to 10.

- A full volume magnetite solvent application at 200°F (for 80 hours) to remove bridged, tube, and tubesheet deposits. The magnetite solvent contained 160 g/l EDTA, 10 g/l hydrazine, 10 ml/l CCI-801 (as a corrosion inhibitor), and ammonium hydroxide (to a pH of 7).

- A low volume (just above the flow distribution plate) magnetite ("crevice") solvent application at 250°F (for 20 hours) to clean out flow distribution plate crevices. This step involved localized boiling to mechanically assist in the crevice cleanup. The crevice solvent contained 200 g/l EDTA, 10 g/l hydrazine, 10 ml/l CCI-801 (as a corrosion inhibitor), and ammonium hydroxide (to a pH of 6).

- A low volume and full volume rinse and cooldown.

- A full volume copper/passivation solvent application at 90-110°F (for 12 hours) to remove copper deposits and to develop a thin oxide layer to protect carbon steel surfaces from corrosion after the chemical cleaning process. The solvent contained 85 g/l EDTA, 2% hydrogen peroxide, and Ethylene-diamine (to a pH of 9.0).

- A low volume and full volume rinse and cooldown.

The following is a description of the two significant changes which were made in the transition from Unit 2 to Unit 3.

1. During the Unit 2 copper step a total of about 9 pounds of copper was removed from each SG. BWNT was able to modify the process to combine the copper and passivation steps. This modification saved about 20 hours of process time and about 12,000 gallons of additional waste.

2. The iron dissolution steps in Unit 3 were extended from the 40 hour process in Unit 2. This time frame was based upon the qualification program which indicated that Unit 2 deposits readily dissolved in the EPRI/SGOG solvent. However, examination of some tubes removed from Unit 2 after chemical cleaning revealed the continued existence of a deposit residue in the upper bundles. Bench-top dissolution testing showed that the residual deposit would dissolve during an extended iron step of 80 hours.

C. Corrosion Monitoring

The corrosion monitoring process was identical to that employed in Unit 2. The computer-based corrosion monitoring system (CMS) electrodes provided on-line free and galvanic corrosion data (the sum of these is provided under "CMS" in Table III.1). Electrodes were weighed before and after the process to provide a weight loss comparison to the on-line predicted data. Additionally, coupons were used to provide weight loss corrosion data and were not measured "on-line". Corrosion data for the electrodes and coupons is also provided in Table III.1.

TABLE III.1: CORROSION SUMMARY [1,4]

Material	Type	Lower Probe SG 31	Upper Probe SG 31	Lower Probe SG 32	Upper Probe SG 32
SA-533	CMS[2]	0.939	0.817	1.007	N/A
	Electrode[3]	0.718	0.928	1.061	0.702
	Coupon[3]	1.509	0.640	1.788	0.470
AISI-1018	CMS[2]	1.522	0.797	1.516	N/A
	Electrode[3]	1.381	0.861	1.734	0.857
	Coupon[3]	1.684	0.577	1.968	0.521
SMAW (E7018)	CMS[2]	2.074	1.176	2.065	N/A
	Electrode[3]	3.682	2.012	3.023	1.389
	Coupon[3]	3.731	1.697	3.327	0.872
SA-106B	Coupon[3]	7.078	0.529	0.770	0.403

Note: 1. All values in mils penetration.
2. These values are the sum of the electronically measured free and galvanic corrosion and are the higher of duplicate specimens.
3. These values were determined from weight loss measurements.
4. All data is preliminary

D. Sludge Lancing

Sludge lancing to remove residual deposits on the tubesheet was performed following completion of chemical cleaning operations. As in Unit 2, the methodology employed lancing of the tubesheet from the divider lane towards the SG annulus. A total of 12 passes were performed in SG 31 and 8 passes in SG 32. Post-lancing inspections in SG 32 necessitated the performance of additional passes to further clean some areas which were identified to have tubesheet deposits exceeding acceptance criteria. The amount of sludge removed through this process is indicated in the Tables III.3 and III.4.

[illegible]

E. Secondary Side Inspection / FOSAR

Secondary side inspections were conducted through both 7" diameter handholes on either side of the divider lane (just above the tubesheet) and one of the 6" diameter handholes (just above the FDP). These inspections were performed in order to document chemical cleaning results as well as retrieve any loose objects discovered in the SG annulus or divider lane section.

The following loose parts were removed from the annulus and divider lane areas of the SGs:

TABLE III.2: LOOSE PARTS RETRIEVED

SG 31	SG 32
2 pc Wire/Nail	5 pc Weld Slag
1 pc Sludge Rock	6 pc Fibrous (Wood?) Chunks
1 pc Knurled Handle	2 pc Metal Shavings
4 pc Castle Nuts	2 pc Sludge Rocks
2 pc Weld Slag	

F. Results of Chemical Cleaning

A total of 5387 and 5123 pounds of deposit were removed from SG 31 and 32, respectively. The bulk of the deposit was magnetite (see Tables III.3 and III.4). As expected, the amount of copper removed was small (<8 pounds per SG). Sludge lancing efforts accounted for approximately <10% of the total deposits. ECT analysis of the upper tube bundle indicates ridged deposits remaining on some tubes in the upper bundle area.

TABLE III.3: DEPOSIT REMOVED DURING CLEANING OF SG 31[1]							
Step	Amount Removed (lb)						
	Fe_3O_4	Cu	NiO	ZnO	MnO_2	Cr_2O_3	Total
Iron	4255	0.3	115	1.8	56.8	4.0	4433
Crevice	399	0.1	6.3	0.1	3.1	0.5	409
Cu/Pass	13.8	6.7	0	0	0	0	21
Sludge	N/A	N/A	N/A	N/A	N/A	N/A	525
Total	4668	7.1	121	1.9	59.9	4.5	5387
Note 1: Preliminary data.							

