APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/94-15
50-529/94-15
50-530/94-15

Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona

Facility Name: Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Inspection At: Maricopa County, Arizona

Inspection Conducted: April 19-29 and May 9-13, 1994

Inspectors: I. Barnes, Technical Assistant
Division of Reactor Safety

L. Ellershaw, Reactor Inspector, Maintenance Branch
Division of Reactor Safety

W. Walker, Resident Inspector, Project Branch C
Division of Reactor Projects

Approved: John Pellet 6/23/94
John L. Pellet, Acting Deputy Director Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1, 2, and 3): Regional initiative, announced inspection to review the history and material condition of steam generator tubing and to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation. The inspection additionally included observation of inservice inspection work and work activities.

Results (Units 1, 2, and 3):

- The Palo Verde Nuclear Generating Station (PVNGS) units utilize two System 80 steam generators, each containing 11,012 high-temperature mill annealed Inconel 600 tubes (Section 2.1).

- The Palo Verde Nuclear Generating Station units were initially operated with a hot-leg temperature of 621°F, which appeared from available Electric Power Research Institute information to be one of the highest temperatures used by pressurized water reactors. Subsequent to the tube rupture in Unit 2 Steam Generator 2-2 in March 1993, an administrative limit of 86 percent power was imposed on all units which resulted in a reduction of hot-leg temperature to 605°F (Section 2.1).

- The tubing material that was utilized in the manufacture of the Palo Verde Nuclear Generating Station steam generators was produced by two manufacturers (i.e., Noranda for Units 1 and 2, and Sandvik for Unit 3). Review of a sample of tubing certified material test reports (from various heats) for each unit found that the standard deviation was lower for chemical composition, mechanical properties, and grain size for the Unit 3 Sandvik tubing material than the Noranda Units 1 and 2 tubing material, indicating less heat-to-heat compositional variation and more restrictive process controls for the Sandvik material (Section 2.2).

- The incidence of tubing stress corrosion cracking damage was greater, for each unit, by up to an order of magnitude in the second steam generator than in the first (Section 2.4.4).

- The predominant steam generator tubing degradation modes in Unit 1 through Refueling Outage 1R4 (October 1993) have been wear and circumferential primary water stress corrosion cracking, circumferential outside diameter stress corrosion cracking, and axial outside diameter stress corrosion cracking in the tube expansion transition area. The total number of tubes plugged during operational service was, respectively, 122 in Steam Generator 1-1 and 167 in Steam Generator 1-2 (Sections 2.4.1 and 2.4.4).

- The predominant steam generator tubing degradation modes in Unit 2 through Outage 2MC5 (March 1994) have been wear and axial outside diameter stress corrosion cracking in the upper bundle region (both in the free span and at supports). The total number of tubes plugged during operational service was, respectively, 211 in Steam Generator 2-1 and 709 in Steam Generator 2-2 (Sections 2.4.2 and 2.4.4).

- The predominant steam generator tubing degradation modes in Unit 3 through Refueling Outage 3R4 (April 1994) have been wear and axial outside diameter stress corrosion cracking in the upper bundle region (both in the free span and at supports). The total number of tubes

plugged during operational service was 55 in both Steam Generator 3-1 and Steam Generator 3-2 (Sections 2.4.3 and 2.4.4).

- Inspection of the secondary side of the steam generators was historically limited by the absence of inspection hand holes in the vicinity of the tube sheet. Current inspection requirements for the tube sheet region (following modification of the steam generators to install inspection hand holes) were consistent with Generic Letter 85-02 and considered to be the maximum permitted by the access points (Section 3.1).

- Eddy current sample sizes consistent with or exceeding Electric Power Research Institute recommendations have been examined by the bobbin coil method during each refueling outage (Section 4.1).

- Licensee use of the eddy current motorized rotating coil examination method was limited until the tube rupture in Steam Generator 2-2 in March 1993. Subsequent use has been comprehensive at all locations where degradation has been identified (Section 4.1).

- The absence of operational experience information in the data analysis guidelines and the limited requirements for tube position verification during eddy current examinations were considered examination program weaknesses (Section 4.2.1).

- Use of two companies for primary and secondary analysis of eddy current data was considered commendable. Plans to use only Electric Power Research Institute Qualified Data Analysts in future examinations was considered proactive in regard to assuring the overall quality of data analysis (Section 4.2.1).

- Oversight of eddy current examination activities was effective and comprehensive since the beginning of 1993 (Section 4.2.3).

- Metallurgical examination of the tube samples by ABB-Combustion Engineering and Babcock and Wilcox Nuclear Technologies confirmed that the operative degradation mechanisms were intergranular stress corrosion cracking and intergranular attack. Much of the degradation, though not all, was associated with surface deposits on the tubes. Copper, sulfur, and lead were associated with cracking regions, but were not established as being clearly significant (Section 5.1.2).

- Babcock and Wilcox Nuclear Technologies and ABB-Combustion Engineering (in one tube sample only) found the amount of intergranular carbides present in the tubing samples to be less than what is normally expected in high temperature mill annealed Inconel 600. The inspectors considered this finding to be of potential significance in regard to possible effects on susceptibility to intergranular stress corrosion cracking (Section 5.1.2).

- The ABB-Combustion Engineering metallographic results gave limited evidence of under prediction of defect magnitudes by field eddy current examination (Section 5.1.2).

- The secondary water chemistry program requirements have been consistent with industry guidelines since commercial operation of the Palo Verde Nuclear Generating Station units (Section 6.1).

- Significant variation between the blowdown rates of the Unit 1 steam generators was measured, with potential impact on individual steam generator chemistry and resulting rate of degradation (Section 6.1).

- The current chemistry records system did not provide for ready assessment of historical chemistry performance (Section 6.2).

- Progressive upgrades of in-line process and laboratory instruments have been made to enhance the performance of required analyses (Section 6.4).

- The inservice inspection program was well structured and administratively controlled, and had been updated to incorporate comments contained in the NRC's program acceptance letter dated October 21, 1987. The licensee appeared to be adhering to the examination schedule for the current inspection period (second) of the first 10-year inspection interval (Section 7.1).

- The observed nondestructive examinations were performed by knowledgeable, appropriately certified individuals in accordance with approved procedures. Calibrations were performed as required. The use of video recorders was considered a good practice (Sections 7.2 and 7.3).

- The inservice inspection procedures contained sufficient detail and instructions to perform the applicable NDE examination and were consistent with the requirements of the ASME Code (Section 7.4).

<u>Summary of Inspection Findings:</u>

- Inspection Followup Item 528;529;530/9415-01 was opened (Section 2.4.4).

- Inspection Followup Item 528;529/9415-02 was opened (Section 3.1).

- Inspection Followup Item 529/9415-03 was opened (Sections 5.1.1.2, 5.1.2.2).

- Inspection Followup Item 529;530/9415-04 was opened (Section 5.2).

- Inspection Followup Item 528;529;530/9415-05 was opened (Section 6.1).

<u>Attachments:</u>

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Documents Reviewed During Inservice Inspection Part of the Inspection
- Attachment 3 - List of Acronyms

DETAILS

1 STEAM GENERATOR TUBE INTEGRITY REVIEW (73755, 79501, 79502)

The objectives of this inspection were: (a) to ascertain the history and material condition of the Units 1, 2, and 3 steam generator tubing; and (b) to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation.

2 STEAM GENERATOR MATERIALS AND TUBE DEGRADATION HISTORY

2.1 Steam Generator Description

Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3, are Combustion Engineering (CE)-designed 1270 megawatt electric pressurized water reactors, which commenced commercial operation on January 28, 1986 (Unit 1), September 19, 1986 (Unit 2), and January 8, 1988 (Unit 3). The unit design, which has been named "System 80," utilizes two vertical recirculating steam generators. Each System 80 steam generator contains 11,012 Inconel 600 (ASME Material Specification SB-163) U-tubes, with a nominal diameter and wall thickness, respectively, of 0.75 inches and 0.042 inches. The inner 18 rows of U-tubes in the tube bundle have 180° bends, with all subsequent rows having double 90° bends. Secondary side tube support structures consist, in sequential order from the tube sheet, of a horizontal flow distribution plate, six full horizontal eggcrate design supports, two partial horizontal eggcrate design supports, and supports for the upper tube bundle (i.e., two diagonal batwing stabilizers which horizontally support the bends in the U-tubes and vertical strap supports at seven locations). Two out of the seven vertical strap support locations are linked to I-beams in the upper part of the vessel, with the remainder floating. The vertical straps and associated support grids provide vertical stabilization for the tubes. The System 80 steam generator contains an economizer section which encircles the cold-leg side of the steam generator. The economizer section consists of a flow distribution box that is located on the flow distribution plate, and which increases steam generator efficiency by preheating a separate source of feedwater to that discharged by the feedwater ring in the upper part of the vessel. Feedwater passes from the distribution box through drilled holes in the flow distribution plate to the region on the cold-leg side of the steam generator immediately above the tube sheet.

The eggcrate supports, diagonal batwing stabilizers, and vertical strap supports in the PVNGS steam generators are fabricated from Type 409 ferritic stainless steel and the flow distribution plate from Type 405 ferritic stainless steel. The inspectors considered that the selection of a ferritic stainless steel for the supports should reduce magnetite buildup and minimize long-term denting problems. The inspectors ascertained from licensee furnished information that structural connections to supports are fabricated from carbon steel, but no carbon steels are in contact with the steam generator tubing with the exceptions of the tube sheet and what are termed

"scallop bars." The scallop bars are part of the structural connections to the partial eggcrate supports. The materials used for fabrication of the steam generator vessel and wrapper plate (i.e., which encloses the tube bundle and forms the annulus with the vessel wall that flow from the feedwater ring and water removed from the steam passes through) are, respectively, low alloy and carbon steels.

