APS

Palo Verde Nuclear
Generating Station

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10 CFR 50.90
10 CFR 50.91

102-04856 CDM/TNW/RJR
October 23, 2002

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-37
Washington, DC 20555-0001

Reference: Letter 102-04844-CDM/TNW/JAP, "Exigent Amendment Request to Technical Specification 5.5.9, Steam Generator (SG) Tube Surveillance Program," dated September 26, 2002," C. D. Mauldin, APS to USNRC

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit 1
Docket No. STN 50-528
Response to Request for Additional Information to Proposed Exigent Amendment to Technical Specification 5.5.9, Steam Generator Tube Surveillance Program

In the letter referenced above, Arizona Public Service Company (APS) requested an exigent amendment to Technical Specification (TS) 5.5.9, Steam Generator (SG) Tube Surveillance Program. During the review, the NRC Staff requested additional information related to the proposed amendment. APS' responses to the NRC questions are contained in the Enclosures to this letter.

Enclosure 1 contains proprietary commercial information taken directly from WCAP-15947-P previously identified as proprietary by Westinghouse Electric Company, LLC. This information is identified by brackets and is covered by the Westinghouse Electric Company, LLC. affidavit included as Enclosure 5 to the letter referenced above. It is requested that Enclosure 1 be withheld from public disclosure in accordance with 10 CFR 2.790(b)(1). Enclosure 2 contains the non-proprietary version of APS' responses to the requested information and a revised mark-up and re-typed page of the change being made to TS 5.5.9.

APS has concluded that this change does not affect the no significant hazards consideration determination submitted in the referenced letter. By copy of this letter, this request is being forwarded to the Arizona Radiation Regulatory Agency (ARRA) pursuant to 10 CFR 50.91(b)(1).

A001

The following commitment is being made to the NRC in this letter.

- Within 90 days of the issuance of the amendment to TS 5.5.9, APS will revise the Bases to Surveillance Requirement 3.4.14.2 to identify that this amendment is only applicable to the Combustion Engineering System 80 steam generators currently installed in Unit 1.

Should you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

David Mauldin

CDM/TNW/RJR

Enclosure 1 Response to Request for Additional Information to Proposed Exigent License Amendment to TS 5.5.9, Steam Generator Tube Surveillance Program – Proprietary

Enclosure 2 Response to Request for Additional Information to Proposed Exigent License Amendment to TS 5.5.9, Steam Generator Tube Surveillance Program – Non-Proprietary

Attachment 1 Technical Specification 5.5.9 Revised Marked-up Page

Attachment 2 Technical Specification 5.5.9 Revised Re-Typed Page

cc:	E. W. Merschoff	(w/o Enclosure 1)
	J. N. Donohew	
	M. B. Fields	(w/o Enclosure 1)
	N. L. Salgado	(w/o Enclosure 1)
	A. V. Godwin	(w/o Enclosure 1)

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, David Mauldin, represent that I am Vice President Nuclear Engineering and Support, Arizona Public Service Company (APS), that the foregoing document has been signed by me on behalf of APS with full authority to do so, and that to the best of my knowledge and belief, the statements made therein are true and correct.

David Mauldin
David Mauldin

Sworn To Before Me This 23 Day Of October, 2002.

Nora E. Meador
Notary Public

My Commission Expires

"OFFICIAL SEAL"
Nora E. Meador
Notary Public-Arizona
Maricopa County
My Commission Expires 4/6/2003

ENCLOSURE 2

Response to Request for Additional Information to Proposed Exigent License Amendment to TS 5.5.9, Steam Generator Tube Surveillance Program – Non-Proprietary

REQUEST FOR ADDITIONAL INFORMATION
PALO VERDE UNIT 1
TECHNICAL SPECIFICATION AMENDMENT - TUBESHEET INSPECTION
(Non-Proprietary Version)

Introduction

The information furnished below provides APS's responses to the NRC Staff's Request for Additional Information (RAI) related to a proposed Technical Specification Amendment Request to Section 5.5.9, ***Steam Generator (SG) Tube Surveillance Program*** (Letter 102-04844-CDM/TNW/JAP dated September 26, 2002). The information does not change the technical basis or conclusions identified in WCAP 15947-P or the APS Supplemental Report included as attachments to the amendment request. However, some of the values have been revised based on more conservative treatment of the analytical and test program results. As indicated in all the correspondence related to this change, APS has elected to provide additional conservatism to all of the WCAP 15947-P components included in the determination of the inspection extent described in the amendment request. The following table is provided as a summary of the inspection extent values provided in the WCAP, as well as the conservative adjustment of the WCAP values by APS as described in the APS Supplemental Report and the information provided in response to the NRC RAI. Information in square brackets (e.g., [ ]) is Westinghouse proprietary as designated in WCAP 15947-P only and is covered by the Westinghouse Electric Company LLC Affidavit included as Enclosure 5 of APS's Amendment Request. Only proprietary information taken directly from WCAP 15947-P is bracketed. No new information in this RAI response has been identified as proprietary.

Table 1

	WCAP 15947-P	PVNGS
Tube Engagement Area – Burst and Pullout	[ ]	3.0"
Tube Engagement Area – Leakage	[ ]	3.0"
Adjustment for Hole Dilation Effects – Pullout	[ ]	2.25"
Adjustment for Hole Dilation Effects – Leakage	[ ]	2.5"
Total Tube Engagement Area (TEA) (Pullout, Burst, and Leakage)	[ ]	5.5"
Adjustment for Uncertainties (e.g. NDE, test variance)	[ ]	1.5"
Total Inspection Extent[1]	[ ]	7"

Note 1. PVNGS inspection extent changed from "as measured from the secondary face of the tubesheet" to "below the bottom of the expansion transition"

NRC Question 1

Section 6.0 of WCAP-15947-P discusses the effects of tubesheet flexure on the tube-to-tubesheet contact load. It is stated that tubesheet flexure results in a reduction of the effective contact load with the largest reduction occurring at the top of the tubesheet. Based on an analysis, the licensee concludes that at a set distance below the top of the tubesheet (i.e., the tubesheet dilation correction factor), the resisting load exceeds the bounding pullout load criteria of 2000 lbf determined at 3NODP. The licensee further states that the tubesheet dilation correction factor will provide sufficient resistance to tube pullout to meet the structural integrity requirements. The staff interprets this to mean that the distance associated with the tubesheet dilation correction factor is the minimum distance of non-flawed tubing required to prevent tube pullout. However, Section 8.0 of WCAP-15947-P implies that the distance associated with the tubesheet dilation correction factor must be added to a "tube engagement length" to determine the minimum distance of non-flawed tubing required to prevent tube pullout. Clarify this apparent discrepancy.

APS Response

APS has confirmed with Westinghouse that the intent of Section 6.0 was to determine an adjustment factor to the test generated pullout distance to account for tubesheet flexure and any consequential hole dilation effects on the contact pressure of the tube-to-tubesheet joint. This position is clearly delineated in Section 1.6 of WCAP 1597-P titled *Overview of Approach* and repeated in Section 8.3, *Tubesheet Dilation Correction Factor.*

Based on these discussions, the final sentence in Section 6.0 should have read:

It is concluded that, for conservatism, the minimum depth required to resist pullout should be adjusted by [ ] inches to account for tubesheet deflection.

Additional information regarding the effects of tubesheet flexure is provided in the APS response to *NRC Question 2.*

NRC Question 2

Section 6.0 of WCAP-15947-P indicates that pull test data from two single tube mockup specimens were used in the development of the average pullout load. Discuss the technical basis for assuming the average load rather than a bounding load as well as for not considering the use of the Boston Edison pull test data. Describe the impact the use of a bounding load would have on the tubesheet dilation correction factor. Please discuss the appropriateness of using the coefficient of friction of 0.2. Is this value consistent with (i.e., bound) the experimental results performed in support of the report?

APS Response

In the preparation of WCAP 15947-P, all test data developed as a part of the CEOG testing program was considered for the appropriateness of use in the results and conclusions. For example, Table 6-1 included data for the 0.048 inch rough bore test specimens. In Table 6-1, the maximum loads for these specimens were all well above 5,000 lbf. In view of the load results approaching the yield strength of the tubing, it was decided to use a cutoff of

6,000 lbf for selecting representative tubes for the calculation of linear load. At the point that the tube yield strength is reached, the tube deforms due to the upward applied load from the load cell. The axial load is intended to simulate the end cap load on the tube. However, because a commensurate pressure was not applied inside the tube diameter in this test setup, necking of the tube occurs from the top of the joint at incrementally greater depths over the length of the joint interface as the load increases in the range of the yield strength. This necking is not representative and causes the linear load to be reduced from actual. In addition to the pull load limit, the WCAP discusses the basis for exclusion of the NOT samples.

The 0.042 inch specimen data was also excluded by Westinghouse based on the anomalous results of Specimen 21. However, this data has been considered and included in the PVNGS Supplemental Report and the APS responses to the NRC RAI.

To respond to the NRC Staff's question of what effect the inclusion of all data (applicable to PVNGS) would have on the results, the WCAP 15947-P Sections 4.0, 5.0 and 6.0 information has been re-evaluated to reflect inclusion of all data. As indicated, this re-evaluation did not result in changes to the overall conclusions or basis for the proposed inspection criteria.

With respect to tube pullout, the data (see response to *NRC Question 12*) considered most applicable to PVNGS is the 0.042 inch tube wall thickness data from the BE steam generator and single mockup Specimens 20 and 21. The applicability of this data, with respect to material, design and fabrication variability has been addressed in the PVNGS Supplemental Report and in responses to *NRC Questions 4 and 5*. This data has been plotted in Figures 2-1 and 2-2. It should be noted that the regression fit in Figure 2-1 did not change appreciably from Figure 11 in the PVNGS Supplemental Report. In order to assess the incremental contact force for the flexure analysis, Figure 2-2 provides a polynomial fit to the data anchored at zero. For Figure 2-2 the raw data were also arithmetically adjusted to develop a 95% lower bound fit (e.g., square points).