TABLE III.4: DEPOSIT REMOVED DURING CLEANING OF SG 32[1]							
Step	Amount Removed (lb)						
	Fe_3O_4	Cu	NiO	ZnO	MnO_2	Cr_2O_3	Total
Iron	4412	0.3	126	2.0	58.3	4.4	4603
Crevice	241	<0.1	4.3	0.6	2.4	0.3	249
Copper	4.6	7.5	0	0	0	2.0	14
Sludge	N/A	N/A	N/A	N/A	N/A	N/A	257
Total	4658	7.8	130	2.6	61	6.7	5123
Note 1: Preliminary data.							

IV. NOZZLE FAILURES

A. Event Description

Two separate SG nozzle leaks caused a significant delay in the return to service of Unit 3 following the U3R4 outage. The leaks had a particularly severe impact on the unit productivity because they were discovered in series. The first leak was discovered upon initial mode ascension. During the subsequent mode ascension following repair of the first nozzle, another leaking nozzle was found. A brief description of the two events is provided below.

Instrument Nozzle Leak

On May 30, Unit 3 was preparing for return to power operation following the U3R4 refueling outage. The plant had entered Mode 3 and was approaching normal operating pressure and temperature (NOP/NOT) conditions in the reactor coolant system. Personnel in containment discovered steam leakage at the vessel nozzle upstream of valve SGEV614. This is the lower instrument nozzle for SG level transmitter SGA-LT-1124A. The SG pressure at the time the leakage was noted was approximately 1150 psia.

Due to the questionable structural integrity of this nozzle relative to Technical Specification (TS) 3.4.9, action b of the LCO was entered, and the plant was cooled down to Mode 5 to affect repairs. A walkdown of all other accessible SG nozzles was conducted, with no additional leakage noted.

The shell cone level indication nozzle was repaired utilizing a design in which the structural pressure boundary weld was moved to the outside of the SG shell. The structural weld was attached to a built up weld pad that was attached to the SG shell and sized to provide sufficient area and depth to support the structural weld in a metallurgically and structurally sound application. Both the pad and the weld were designed and installed per the applicable requirements of the ASME B&PV Code, Section III, and sufficient non-destructive examinations (NDE) were performed before (SG shell base material), during, and after the repair process to provide assurance that the secondary pressure boundary was restored to its original structural limits.

The SG secondary pressure boundary was technically restored to its structural limits per TS 3.4.9. The repaired condition has been shown to be acceptable, in terms of the structural integrity of the secondary pressure boundary and its ability to perform its intended function for all of the original design conditions as well as or better than the original nozzle design.

Downcomer Sample Nozzle Leak

Following the repair of the SG 32 level instrument nozzle, the plant was heated up to NOP/NOT for retest of the weld repair and to progress toward power operation. On June 8, a steam leak was discovered at the SG 32 downcomer sample nozzle upstream of valve SGEV428. The leakage source was not visually evident on any part of the nozzle on the outside of the SG, and since the original nozzle attachment to the SG shell design was a partial penetration weld on the inside of the SG shell, it was suspected that a weld failure was the cause of the leakage.

The structural integrity of the SG at this penetration was once again determined to be impaired. Following this loss of integrity (relative to TS 3.4.9), action b of the LCO was entered, and the plant was taken to Mode 5 to affect repairs. The repair process was similar to that employed for the instrument nozzle.

A comparative analysis of the geometry and material properties of the replacement nozzle and the structural weld (vice a stress or fatigue analysis), as well as a comparison of the new structural weld configuration to the ASME code requirements concluded that the replacement nozzle and structural weld are structurally equivalent to (or better than) the nozzle and weld they replace. Additionally, the replacement structural weld configuration meets all requirements of the ASME code.

Repair of the downcomer sample nozzle was completed on June 15. The plant was heated to NOP/NOT where an inservice leak test was performed satisfactorily. The Unit was then returned to power operation.

B. Evaluation

Nozzle Design

The nozzles which leaked in Unit 3 were a shell cone level nozzle and the downcomer sample nozzle. Both are designed as indicated in Detail J of Figure IV.1. The carbon steel SA106 grade B, 3/4" nozzles were attached to the Class 2 SG shell wall with an internal ID partial penetration weld. This partial penetration weld provided the structural pressure boundary support for the nozzle and met ASME Section III, Class 2 design stress requirements.

A similar leak from an upper level indication tap occurred in Unit 2 in 1993. In this design, a pad is welded onto the inner wall of the SG at the nozzle location. A "J" groove is machined into the pad and a "butter" weld of Inconel was laid on the pad. This Inconel layer forms a transition for the "J" weld which allows utilization of a weld process that does not require post weld heat treatment of the final nozzle weld. The Unit 2 nozzle was accessible and it was determined through liquid penetrant testing (PT) that the leak was due to weld porosity. Repair was performed at the inner weld, using the existing nozzle.

Routine NDE Evaluations

Routine NDE evaluations of the SG nozzles are not required. The ISI program does not include examination of Class 2 piping with a diameter $\leq$ 1" in diameter. Additionally, the boric acid walkdowns required by Generic Letter 88-05 only address primary systems containing boric acid.

Difficulties With NDE Evaluations

Performance of NDE evaluations (of any type) to determine the extent or existence of flaws in SG nozzle configurations cannot be effectively implemented and the results may not be conclusive, especially with a failure associated with weld porosity. Visual examinations from outside the SG could be affected by the following conditions or circumstances:

1. The insulation may hide a leak by diverting condensation down the inside of the insulation where it could evaporate without being seen.