The inspectors ascertained that an initial hot-leg temperature (T-Hot) of 621°F was used for operation of all units until a rupture of Tube R117L144 occurred in Unit 2 Steam Generator 2-2 in March 1993. The inspectors noted that, based on available Electric Power Research Institute (EPRI) information, 621°F was one of the highest T-Hot values used by pressurized water reactors. In response to the tube rupture, the licensee administratively limited power in all units to 86 percent which resulted in a T-Hot reduction to 605°F. The inspectors ascertained that the licensee plans to return Units 1 and 3 to 100 percent power, using a hot-leg temperature of 611°F. The inspectors noted that reduction of T-Hot is being pursued by individual licensees as an approach to limit initiation and propagation of stress corrosion cracking.

As of the start of the inspection, the accrued effective full power years (EFPYs) of operation were 4.89 (Unit 1), 4.95 (Unit 2), and 4.43 (Unit 3).

2.2 Tubing Material

The inspectors reviewed the technical requirements for PVNGS, Units 1, 2, and 3 steam generator tubing contained in CE Purchase Orders 45-80712 dated January 26, 1976, through Supplement 2 dated December 8, 1976 (Unit 1); 46-80303 dated January 11, 1977, through Supplement 6 dated April 23, 1979 (Unit 2); and 48-80435 dated April 4, 1979, through Supplement 4 dated June 2, 1980 (Unit 3). The purchase orders for the PVNGS steam generator tubing were placed with two vendors (i.e., Noranda for Units 1 and 2, and Sandvik for Unit 3). Each of the purchase orders required conformance to ASME Material Specification SB-163; ASME Sections II and III Codes (1971 Edition through the Summer 1973 Addendum for Units 1 and 2 tubing, 1971 Edition through the Winter 1973 Addendum for Unit 3 tubing); and CE Purchase Specification P43B2(h) dated October 30, 1973. The licensee was requested to obtain a copy of the purchase specification from ABB-CE to enable completion of review of the technical requirements. The furnished document was marked by ABB-CE as containing proprietary information. It was noted from the review of the purchase orders and purchase specification that the tubing was required to be furnished in the bright annealed condition, but a specific annealing temperature was not identified. The procurement requirements included a defined range for 0.2 yield strength properties and grain size, performance on a sample basis of a corrosion test (for determination of resistance to intergranular attack) and determination of microstructure, and ultrasonic and eddy current nondestructive examinations (NDEs) of the tubing. It was ascertained from review of the purchase orders that eddy current noise acceptance criteria were less stringent for the Units 2 and 3 tubing than that imposed for the Unit 1 tubing (i.e., Unit 1 - 400 MV horizontal indication, 100 MV vertical

indication; Units 2 and 3 - 800 MV horizontal indication, 150 MV vertical information). Licensee staff had no information in regard to the reasons for the relaxation in noise acceptance criteria for the Units 2 and 3 steam generator tubing.

During review of samples of certified material test reports (CMTRs) for the Units 1, 2, and 3 steam generator tubing, the inspectors observed that the Units 1 and 2 tubing CMTRs from Noranda did not include the actual annealing temperature used. The CMTRs from Sandvik for the Unit 3 tubing CMTRs were noted, however, to contain the annealing temperature used for the tubing (i.e., 980°C which corresponds to 1796°F). The inspectors also noted from review of the CMTRs that the heat-to-heat range of chemical composition and mechanical properties for the various Sandvik heats of tubing material appeared lower than for the heats of Noranda tubing material. The CMTRs reviewed by the inspectors from both vendors were noted to conform to the procurement requirements. To verify the observation made regarding an apparent difference in the range of chemical composition and mechanical properties reported by the two vendors, the inspectors calculated the mean value and standard deviation for carbon content, 0.2 percent yield strength, ultimate tensile strength, and ASTM E112 grain size of samples of Units 1, 2, and 3 steam generator tubing CMTRs. In addition, the mean value and standard deviation for chromium content were calculated for the Units 1 and 3 tubing CMTR samples. The results obtained from these calculations are listed below in Table 1.

Table 1

TUBING CMTR CHEMICAL COMPOSITION AND MECHANICAL PROPERTY DATA

Parameter	SG 1-2		SG 2-2		SG 3-2	
	Mean	* S.D.	Mean	* S.D.	Mean	* S.D.
Carbon %	0.028	0.007	0.028	0.007	0.017	0.002
Chromium %	15.24	0.45	# N.D.	# N.D.	16.43	0.14
0.2 % YS (KSI)	40.7	3.9	45.0	5.4	49.2	2.5
UTS (KSI)	99.1	3.1	100.5	3.2	103.2	1.6
Grain Size	**7.5	0.5	** 8	1.2	**8.5	0.4

* S.D. - Standard Deviation.
# N.D. - Not determined.
** - Reported to nearest 0.5.

The inspectors noted that the standard deviation values for all parameters were lower for the Sandvik Unit 3 tubing CMTR sample than the corresponding

values obtained from the Noranda Units 1 and 2 CMTR samples, which was considered indicative of both less heat-to-heat chemical composition variation and more restrictive process controls for the Sandvik material. The difference in mean 0.2 percent yield strength values between the Units 1 and 2 Noranda tubing CMTR samples, coupled with the lower standard deviation values for this parameter and grain size for the Unit 1 versus the Unit 2 tubing CMTR samples, were viewed by the inspectors as not statistically significant, but possibly indicating that there was a difference between the Units 1 and 2 tubing material with respect to annealing practices that were used. The inspectors additionally observed that the Sandvik CMTR documentation contained photomicrographs of microstructure for various heats of tubing, whereas the Noranda CMTR documentation did not. It appeared to the inspectors that the CE procurement specification requirements mandated that photomicrographs of sample tubing heats be forwarded to CE by the tubing manufacturer. The reason(s) for the licensee Noranda CMTR documentation not containing photomicrographs was not established during the inspection.

2.3 Tube-to-Tube Sheet Expansion

The inspectors requested the licensee to obtain the applicable tube-to-tube sheet explosive expansion procedure(s) that were used for manufacture of the Units 1, 2, and 3 steam generators. ABB-CE furnished CE Nuclear Fabrication Practice 727-1-7, "Explanding Steam Generator Tubes Into Tubesheets," effective date January 26, 1981, in response to the licensee's request, with this document also marked as containing proprietary information. It was noted from review of the document that the primary quality verification activities pertained to assuring the correct placement of explosives in the tubes, with the only inspection activity performed subsequent to completion of expansions being verification of actual detonation of charges in individual tubes.

2.4 Steam Generator Tube Degradation History

2.4.1 Unit 1

Prior to operational service, Steam Generators 1-1 and 1-2 contained, respectively, 8 and 26 plugged tubes. The number of tubes plugged during steam generator manufacture was 4 in Steam Generator 1-1 and 20 in Steam Generator 1-2. Four and 6 tubes, respectively, were plugged in Steam Generators 1-1 and 1-2 as a result of preservice inspection baseline results. The plugging history for the two Unit 1 steam generators is documented below in Table 2 as a function of EFPYs of operation at the time of repair.

Initial tube degradation problems identified by eddy current examinations through Refueling Outage 1R2 were primarily wear related, with two tubes also plugged in Steam Generator 1-1 during Refueling Outage 1R2 due to the presence of possible cold-leg side loose parts.

During Refueling Outage 1R3, eddy current examination identified further evidence of wear and possible loose parts and, for the first time, a limited amount of axial outside diameter stress corrosion cracking (ODSCC). The

location of the tube ODSCC was at the tube sheet on the hot-leg side of the steam generators. Three tubes and six tubes, respectively, were plugged in Steam Generators 1-1 and 1-2 because of identified axial ODSCC.

Table 2 - Unit 1 Plugging History

STEAM GENERATOR (SG) 1-1 AND 1-2 HISTORY			
Time of Repair Unit 1 Refueling Outage (1R)	Operational Time EFPYs	SG 1-1	SG 1-2
		Tubes Plugged	Tubes Plugged
Pre-Commercial	0	8	26
Pre-1R1 (2/87)	* NDA	** 20	** 14
1R1 (11/87)	1.22	11	1
1R2 (8/89)	2.00	12	8
1R3 (3/92)	3.37	23	18
1R4 (10/93)	4.57	56	126
Total Repairs		130	193

* - NDA (No data available).
** - The reasons for the plugging activity were not reviewed.

During Refueling Outage 1R4, further evidence of tube axial ODSCC at the tube sheet was found by eddy current examination which resulted in the plugging of 6 and 10 tubes, respectively, in Steam Generators 1-1 and 1-2. The inspectors ascertained from review of licensee document, "Unit 1 Steam Generator Inspection Report," dated October 1993, that the location of the Steam Generator 1-1 axial ODSCC ranged from 0.20 inches to 1.36 inches below the tube sheet secondary side surface. Five of the 6 tubes which were plugged for identified axial ODSCC were found by eddy current examination to be not fully expanded in the tube sheet (i.e., resulting in a crevice condition which could result in concentration of impurities at the location where the ODSCC initiated). One tube was identified to contain an axial inside diameter defect indication at 1.51 inches above the tube end (i.e., close to the primary side of the tube sheet) on the hot-leg side. The defect magnitude, 79 percent through wall, was indicative of primary water stress corrosion cracking (PWSCC). The location of the Steam Generator 1-2 axial ODSCC ranged from 0.15 inches above to 1.15 inches below the secondary side of the tube sheet. Seven of the 10 tubes which were plugged for identified axial ODSCC were documented as not being fully expanded in the tube sheet. One of the remaining tubes (i.e., the one exhibiting axial ODSCC in the tube expansion transition region at 0.15 inches above the tube sheet) was not associated with incomplete tube expansion. The remaining tubes could not be verified from the

information in the licensee report as to whether the tubes were fully expanded.

Tube examinations in Refueling Outage 1R4 also resulted in the initial identification of circumferential PWSCC and circumferential ODSCC at the tube sheet. Five tubes and two tubes, respectively, were plugged in Steam Generator 1-1 because of detected circumferential PWSCC and circumferential ODSCC. The incidence of this type of degradation was found to be greater in Steam Generator 1-2, with 32 tubes plugged for identified circumferential PWSCC and 37 tubes plugged for identified circumferential ODSCC. A further 7 tubes were plugged in Steam Generator 1-2 because of the detection of the presence of both circumferential PWSCC and circumferential ODSCC in the tubes. Single volumetric indications were also detected during Refueling Outage 1R4, which resulted in the plugging of 11 tubes and 23 tubes, respectively, in Steam Generators 1-1 and 1-2. This type of indication can be indicative of either manufacturing flaws (e.g., burnishing marks) or corrosion mechanisms such as pitting or intergranular attack.