Figure 2-1

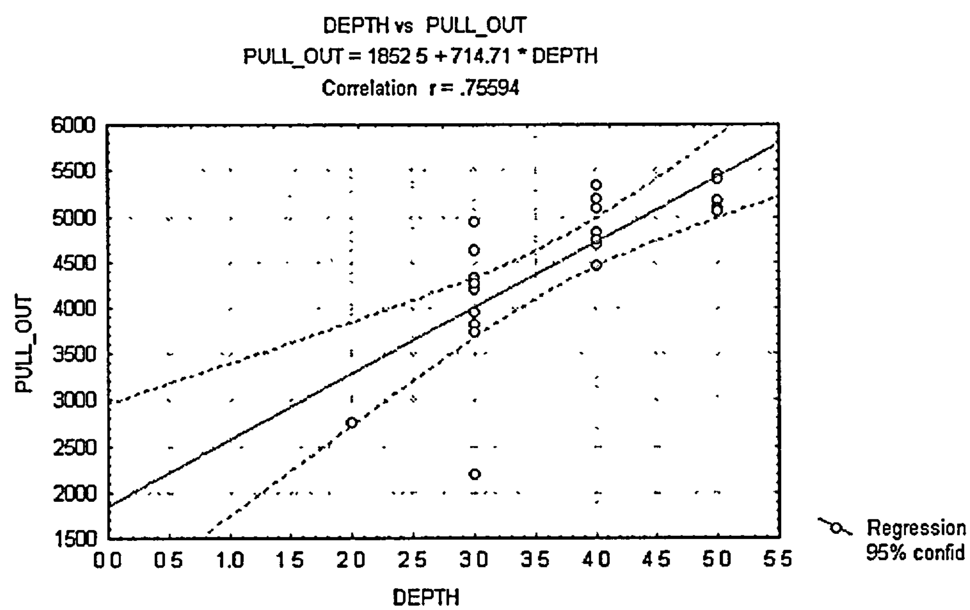
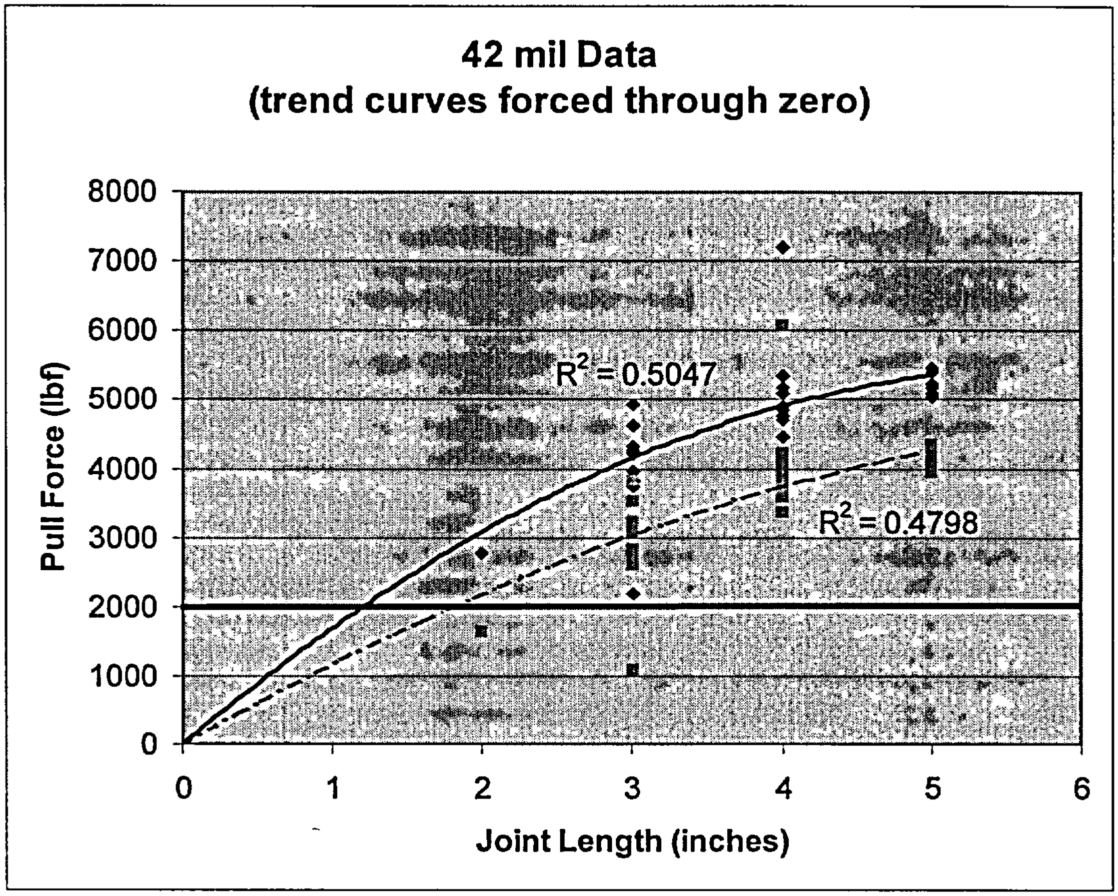


Figure 2-2



With respect to the effects of tubesheet flexure, as indicated in WCAP 15947-P, a finite element model was used to calculate the effect of the tubesheet deflection (flexure) on the contact load between the tube and tubesheet. Tubesheet dilation effects applied to a single tube model were calculated from tubesheet stresses for the worst case conditions for the limiting CE steam generator design. Symmetry of the tube/tubesheet was used to reduce the finite element model size, incorporating axi-symmetric 2-D modeling of the tube and tubesheet. The model length was 8.0 inches, simulating the distance of concern from the tubesheet secondary face into the tubesheet.

The finite element model was subjected to an internal tube pressure of 0 psia for the flexure case only, with the thermal expansion properties for the tube and tubesheet at 600°F. The tube hole displacements applied to the model were based on an equivalent solid plate effect (which considers the tube hole sizes and pattern) from the limiting plant steam generator design report. In the design report, a conservative classical interaction type of analysis was performed on the tubesheet, which also included the primary head, secondary shell, and stay cylinder in the interaction model. The divider plate, which would reduce deflections, was conservatively neglected. The worst location (point of maximum tubesheet deflection) in this model from the design report was at a radius of 40.0 inches from the centerline of the tubesheet. The pressure differential at this location (i.e. design pressure per the design stress report) resulted in the maximum equivalent solid plate stresses and maximum tube hole displacements to use for input into the finite element model. The tubesheet membrane and bending stresses as a function of depth are applied to the model to determine the loss of contact pressure due to this loading. Table 2-1 provides the results of this analysis in terms of reduction in contact load for incremental locations within the tubesheet. As indicated in WCAP 15947-P, a friction factor of 0.2 was used to generate the axial load (Fz) from the net contact load (Fx). This value was not arrived at experimentally for the CEOG program. During development of the CEOG program it was determined that the use of a 0.2 friction factor in this application had been approved by the NRC. Both the W* and F* topical reports reference 0.2 as a friction coefficient. Additionally, during APS review it was found that Marks' *Standard Handbook for Mechanical Engineers, Eighth Edition*, reported friction coefficients for interference fits that vary between 0.03 and 0.33. The average values are from 0.1 to 0.15. Therefore, APS considers the value used in the WCAP to be reasonable for this application.

Table 2-1 Tubesheet Deflection Analysis Results
Reduction in Contact Load in the X and Z directions

Depth into Tubesheet (inch)	Fx Load (lbf)	Fz Load (Lbf)
0.25	-1498.29	-299.66
0.50	-1474.59	-294.92
0.75	-1450.57	-290.11
1.00	-1422.72	-284.54
1.25	-1393.43	-278.69
1.50	-1366.57	-273.31
1.75	-1338.67	-267.73
2.00	-1311.4	-262.28
2.25	-1283.8	-256.76
2.50	-1256.34	-251.27

Using the information from the re-evaluation of all the 0.042 data, the tubesheet deflection data and an assessment of force contribution due to pressure, Table 2-2 was developed to reassess the axial force required for development of the tube deflection adjustment for pullout and leakage. The table column descriptions are as follows:

- Column A. The joint length (assuming BET equals TTS). The 0.25 inch increments correspond to the tubesheet deflection analysis.

- Column B. From Figure 2-2, the axial contact force (F_c) of the explansion (at 95%) in 0.25 inch increments.
- Column C. The axial force due to MSLB pressure (F_p) determined from the thick-wall pressure formulations (Reference – Roark Formulas for Stress and Strain, Seventh Edition, Table 13.5).
- Column D. The axial force reduction due to tubesheet flexure (F_d) from Reference 24 of WCAP 15947-P. Table 2-1 contains the applicable results.
- Column E. The sum of the Columns B, C and D at each incremental location.
- Column F. The cumulative results of Column E. The required adjustment for tubesheet deflection is determined for the point at which the Column E force exceeds the 2000 lbf acceptance criteria from WCAP 15947-P.

Table 2-2 Effect of Tube Deflection on Force

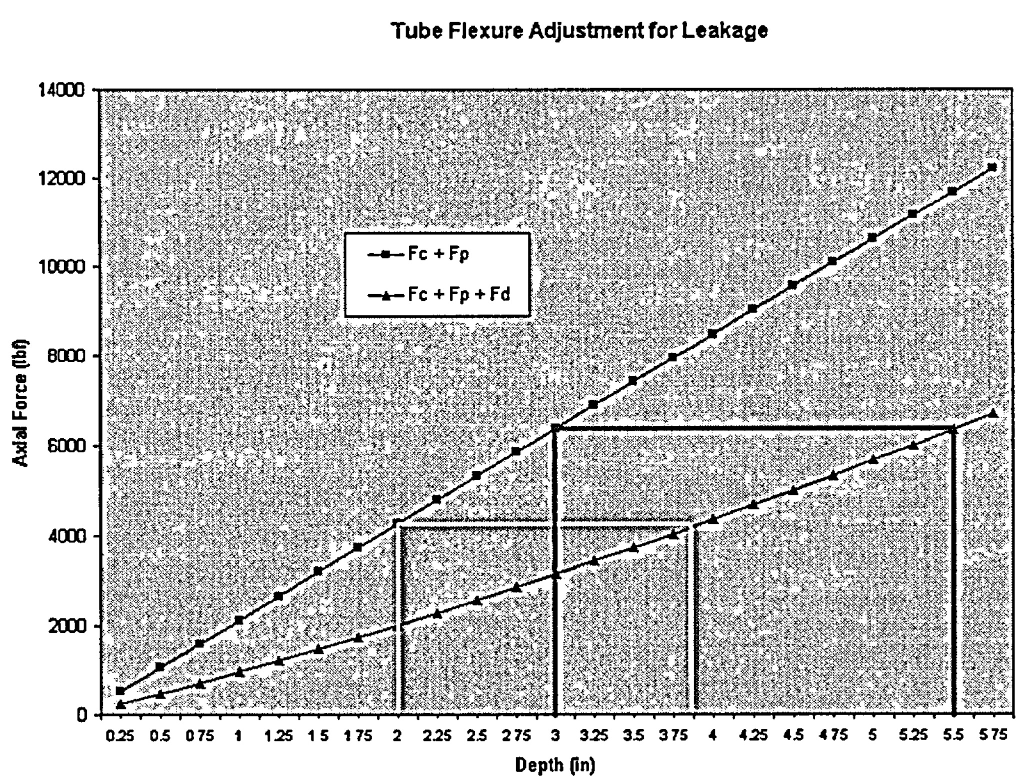
A. Depth in Tubesheet	B. Axial Force from Figure 2-2	C. Axial Force due to Pressure	D. Axial Force due to Dilation	E. Total Axial Force	F. Cumulative Axial Force
0.25	300	231	-299.66	231.34	231.34
0.5	300	231	-294.92	236.08	467.42
0.75	300	231	-290.11	240.89	708.31
1	300	231	-284.54	246.46	954.77
1.25	300	231	-278.69	252.31	1207.08
1.5	300	231	-273.31	257.69	1464.77
1.75	300	231	-267.73	263.27	1728.04
2	300	231	-262.28	268.72	1996.76
2.25	300	231	-256.76	274.24	2271.0
2.5	300	231	-251.27	279.73	2550.73

For consistency with WCAP 15947-P, the pullout engagement length adjustment for tubesheet deflection is related to an analytical value that exceeds the 3NODP criteria. This analysis result is added to the test demonstrated pullout engagement length for conservatism. The results from Table 2-2 indicate that the adjustment to the pullout engagement length should be approximately 2 inches. For added conservatism, PVNGS will use 2.25 inches.