2. An intermittent leak may not be visible during the inspection time period.

3. Accessibility to all nozzles is limited without scaffolding.

4. Nozzles in the steam space may not have enough moisture to form a steam plume.

5. The fitting would have to be cut off in order to allow a boroscopic examination of the nozzle and/or internal weld. Any magnetite buildup would interfere with the evaluation.

An external PT evaluation, which would require removal of the valves, would be adversely affected by magnetite buildup, surface roughness, and the difficulties associated with applying the penetrant materials in a restricted space. Additionally, this method would only allow examination of the nozzle, not the internal weld.

Any examination performed internally would require a "jump" by personnel. In that case radiation doses would limit stay time, a work platform would have to be installed, physical access to nozzles would have to be established, and any magnetite buildup would have to be removed (wire brush). Flaws may not be detectible with the naked eye, penetrant testing would require that the flaw be open to the surface with no foreign debris within the flaw, and magnetic particle testing would reveal shallow surface flaws but would probably not detect porosity.

Original Fabrication Review

The original fabrication records of both Unit 3 SGs were obtained from ABB-CE. The records were in the form of shop travelers and QC inspection reports. They generally consisted of weld inspection forms and NDE reports: MT, PT, and ultrasonic testing. These reports, along with the generic weld procedures common to both SGs were reviewed in detail in the same step by step sequence used for initial fabrication for each type of nozzle, along with the applicable drawings referenced in the travelers. Particular attention was concentrated on the detection of any apparent anomalies in the fabrication sequence and non-destructive testing utilized for fabrication, especially for the nozzle types that had experienced failure (i.e.: shell cone level and sample nozzles).

The most significant result was noted to be an apparent lack of inspection record for the fit-up of the SG 32 sampling nozzle. Comparison with the SG 31 inspections showed the inspection of the four shell cone level nozzles and the sampling nozzle was performed and recorded on the same report, and most likely should have been noted in this manner for SG 32. Review with ABB-CE personnel concludes that the lack of fit-up recording for the sample nozzle was an apparent oversight.

It should be noted that following original construction, the nozzles underwent visual and MT surface examinations. This process was intended to find surface and slightly subsurface flaws. The MT examination is not sensitive to the existence of porosity due to the rounded shape of the defect. Shielded metal arc welding (at the start and stop areas of the weld) was used in the construction of the nozzles. This process is susceptible to the development of weld porosity.

Other than the minor anomalies noted, no other significant problems appear to have been present during the manufacturing of the SG nozzle welds. Also, there does not appear to be a negative human performance trend associated with any of the manufacturing activities of the failed nozzles.

Chemical Cleaning Effects

Personnel safety and radiation exposure concerns prevented NDE inspection of the inside attachment weld for these nozzles. A visual inspection of both nozzle to shell welds was performed from inside the SG utilizing robotic video equipment. The overall exam effort was not conclusive due to limited accessibility and the surface condition of the inside shell. The visual examination did confirm that no pitting or general corrosion existed that might have been caused by chemical cleaning. It should be noted that chemical cleaning could have been a factor in the nozzle failures. Coupon testing in Units 2 and 3 show total dissolution of weld material in the 2 to 3 mil range. While this is insufficient to develop a "through-weld" leak, ligaments in a porous weld could have been damaged or destroyed by the process, leading to a leak.

C. Apparent Cause

It is currently believed that the SG nozzle leaks encountered in Units 2 and 3 were due to weld porosity of the original, inside nozzle to shell, weld. The presence of porous weld in the SG nozzles may not have been identified during fabrication and would perform adequately for a period of time.. At some point it is believed that cyclic stress (thermal, vibration, etc) can cause ligaments between the areas of weld porosity to degrade and open a path for leakage through the weld. The welds opened up over the period of plant operation until a leak path developed to containment atmosphere.

The fact that Unit 3 developed nozzle leaks after undergoing SG chemical cleaning has been reviewed. Based on observations from the video examination of the Unit 3 nozzles, through-wall corrosion due to chemical cleaning is not believed to be responsible for the leakage.

During evaluation of Unit 3 leaks it was concluded that additional evidence gathering, which required SG entry, was not warranted. This effort would have involved significant radiological exposure as well as industrial safety concerns. This decision eliminated the possibility of gathering physical evidence and performing root cause analysis.

The detailed fabrication review performed during this evaluation has not identified a common factor in the failed nozzles during fabrication. At this time, no design factor has been identified which implicates a specific subset of nozzles as most susceptible. In fact, two distinct nozzle weld designs have leaked, indicating the cause is not related to a specific design.

D. Inspection Options

Physical inspection and penetrant testing of each nozzle would be required to help confirm the integrity of every nozzle. It is not feasible to physically inspect the weld of each nozzle. A shutdown of each unit would be required, along with a physical entry into each SG (nozzle welds are only visible from inside the SG). This effort would involve substantial radiological exposure as well as industrial safety concerns. Complete inspection of all nozzle welds is impossible as some of the nozzle welds would not be physically accessible due to location. Finally, penetrant testing will not confirm that the weld is free of porosity problems if the porosity has not breached the outer surface of the weld.

Inspection of the nozzles from outside the SG during plant operation would provide assurance that no undetected leakage exists. However, such an inspection would require entry inside the bioshield (which is not feasible with the reactor at power) as well as removal of insulation to allow access to the surface of the SG for inspection. One nozzle, the top head pressure sensing line, may not be accessible from the outside (or inside) of the SG without significant effort, due to very limited accessibility.

E. Safety Evaluation

A SG nozzle failure is bounded by the analysis presented in UFSAR Chapter 15.1.5, "Steam System Piping Failures Inside and Outside Containment". In that analysis a main steam line break area of 1.28 ft^2 is postulated based on the flow restrictors in the throat of each main steam line. The smaller the postulated area of the line break the less severe the consequences of the failure. The effective break area for any of the SG nozzles is much less than this value.