2.4.2 Unit 2

Prior to operational service, Steam Generators 2-1 and 2-2 contained, respectively, 15 and 32 plugged tubes. The number of tubes plugged during steam generator manufacture was 9 in Steam Generator 2-1 and 28 in Steam Generator 2-2. Six and 4 tubes, respectively, were plugged in Steam Generators 2-1 and 2-2 as a result of preservice inspection baseline results. Table 3 below provides the plugging history for the two steam generators as a function of EFPYs of operation at the time of repair.

Initial tube degradation problems identified by eddy current examinations through Refueling Outage 2R3 were primarily related to wear at the cold-leg corner, stay cylinder, and upper tube bundle. It was noted that four tubes in Steam Generator 2-1 and five tubes in Steam Generator 2-2 were plugged in Refueling Outage 2R3 because of the identification of possible loose parts.

During Refueling Outage 2R4, which immediately followed the March 1993 tube rupture in Steam Generator 2-2, eddy current examinations resulted in the plugging, respectively, of 78 tubes in Steam Generator 2-1 and 174 tubes in Steam Generator 2-2. Thirty tubes were plugged in Steam Generator 2-1 due to identified wear. Nineteen tubes were also plugged as a result of the detection of axial ODSCC at the top of the tube sheet (2 tubes), free span (11 tubes), and at supports in the upper tube bundle (6 tubes). Twenty-three tubes were plugged because of identified volumetric indications and two for possible hot-leg side loose parts. In Steam Generator 2-2, 34 tubes were plugged during Refueling Outage 2R4 due to identification of wear. The incidence of axial ODSCC detected in Steam Generator 2-2 was significantly greater than in Steam Generator 2-1, with a total of 108 tubes plugged because of this type of degradation. The axial ODSCC in the tubing was located at the 01H flow distribution plate (3 tubes), free span (57 tubes), upper bundle supports (42 tubes), and free span and upper bundle supports (5 tubes). One tube was plugged due to the detection of an axial crack at the end of the tube

on the hot-leg side. Eleven tubes were plugged because of identified volumetric indications and 3 for possible cold-leg side loose parts. A further 18 tubes were plugged in Steam Generator 2-2 during this outage, 17 of which were tube-pull related and 1 due to error.

Table 3 - Unit 2 Plugging History

STEAM GENERATOR (SG) 2-1 AND 2-2 HISTORY			
Time of Repair Unit 2 Refueling Outage (2R)	Operational Time EFPYs	SG 2-1	SG 2-2
		Tubes Plugged	Tubes Plugged
Pre-Commercial	0	15	32
Pre-2R1 (2/87)	NDA	30	21
2R1 (4/88)	1.22	34	27
2R2 (4/90)	2.30	20	90
2R3 (11/91)	3.49	15	26
2R4 (3/93)	4.62	74	174
* 2MC5 (3/94)	4.95	38	371
Total Repairs		226	741

* - 2MC5 (Mid-Cycle 5)

In Outage 2MC5 (i.e., the mid-cycle outage following Refueling Outage 2R4), eddy current examinations of Steam Generator 2-1 resulted in the plugging of a total of 38 tubes. Thirteen of the tubes were plugged due to identified wear and 22 tubes because of detected axial ODSCC (i.e., free span, 11 tubes; upper bundle supports, 9 tubes; free span and upper bundle supports, 2 tubes). Three additional tubes were plugged in Steam Generator 2-1 due to identified volumetric indications. In Steam Generator 2-2, a total of 371 tubes were plugged during Outage 2MC5. Twenty-six tubes were plugged because of identified wear. As in Refueling Outage 2R4, a significantly greater incidence of axial ODSCC was detected in Steam Generator 2-2 than in Steam Generator 2-1, with 309 tubes plugged for this type of degradation. The locations of the tube ODSCC were as follows: flow distribution plate, 2 tubes; free span, 204 tubes; upper bundle supports, 52 tubes; and free span and upper bundle supports, 51 tubes. Four tubes were also plugged due to the detection (for the first time in Steam Generator 2-2) of circumferential PWSCC in the tube expansion transition region. The remaining tubes (32 out of 371) were plugged due to the identification of possible loose parts on the cold-leg side (2 tubes), volumetric indications (23 tubes), and as a result of tube pulls (7 tubes).

2.4.3 Unit 3

Prior to operational service, Steam Generators 3-1 and 3-2 contained, respectively, 73 and 83 plugged tubes. The number of tubes plugged during steam generator manufacture was 4 in Steam Generator 3-1 and 20 in Steam Generator 3-2. Nine and 3 tubes, respectively, were plugged in Steam Generators 3-1 and 3-2 as a result of preservice inspection baseline results. Sixty tubes in the cold-leg corners of both steam generators were also preventively plugged in April 1987 to minimize the effects of wear at this location. Table 4 below provides the plugging history for the two steam generators as a function of EFPYs of operation at the time of repair.

Table 4 - Unit 3 Plugging History

STEAM GENERATOR (SG) 3-1 AND 3-2 HISTORY			
Time of Repair Unit 3 Refueling Outage (3R)	Operational Time EFPYs	SG 3-1	SG 3-2
		Tubes Plugged	Tubes Plugged
Pre-Commercial	0	73	83
3R1 (5/89)	1.09	7	10
3R2 (4/91)	2.16	2	1
3R3 (10/92)	3.33	23	0
* 3MC4 (12/93)	NDA	16	20
3R4 (4/94)	4.43	7	24
Total Repairs		128	138

* - 3MC4 (Mid-Cycle 4)

Tube plugging in both steam generators through Refueling Outage 3R3 was related primarily to the eddy current examination identification of wear in the vicinity of supports in the upper tube bundle and possible loose parts on the cold-leg side of the steam generators. One tube was plugged in Steam Generator 3-2 during Refueling Outage 3R2 because of the visual identification of slight leakage in the tube in the vicinity of the tube-to-tube sheet weld. The presence of a suspected axial crack was not confirmed by eddy current examination.

In the mid-cycle outage following Refueling Outage 3R3 (i.e., 3MC4), eddy current examinations identified further tube wear in the vicinity of upper tube bundle supports, which resulted in the plugging of 13 tubes in Steam Generator 3-1 and 11 tubes in Steam Generator 3-2. Four tubes were plugged in Steam Generator 3-2 due to the detection, for the first time in Unit 3, of

circumferential PWSCC at the top of the tube sheet on the hot-leg side. Three tubes in Steam Generator 3-1 and 5 tubes in Steam Generator 3-2 were plugged because of single volumetric indications.

Eddy current examinations performed during Refueling Outage 3R4 resulted in the plugging of 7 tubes in Steam Generator 3-1 and 24 tubes in Steam Generator 3-2. One of the 7 Steam Generator 3-1 tubes was plugged as a result of the detection of an outside diameter single axial crack at 22.6 inches above the end of the tube (i.e., approximately 1 inch below the tube sheet surface). This tube was not fully expanded in the tube sheet, thus creating a crevice condition. Four of the 7 Steam Generator 3-1 tubes were plugged because of identified wear in the vicinity of upper tube bundle supports. The remaining two Steam Generator 3-1 tubes were plugged because of the detection of a single volumetric indication and an axial outside diameter crack. The defect location for both of these tubes was in the vicinity of the batwing stabilizer on the hot-leg side. Four of the tubes in Steam Generator 3-2 were plugged because of identified wear in the vicinity of upper tube bundle supports. Two tubes were plugged as a result of a sample being removed from one (for laboratory examination of a location at which eddy current examination showed a single volumetric indication), and cutting of the other tube being required to gain access to the sample tube. The remaining 18 tubes in Steam Generator 3-2 were plugged because of the detection of axial cracking. The inspectors concluded from the reported locations of the axial cracks in 17 of the tubes (i.e., U-bend, 1 tube; upper bundle free span, 5 tubes; upper bundle supports, 8 tubes; and upper bundle supports and free span, 3 tubes) that the cracking was ODSCC. The final degradation information provided by the licensee (which was received subsequent to the onsite inspection) did not specifically indicate that the degradation was ODSCC. The location of the axial crack in the remaining tube was identified as being 2.69 inches above the end of the tube. The inspectors concluded from the location information that the degradation was PWSCC. The licensee furnished information did not specifically indicate, however, that the cracking was PWSCC, or state that the defect location was on the inner diameter of the tube.

2.4.4 Comparison of Degradation Between Units

As noted in Sections 2.4.1, 2.4.2, and 2.4.3 above, review by the inspectors of repair history indicated that the incidence of stress corrosion cracking damage was greater, for each PVNGS unit, in the second steam generator than the first. To illustrate this point and provide an overall comparison of degradation between units, the inspectors extracted from Tables 2, 3, and 4 (and supporting information) the total inservice repairs and stress corrosion cracking related repairs for each steam generator. This information is listed below in Table 5.

Table 5

STEAM GENERATOR DEGRADATION COMPARISON BY UNIT						
Tube Repairs Inservice Total & Stress Corrosion	Unit 1		Unit 2		Unit 3	
	SG 1-1	SG 1-2	SG 2-1	SG 2-2	SG 3-1	SG 3-2
Inservice Total	122	167	211	709	55	55
Stress Corrosion	17	92	41	421	2	23

The above data indicated to the inspectors that significant differences in the overall rate of steam generator tubing degradation had occurred between units, despite the similarity of the EFPYs of operation (see Section 2.1 above). It should be noted that preventive plugging was performed in the Unit 3 steam generators prior to operational service, which may have contributed to the relatively low inservice total repair numbers for these steam generators. The incidence of stress corrosion cracking in steam generator tubing also appeared for Units 2 and 3 to be an order of magnitude higher for the second steam generator when compared to the first, with Unit 1 steam generators currently exhibiting approximately half that differential. The inspectors observed no documents during the inspection in which licensee personnel identified any positions (e.g., with respect to unit design or operational practices), that would provide an explanation for or account for these apparent differences in both overall unit tubing damage rate and stress corrosion damage rates between unit steam generators. Further review of the reasons for the apparent difference in unit steam generator tubing degradation rates is considered an inspection followup item (528;529;530/9415-01).