With respect to the effect of tube dilation on leakage, note that the net radial contact pressure of the combined effect of explansion, MSLB pressure, and tubesheet flexure (Column E) results in no gap between the tube and tubesheet at any location. The absence of a gap indicates that the leakage would be restricted despite any tubesheet flexure. Additionally, limited testing of leakage samples at operating temperature did indicate, as expected, that additional compression and increased leakage resistance will result from thermal expansion. These results are discussed further in APS response to *NRC Question 19*. The above gap analysis and the NOT leakage testing, in of themselves, should be sufficient to account for tube flexure effects. However, APS has elected to further relate contact force for the CEOG test samples to the analyzed contact pressures at accident conditions. Although the CEOG program did not explicitly test for the effects of tubesheet flexure, APS believes that the results of the flexure analysis can be compared to the test parameters and results of the testing described in WCAP 15947-P, to determine a conservative adjustment for tubesheet flexure on leakage.

As indicated in WCAP 15947-P, the leakage testing on the BE steam generator samples were conducted at ambient conditions to a pressure corresponding with MSLB pressures. In that regard, the test samples were exposed to contact pressures from the explansion and the internal test pressure (F_c and F_p). From Figure 2-3, this sum is plotted per incremental depth. The effect of tube dilation is also plotted ($F_c + F_p + F_d$). The adjustment for tube dilation occurs at the normalization of these conditions such that the cumulative contact force accounting for tube dilation is equivalent to the test conditions. This adjustment for the leakage test results indicates the required engagement length. For the WCAP 15947-P engagement length for leakage (Section 8.2) of two (2) inches, the adjustment would be 1.9 inches. As indicated in APS response to *NRC Question 19*, APS has elected to use an engagement length of three (3) inches to bound the test data. The corresponding adjustment to the APS specified engagement length for leakage for tubesheet flexure as shown in Figure 2-3 as 2.5 inches. The value is listed in Table 1 of the RAI *Introduction*.

Figure 2-3



In summary, the results presented in Table 2-2 are expected in comparison to W*. The CE joint is designed to have residual contact force at ambient conditions, and is considered more representative of a rolled joint in terms of contact pressure, and is therefore conservative to the W* application. The test and analysis results indicate that a 2.25 inch adjustment over and above to the required engagement length for pullout provides significant conservatism. The adjustment for leakage permits a connection between the analyzed effect for tubesheet flexure and the leakage test program. This adjustment, along with test data that indicates that additional compression can be expected due to thermal expansion (not considered in Table 2-2), is also conservative. Both adjustments for tubesheet flexure in relation to the total proposed inspection length are given in Table 1 of RAI *Introduction.*

NRC Question 3

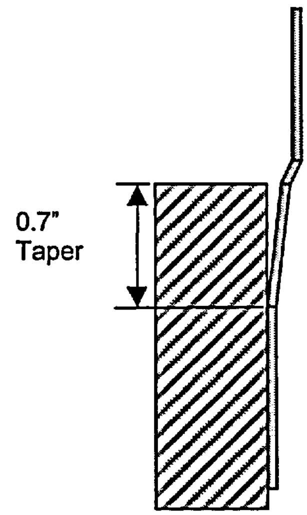
The Supplemental Report to WCAP-15947-P indicates that beginning in the Fall 2002 refueling outage (U1R10), the licensee will record the bottom of expansion transition (BET) location for all tubes. In addition, the supplemental reports states that if the BET location is greater than 0.7 inches below the top of the tubesheet then the inspection extent (i.e., 7 inches) would need to be increased accordingly. Please clarify if the BET location will account for effects due to both underexpansion of the explansion joint as well as taper of the joint. In addition, discuss whether you plan to modify the 0.7 inch value based on results from the ongoing steam generator tube inspections at Unit 1. Lastly, the commitment to increase the inspection extent under these circumstances must be incorporated into your Technical Specifications.

APS Response

As shown in Figure 5 in the PVNGS Supplemental Report, the bottom of the expansion transition (BET) is the point at which full contact of the tube to tubesheet is made. As such, the measurement accounts for any section of the tube not in full contact engagement. This region has been referred to in NRC and industry documentation as non-contact zone, underexpansion or taper. For clarification purposes, it is considered useful to restate the differences between the WEXTEX and CE "explansion" tubesheet joints and provide details of the inspection results from Unit 1.

Both WCAP 15947-P and the PVNGS Supplemental Report make comparative statements with respect to the WEXTEX joint which contains a non-contact region defined as a taper (see Figure 3-1).

Figure 3-1 WEXTEX Joint



As indicated in WCAP 15947-P, microscopic examination of tubes and tubesheet single tube mockups removed after pullout testing indicate that a similar taper is essentially non-existent in a CE explansion joint. WCAP 15947-P further states that the lack of a taper in CE-designed joint is reasonable to expect because of the process design and controls. The explansion charge assembly illustrated on Figure 1.2 of WCAP 15947-P shows the plastic charge carrier extending beyond the secondary face of the tubesheet. The carrier served two purposes: (1) to hold the position of the primer cord and (2) to carry the explosive force uniformly through the range of the tubesheet. The explosive force combined with the carrier function apparently is effective in providing a distinct transition from explanded to unexplanded tube diameter and negating any reduction in contact at or just below the bottom of the transition (i.e. taper).

The BET measurements taken for Unit 1 support the statements in the WCAP. The BET measurement was taken for each active tube using bobbin profilometry to indicate the exact point of "constant diameter" or the point of full engagement. The results, as presented in the Figures 3-2 and 3-3, indicate that a WEXTEX-type taper region is not present. Procedurally, during U1R10 APS elected to ensure that any tube with a BET greater than 0.25 inches below the tubesheet secondary face contained an inspection extent of greater than 7.25 inches. This verification was accomplished by comparing the BET measurement with the BOD (Bottom of Data) measurement. Table 3-1 provides the statistics for U1R10.

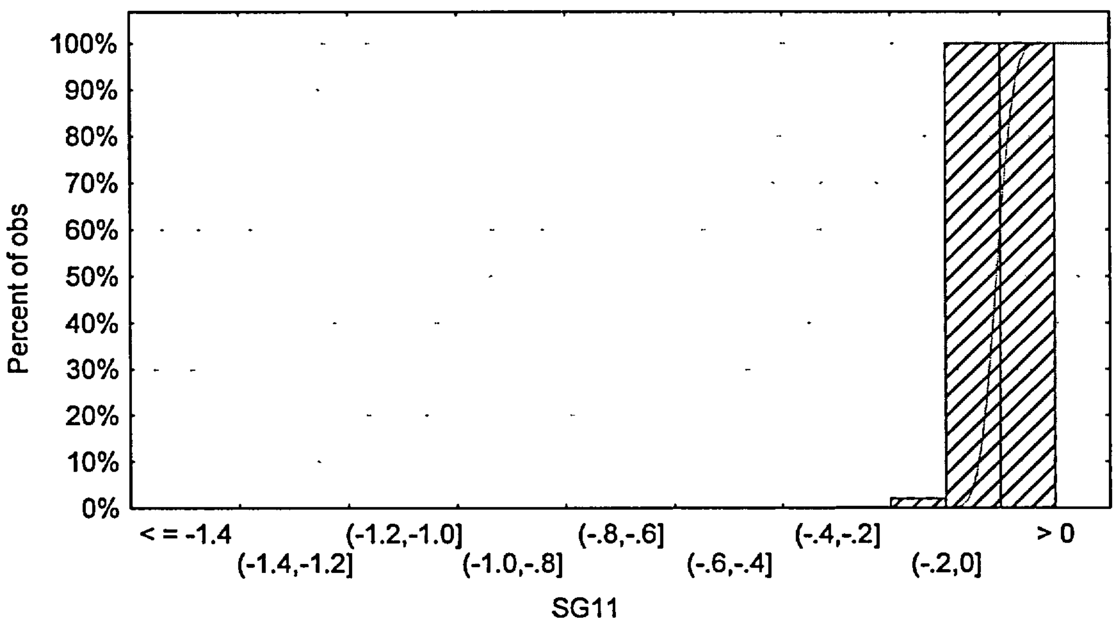
Table 3-1 Unit 1 BET Statistics

	SG 11	SG 12
Mean BET	-0.0067"	-0.0252"
Standard Deviation	0.0252"	0.0844"
# Greater than - 0.25"	9	406
# Greater than - 0.7"	0	15
Largest BET	- 0.53"	-1.31"