A SG nozzle failure would be considered a high energy line break. Analysis of the effects of the creation of a missile or pipe whip was performed for all of the related steam piping in the original FSAR and the consequences are bounded by that analysis.

The type of fault that results from excess weld porosity is likely to result in a slowly developing leak rather than a catastrophic failure. As discussed in the short term action plan below, a nozzle leak to the point it exceeds 1 gpm will be readily detected by existing leakage detection systems and containment monitoring instrumentation.

Although the actual cause of these nozzle failures has not been verified, weld porosity is considered the most probable cause of the leakage. There is evidence that the earlier failure of a Unit 2 SG nozzle resulted from weld porosity. If other welds have similar weld porosity, they too can develop leakage over time as the effects of operational cycles accumulates. The probability of encountering additional nozzle leaks cannot be determined. It is clear from the review of operating experience that very few leaks of this type have been encountered in industry.

F. Short Term Action

It is currently believed that the SG nozzle leaks encountered in Units 2 and 3 were due to weld porosity of the original, inside nozzle to shell, weld. The welds opened up over the period of plant operation until a leak path developed to containment atmosphere. At this time, no common factor has been identified which implicates a specific subset of nozzles as most susceptible.

Detailed inspections of all the SG nozzles in the Units would require shutdown. Such action is not considered practical nor warranted in the short term. Instead the following short term actions will be adopted:

1. Initiate night orders/briefings that describe the leakage experienced in Unit 2 and 3. The night order will reiterate the possible indications of a SG nozzle leak available in the control room and include the expected containment sump level response.

2. Containment entries planned for other purposes will include inspection in the general vicinity of the SGs when nozzle leakage is indicated.

3. Evaluate the use of thermographic analysis during planned containment entries as an aid in identification of SG nozzle leakage.

G. Long Term Action

Based on the significant economic impact that leaking SG nozzles can have on PVNGS, the following long term action plan is under evaluation:

1. Continue to monitor for SG nozzle leakage as indicated in the short term action plan.

2. Inspect nozzles as practical during planned shutdowns and post outage during heat up to detect any leakage. The first such inspections could be planned for Unit 2 and 3 midcycle outages and the next Unit 1 refueling outage.

3. Prepare, as much as possible, for a nozzle repair. Items to be considered include development of required work packages, procurement of materials, weld process, etc. If a repair is required, the impact will be minimized.

4. Evaluate preemptive repair of all the SG nozzles. Under this approach all the nozzles would be repaired during a normal planned outage, and not be critical path work. The repairs would be essentially the same as those performed in Unit 3 and would not require entry into the SG.

V. EVALUATION OF HARVESTED TUBES

A. Background

During the Cycle 4 mid-cycle outage in Unit 3 several tubes were discovered with SVIs in the upper bundle region. One such tube (R152C73), with an SVI on the intrados about 3 inches above the center of the batwing support, was adjacent to a peripheral tube. Therefore, this tube was readily available for removal for destructive examination to characterize the SVI. Early in the U3R4 outage, the hotleg bend sections of this tube (R152C73) and the adjacent tube (R154C73) were removed (see Section II).

The scope of work for the examination included:

1. Visual and low-power examination of the tube OD surfaces in the as-received condition.
2. Review of field ECT data.
3. Analysis of deposits from the tube OD surfaces using x-ray diffraction, x-ray fluorescence and ion coupled plasma techniques.
4. Swelling (to 8000 psi), followed by visual examination.
5. Tube descaling, followed by visual and low-power examination.
6. Sensitization assessments using modified Huey tests.
7. Light metallography examination of defect areas.
8. Scanning electron microscopy examination of SVI location.
9. Dual etch microstructure evaluations.
10. Tensile tests to determine mechanical properties.
11. Bulk chemical analysis.
12. Micro-hardness testing.
13. Outside and inside diameter measurements.

B. Analytical Results and Discussion

Figure V.1 shows the results of the visual examination of the R152C73 tube section (65.5 inches). Wear scars were evident at the batwing support location. A long axial scrape from the bottom of the tube section to just below the bend was determined to be a fabrication flaw. A ridge deposit and an apparent wear scar existed at the tube intrados approximately 35 inches above the 09H location. Heavy deposits were located in the 270° orientation 30 to 34 inches above the 09H location. The tube was sectioned into six pieces for further evaluation. Visual examination after tube swelling and descaling revealed no indications of IGA.

General tube deposits from both tubes and ridge deposit material from the R152C73 tube were analyzed by x-ray fluorescence and inductively coupled plasma analysis. The deposit compositions are listed in Table V.1. The material was determined to be greater than 90% iron oxide. Smaller quantities of copper, manganese, and nickel were also found. These results are typical of SG deposit analyses.

The SVI was determined to be a long (2-3/16 inches), narrow (1/4 inch) groove area of OD metal loss that extended approximately 26% throughwall on the intrados of the tube. Scanning electron microscope examination indicated a general corrosion process (micropitting) beneath a ridged deposit. Sulfur was detected in the deposit analysis (Table V.1). The chemistry conditions that produced the area of degradation could not be determined. There was no indication of cold work or increased microhardness in the thinned region. However, tube-to-tube contact was suspected and may have influenced the corrosion. No IGSCC or IGA was found to be associated with the corrosion area.

The microstructure of both tubes had the characteristics of tubes with a demonstrated susceptibility to primary water stress corrosion cracking and caustic IGSCC. This conclusion is supported by relatively fine grain microstructures with essentially all of the carbides being intergranular. The carbide distribution indicates that the temperature of the final anneals of these tubes were not high enough to dissolve all of the carbides that had precipitated during earlier processing steps, but they were high enough to recrystallize the deformed grains present after the last tube reduction step.