2.5 Conclusions

- The PVNGS units utilize two System 80 steam generators, each containing 11,012 high-temperature mill annealed Inconel 600 tubes.

- The PVNGS units were initially operated with a hot-leg temperature of 621°F, which appeared from available EPRI information to be one of the highest temperatures used by pressurized water reactors. Subsequent to the tube rupture in Steam Generator 2-2 in March 1993, an administrative limit of 86 percent power was imposed on all units which resulted in a reduction of hot-leg temperature to 605°F. The inspectors ascertained that the licensee currently plans to return Units 1 and 3 to 100 percent power using a hot-leg temperature of 611°F. The inspectors noted that reduction of hot-leg temperature is being pursued by individual licensees as an approach to limit initiation and propagation of stress corrosion cracking.

- The tubing material that was utilized in the manufacture of the PVNGS steam generators was produced by two manufacturers (i.e., Noranda for Units 1 and 2, and Sandvik for Unit 3). Review of a sample of tubing CMTRs (from various heats) for each unit found that the standard deviation was lower for chemical composition, mechanical properties, and grain size for the Unit 3 Sandvik tubing material than the Noranda Units 1 and 2 tubing material, indicating less heat-to-heat compositional variation and more restrictive process controls for the Sandvik material.

- The incidence of tubing stress corrosion cracking damage was greater, for each unit, by up to an order of magnitude in the second steam generator than in the first.

- The predominant steam generator tubing degradation modes in Unit 1 through Refueling Outage 1R4 (October 1993) have been wear and tube expansion transition area circumferential PWSCC, circumferential ODSCC, and axial ODSCC. The total number of tubes plugged during operational service was, respectively, 122 in Steam Generator 1-1 and 167 in Steam Generator 1-2.

- The predominant steam generator tubing degradation modes in Unit 2 through Outage 2MC5 (March 1994) have been wear and axial ODSCC in the upper bundle region (both in the free span and at supports). The total number of tubes plugged during operational service was, respectively, 211 in Steam Generator 2-1 and 709 in Steam Generator 2-2.

- The predominant steam generator tubing degradation modes in Unit 3 through Refueling Outage 3R4 (April 1994) have been wear and axial ODSCC in the upper bundle region (both in the free span and at supports). The total number of tubes plugged during operational service was 55 in both Steam Generator 3-1 and Steam Generator 3-2.

3 VISUAL EXAMINATION OF THE SECONDARY SIDE OF THE STEAM GENERATORS

3.1 Review of Program Requirements and Inspection Data

The inspectors ascertained that inspection of the secondary side of the steam generators was historically limited by the absence of inspection hand holes in the vicinity of the tube sheet in the original steam generator design. The absence of hand holes led to the development of and reliance on eddy current examination methods for detection of foreign objects in the steam generators and monitoring of wear in abutting tubes. Modifications were subsequently made to the steam generators to incorporate inspection hand holes, which would permit both inspection of the tube sheet region of the steam generators and performance of sludge lancing. These modifications were completed in the Units 1, 2, and 3 steam generators during Refueling Outages 1R3 (1993), 2R4 (1993), and 3R4 (1994). The inspectors were informed that the licensee utilized contractors and contractor procedures to perform secondary side visual inspections. Inspections were to be performed of Steam Generator 3-2

during Refueling Outage 3R4 (i.e., in the time period of this inspection) by Babcock and Wilcox Nuclear Technologies (BWNT) using their procedure, 85CP-9BT46, "Secondary Side Visual Inspection/FOSAR of CE System 80 Recirculating Steam Generators," Revision 1. The inspectors reviewed the procedure and ascertained the inspection was to be performed prior to and after chemical cleaning of the steam generator. The inspection scope consisted, in part, of hot-leg tube surfaces above the flow distribution plate, the top of the flow distribution plate, and the underside of the first horizontal eggcrate support. This part of the inspection was to be performed using a hand hole that was located above the flow distribution plate. The remaining inspection was to be performed on both the hot-leg and cold-leg sides of the steam generator using the newly installed hand holes, and included the sludge pile region, the bottom of the flow distribution plate, the annulus area, and mid-span tube surfaces. The inspectors considered the planned inspection scope to be consistent with Generic Letter 85-02 and to be the maximum permitted by the access points.

The inspectors additionally reviewed the results of foreign object search and retrieval (i.e., FOSAR) inspections performed by ABB-CE in the annulus and blowdown lanes during Refueling Outages 1R4 (October 1993) and 2R4 (May 1993). The documentation indicated that the inspections had been thoroughly performed. Comparison of the location of identified foreign objects that could not be removed, against eddy current examination program results, is considered an inspection followup item (528;529/9415-02). Information was not provided to the inspectors which would indicate that any visual inspections had been performed of the steam generators in the areas above the tube bundle. The reasons for not performing inspection of the upper vessel, which was a normal inspection at other CE units where steam generator tube integrity reviews had been performed, were not ascertained during the inspection.

3.2 Conclusions

- Inspection of the secondary side of the steam generators was historically limited by the absence of inspection hand holes in the vicinity of the tube sheet. Current inspection requirements for the tube sheet region (following modification of the steam generators to install inspection hand holes) were consistent with Generic Letter 85-02 and considered to be the maximum permitted by the access points.

4 REVIEW OF TUBE EXAMINATION HISTORY, PROGRAM REQUIREMENTS, AND DATA

4.1 Review of Tube Examination History

Review of the bobbin coil examination history for the three PVNGS units identified that the scope of full-length examinations consistently exceeded the EPRI NP-6201, "PWR Steam Generator Examination Guidelines," Revision 3, recommended 20 percent random sample, with the minimum sample size noted being a 21 percent sample in the Unit 1 steam generators during Refueling Outage 1R1. Following the tube rupture in Steam Generator 2-2 in March 1993, the licensee performed a 100 percent bobbin coil examination of the Unit 2

steam generators. A 100 percent bobbin coil sample was also examined in the Unit 1 steam generators during Refueling Outage 1R4 in October 1993, and in the Unit 3 steam generators during Refueling Outage 3R4 in April 1994. During Outage 2MC5 in early 1994, full-length bobbin coil examinations were performed, respectively, of 40 percent of Steam Generator 2-1 and 39 percent of Steam Generator 2-2. The tube selection approach was based on the results of Refueling Outage 2R4, in which it was found that upper bundle axial defect indications were concentrated on the hot-leg side of the steam generators in an "arc" region of approximately 1800 steam generator tubes, near the periphery of the tube bundle. Thermal-hydraulic analysis confirmed that this region and location of the steam generator would be subject to buildup of deposits. In addition to 100 percent examination of the arc region, approximately 400 tubes were examined by bobbin coil in each steam generator at locations throughout the tube bundle.

Limited motorized rotating pancake coil (MRPC) examinations were performed at the tube expansion transition area on the hot-leg side of the steam generators (see Section 4.2.2 below) prior to the tube rupture in Steam Generator 2-2 in March 1993. Following the tube rupture, approximately 7.5 percent of the tubes in Steam Generators 2-1 and 2-2 (i.e., 850 tubes in Steam Generator 2-1 and 824 tubes in Steam Generator 2-2) were examined at this location. As a result of the identification of PWSCC and ODSCC at the tube expansion transition area in the Unit 1 steam generators during Refueling Outage 1R4, a 100 percent MRPC examination was performed at this location in both steam generators. During Outage 3MC4, an initial MRPC sample size of approximately 20 percent was examined at the expansion transition area of the tubes in both steam generators. Following the detection of limited PWSCC in Steam Generator 3-2 at this location, the scope of examination was expanded in this steam generator to 100 percent. The same examination scope was utilized in the Unit 2 steam generators during Outage 2MC5 in early 1994 as was performed in Outage 3MC4 (i.e., approximately 20 percent in Steam Generator 2-1 and 100 percent in Steam Generator 2-2), as a result of the detection of limited PWSCC at the tube expansion transition area in Steam Generator 2-2.

All of the Unit 2 arc region tubes were examined by MRPC during Refueling Outage 2R4 and Outage 2MC5 on the hot-leg side in the region of the upper bundle subject to axial cracking (i.e., from the first partial eggcrate support to the first vertical support). Similar MRPC examinations were performed of Unit 1 steam generator arc region tubes during Refueling Outage 1R4. A 20 percent sample of the Unit 3 steam generator arc region tubes was examined by MRPC on the hot-leg side at this location during Refueling Outage 3R4. The rationale utilized by the licensee for a sampling approach in the arc region tubes of the Unit 3 steam generators was that previous inspections had not identified any axial cracking in these tubes.

4.2 Review of Examination Program Requirements

4.2.1 Current Program

The inspectors reviewed the current eddy current examination program requirements which were defined by Procedure 73TI-9RC01, "Steam Generator Eddy Current Examinations," Revision 11. The bobbin coil and MRPC data analysis guidelines were included as appendices to the procedure. The eddy current program requirements were found to be generally consistent with the recommendations contained in EPRI NP-6201, Revision 3. Exceptions noted were the absence of criteria for noisy data, and the failure of the data analysis guidelines to address operating experience of the PVNGS steam generators and review of previous data. The absence of operating experience information (including graphics with appropriate discussion and captions) in the data analysis guidelines was considered by the inspectors to be a weakness. The inspectors did note, however, that PVNGS operating experience information was included in the training given to eddy current data analysts on their arrival at the PVNGS site. The inspectors additionally observed that the program requirements lacked specificity, in terms of defined criteria for inclusion of potentially degraded tube conditions (e.g., tubes with previous distorted indication calls, tubes that had not been fully expanded into the tube sheet, tubes next to previously identified possible loose parts, and low radius U-bend tubes) in an outage bobbin coil examination plan. The inspectors additionally observed that the program requirements did not address whether lead analysts could perform resolution of differences in calls, if they had performed the primary or secondary production analysis. Procedure 73TI-9RC01 was noted by the inspectors to contain very limited requirements in regard to verification that desired tubes were, in fact, being examined. The procedure only required verification, using known landmarks such as peripheral tubes, stay areas, or plugged tubes, during initial installation and before relocating or removing the fixture. The inspectors considered the absence of more prescriptive position verification measures to be a program weakness. No information was obtained by the inspectors, however, which would indicate that significant errors had occurred with respect to incorrect tubes being examined during Refueling Outage 3R4. As noted in Section 7.2, the contractor, Conam, was observed to be performing position verifications approximately every 8-10 tubes.