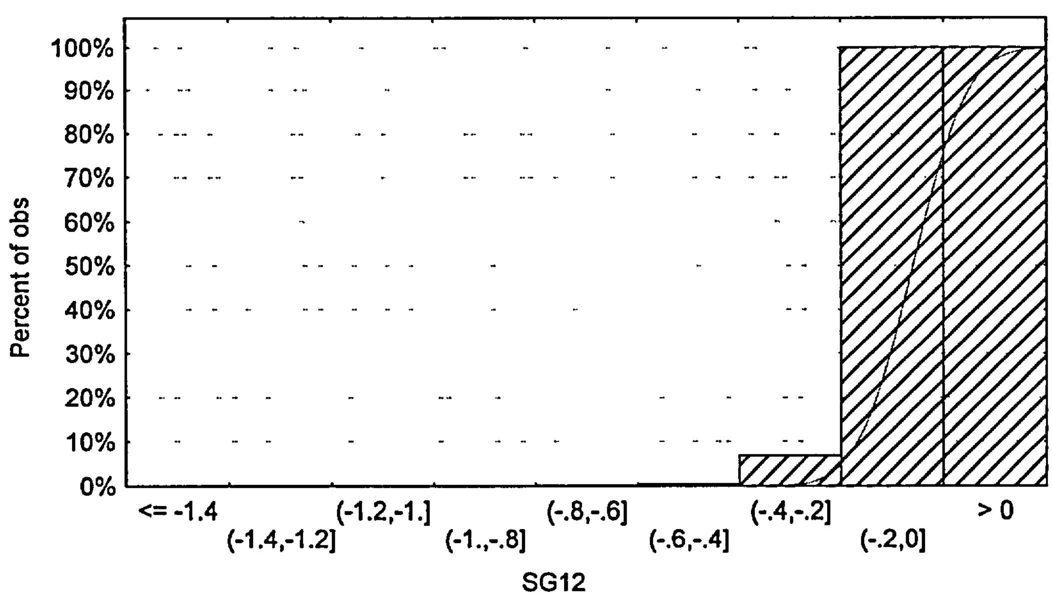
Although, there is sufficient margin in the seven-inch inspection extent, to account for even the largest underexpansion found in Unit 1, the Technical Specification wording has been revised to state that the inspection extent for PVNGS Unit 1 shall be seven (7) inches from the bottom of the expansion transition. This ensures that there is a least seven (7) inches of tubing free from detected service-induced degradation is in full contact with the tubesheet resisting both pullout and leakage.

Figures 3-2 and 3-3

Bottom of Expansion Transition (BET) SG11
Mean = -0.0067, Standard Deviation =0.0252



Bottom of Expansion Transition (BET) SG12
Mean = -0.059, Standard Deviation = 0.0844



NRC Question 4

The Supplemental Report to WCAP-15947-P describes a noise evaluation that was performed to confirm that Unit 1 bore roughness was consistent with a rough bore characterization. The report concludes that the Unit 1 joints are comparable to the Boston Edison joints. Please clarify what factors or conditions were determined to be comparable.

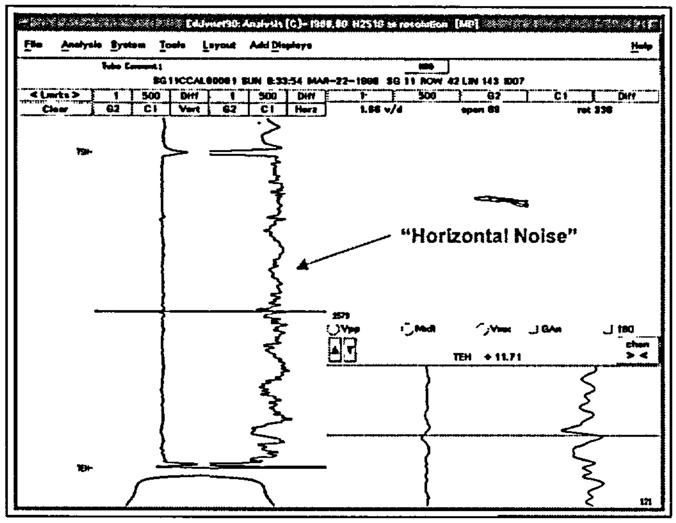
APS Response

The noise evaluation performed by APS was conducted as a point of reference. As indicated in Section 1.2 of WCAP 15947-P, a gun drill process was used for drilling the PVNGS Unit 1 steam generator tubesheets. In the original CEOG study, it was reported that Combustion Engineering changed their drilling process during fabrication of the PVNGS Unit 2 steam generators. The new process referred to as a Bore Trepanning Process (BTA) was adopted to increase productivity. The process had a consequential effect of producing smoother bore surfaces. For this reason, steam generators were either classified as rough bore or smooth bore in the CEOG study. Although CE was knowledgeable regarding the time frame the switch was made to BTA, fabrication records did not explicitly call out whether the tubesheet holes were gun drilled or drilled using BTA. However, time line records showed that both Unit 1 steam generators and the Boston Edison steam generators were fabricated prior to the change to BTA.

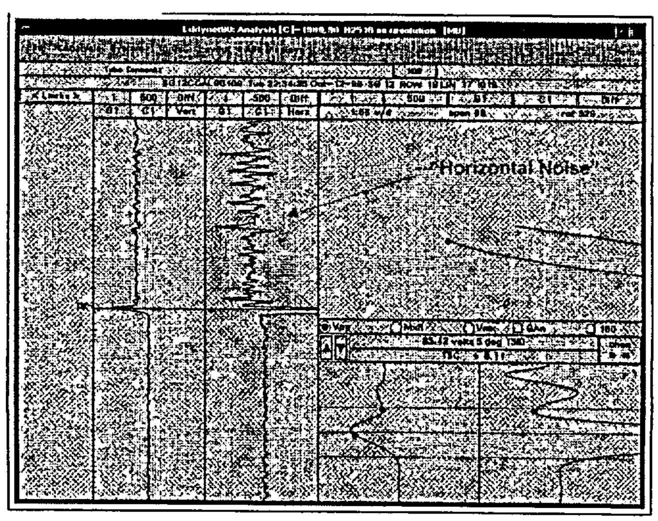
In evaluating all six PVNGS steam generators, APS found that a distinct difference in the ECT horizontal noise signature between Unit 1 and Units 2/3. The results appear to confirm CE fabrication records indicating a change to the BTA process sometime during fabrication of the Unit 2 steam generators. APS requested similar ECT measurements of the BE steam generator and a visual comparison of the graphics indicates a similarity in horizontal noise. The BE raw data was not subjected to the same newly developed noise software, and therefore this data was not quantitatively addressed in the APS noise study. However, example graphics of a BE tube, Unit 1 tubes (including a mean level noise) and a smooth bore mock-up are provided below. These graphics are all measured at the same span for comparative purposes.

Based on this evaluation and CE records, APS concluded that the fabrication process used in the Boston Edison (BE) steam generators was the same as PVNGS Unit 1. As such, the results could be used without adjustment.

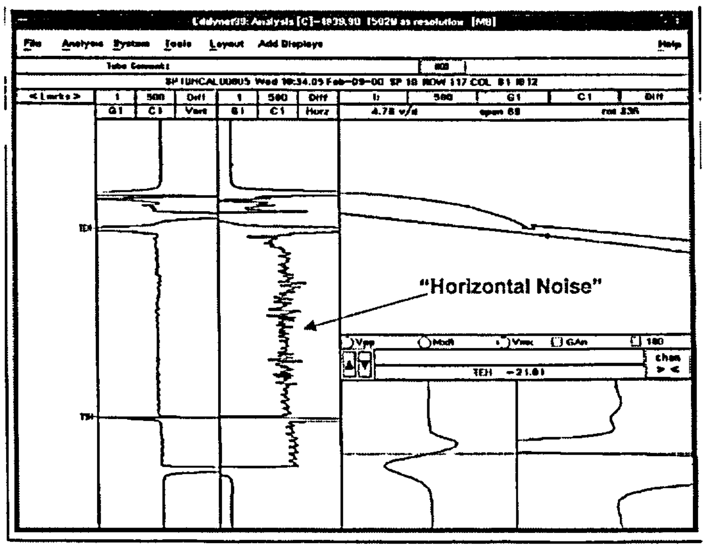
Unit 1 Tube (Noise ~ to Unit 1 Mean)



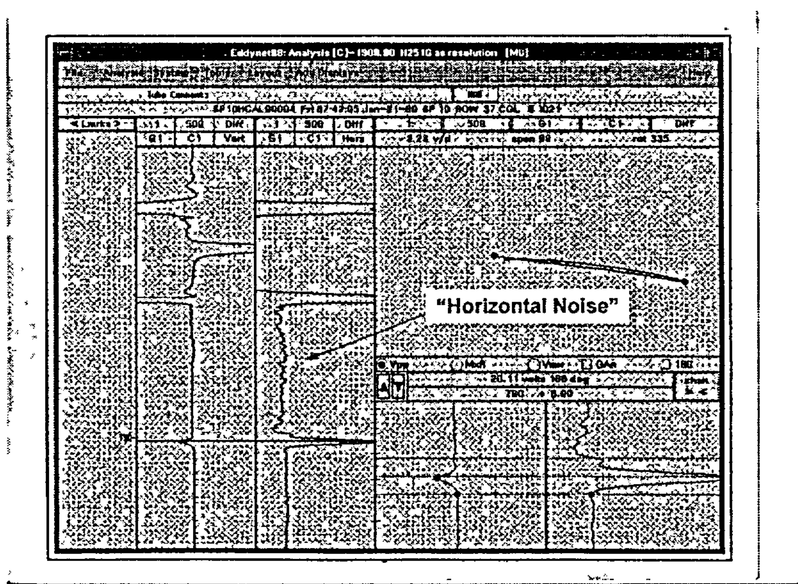
Unit 1 tube - example



Boston Edison Steam Generator



Smooth Bore Mockup



NRC Question 5

How was variability in tubesheet hole roughness accounted for in the analysis?

APS Response

As indicated in WCAP 15947-P and the PVNGS Supplemental Report, the design and fabrication of the Boston Edison steam generator is considered to be closely representative of the PVNGS Unit 1 steam generators. Furthermore, it is APS position that the Boston Edison test bed has a sufficient cross section of tubesheet holes, joint fabrication and tubing materials to account for variances in the Unit 1 as-built condition. The basis for this position is as follows.

The Boston Edison (Pilgrim) steam generator was fabricated for the Boston Edison NSSS contract that was subsequently canceled. The steam generator is of System 80 design. The tube material is typical of production material installed in the PVNGS Unit 1 steam generators. The Boston Edison tube material, provided by Noranda, is 0.042 inch average wall thickness and should have the normal variations in tube wall thickness and yield strengths that would be expected in PVNGS Unit 1. A review conducted by APS of PVNGS certified material test reports (CMTRs) indicates that some tubing manufactured for the Boston Edison contract was, in fact, installed at PVNGS.