C. Conclusions

1. There was no IGA or IGSCC in tube R152C73 which had an SVI.

2. The SVI examination revealed the presence of a localized, general corrosion process under a ridge-like deposit which concentrated impurities in the bulk water.

3. The SVI was not due to active wear caused by repeated tube-to-tube contact.

4. The microstructures of the tubes examined were not typical of Alloy 600 with good resistance to stress corrosion cracking.

TABLE V.1: TUBE DEPOSIT ANALYSIS						
Assumed Oxide	Inductively Coupled Plasma			X-ray Fluorescence		
	R152C73 Deposit	R152C73 Ridge	R154C73 Deposit	R152C73 Deposit	R152C73 Ridge	R154C73 Deposit
Fe_3O_4	90.3	88.9	96.5	94	86	96
Cu	1.58	1.68	0.07	1.3	1.0	0.2
NiO	0.63	2.50	0.85	0.5	2.0	0.7
MnO	5.97	4.82	1.70	3.5	6.4	1.7
ZnO	0.13	0.16	0.05	<0.1	0.2	<0.1
Cr_2O_3	0.08	0.34	0.07	0.2	0.9	0.2
TiO_2	0.12	0.34	0.13	0.2	0.7	0.2
SiO_2	0.10	0.25	0.17	0.1	0.8	0.3
Al_2O_3	0.19	0.30	0.15	<0.1	0.1	<0.1
P_2O_5	0.63	0.28	0.06	0.3	0.4	<0.1
SO_3	ND	ND	ND	<0.1	0.3	0.1

All values in weight percent. ND=not detectable.

VI. REFERENCES

1. PVNGS "Unit 2 Steam Generator Inspection Report" dated March 1994.

2. Letter 102-02847, dated March 2, 1994, from J. M. Levine, VP Nuclear Production, APS, to USNRC, "Steam Generator Tube Inspection Plan".

3. PVNGS Updated Final Safety Analysis Report 15.1.5 - Steam Systems Piping Failures Inside and Outside Containment.

4. PVNGS Technical Specification 3/4.4.9 - Structural Integrity.

5. ASME Boiler and Pressure Vessel Code

6. V-PENG-TR-004, "Examination of Palo Verde-3 Steam Generator Tubes Removed During the 1994 Outage", ABB-CE, June, 1994.

7. PVNGS "Unit 3 Nozzle Failure" report dated June 1994.

APPENDIX A TUBE PLUG SUMMARY

Appendix A contains tubesheet maps which illustrate those tubes which were plugged during U3R4. Additionally, a summary table of the plugged tubes are included.

The following figures and tables are included in this Appendix:

Figure A-1	SG 31 Tube Plug Map
Table A-1	SG 31 Tube Plug Summary Report
Figure A-2	SG 32 Tube Plug Map
Table A-2	SG 32 Tube Plug Summary Report