The inspectors noted that the licensee was using two separate companies (i.e., Conam and ABB-CE) to perform independent primary and secondary analysis of Refueling Outage 3R4 eddy current data. The inspectors considered this approach to be commendable in terms of attempting to optimize the quality of data analysis results. The inspectors also noted that the program requirements stated that all Level IIA and Level III personnel interpreting eddy current data will be required, after January 1, 1995, to have successfully passed the EPRI Qualified Data Analysis course and test. The inspectors considered this requirement to be a proactive measure in regard to assuring the overall quality of data analysis.

Criteria had been established for training and testing of eddy current data analysts prior to their performance of analysis at the PVNGS site. The inspectors reviewed the manual which was used to train the Refueling Outage 3R4 analysts, and noted it appropriately addressed PVNGS steam generator design and operational experience. Specific discussion of the graphics in the manual was considered an area where the training manual could be further improved. During review of the training manual, the inspectors noted a reference to daily tracking of analyst performance and feedback to analysts of identified errors. The inspectors discussed this subject with licensee personnel and verified its implementation by records review. The use of this practice was considered both an effective corrective action vehicle and an indicator of a strong eddy current data management system. The inspectors reviewed the testing records for the data analysts employed for Refueling Outage 3R4 and identified no problems with the implementation of program requirements.

4.2.2 Response to Generic Communications

The inspectors performed a limited review of the licensee's handling of NRC generic communications pertaining to steam generator problems. The sample used for this review was Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," and Information Notices (Ins) 90-49, "Stress Corrosion Cracking in PWR Steam Generator Tubes," and 91-67, "Problems With the Reliable Detection of Intergranular Attack (IGA) of Steam Generator Tubing."

The review indicated that the licensee appropriately responded to the actions requested by Bulletin 89-01, with replacement of affected plugs (only applicable to Unit 2 steam generators) accomplished during Refueling Outage 2RF2 in 1990. The inspectors noted, with respect to Information Notice 90-49, that the licensee operating experience package indicated that a total of approximately 30 tubes would be examined by MRPC (at the top of the tube sheet expansion transition area along with the flow distribution plate) during each refueling outage. This planned scope of examination was considered by the inspectors as offering little probability of detection of the onset of stress corrosion cracking at the expansion transition area of tubes. The actual scope of MRPC examinations performed, prior to the tube rupture in Unit 2 Steam Generator 22, was slightly greater than the scope indicated in the operating experience package (i.e., from 41 to 92 tubes were examined at the expansion transition area on the hot-leg side of individual steam generators during unit outages that occurred through October 1992). As discussed in Section 4.1 above, the scope of MRPC examinations of the expansion transition area of Units 1, 2, and 3 steam generator tubing was increased significantly following the Steam Generator 2-2 tube rupture in March 1993. The inspectors noted that the licensee operating experience package for Information Notice 90-49 had not been updated to reflect the change in organizational thinking regarding MRPC use. The licensee evaluation

of Information Notice 91-67 was considered appropriate. No updating of the operating experience package had been made to reflect the knowledge gained from tube samples that had been shown by metallurgical examination to contain varying amounts of intergranular attack.

4.2.3 Eddy Current Program Oversight

The inspectors requested to see available records pertaining to licensee oversight of eddy current contractors. Thirty-four QA monitoring reports were furnished in response to this request, which covered the time period from January 1993 to April 1994. The inspectors noted from review of the reports that the attributes addressed were clearly denoted, and that monitoring activities had included data acquisition and analysis, certifications of eddy current data analysts, control of plugging activities, and adequacy of examination plans. The inspectors also noted that an individual from another utility participated in some of the monitoring activities, which was considered a good practice. The inspectors did not ascertain the scope of oversight activities prior to 1993. The inspectors additionally observed that an ongoing overview of contractor performance was performed by licensee inservice inspection (ISI) staff. Overall, the inspectors concluded that oversight activities were both effective and comprehensive for the time period reviewed.

4.3 Review of Tube Examination Data

The inspectors reviewed a sample of bobbin coil and MRPC data that were obtained from the Refueling Outage 3R4 examinations. The sample included both repairable indications, tubes for which bobbin coil examination had resulted in ambiguous signals; and tubes which had been determined to exhibit throughwall degradation in the range immediately below the 40 percent limit of the Technical Specifications. The inspectors noted no problems in regard to the "calls" made by the analysts. Discussions with the Level III analysts indicated that they were both experienced and cognizant of degradation mechanisms at PVNGS and other facilities.

4.4 Conclusions

- Eddy current sample sizes consistent with or exceeding EPRI recommendations have been examined by the bobbin coil method during each refueling outage.

- Licensee use of the MRPC method was limited until the tube rupture in Steam Generator 2-2 in March 1993. Subsequent use has been comprehensive at all locations where degradation has been identified.

- The absence of operational experience information in the data analysis guidelines and the limited requirements for position verification during eddy current examinations were considered eddy current examination program weaknesses.

- Use of two companies for primary and secondary analysis of eddy current data was considered commendable. Plans to use only EPRI qualified data analysts in future examinations was considered proactive in regard to assuring the overall quality of data analysis.

- Oversight of eddy current examination activities was effective and comprehensive since the beginning of 1993.

5 LABORATORY EXAMINATIONS OF DEFECTIVE TUBES

The licensee removed Unit 2 tube samples during Refueling Outage 2R4 (following the tube rupture in March 1993) and Outage 2MC5, and Unit 3 samples during Refueling Outage 3R4. These samples were subjected to laboratory examination, in order to assess the operative damage mechanisms and establish the capability of nondestructive examination methods in detection and sizing of defects.

5.1 Refueling Outage 2R4

5.1.1 Sample Selection

During Refueling Outage 2R4 in Spring 1993, portions from the hot-leg side of eight tubes were removed from Steam Generator 2-2 for laboratory examination. Seven of the sampled tubes exhibited eddy current axial defect indications in either the free span or at tube support (eggcrate and flow distribution plate) locations. One of the seven tube samples containing defect indications was a section of the ruptured tube (i.e., R117L144) that was removed from the area beneath the rupture. The eighth tube sample contained no eddy current identified defect indications and was used for validation of the eddy current examination methodology. Four of the tube samples were sent to ABB-CE and four to BWNT for laboratory examination.

5.1.1.1 ABB-CE Tube Samples

The four tube samples sent to ABB-CE for laboratory examination included the R117L144 sample discussed above, and samples from R105L156, R103L156, and R127L140. Prior to removal of the R117L144 tube sample, video inspection showed that the tube rupture was "fish mouthed" in shape and was located on the hot-leg side below the 09H top partial eggcrate support. Eddy current examination showed the defect associated with the rupture to be 9 inches in length. The R105L156 sample was determined by eddy current examination to contain an approximately 80 percent through-wall outside diameter defect indication, 2 inches in length, which was located in the free span at 25.9 inches above the first partial egggcrate support on the hot-leg side (i.e., 08H). The R103L156 sample was identified by MRPC examination to contain free span multi-axial indications on the hot-leg side at 19.25 inches above the 08H partial eggcrate support. The R127L140 tube sample was found by eddy current examination to exhibit axial defect indications at the top full eggcrate support on the hot-leg side, 07H, and at the top of the 08H partial

eggcrate support. The eddy current estimated sizes for the 07H and 08H defect indications were, respectively, 31 percent through wall maximum, 0.41 inches length and 39 percent through wall maximum, 0.30 inches length.

5.1.1.2 BWNT Sample

The four tube samples sent to BWNT for laboratory examination included R116L41, the tube sample with no defect indications detected by eddy current examination, and samples from R117L40, R22L13, and R29L24. The R117L40 sample was identified by MRPC eddy current examination to contain axial free span defects, with no defects detected by bobbin coil examination. The tube samples from R22L13 and R29L24 were found by eddy current examination to exhibit axial defect indications at the flow distribution plate on the hot-leg side (i.e., 01H). The field eddy current examination results for the BWNT tube samples were inadvertently not included in the information provided by the licensee to the inspectors, thus, precluding a comparison against laboratory metallographic results. Review of the field eddy current examination results for the BWNT tube samples is considered an inspection followup item (529/9415-03).

5.1.2 Examination Results

5.1.2.1 ABB-CE Sample Tubes

Comprehensive examinations were performed by ABB-CE which included use of radiography, burst testing, fractography, metallography, chemical analyses of surface deposits and films using state-of-the-art technology, and determination of mechanical properties. The results of the examinations were documented in ABB-CE Report TR-MCC-272, Volumes 1 and 2, "Examination of Steam Generator Tubes Removed From Palo Verde Unit 2 in 1993," dated November 1993. Findings from the examination process are summarized below:

- Metallographic examination of the section of R117L144 removed from below the tube rupture showed the presence of axial intergranular stress corrosion cracking (IGSCC), 4 inches in length, with little associated intergranular attack. the cracking had initiated from the outside surface of the tubing, with the maximum and average depths of IGSCC determined to be, respectively, 98.2 percent and 70.2 percent through wall. Numerous secondary cracks of approximately 0.014 inches maximum depth were present adjacent to the main crack face, with another crack, 0.013 inches in depth, also observed at 100° from the main crack face. The grain size of the failed tube was found to be coarser than the other tube samples (i.e., ASTM E 112 Nos. 6-7 versus Nos. 7-8 and 8-9), and the microstructure was observed to show an absence of intragranular and few intergranular carbides. ABB-CE postulated from the relative absence of boundary carbides, that either the tube had a lower carbon content than was typical, or a rapid cool down from the final annealing temperature had occurred which would prevent precipitation of carbide particles. Based on the review of tubing properties, which is discussed

in Section 2.2 above, the inspectors viewed a rapid cool down rate from the annealing temperature as more probable. The inspectors viewed the reduced amount of intergranular carbides as being potentially significant in regard to effect on susceptibility to IGSCC.