The explosive expansion process was performed using the same procedures and control processes. The CE fabrication procedures provide detailed instructions for procurement of the charge components (polyethylene sheath and detonating fuse); assembly; installation in tubesheet holes including specific reference to number of tubes per shot by row number; cleanliness requirements; pre and post explansion inspection requirements with sign-off responsibilities; identification and flagging of unexplanded tubes, all indicating a thorough controlled process.

WCAP 15947-P provides photographs illustrating the location of the Boston Edison test bed. The data from the test bed is considered to be representative of the spread of hole roughness data expected to be present in the PVNGS Unit 1 steam generators based on a review of the tubesheet drilling process. By procedure, the tubesheet was drilled by row, and the drill bits in the production process were changed at least every 25 holes. Although the test bed is in one general location, the data was taken in different rows, each of which included more than 25 holes (~ 60 per row), thereby incorporating the process variability in hole surface finish for a typical vintage steam generator. Therefore, APS considers the adjacent rows and columns of the Boston Edison test bed to represent a collective fabrication of hundreds of tubes (~900) and by consequence represents a significant range of process variability for the drilling process and resulting bore surface finish.

NRC Question 6

Section 7.3 of the WCAP indicates that the NDE probe axial position uncertainty during inspections can be addressed on a plant-specific basis. Describe the NDE uncertainty you experience at PV with regards to probe axial position, the basis for this value, and how this is accounted for in the proposed inspection distance.

APS Response

Several sources of information were reviewed to establish a basis for NDE axial position uncertainty. These included information contained within WCAP 14797, *Revision 1, Generic W* Tube Plugging Criteria for 51 Series Steam Generator Tubesheet Region WEXTEX Expansions, February 1997*, EPRI ETSS data for axial crack length uncertainty, discussions with EPRI NDE Center personnel, and test data taken at PVNGS.

With respect to W*, the NDE uncertainty information was used as a point of reference, as probe qualification changes have occurred since the issuance of WCAP 14797 and the W* objective of allowing detected axial flaws to remain in service is beyond the PVNGS technical specification request of allowable inspection extent. However, the axial position uncertainties with respect to the BWT and the TTS, and the inspection extent uncertainty are expected to be good approximations. For W*, the bobbin coil position uncertainty for the BWT to TTS is 0.08 inches. The Plus Point uncertainty for the W* extent is given as 0.12 inches.

A similar point of reference for axial position uncertainty can be specified from EPRI ETSS 21511.1 for axial PWSCC. This uncertainty is the difference in actual axial length and measured NDE length for the axial flaw dataset. In the ETSS record for length uncertainty, the 90/50 value is given at 0.19 inches.

Finally, PVNGS evaluated in situ Unit 1 ECT data for support plate thickness in comparison to actual support thickness measurements in an effort to trend axial position uncertainty. The results are presented in Table 6-1. The mean error is 0.078 inches with the upper 95% at 0.138 inches.

Based on this review, PVNGS has assumed a combined NDE uncertainty (BET/TTS and BOD/TTS) of 0.25 inches. This measurement uncertainty is within the allowable uncertainty described in the amendment request. Therefore, the inspection extent does not need to be further revised to account for this uncertainty.

Table 6-1 PVNGS NDE (Plus Point) Measurements (inches)

Support	Actual	Measured	Error
08H	2	1.82	0.18
01H	1	1.05	-0.05
01H	1	0.96	0.04
04H	2	2.04	-0.04
03H	2	1.97	0 03
02H	2	1.8	0.2
01H	1	0.72	0.28
01H	1	1.02	-0.02
02H	2	1.99	0.01
03H	2	1.89	0.11
04H	2	1.89	0.11
01H	1	0.95	0.05
02H	2	1.88	0.12

NRC Question 7

Figure 2 in the Supplemental Report to WCAP-15947-P depicts the number of circumferential cracks detected in the tubesheet at Palo Verde Units 1, 2 and 3. Clarify whether these numbers are the sum of all circumferential cracks detected in the tubesheet over the life of the plant or whether the numbers are limited to circumferential cracks detected during particular refueling outages. If it is the latter, identify which refueling outages.

APS Response

The numbers of circumferential cracks identified in Figure 2 of the PVNGS Supplemental Report are cumulative to date for each steam generator. Table 7-1 provides a more detailed breakdown by refueling outage. The table includes outage, mean inspection extent (BOD), the number of tubes with recordable circumferential cracks from TTS to –7 inches and tubes with circumferential flaws at depth greater than seven inches only, and finally, the total number of circumferential flaws is provided to account for tubes with multiple sites. The listing does not include cracks found above the BET, as these are considered expansion transition defects and represent a different defect mechanism. The results from the recently completed U1R10 steam generator inspection are also included in the table. These results indicate that this defect mechanism is not significant in Units 1 and 3. The steam generators in Unit 2 will be replaced in 2003. Additionally, a higher quantity of PWSCC defects is expected in Unit 2 based on operation at a higher Thot (614° F vs. 611° F).

Table 7-1 PVNGS Circumferential Flaw Summary

	Mean BOD		Tubes with Circ <7		Tubes with Circ >7 only		Total <7		Total >7	
Outage	SG 1	SG 2	SG 1	SG 2	SG 1	SG 2	SG 1	SG 2	SG 1	SG 2
U1R7	NA	NA	0	0	0	0	0	0	0	0
U1R8	-3.57	-3.61	0	0	0	0	0	0	0	0
U1R9	-6.85	-7.1	0	2	1	1	0	3	1	3
U1R10	-8.89	-8.61	9	0	3	3	11	0	7	6
U2R7	NA	NA	0	6	0	0	0	7	0	0
U2R8	-3.51	-3.54	0	9	0	1	0	17	0	1
U2R9	-6.56	-7.08	1	66	0	0	1	104	0	32
U2R10	-6.73	-6.96	0	40	2	4	0	61	4	20
U3R6	NA	NA	0	2	0	0	0	2	0	0
U3R7	NA	NA	0	1	0	1	0	1	0	1
U3R8	-6.84	-6.83	0	4	0	0	0	8	0	1
U3R9	-6.81	-6.5	0	2	0	0	0	3	0	1

NRC Question 8

Figure 3 in the Supplemental Report to WCAP-15947-P indicates that because a portion of every steam generator tube within the tubesheet has not been inspected with a rotating probe, there is a 50% (mean) probability that there are less than 104 undetected circumferential cracks present in the tubesheet of steam generator 22. Figure 2 indicates that for the portion of the tubes within the tubesheet of steam generator 22 that have been inspected with a rotating probe, approximately 150 circumferential cracks have been detected. Given that the length of tube that has not been inspected with a rotating probe is equal to or greater than the length of tube inspected with a rotating probe, it does not seem logical that the predictive model would conclude that fewer undetected flaws are present than those detected. Please discuss.

APS Response

As indicated in the Supplemental Report to WCAP-15947-P, Figure 3 provides an estimate of the undetected circumferential cracks within the tubesheet. The intent of including this information was to provide a point of reference for the limiting PVNGS steam generator as to the number and severity of undetected circumferential cracks as a result of the PVNGS steam generator design and inspection program. The operational assessment model used in this evaluation contained significantly more detail than was provided in the Supplemental Report. Some additional information is provided below, however the more simplified and conservative life estimate provided in APS response to *NRC Question 9*, is considered more appropriate for Unit 1 with respect to an end of licensed life prediction.

The Unit 2 estimate, illustrated in Figure 3 of the Supplemental Report, includes both the inspected and uninspected regions of the tubesheet. As also indicated, the projection was an operational assessment result. As such, it was specific to the fuel cycle analyzed. The projections made in Figure 3 were for Cycle 9 and were based on the results of the inspections made in U2R8. During the U2R8 inspection, 18 flaws (10 tubes) were found in SG 22. The mean inspection extent for SG 22 in U2R8 was 3.54 inches below the secondary face of the tubesheet. As indicated in Figure 3, the mean predicted number of flaws for EOC 9 was 104. During U2R9, the inspection extent nearly doubled and the number of detected flaws was 136 (66 tubes) of which 17 were found within the region inspected previously. The U2R9 inspection provided some additional insights. These included:

- The presence of tubes with multiple crack sites, many of which were found during confirmatory inspections of the original call that included extra inspection extent, indicates a large difference in tube susceptibility with respect to circumferential degradation within the tubesheet. This observation appears to demonstrate that the inspection eliminates many of the flaws below the inspection extent by removing highly susceptible tubes from service. This is consistent with the postulated root cause. It is believed that the circumferential PWSCC within the tubesheet results from local stress risers that are an artifact of drilling and expansion anomalies.
- The flaws are short (circumferential extent) in nature with no real indication

of growth in the circumferential direction. This indicates a low propensity for leakage. This conclusion is based on historical reviews of precursor signals indicating little or no growth in the circumferential direction. Additionally, the largest flaws to date in the Plus Point inspected region are those shown in Table 1 of the PVNGS Supplemental Report. These are flaws selected for in situ pressure testing based on meeting freespan leakage screening criteria. As indicated, the flaws range from a PDA (percent degraded area) of 8 to 24 percent. The largest flaw in tube R28C121, with a PDA of 23.28% had a circumferential extent of 93 degrees. As also indicated, none of these flaws exhibited leakage during the in situ tests.

- The need to predict the number of new flaws that would incubate between inspections is required for good benchmarking. The Cycle 9 model did not include such an adjustment. This was included in the Cycle 10 prediction.

The operational assessment model for Unit 2 Cycle 10 predicted that 142 flaws remained in service. If the model was performing as expected about 60% (84) of these flaws would be detected in the U2R10 inspection. This is based on a weighting factor linked to tube susceptibility and the variability of inspection extents. That is, although approximately one third of the tubesheet region is inspected, there is an increased probability that a highly susceptible tube will be removed from service by the required inspection extent. A total of 81 flaws (44 tubes) were detected in SG 22 during U2R10 providing a good fit to the model projections.

As indicated previously, this modeling approach was used for operational assessment purposes and not for life predictions of flaw initiation and growth. The model indicates a somewhat stable "saw-tooth" effect that limits the population of undetected defects in the 100-200 flaw range over the life of the steam generator. However, this condition has not been validated by full length inspections and therefore the model discussed in APS response to *NRC Question 9* is considered more conservative for Unit 1 for an end of licensed life prediction.

<u>NRC Question 9</u>

In the Supplemental Report to WCAP-15947-P, the licensee concludes that the projected number of undetected flaws in the region of the tube inspected only with the bobbin coil, at 95% probability, is significantly less than the 1100 tube assumption used in the CEOG report. Given that the licensee's projection is a current projection, and the license amendment is requested as a permanent amendment, what assurances are there that the 1100 tube assumption used in the CEOG report will remain conservative as the SG tubing in the lower region of the tubesheet continues to degrade? Why shouldn't all tubes be assumed to have the potential to leak?