FIGURE A-1: SG 31 TUBE PLUG MAP

PLUGGED 121 X TBP 7 ◆

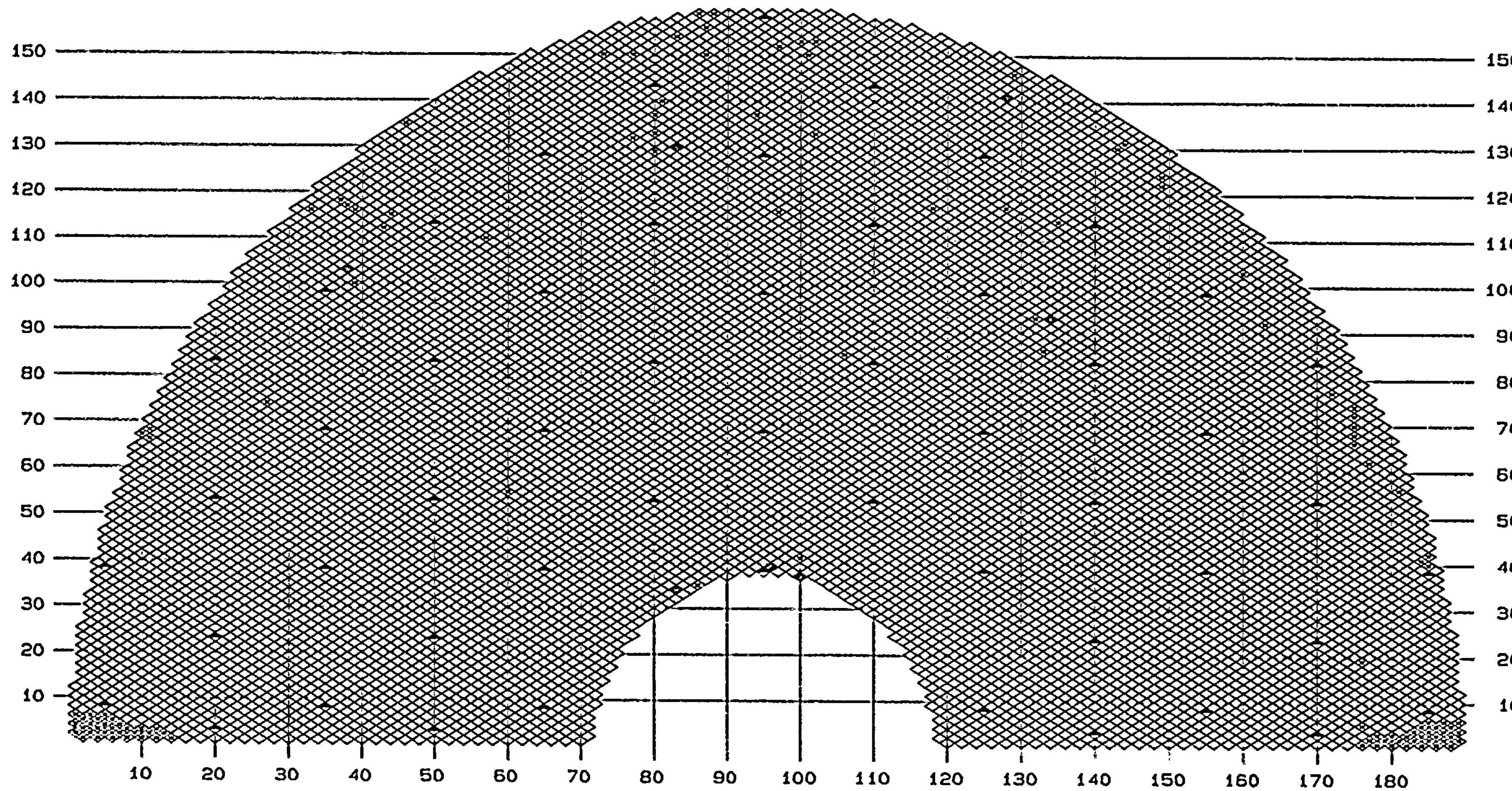

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TABLE A-1: STEAM GENERATOR 3-1 TUBE PLUG SUMMARY REPORT

Row	Column	ET Call	Degradation	Elevation	Hot Leg Configuration	Cold Leg Configuration	Outage/Date Removed
103	38	SAI	Support Axial Indication	BW1-2.41"	B&W Rolled Plug + 376" Stake	B&W Rolled Plug	U3R4 - 5/94
34	83	SAI	Tubesheet Axial Indication	TEH+22.6"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
130	83	SVI	Single Volumetric Indication	BW1-2.90"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
39	96	28%	Bat Wing Stay Cylinder Wear	BW1-2.01	B&W Rolled Plug + 390" Stake	B&W Rolled Plug	U3R4 - 5/94
37	100	23%	Bat Wing Stay Cylinder Wear	BW2-1.97"	B&W Rolled Plug + 384" Stake	B&W Rolled Plug	U3R4 - 5/94
141	128	41%	Vertical Support Wear	VS5+0.83"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
93	134	41%	Bat Wing Wear	BW1+2.72"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94