- Burst testing of the R105L156 tube sample resulted in a burst failure at 3200 psig, with a burst opening of 1.38 inches in length. This burst pressure was below the requirements of Regulatory Guide 1.121 (i.e., the burst pressure should exceed three times the primary-to-secondary operating pressure differential). Ridge-like deposits were present on the tube surface at the 90° and 270° axes, with a major crack (8 inches in length) associated with the 270° axis deposit. The maximum depth of the defect was determined to be 98 percent through wall, with the average depth of intergranular attack and IGSCC determined to be, respectively, 21.6 percent and 34.5 percent. Additional intergranular attack and IGSCC were noted at the 0° axis which were not associated with ridge-like deposits. The average depth of intergranular attack and IGSCC at the 0° axis were, respectively, 19.6 percent and 32.6 percent.

  Deposit and film analyses performed at the burst region showed nickel enrichment (i.e., a high nickel/chromium ratio which is indicative of alkaline or caustic conditions) at the crack mouth, with the enrichment not as pronounced at mid-surface crack locations. The inspectors focused their review of deposit and film chemistry on the presence of sulfur and copper, which are known contributors to corrosion damage. In addition, note was made of whether lead was detected, because of recent work which indicated it may have a deleterious effect. Sulfur was detected at all depths and locations in the burst region. In the ridge-like deposits, elemental copper was concentrated in the inner layer of the deposit. Sulfur was consistently found to be present throughout films at other locations, with concentrations ranging from 0.3 to 1.5 percent by weight. X-ray photoelectron spectroscopy indicated the element was present as sulfides and sulfates, with sulfates not detected at all locations. Copper was also present at the various locations analyzed, with the concentrations detected ranging up to 4 percent by weight. Lead was found to be present at low levels in the films examined.

- Burst testing of the R103L156 tube sample resulted in a burst failure at 6968 psig, with a burst opening of 1.0 inches in length. Two regions of ridge-like deposits (120° apart), with associated intergranular attack and IGSCC, were observed which spanned 16.5 inches of the tube length. Eddy current examination had indicated the defects were within a 2.5 inch band. Most of the defect region was less than 40 percent throughwall, with a maximum penetration of 57.1 percent measured. Metallography determined that the amount of intergranular attack was significant under the deposits.

- Burst testing of the R127L140 tube sample resulted in a burst failure at 6118 psig at the 07H eggcrate defect location, with the burst opening length not recorded by the inspectors. The maximum depth and length of IGSCC found by metallography were 89.3 percent and 1 inch, respectively, with the average depth determined to be 58 percent. As noted in Section 5.1.1.1 above, field eddy current examination had indicated this defect to be significantly smaller (i.e., 31 percent maximum throughwall, 0.41 inches in length). Significant wear was found at the 08H location, 61 percent throughwall, with deposit buildup associated with the wear. No evidence of intergranular attack or IGSCC was observed at this location.

  The nickel/chromium ratios were found to be variable in this tube sample. Similar findings to those obtained in the R105L156 tube sample were noted with respect to the presence of sulfides and sulfates, copper, and minor quantities of lead in surface deposits and films.

5.1.2.2 BWNT Sample

Similar scope examinations to those performed by ABB-CE were performed by BWNT of the four samples they received for examination. The results of the examinations were documented in BWNT Report "Examination of Steam Generator Tubes From Palo Verde Nuclear Station," dated October 1993. Findings from the examination process are summarized below.

- Burst data was not reviewed by the inspectors for the BWNT tube samples and is considered part of Inspection Followup Item 529/9415-03 (see Section 5.1.1.2 above).

- Metallographic examination of the R116L41 tube sample, which had not been found by eddy current examination to contain defects, revealed the presence of general intergranular attack. The depth of penetration was less than 10 percent throughwall.

- Metallographic examination of the R117L40 tube sample revealed that intergranular attack and IGSCC were present under two parallel ridges of deposit that ran the full section examined (i.e., 13 inches). The average and maximum throughwall penetrations were 27 percent and 61 percent, respectively. Patches of intergranular attack up to 30 percent throughwall were also detected at the 08H support, which were associated with an obvious support contact point and areas of minor wear.

  Copper, nickel, chromium, manganese, silicon, and lead were found to be present in greater concentrations in corrosion films on upper spans of the tube sample than in corresponding films at lower spans. An example provided by BWNT was the concentration values for copper. Copper concentrations were found to be 5.8 percent by weight in the free span above the 09H support, 3.3 percent by weight at the 08H support,

0.5 percent by weight at the 05H support, and 0.15 percent by weight at the 01H flow distribution plate. Similar variations in sulfur content were not observed at different steam generator elevations.

- Metallographic examination of the two 01H flow distribution plate location samples found 62 percent maximum throughwall IGSCC in the R22L13 tube sample and separate 21 percent maximum throughwall and 32 percent maximum throughwall IGSCC in the R29L24 tube sample.

- The carbide distribution in all four tube samples was found to be similar with respect to distribution between grain boundaries and within the grains. BWNT observed that the amount of intergranular carbides would normally be expected to be greater in high temperature mill annealed Inconel 600.

5.2 Outage 2MC5 and Refueling Outage 3R4 Samples

The laboratory examination results for the samples removed from the Units 2 and 3 steam generators during, respectively, Outage 2MC5 and Refueling Outage 3R4 were not available as of the end of the inspection. Review of this information is considered an inspection followup item (529;530/9415-04).

5.3 Conclusions

- Metallurgical examination of the tube samples by ABB-CE and BWNT confirmed that the operative degradation mechanisms were IGSCC and intergranular attack. Much of the IGSCC and intergranular attack, though not all, was associated with surface deposits on the tubes.

- Copper, sulfur, and lead were associated with cracking regions, but were not established as being clearly significant.

- BWNT and ABB-CE (in one tube sample only) found the amount of intergranular carbides present in the tubing samples to be less than what is normally expected in high temperature mill annealed Inconel 600. The inspectors considered this finding to be of potential significance in regard to possible effects on susceptibility to IGSCC.

- The ABB-CE metallographic results gave limited evidence of under prediction of defect magnitudes by field eddy current examination.

6 REVIEW OF SECONDARY WATER CHEMISTRY CONTROLS AND HISTORY

Many impurities that enter the secondary side of steam generators can contribute to corrosion of steam generator tubes and support plates. While the concentration of impurities needed to cause corrosion problems is normally much higher than that present in steam generator bulk water, concentration of impurities to aggressive levels is possible in occluded areas where dryout occurs. Typical areas where dryout and resulting concentration of impurities

can occur are tube sheet crevices, tube support plate crevices, and sludge piles. Impurities known to contribute to tube denting (i.e., squeezing of tubes at tube supports or tube sheets as a result of the pressure of corrosion products) are chlorides, sulfates, and copper and its oxides. Pitting of steam generator tubes has been attributed to the presence of copper and concentrated chlorides. Concentrated sulfates and sodium hydroxide are believed to be major causes of IGSCC and intergranular attack in steam generator tubes. Iron oxide deposits and sludge promote local boiling and concentration of impurities leading to these damage mechanisms.

6.1 Program Evolution

The inspectors reviewed the licensee's secondary water chemistry control program for PVNGS. Each of the PVNGS units used the same secondary water chemistry control program, which was documented in Nuclear Administrative and Technical Manual Procedure 74AC-9CY04, "Systems Chemistry Specifications," Revision 8. The inspectors compared the program requirements contained in this revision of the procedure (and in an earlier revision that was in effect at the start of PVNGS commercial operation) against the criteria contained in EPRI NP-6239, "PWR Secondary Water Chemistry Guidelines," Revisions 1 through 2, and EPRI TR-101230, "Interim PWR Secondary Water Chemistry Recommendations for intergranular attack/IGSCC Control," dated September 1992. It was found that the program requirements fully conformed to the EPRI guidelines throughout the PVNGS operating history with respect to scope of chemical parameters, analytical frequency, limits for critical parameters, and required actions when critical parameters were exceeded.

The inspectors ascertained that EPRI recommended initiatives such as molar ratio control, elevated hydrazine, secondary side boric acid treatment, and use of alternative amines were at various stages of implementation in the PVNGS units. Review of the status of these initiatives will be reviewed during a subsequent inspection. The inspectors also noted during review of a secondary chemistry control status report, that was submitted to senior management in April 1994, that a chemical tracer injection test had identified that the blowdown flow rate in Steam Generator 1-1 was approximately twice the flow rate that was occurring in Steam Generator 1-2. The inspectors were subsequently informed that a steam generator blowdown optimization plan was in process, which had been implemented for Unit 2. Variations in blowdown rate between steam generators in a unit were considered by the inspectors as probably resulting in chemistry differences during power operation between the steam generators, and potentially explaining differences in steam generator degradation rates. The inspectors also ascertained from review of monthly performance monitoring reports (in the time period February 1991 to April 1994) that variations had occurred between units in the average hours/month of steam generator abnormal blowdown (i.e., Unit 1, 153; Unit 2, 300; Unit 3, 281). Review of the steam generator blowdown optimization plan results and pertinent operational experience information are considered an inspection followup item (528;529;530/9415-05).

6.2 Secondary Side Operating History

The inspectors reviewed the available history of the PVNGS steam generators with respect to significant chemistry events and compliance with the EPRI secondary water chemistry guidelines. Details of off-normal chemistry are discussed below in Section 6.5.