The staff recommends you consider performing an analysis that predicts the number of undetected circumferential flaws that will be present when the Palo Verde Unit 1 license expires. This analysis should be benchmarked based on the current inspection results, as well as at every refueling outage, by comparing the total number of circumferential cracks detected against the predicted number of undetected circumferential cracks at the mean value (i.e., 50% probability of undetected circumferential cracks). Every outage, the results of this analysis should be compared against the 1100 tube assumption used in the CEOG report to ensure that 1100 tubes is still a conservative assumption. If the 1100 tube assumption is found to be non-conservative, the associated leakage predictions shall be assessed and modified, if necessary. Please state your plans in this regard and provide a commitment to be tracked in your commitment tracking system.

APS Response

APS performed an evaluation based on the Unit 1 inspections to date, in an effort to perform a long term assessment of circumferential cracks in the region of tubing only inspected with the bobbin coil. As opposed to the assumptions made in the model described in APS response to *NRC Question 8*, APS makes the following assumptions for a Unit 1 model.

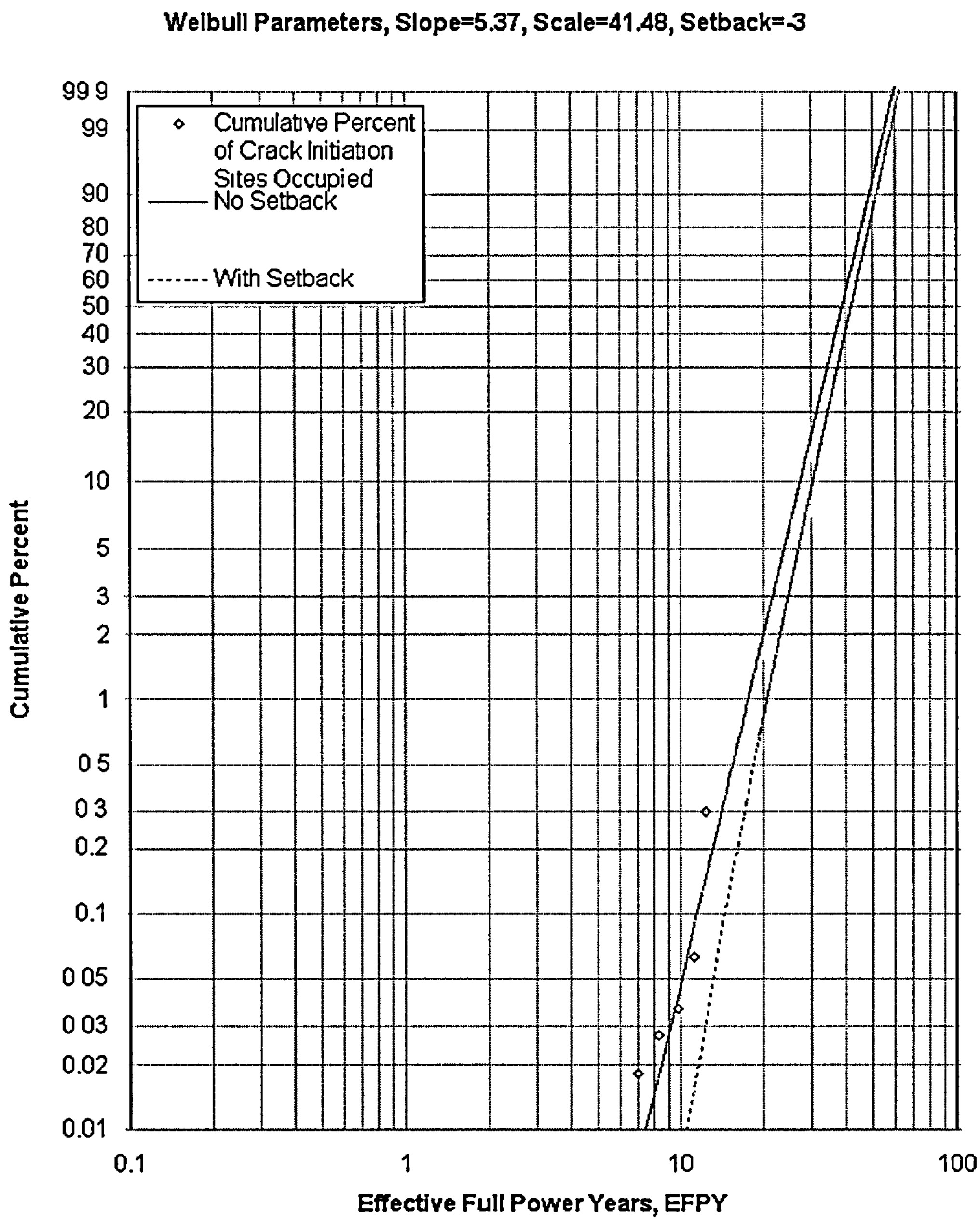
- The completed inspection extents were assumed to be the mean BOD results for the Unit 1 inspections as shown in Table 7-1.
- The inspection extents are treated as a percentage of the entire tubesheet extent.
- The number of flaws in the bobbin-only inspected region is determined by multiplying the detected flaws by the ratio of bobbin-only region inspected to Plus Point inspected regions.
- For inspections where no flaws were detected, one (1) flaw was assumed for bobbin-only inspected region. This was done for conservatism and to anchor the Weibul projection.
- A setback value of 3 EFPY was used. As most detected flaws are not 360°, 100% throughwall flaws, it is conservatively estimated that a detectable circumferential flaw could grow to that level in 3 EFPY.
- The estimated number of flaws was plotted using a Weibul function. Use of the Weibul function is an industry recognized approach to projecting defect propagation in Alloy 600 tubing (Reference EPRI Report TR-104030, PWSCC Prediction Guidelines, July 1994).
- The flaws would all be assumed to reside at just below the proposed inspection extent. Whereas, in reality the flaws would be dispersed throughout the non-Plus Point inspected region, with leakage expected to be less (or zero) for flaws deep within the tubesheet.

The analysis (Figure 9-1) indicates that the number of predicted tubes will be below the 1100 tube assumption until 31 EFPY. Based on the current licensed life[1], the expected end of life EFPY is 30-32 EFPY based on the current EFPY (12.4) with an 80-90% capacity factor. It should be noted that the expected capacity factor for Unit 1 should the existing steam generators last until end of life should be less than this assumption, based on plugging projections and maintenance issues associated with Alloy 600 MA steam generator tubing.

1 On August 28, 2002, APS submitted a request to extend the expiration date of the Unit 1 operating license from December 31, 2024 to June 1, 2025 in order to recapture low power testing time. For conservatism the APS response to NRC Question 9 assumes the latter date, as not to impact NRC Staff review of the extension request.

As such, the 1100 tube assumption in WCAP 15947-P is considered reasonable for an end of life prediction for Unit 1.

Figure 9-1



Since the projected flaw rate is expected to remain within the leakage assumptions in WCAP 15947-P, APS does not believe that separate tracking in the PVNGS commitment tracking system is required. PVNGS does perform condition monitoring and operational assessment for each operating cycle per PVNGS procedure 81DP-9RC01 and a commitment to NEI 97-06 (see APS response to *NRC Question 10*). In the PVNGS procedure, requirements for additional assessment are delineated if condition monitoring results exceed the operational assessment predictions.

NRC Question 10

The documents submitted in support of the technical specification amendment reference various assumed accident leakage values. Clarify the accident leakage value you intend to assume in operational assessments.

APS Response

The PVNGS Updated Final Safety Analysis Report (UFSAR) assumes a one (1) gpm primary-to-secondary accident leakage rate for the faulted steam generator during a Main Steam Line Break Event. However, for operational assessments (OA), PVNGS assumes a lower allowable of 0.5 gpm per steam generator. This is the value reported in WCAP 15947-P. Therefore, from an operational assessment standpoint, the 0.1 gpm assumption in the WCAP represents 20% of the OA allowable versus 10% of the design basis limit.

However, based on the discussions provided in APS response to *NRC Questions 2, 8, 9, 11,14, and 19* with respect to joint leakage, flaw distribution, and operational assessment, it is believed that it is more appropriate to assess predicted accident leakage as part of APS's existing commitment to perform condition monitoring and operational assessment per NEI 97-06, rather than introduce validation requirements for the 1100 tube assumption given in WCAP 15947-P. The 10% or 1100 tube assumption was originally established as a CEOG program objective target and not necessarily intended to be an accident analysis assumption. Additionally, as indicated in Section 8.2 of the WCAP and APS response *to NRC Question 19*, a three (3) inch joint limits the leakage to below the accident limit if all active tubes are assumed to be leaking (as indicated in APS Response to *NRC Question 9*, a highly improbable condition). Therefore, based on the CEOG program results, APS intends to conduct operational assessments as follows.

Per APS response to Generic Letter 97-05 (letter 102-04094 – JML/SAB/RMW dated March 13, 1998), APS complies with the requirements of NEI 97-06 as tracked by the PVNGS commitment tracking program. Per the APS program, Condition Monitoring and Operational Assessments are performed on a cycle by cycle basis in accordance with the guidance in the EPRI *Steam Generator Integrity Assessment Guideline* (SGIAG). As indicated in APS response to *NRC Question 8*, the quantity and severity of degradation within the tubesheet region can be predicted by the evaluation of the inspection extent, POD and inspection results. Using a multi-cycle approach, the results can be continually benchmarked, during both the condition monitoring and operational assessment process. Since the requirement to conduct these assessments is in place, no additional commitments are necessary with respect to determining accident leakage. The only change to the analysis process will be to calculate leakage based on the CEOG program results rather than as freespan leakage as described in APS response to *NRC Question 8* and the PVNGS Supplemental Report.

As accident leakage is assessed at 95/95 in the APS Operational Assessment Model, APS will assume the 95% upper bound leakage value based on the approach described in APS response to *NRC Question 19* for the predicted number of undetected circumferential flaws. As required by NEI 97-06, the total predicted SG leakage for all mechanisms shall be assessed against the design basis accident leakage limit.

If the limit is exceeded, potential actions to be taken could include reduced operating cycles or removing additional tubes from service. Furthermore, condition monitoring requirements include the benchmarking of inspection results to the past cycle's operational assessment to ensure no significant changes to initiation or growth rate have occurred. As a point of reference, the predicted accident leakage for Unit 1 based on the Cycle 10 operational assessment was less than 0.01 gpm at 95/95 for all mechanisms exclusive of flaws below the proposed inspection extent. Based on a predicted number of flaws in the limiting Unit 1 SG (SG 11 – 35 flaws), the contribution to leakage from flaws predicted in the non-burst, non-pullout region is estimated to be 0.0016 gpm.