FIGURE A-2: SG 32 TUBE PLUG MAP

PLUGGED 113 X TBP 25 ◆

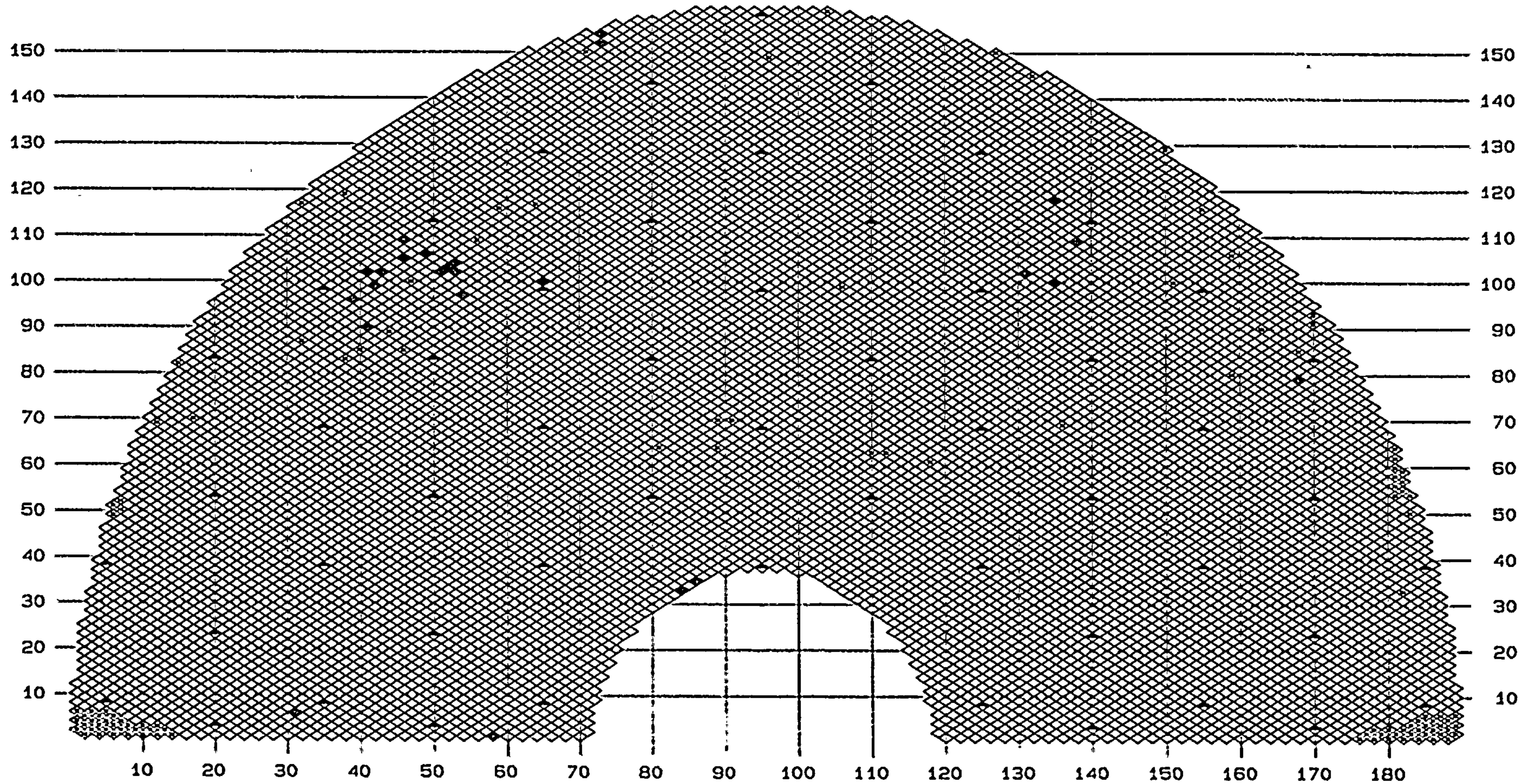

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TABLE A-2: STEAM GENERATOR 3-2 TUBE PLUG SUMMARY REPORT

Row	Column	ET Call	Degradation	Elevation	Hot Leg Configuration	Cold Leg Configuration	Outage/Date Removed
6	31	SAI	Tube End Axial Indication	TEH+2.69"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
96	39	SAI SAI	Support Axial Indication Support Axial Indication	BW1-0.25" VS2+2.02"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
90	41	SAI SAI	Support Axial Indication Midspan Axial Indication	VS2+2.00" VS2+2.73"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
102	41	SAI SAI	Midspan Axial Indication Midspan Axial Indication	VS2+2.10" VS2+4.19"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
99	42	SAI SAI	Support Axial Indication Midspan Axial Indication	VS2+1.29" VS2+3.59"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
102	43	SAI	Midspan Axial Indication	VS2+3.00"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
105	46	SVI	Single Volumetric Indication	08H+34.89"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
109	46	SAI	Midspan Axial Indication	08H+32.07"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
106	49	SAI	Midspan Axial Indication	08H+41.16"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
102	51	SAI	Support Axial Indication	BW1+0.88"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
103	52	SAI	Support Axial Indication	BW1-1.20"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
102	53	SAI	Support Axial Indication	BW1-1.04"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
104	53	SAI SAI SAI	Midspan Axial Indication Midspan Axial Indication Support Axial Indication	08H+35.81" 08H+36.91" BW1+0.11"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
97	54	SAI	Support Axial Indication	BW1-0.65"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
1	58	SAI	U-Bend Axial Indication	BW1+9.58"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
100	65	SAI	Support Axial Indication	BW1-0.11"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
152	73	N/A	Tube Harvest (Note 1)	N/A	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
154	73	N/A	Tube Harvest	N/A	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94

TABLE A-2: STEAM GENERATOR 3-2 TUBE PLUG SUMMARY REPORT

Row	Column	ET Call	Degradation	Elevation	Hot Leg Configuration	Cold Leg Configuration	Outage/Date Removed
33	84	24%	Bat Wing Stay Cylinder Wear	BW1-2.00"	B&W Rolled Plug + 373" Stake	B&W Rolled Plug	U3R4 - 5/94
35	86	21%	Bat Wing Stay Cylinder Wear	BW1+1.88"	B&W Rolled Plug + 379" Stake	B&W Rolled Plug	U3R4 - 5/94
102	131	SAI	Support Axial Indication	BW1+2.45	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
100	135	SAI	Midspan Axial Indication	BW1+3.83	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
118	135	39%	Bat Wing Wear	BW1-1.79"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
109	138	SAI	Support Axial Indication	BW1+2.45"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94
79	168	40%	Vertical Support wear	VS3+0.93"	B&W Rolled Plug	B&W Rolled Plug	U3R4 - 5/94