During the review, the inspectors were provided with water chemistry information which consisted of the raw water chemistry data. This data was not in a summary format which would allow ready interpretation of the effects of reactor power on the chemistry data. This made it difficult to assess the effectiveness of implementation of chemistry controls. Trending information was available; however, the licensee did not have any form of data compilation that would facilitate interpretation of overall historical chemistry performance. Sampling review by the inspectors of the available trend information and operations records, indicated that impurity values were generally within the limits of the EPRI secondary water chemistry guidelines.

6.3 Self-Assessment of Primary and Secondary Water Chemistry

The inspectors reviewed several licensee audit and quality monitoring/observation reports pertaining to the secondary water chemistry control program. The reports included two audits performed during 1990 and 1992, three monitoring reports performed during 1993, and one observation report which addressed implementation of corrective actions taken in response to the Unit 2 steam generator tube rupture. The inspectors determined the scope of the audits and monitoring/observation reports were comprehensive and appropriate for evaluation of the water chemistry program. Review by the inspectors of the audit and monitoring/observation reports did not indicate any significant adverse findings which would bring into question the quality of the water chemistry program.

6.4 Chemistry Instrumentation

The inspectors toured the turbine building and observed the sampling points used for in-line process secondary water chemistry analysis and the secondary sampling panel of in-line process chemistry analyzers. The inspectors also toured the chemistry laboratory and observed the analytical instrumentation used for analyzing in-line process chemistry samples. The inspectors verified that necessary instrumentation was installed in the process lines for analysis of the diagnostic and control parameters specified in the secondary water chemistry control program. The inspectors noted that in 1991 an extensive effort was made by the licensee to upgrade the in-line process and laboratory instruments needed to perform the required chemical analyses. The most recent upgrade was the installation of a mini-laboratory in the turbine building. This allowed for much shorter transport times for secondary water chemistry samples which resulted in a more representative sample being available for more accurate analysis of real time conditions in the secondary water chemistry system. This upgrade was made by the licensee to enhance their

ability to monitor secondary water chemistry conditions which could affect the steam generators.

6.5 Off-Normal Secondary History

The inspectors noted during review of the data discussed in Section 6.2 that interpretation of the out-of-specification chemistry events required extensive effort to assess the chemistry data provided. The licensee subsequently provided the inspectors with a summary of off-normal chemistry excursions which occurred from 1987 to the present; however, this information was not easily put together by the licensee and required researching past records. This was another indication that a system for easy retrieval of historical information was not readily available. The licensee provided the inspectors with historical information concerning off-normal chemistry as it related to entry into EPRI Guidelines Action Level 2, which requires a reduction in reactor power; and Action Level 3, which requires a plant shutdown. The parameters monitored were cation conductivity, sodium, chloride, and sulfates. From 1987 to the present, the licensee entered Action Level 2 for Unit 1 a total of 10 times , Unit 2 a total of 12 times, and Unit 3 a total of 11 times. Sodium was the parameter for Unit 2, in particular, which resulted in entry into Action Level 2. Entry into Action Level 3 also occurred twice, once in Unit 2 and once in Unit 3. Both excursions resulted from excessive concentrations of sodium in the steam generator blowdown. The inspectors concluded from the information provided by the licensee that Unit 2 steam generators had experienced a greater number of events in which alkaline conditions were present. The Action Level 2 data is summarized in Table 6 below.

In discussions with licensee personnel concerning some of these off-normal events, the inspectors noted that the licensee personnel had difficulty in reconstructing and establishing how some of the chemistry data was provided. This was evident in trying to reconstruct how some molar ratios were calculated. Some of the difficulty involved trying to establish actual plant conditions at the time of the data collection and the method of calculation which was in effect at the time of the data collection. This appears to be an area which requires more attention to assure reliability of the data.

The licensee informed the inspectors that, in recognition of the need for a better system to manage, manipulate and interpret data, a two phase project was ongoing to upgrade the chemistry information management system. The two phase plan would have Phase 1 implemented by September 1994 which would provide the ability to enter data, graph data, and provide reports as defined by the user. Phase 2, which is estimated to be implemented by mid 1995, would include such features as auto trending of parameters as defined by the user, more extensive reports as defined by the user, better graphing capabilities, and laboratory analytical control data entry. The inspectors viewed these improvements as a positive step towards providing more user friendly secondary water chemistry trending information.

Table 6

OFF NORMAL SECONDARY CHEMISTRY HISTORY									
Unit (U)	A.L. *	Number of Times Action Level 2 was Exceeded							
		1987	1988	1989	1990	1991	1992	1993	1994
U1	Na	1	0	0	1	1	0	0	0
	Cl	1	0	0	1	0	0	1	0
	SO4	1	0	0	0	0	0	1	0
	#C.C.	1	0	0	0	0	0	1	0
	Total	4	0	0	2	1	0	3	0
U2	Na	0	1	1	2	0	4	0	1
	Cl	0	0	0	0	0	0	1	0
	SO4	0	0	0	0	0	1	0	0
	#C.C.	0	0	0	0	0	1	0	0
	Total	0	1	1	2	0	6	1	1
U3	Na	0	0	0	0	1	2	0	0
	Cl	0	0	0	0	0	1	1	0
	SO4	1	0	0	0	0	2	2	0
	#C.C.	0	0	0	0	1	0	0	0
	Total	1	0	0	0	2	5	3	0

* A.L. - Action Level
\# C.C. - Cation Conductivity

6.6 Conclusions

- The secondary water chemistry program requirements have been consistent with industry guidelines since commercial operation of the PVNGS units.

- Significant variation between the blowdown rates of the Unit 1 steam generators was measured, with potential impact on individual steam generator chemistry and resulting rate of degradation.

- The current chemistry records system did not provide for ready assessment of historical chemistry performance.

- Progressive upgrades of in-line process and laboratory instruments have been made to enhance the performance of required analyses.

7 ISI-OBSERVATION OF WORK AND WORK ACTIVITIES (73753)

The objective of this part of the inspection was to determine whether: (a) the performance of ISI examinations and any repair or replacement of Class 1, 2, and 3 pressure retaining components were accomplished in accordance with the applicable ASME Code; and (b) the licensee had appropriately satisfied industry initiatives.

7.1 ISI Program

The inspectors reviewed Revisions 0 and 1 of the licensee's ISI program for PVNGS, Unit 3 (i.e., Program ISI-3). Program ISI-3, Revision 0, was accepted by NRC letter dated October 21, 1987. According to 10 CFR 50.55a(b)(2), and in conjunction with the issuance of the operating license for Unit 3 on March 25, 1987, the 1983 Edition through the Summer 1983 Addenda of Section XI of the ASME Code was used to prepare the program. However, the NRC acceptance letter allowed the licensee to use the 1980 Edition through the Winter 1981 Addenda of the Code for the first 10-year inspection interval in order to maintain consistency with the programs established for Units 1 and 2. Revision 1 to Program ISI-3 dated December 23, 1991, was prepared to incorporate the changes resulting from the NRC review and acceptance of Revision 0. The principal changes dealt with establishment of a three unit common Code Edition and Addenda, and a common inspection interval date (i.e., January 8, 1988, to January 10, 1998), including the three corresponding inspection periods. Unit 3 was currently in its fourth refueling outage, which placed it in the second period of the first inspection interval. Other changes included an update to the requests for relief (based on NRC acceptance), and inclusion of zone references for components on drawings. The inspectors' review verified that the changes incorporated in Revision 1 were made as a result of the NRC acceptance letter, and that all changes had been appropriately documented. Besides licensee management review and approval, the inspectors noted that Revision 1 had also received the authorized nuclear inservice inspector's concurrence on February 10, 1992. The licensee submitted Revision 1 to the NRC under cover letter 102-02447-RJS/TRB/JRP dated March 12, 1993.

The licensee had also established Nuclear Administrative and Technical Manual Procedure 73DP-9EE02, "Inservice Inspection Examination Activities," Revision 00.03, to provide guidance and control of onsite nondestructive examination (NDE) activities associated with implementing the ISI program. The procedure defined personnel responsibilities, and stated requirements for establishing outage schedules and plans (i.e., a listing of the items scheduled to be examined during the outage), verifying and/or preparing NDE procedures, determining calibration requirements, reviewing personnel and equipment certifications, and controlling documentation and records.

The inspectors reviewed "PVNGS 10 Year Interval-Examination Summary," a summary report submitted to the NRC by letter dated February 23, 1993, which identified all examinations completed through the first ISI in Period 2 of Interval 1 (November 20, 1992). The licensee, before each outage, performed a review of the summary report to determine the status of ISI Program required examinations. After completing the review, the licensee developed an "Outage Plan Table," a document that listed all examinations to be performed during the next outage. The table also identified the specific components to be examined, the examination requirements, NDE procedures to be used, and calibration blocks required. Additionally, the table was used to maintain the status of examination progress; thus, helping to ensure the completion of all required examinations. Upon completion of NDEs, the table formed the basis for updating the summary report.

A sample of NDEs, shown by both the ISI program and the summary report to be required during this outage, were compared to the table to verify that they had been scheduled. Since most ISI examinations had been completed prior to this inspection, the inspectors were also able to verify that the table was being used to status the examinations. The inspectors also randomly reviewed ISI reports from the first three refueling outages (dated March 7, 1990; August 13, 1991; and November 20, 1992, respectively) and verified that they had been properly documented in the summary report. The inspectors did not identify any instances in the sample where summary report-required examinations had not been scheduled and performed.

7.2 Observation of NDEs

The inspectors were informed that the majority of ISI examinations had been completed prior to this inspection. The examination schedule showed that volumetric examinations consisting of ultrasonic examinations of the valve/piping welds in the main steam relief valves of Steam Generator 3-2, and eddy current examinations of Steam Generator 3-2 tubing, were being performed during the week of April 25, 1994. The inspectors were also informed that no ASME Code repair and replacement activities had been scheduled or performed during this outage.