Several additional program elements are committed to by APS, which provided further conservatism. Per APS response to Generic Letter 97-05, all detected corrosion related degradation is removed from service upon detection. For tubesheet inspections this includes degradation detected within the proposed inspection extent or outside. No detected corrosion related degradation is left in service. Additionally, notification to the NRC is required per NEI 97-06 if it is determined that a steam generator tube failed to meet a performance criterion discovered by condition monitoring. Finally, it should be noted that APS employs a primary-to-secondary leakage monitoring program that is more conservative than the EPRI *Primary-to-Secondary Leakage Guidelines*. The administrative shutdown limit (in place since 1994) is 50 gallons per day (gpd) with action levels as low as 10 gpd. Since flaws in below the proposed inspection criteria are not at risk for burst and will not result in a sudden "pop-through", should any joint(s) develop leaking flaws in excess of the anticipated values, an orderly plant shutdown would occur.

NRC Question 11

The Supplemental Report to WCAP-15947-P provides additional information applicable to leakage assumptions. Figure 12 provides information on joint leakage, and the associated text indicates that for the bounding leak rate value, the predicted leakage is 0.03 gpm for the limiting steam generator. Discuss the source of the data points in Figure 12 and explain whether a bounding data set was used (given all the Boston Edison and single tube mockup data). Describe how the data from Figure 12 is utilized to calculate the 0.03 gpm predicted leakage (i.e., what data point/leakage value and how many cracks are assumed). Is the 0.03 gpm predicted leakage calculated using the 1100 tube CEOG assumption? If not, what is the predicted leakage assuming the 1100 tube CEOG assumption?

APS Response

The source of the data points for Figure 12 of the PVNGS Supplemental Report is discussed in the response to *NRC Question 19*. As discussed in APS response to *NRC Question 8*, APS used the results of a Unit 2 operational assessment model to provide a point of reference for the limiting PVNGS steam generator. In APS response to *NRC Question 19*, there is reference to a 2 inch specimen data point from the CEOG program planning test mockup. The leakage from this specimen was measured at 1.76e-4 gpm. Figure 12 of the

Supplemental Report also included the 3 and 4 inch data points from the scoping mockup (1.83 e-4 gpm and 2.4 e-6 gpm respectively).

With respect to WCAP 15947-P and the leakage values used in support of the required engagement length for leakage, the CEOG program planning test mockup is not considered applicable to PVNGS Unit 1. The mockup was fabricated as a demonstration piece for a potential replacement steam generator project for a foreign utility in 1985. The mockup tubesheet holes were bored on a lathe with a surface finish considered much smoother than a gun drilled tubesheet. The tubing material was different (Alloy 690) as was the tube wall thickness (0.043 inch). Additionally, quality documentation had not been archived for either the mockup materials or fabrication processes.

Although the mockup was not considered applicable to PVNGS Unit 1, it was used in the PVNGS Supplemental Report as an upper bound leakage value applied to the predicted number of flaws for the limiting steam generator. The Figure 11 leakage value bounding the scoping mockup and the average leak rates for the BE steam generator was determined to be 2.1e-4 gpm. This was multiplied by the Figure 3 upper bound defect prediction of 130 flaws yielding 0.027 gpm.

Despite the fact that the Unit 2 operational assessment model benchmarked well (see APS response to *NRC Question 8)*, APS considers the data and analysis provided in APS responses to *NRC Questions 2, 10 and 19* to be the more representative information with respect to the treatment of leakage from the tubesheet region below the proposed inspection extent.

NRC Question 12

Section 3.3.2.3 of WCAP-15947-P states that not all tests in the plan were completed for various reasons as explained in the sections describing the test results. These reasons do not appear in the test results section and several discrepancies regarding the Boston Edison leak tests were identified as follows: Table 3-2 of the WCAP indicates that 14 tubes from the Boston Edison (BE) mockup will be leak tested. The text in Section 5.1 states that leak tests were conducted on 12 tubes from the BE mockup. Figure 5.1 appears to contain fewer than 12 data points related to BE leak rate data. The table in Appendix B contains BE leak test data, but contains even fewer data points than Figure 5.1. In addition, the text in Section 5.1 documents a maximum leak rate for the BE mockup, which does not appear in Figure 5.1. Please explain these apparent discrepancies.

APS Response

APS has reviewed all the available test program data and the WCAP 15947-P discrepancies identified by the NRC Staff. The following information is intended to provide clarifying information.

The data for the Boston Edison samples and Specimens 20 and 21 have been assembled in the following table (Table 12-1). The information includes sample identification, target length, actual length, test plan, test results and a comment field related to WCAP 15947-P. As indicated, the original planned tests for two (2) inch BE samples were not performed. This explains the difference between 14 planned leak tests versus 12 performed. All 12 leakage tests are included in Figure 5.1 of WCAP 15947-P. As indicated from the APS

Table 12-1, with respect to Figure 5.1 of the WCAP, leakage values from BE tubes 125/83 and 111/83 are equivalent and as such overlap. Additionally, the average leak rates for tubes 109/83 and 113/83 are sufficiently close that data points appear as one point.

As stated in Section 3.1.2, the leakage test sequence for the CEOG program was repeated three (3) times for each specimen. The data provided in the Section 5 tables and Figures 5.1 and 5.2 are the average of the three tests. The text in Section 5.1 reports the range of all the tests conducted. Averaging the test results for each specimen was considered appropriate due to test results so close to the minimum detectable leak rate. However, all of the leakage data was plotted by APS in response to *NRC Question 19.*

Table 12-1 BE Steam Generator Summary Table

Row	Line	Nominal Joint Length (in.)	Actual Length (in)	Leak Test	Pull Test	Pull Out Force (lbf)	Ave Leak Rate (gal/min)	Comments (re WCAP 15947)
112	82	2	NA	NA	NA	NA	NA	No data/not used
114	82	2	NA	NA	NA	NA	NA	No data/not used
129	83	3		N	Y	[ ]	NA	Not in Table 4-1
131	83	3		Y	Y	[ ]	[ ]	
130	82	3		N	Y	[ ]	NA	Not in Table 4-1
128	82	3		Y	Y	[ ]	[ ]	
126	82	3		N	Y	[ ]	NA	Not in Table 4-1
124	82	3		N	Y	[ ]	NA	Not in Table 4-1
122	82	3		N	Y	[ ]	NA	Not in Table 4-1
107	81	3		N	Y	[ ]	NA	Not in Table 4-1
107	83	4	4 1/4	Y	Y	[ ]	[ ]	
115	83	4	4 1/16	Y	Y	[ ]	[ ]	
117	83	4	4 1/16	Y	Y	[ ]	[ ]	
119	83	4	4 1/16	Y	Y	[ ]	[ ]	
127	83	4		Y	Y	[ ]	[ ]	
108	82	4		N	Y	[ ]	NA	Not in Table 4-1
110	82	4		N	Y	[ ]	NA	Not in Table 4-1
123	83	5		Y	Y	[ ]	[ ]	Not in App B
125	83	5		Y	Y	[ ]	[ ]	Not in App B
109	83	5		Y	Y	[ ]	[ ]	Not in App B
111	83	5		Y	Y	[ ]	[ ]	Not in App B
113	83	5		Y	Y	[ ]	[ ]	Not in App B
Specimen 20		2	2 1/4	N	Y	[ ]	NA	
Specimen 21		3	3 1/8	N	Y	[ ]	NA	

NRC Question 13

Section 3.3.2.3 of WCAP-15947-P states that not all tests in the plan were completed for various reasons as explained in the sections describing the test results. These reasons do not appear in the test results section and several discrepancies related to the BE and single tube mockup pull tests were identified as follows: Table 3-2 indicates that 22 BE specimen will be tested for pullout. Table 4-1 only contains results from 12 pull tests and Appendix B contains results from 20 pull tests. Table 3-3 indicates that 21 single tube mockup specimen will be tested for pullout and Table 4-2 only contains results from 14 pull tests. Explain these apparent discrepancies.

APS Response

The data discrepancies for the BE steam generators were addressed in APS response to *NRC Question 12*. APS similarly reviewed the data set for the single tube mockups. The following table (Table 13-1) provides an update of the test matrix presented in Table 3-3 of WCAP 15947-P. Some of the changes include an update of Specimens 7 and 10 to indicate the decision to conduct elevated temperature leak tests (Note: Section 3.2.2 states four elevated temperature tests were performed, however only two tests were performed on rough bore samples). Additionally, Table 3-3 of the WCAP did not show that Specimen 19 was a spare.

Table 13-1 Rough Bore Sample Summary

Spec. No.	Tube Wall	Joint Length (in.)	Pressure	Temp.	Leak Test	Pull Test	Comment
1	0.048"						Explansion Test Sample
2	0.048"	2	MSLB	Ambient	N	Y	
3	0.048"	2	MSLB	Ambient	NA	NA	No data
4	0.048"	2.5	MSLB	Ambient	N	Y	
5	0.048"						Explansion Test Sample
6	0.048"	2.5	MSLB	Ambient	N	Y	
7	0.048"	3	MSLB	Ambient	Y	N	Used in NOT leak test
8	0.048"	3	MSLB	Ambient	Y	Y	
9	0.048"	3.5	MSLB	Ambient	Y	Y	
10	0.048"	3.5	MSLB	Ambient	Y	N	Used in NOT leak test
11	0.048"	4	MSLB	Ambient	Y	Y	

Spec. No.	Tube Wall	Joint Length (in.)	Pressure	Temp.	Leak Test	Pull Test	Comment
12	0.048"	4	MSLB	Ambient	Y	Y	
13	0.048"	2	Atm.	NOT	NA	NA	No Data
14	0.048"	2	Atm.	NOT	N	Y	
15	0.048"	3	Atm.	NOT	N	Y	
16	0.048"	3	Atm.	NOT	N	Y	
17	0.048"	4	Atm.	NOT	N	Y	
18	0.048"	4	Atm.	NOT	N	Y	
19	0.048"						Spare
20	0.042"	2	Atm.	Ambient	N	Y	
21	0.042"	3	Atm.	Ambient	N	Y	

<u>NRC Question 14</u>

Explain how the value in the last column of Tables 5-1 and 5-2 of WCAP-15947-P is calculated. It appears that the value in the 4th column should be multiplied by the 1100 tube CEOG assumption to calculate the 5th column. However, this calculation does not yield the values in the 5th column.