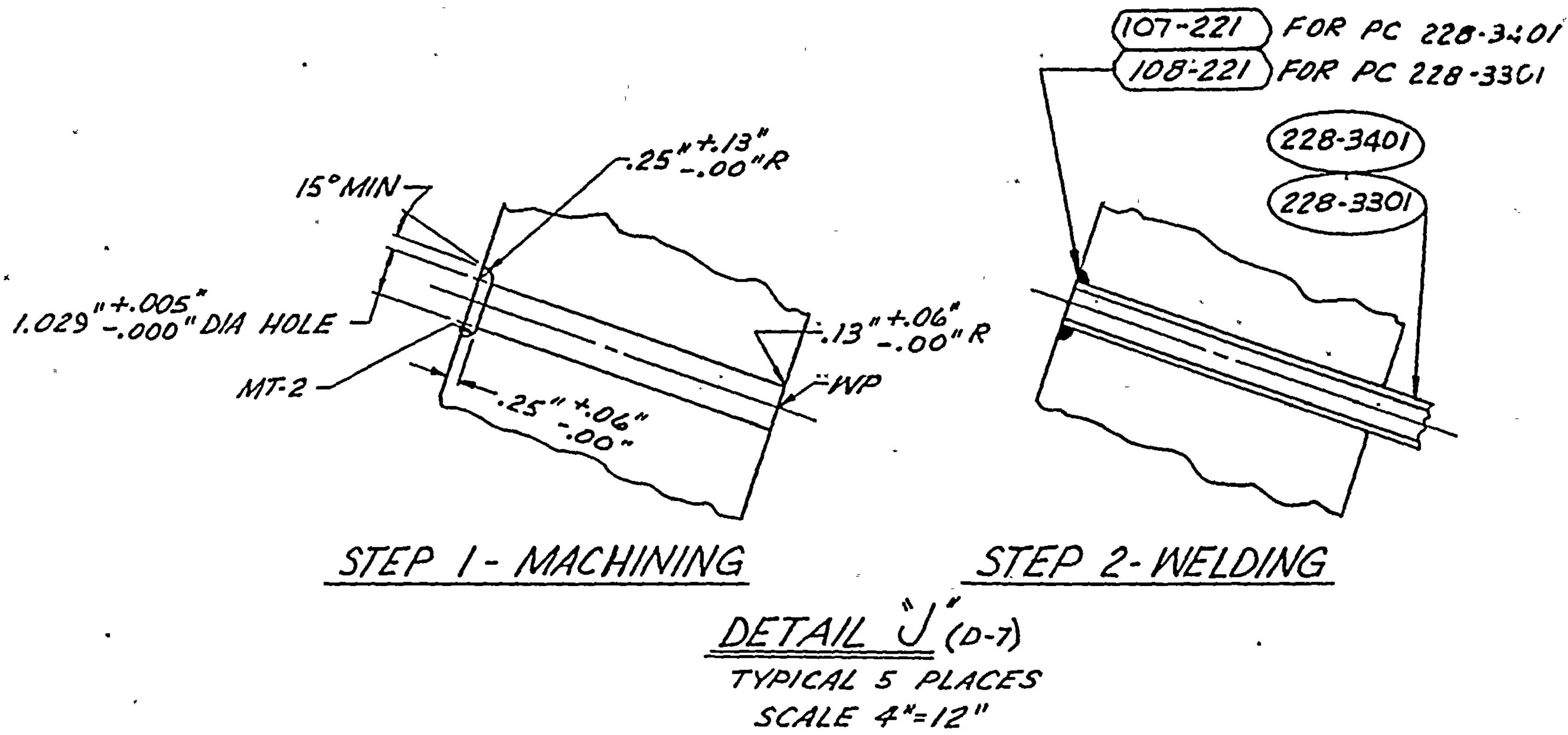
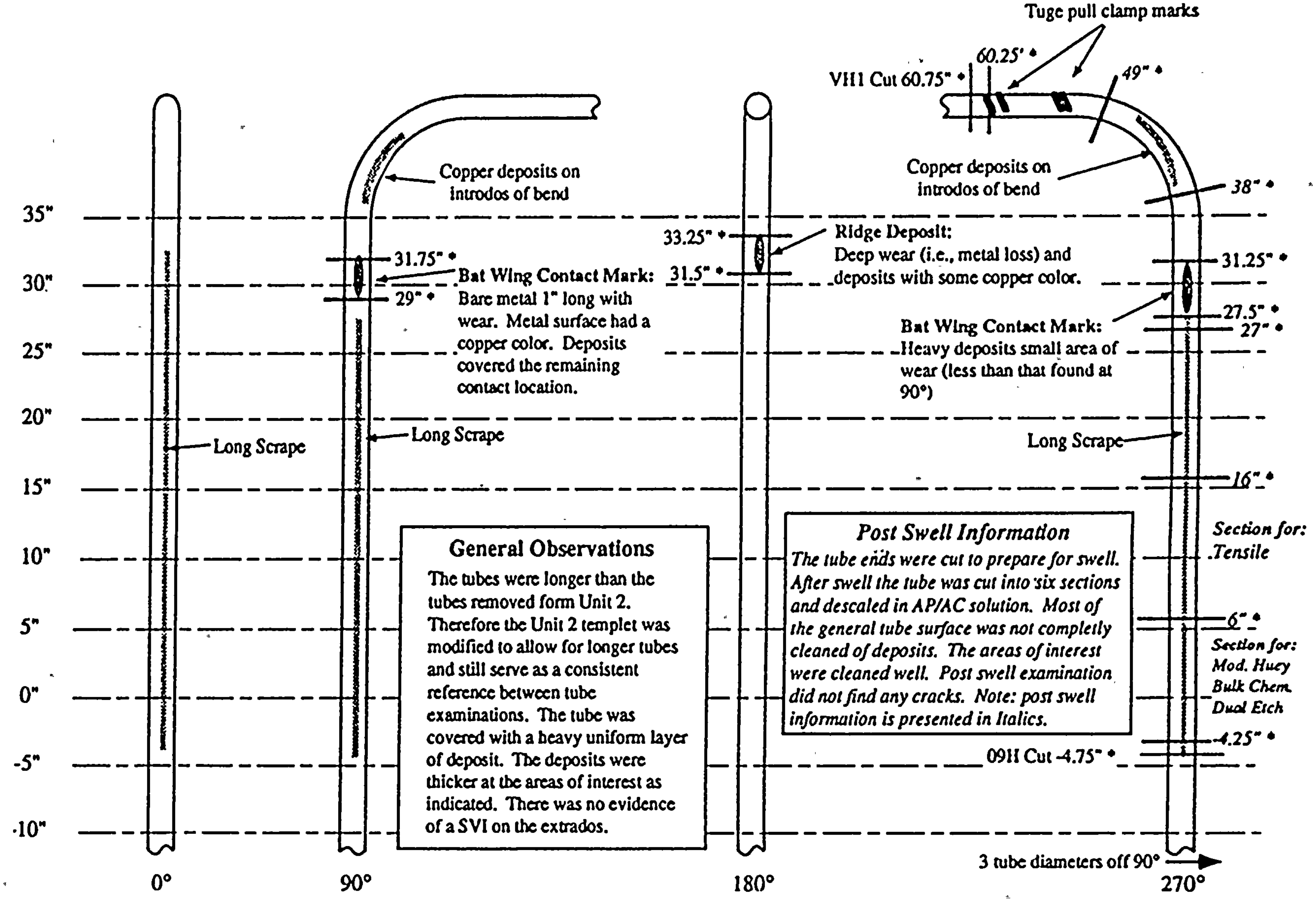


FIGURE IV.1

SHELL CONE LEVEL TAP AND SAMPLE NOZZLE DETAIL



* ABB Laboratory Reference - Used Templet From Unit 2 Steam Generator Tubes Examination

FIGURE V.1
VISUAL OBSERVATIONS FOR TUBE R152C73