The inspectors observed the performance of ultrasonic examinations of the following main steam relief valves/weld numbers: PSV-0554/20, PSV-0555/16, PSV-0556/12, PSV-0557/8, PSV-0695/4, PSV-0559/12, PSV-0560/16, and PSV-0561/20. The examinations of the circumferential welds were conducted with a shear wave mode (45 degree angle beam) in two directions (perpendicular and parallel to the weld axis) using a transducer with a frequency of 2.25 MHZ. The inspectors verified that designated Procedure 73TI-9ZZ09, "Ultrasonic Examination of Pipe Welds," Revision 06.01, had been approved, and was being followed. The NDE examiners also performed a calibration check at the beginning and end of each examination.

Before the ultrasonic examinations were conducted, the inspectors observed the system calibration which included both axial and circumferential scans. The transducer selection, sensitivity calibration, and construction of the

distance amplitude correction curve was performed in accordance with Procedure 73TI-9ZZ09. The inspectors also verified, by review of the CMTR, that the correct calibration block was used (i.e., similar to the component to be examined in terms of material, diameter, and wall thickness).

The NDE examiners documented their calibration and examination results on an ultrasonic calibration report and an ultrasonic examination report, respectively. The reports were numerically identified and contained all pertinent information specified by the procedure. Recording of identified indications was conducted at the primary reference or distance amplitude correction curve sensitivity. All of the calibration checks and examinations were recorded on a direct-linked videotape recorder to aid in review of identified indications.

The inspectors observed acquisition of eddy current data from 37 Steam Generator 3-2 tubes using approved Procedure 73TI-9RC01, "Steam Generator Eddy Current Examinations," Revision 11. The identity of the 37 tubes observed being examined are listed in Attachment 2. The inspectors did not observe initial system calibration; however, since eddy current examinations, including calibration, were videotaped, all information was retrievable and observable. The inspectors observed calibration checks for bobbin coil examinations, which were performed at a frequency not exceeding once per each 4 hour period, and were documented in the CONAM Nuclear, Inc., daily log. Review of the logs since April 7, 1994, by the inspectors, revealed that the calibration check frequency was much more often than once every 4 hours. In addition, the review clearly showed that calibration was performed each time a piece of equipment was changed. The eddy current examiner used the approved Acquisition Technique Sheet SG-1.06 dated April 19, 1994. This acquisition technique sheet was applicable to bobbin coil examinations of steam generator tubing and provided specific equipment and technique parameters to be complied with during the performance of the examinations. The remote fixture used to position the probe guide tube was a Zetec SM-22. The inspectors also verified that the examiner did not exceed the maximum allowable retraction speed of 24 inches per second. The eddy current acquisition system employed the use of a television camera to provide monitoring capabilities. The camera provided excellent resolution and assisted the examiners in establishing identification and verification of tube locations. This information was also recorded on a video recorder. The procedure required that identification and verification be performed during initial installation and before relocating or removing the fixture. The inspectors observed the examiner perform identification and verification after approximately every 8-10 tubes had been examined. Each time the examiner performed identification and verification, he entered "positive verification" on his list of examined tubes. In the case of an error in recording of location, this allowed the examiner to re-examine all tubes examined since the previous identification and verification.

The inspectors also observed 3-coil rotating pancake coil examinations of four steam generator tubes (identified in Attachment 2) after they had been chemically cleaned. The examiner used Acquisition Technique Sheet SG-2.07, which was approved for use on April 7, 1994, and was applicable to 3-coil MRPC

examination of steam generator tubing utilizing one or two probes. The inspectors verified that the examiner did not exceed the maximum speed of 0.2 inches per second.

Discussions with the examiners performing the ultrasonic and eddy current examinations indicated that they were experienced and knowledgeable NDE personnel. They were cognizant of the procedural and documentation requirements, and understood the examination techniques.

7.3 Personnel Qualifications and Certifications

The inspectors were informed that the individuals that performed the ultrasonic examinations were contractor personnel employed by Lambert-MacGill-Thomas, Inc., while the eddy current examiners were employed by CONAM Nuclear, Inc.

The inspectors reviewed the qualification files of the NDE personnel who performed the observed examinations. The files contained certifications for the NDE methods that the inspectors observed. One individual was certified by EPRI examination as a Level III ultrasonic examiner, while the other three individuals were certified as Level II examiners (two in eddy current examination and the other in ultrasonic examination). The records showed that they had been certified in accordance with American Society of Nondestructive Testing Recommended Practice SNT-TC-1A, 1980. As required by the ASME Code, all of the individuals had received annual near distance acuity and color vision examinations.

7.4 ISI Procedures Review

In addition to the procedures used during the observed examinations, the inspectors reviewed other NDE procedures used for ISI during this refueling outage to verify that they were consistent with the requirements of Section XI of the ASME Code, 1980 Edition, Winter 1981 Addenda. The procedures were found to be well written and contained sufficient detail and instructions to perform the intended examinations.

7.5 Conclusions

- The ISI program was well structured and administratively controlled, and had been updated to incorporate comments contained in the NRC's program acceptance letter dated October 21, 1987. The licensee appeared to be adhering to the examination schedule for the current inspection period (second) of the first 10-year inspection interval.

- The observed NDEs were performed by knowledgeable individuals and in accordance with approved procedures. Calibrations were performed as required. The use of video recorders was considered a good practice.

- The NDE personnel observed by the inspectors were properly certified to perform those examinations.

- The ISI procedures contained sufficient detail and instructions to perform the applicable NDEs, and they were consistent with the requirements of the ASME Code.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

**R. Bernier, Supervisor, Nuclear Regulatory Affairs
#W. Blaxton, Supervisor, Unit 1 Chemistry
*C. Brown, Inservice Inspection Engineer, Inservice Inspection
*R. Browning, Senior Inservice Inspection Engineer
G. Bucci, Senior Adviser, Steam Generator Project Group
*T. Cannon, Supervisor, Inservice Inspection/Inservice Testing
P. Crawley, Director, Nuclear Fuel Management
#D. Elkinson, Senior Quality Monitor, Quality Assurance
#D. Fuller, Consultant, Site Chemistry
#P. Guay, Manager, Unit 3 Chemistry
*D. Hansen, Senior Consulting Engineer, Inservice Inspection
#L. Johnson, Manager, Unit 2 Chemistry
#A. Krainik, Manager, Regulatory Affairs
F. Lindy, Administrator, Risk Management
*A. Morrow, Primary Discipline Engineer, Inservice Inspection
#K. Neese, Project Engineer, Steam Generator Project Group
D. Pratt, Project Engineer, Steam Generator Project Group
#J. Provasoli, Senior Project Manager, Nuclear Regulatory Affairs
#R. Schaller, Manager, Steam Generator Project Group
#J. Scott, Director, Site Chemistry
#J. Shawver, Senior Technical Adviser, Site Chemistry
**K. Sweeney, Senior Project Manager, Steam Generator Project Group

1.2 Other Personnel

*F. Gowers, Site Representative, El Paso Electric
**R. Henry, Site Representative, Salt River Project
M. Marugg, Account Engineer, American Nuclear Insurers
D. McGarvey, Account Executive, Johnson and Higgins

1.3 NRC Personnel

**K. Johnston, Senior Resident Inspector
H. Freeman, Resident Inspector
A. MacDougall, Resident Inspector
J. Kramer, Resident Inspector
#W. Ang, Chief, Plant Support Branch

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes those persons that attended the exit meeting on April 29, 1994.
**Denotes those persons that attended both the exit meetings on April 29 and May 13, 1994.
#Denotes those persons that attended the exit meeting on May 13, 1994.

2 EXIT MEETING

Exit meetings were conducted on April 29 and May 13, 1994. During these meetings, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on inspection findings documented in this report. Documents identified by ABB Combustion Engineering and Babcock and Wilcox Nuclear Technologies as containing proprietary information were reviewed during this inspection. No information was included in the inspection report that was considered proprietary.

ATTACHMENT 2

NDE Procedures Reviewed

73TI-9ZZ09, "Ultrasonic Examination of Pipe Welds," Revision 06.01

73TI-9RC01, "Steam Generator Eddy Current Examinations," Revision 11

73TI-9ZZ10, "Ultrasonic Examination of Welds in Ferritic Components," Revision 3

73TI-9ZZ07, "Liquid Penetrant Examination," Revision 3

73TI-9ZZ05, "Dry Magnetic Particle Examination," Revision 3

73TI-9ZZ18, "Visual Examination of Support Components," Revision 5

73TI-9ZZ17, "Visual Examination of Welds, Bolting, and Components," Revision 4

Identity of Steam Generator Tubes Observed-Bobbin Coil Examined

Line 50 Row 91
Line 50 Row 93
Line 50 Row 95
Line 50 Row 97
Line 50 Row 99
Line 50 Row 101
Line 50 Row 103
Line 50 Row 105
Line 50 Row 107
Line 50 Row 109
Line 50 Row 111
Line 50 Row 115
Line 50 Row 117
Line 50 Row 119
Line 50 Row 121
Line 50 Row 123
Line 50 Row 125
Line 50 Row 127
Line 50 Row 129
Line 50 Row 131
Line 50 Row 133
Line 50 Row 135
Line 50 Row 137
Line 50 Row 139
Line 49 Row 138
Line 49 Row 136
Line 49 Row 134
Line 49 Row 132
Line 49 Row 130
Line 49 Row 128

Line 49 Row 126
Line 49 Row 124
Line 49 Row 122
Line 49 Row 120
Line 49 Row 118
Line 49 Row 116
Line 49 Row 114

Identity of Steam Generator Tubes Observed-Rotating Pancake Coil Examined

Line 73 Row 150
Line 75 Row 150
Line 76 Row 145
Line 77 Row 148

ATTACHMENT 3

List of Acronyms

BWNT	Babcock and Wilcox Nuclear Technologies
CE	Combustion Engineering
CMTR	Certified Material Test Report
EFPY	Effective Full Power Years
EPRI	Electric Power Research Institute
IGSCC	Intergranular Stress Corrosion Cracking
IN	Information Notice
MRPC	Motorized Rotating Pancake Coil
NDE	Nondestructive Examination
ODSCC	Outside Diameter Stress Corrosion Cracking
PVNGS	Palo Verde Nuclear Generating Station
PWSCC	Primary Water Stress Corrosion Cracking