<u>APS Response</u>

PVNGS has confirmed that the values in the **"Leakage x 10% of tubes per SG, gpm"** column in Tables 5-1 and 5-2 were incorrectly calculated. The values listed are for a CE 3410 steam generator with 9350 tubes (similar to SONGS Units 2 and 3). APS has recalculated the result with the correct leakage values applicable to PVNGS Unit 1. Additionally, it was determined that the average leak rates for Specimens 7 and 10 did not include all of the MSLB test pressure data presented in Appendix C of WCAP 15947-P. As such, these values were further recalculated to include this information. Inclusion of all the test data results in a lower value for Specimen 10. A discussion of all the leak test data is provided in APS response to *NRC Question 19.*

With respect to Table 5-2, it should also be noted that APS identified an error in the **"Average Leak Rate (x 10^{-5} gpm)"** values in the table. APS went back to the original test results and recalculated the average leak rate for all the conducted tests. A separate table is provided by APS. The results in this table have been reviewed and should be used for Staff evaluation purposes. The corrected values do not change the conclusions of WCAP 15947-P non-conservatively. In fact, the results provided a better indication of the improved leak resistance as a result of thermal expansion. This result is expected and is consistent with the assumptions and conclusions made in the NRC approved W* ARC.

Table 14-1

Information correction for WCAP Table 5-1
Single Tube Mockups: Leak Test Data @ Room Temperature

Specimen Number	Joint Length Target (in.)	Average leak rate ($x\ 10^{-5}$ gpm)	Leakage x 10% of tubes per SG, gpm
7	3	1.114	0.0123
9	3.5	[ ]	0.0044
10	3.5	16.06	0.1767
8	3.5	[ ]	0.0482
11	4	[ ]	0.0221
12	4	[ ]	0.00575

Table 14-2

Information Correction for WCAP Table 5-1
Single Tube Mockup: Leak Test Data @ NOT

Specimen Number	Average Leak rate ($x\ 10^{-5}$ gpm)	Leakage x 10% of tubes per SG, gpm
7	0.5151	0.00575
10	0.5617	0.00618

NRC Question 15

Can the 4[th] and 5[th] columns of Tables 5-1 and 5-2 of WCAP-15947-P be directly compared? For example, were the leakage values in Table 5-1, originally tested at room temperature, adjusted for normal operating temperatures?

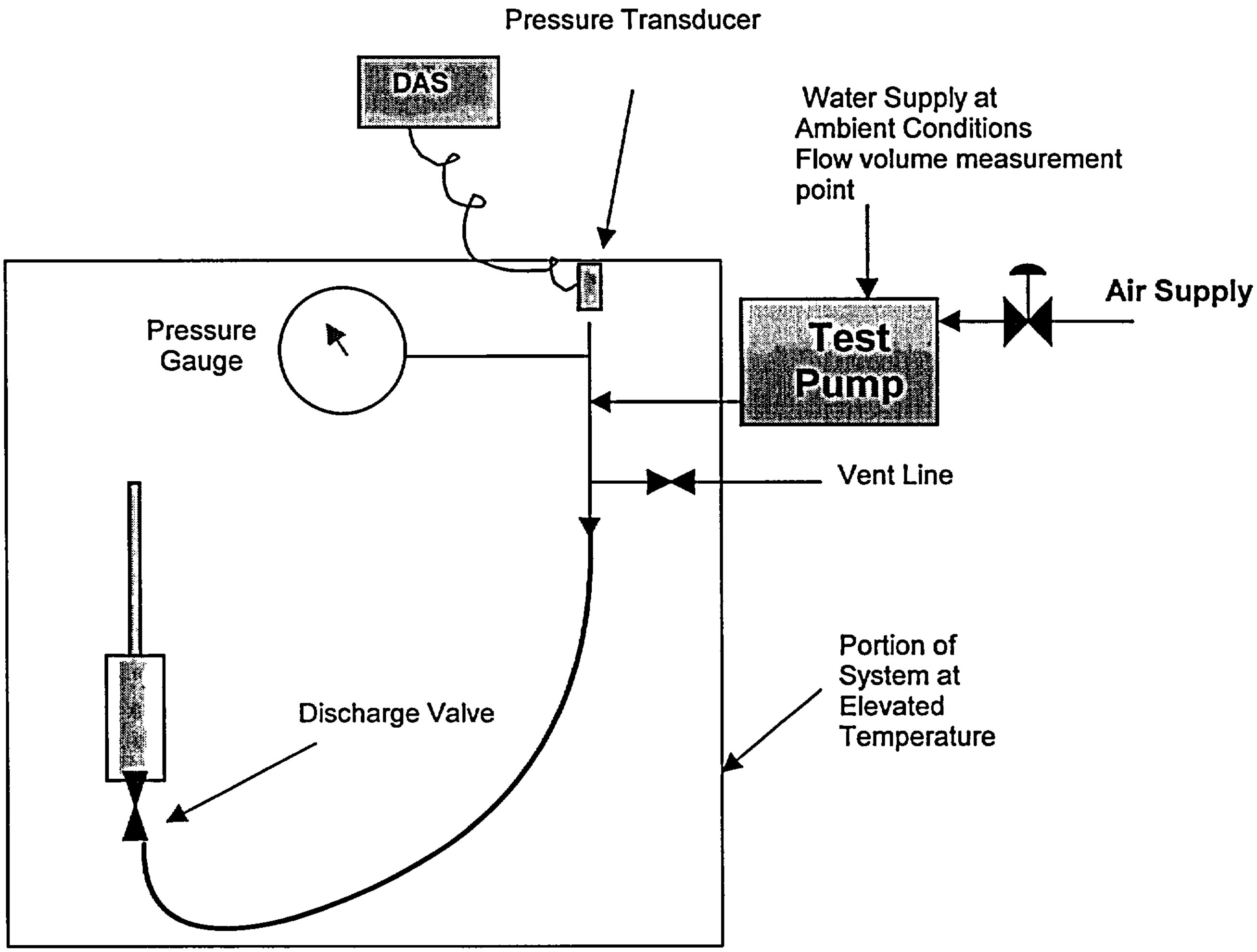
APS Response

The leakage values in Table 5-1 of WCAP 15947-P were not adjusted for temperature. As indicated in 3.1.2 of WCAP 15947-P, upon review of the *EPRI Steam Generator In Situ Pressure Test Guidelines* (TR-107620-R1), it was determined that the temperature adjustments listed in Appendix D of the EPRI Guideline were either not necessary or non-conservative. The EPRI guideline lists three (3) factors that can influence room temperature test results; 1) increased crack opening area due to material property differences with temperature: 2) ligament tearing, and 3) thermal hydraulic effects of leakage at accident conditions (phase change and flashing). The flaws in the CEOG program were 360 degree, 100% throughwall MDM cuts contained within the tubesheet. As such, crack opening area and ligament tearing are not issues and the adjustments called for in the EPRI Guideline do not apply. In WCAP 15947-P, Westinghouse indicated that due to choked flow at MSLB conditions, the room temperature leak rates (used in comparison with accident leakage allowables) were conservative.

APS confirmed this position by comparing calculated single phase room temperature leakage rates with two phase flow MSLB estimates using the calculation approach in the EPRI *Steam Generator Integrity Assessment Guidelines* (SGIAG) and an in-house computer code based on the EPRI PICEP model. For example, for PVNGS tubing (0.75" diameter, 0.042" wall thickness), a 180 degree freespan 100% throughwall circumferential flaw would be predicted to leak at 1.54 gpm at ambient conditions. Using the same modeling approach, at MSLB conditions the same flaw is predicted to leak at 0.92 gpm. As indicated in the EPRI SGIAG, both leak rates are room temperature predictions and the MSLB value requires adjustment. The adjustment per the SGIAG is a ratio of the specific volumes. Therefore, the accident condition leak rate is 1.28 gpm. As indicated the ambient value is greater. Therefore, the room temperature test results compared to accident allowables is conservative.

As to whether the results in Tables 5-1 and 5-2 can be directly compared, PVNGS reviewed the leak test procedures. As indicated in WCAP 15947-P, the leakage rate was measured in both the room temperature and elevated temperature tests by counting pump strokes of a small capacity positive displacement pump. The schematic in Figure 15-1 depicts the set-up for the high temperature test. Although flashing is assumed to have occurred in the high temperature tests, the leakage was measured at the pump suction in terms of make-up capacity at the ambient temperatures. To evaluate the effect of the differential thermal expansion and compare leak rates in terms of volume per unit time, the leak rates in Table 5-2 do not need adjustment.

Figure 15-1


Pressure Transducer
DAS
Water Supply at
Ambient Conditions
Flow volume measurement
point
Air Supply
Test
Pump
Pressure
Gauge
Vent Line
Portion of
System at
Elevated
Temperature
Discharge Valve

NRC Question 16

Section 1.2 of WCAP-15947-P indicates that CE explansion joints are of consistent high quality and radial force and that this was verified from the BE SG tube pull test. Please describe how the results of the BE SG tube pull test verified the consistency of the CE explansion joint.

APS Response

See APS responses to *NRC Questions 4 and 5* regarding fabrication and verification of BE and PVNGS Unit 1 joints. The statement made in the WCAP is based on the goodness of fit of the BE data compared to the single mockup data. Since the BE steam generator represents the as-built condition of the PVNGS Unit 1 steam generators, the statement is considered justified.

NRC Question 17

Section 1.7 of WCAP-15947-P indicates that there was no evidence that metal disintegration machining resulted in solidification of the tube to tubesheet interface. Discuss how this was verified.

APS Response

This conclusion in WCAP 15947-P was verified by several means. During the planning stages for the CEOG program, Combustion Engineering and utility participants (including APS) met to discuss sample preparation. Several cutting alternatives were considered. Metal Disintegration Machining (MDM) cutting was selected based on an expected least impact of the cut location impacting the results non-conservatively. The scoping tube/tubesheet mockup (referred to in APS response to *NRC Question 11*) was used to verify the cutting process. The tubes removed from the trial mockup were inspected to verify that solidification had not occurred. The tube ends were found to be smooth, without evidence of tearing which would be expected had solidification occurred. Instead, there was evidence of tube drawback due to MDM heatup and contraction, reducing the benefit of an end effect one would expect if an SCC circumferential defect were to pull apart or sever, thereby contributing to the conservatism of the results.

Additionally, Figures 4.2 through 4.4 of WCAP 15947-P provide photographs of samples from the single tube mockups. The photographs also reveal a relatively smooth surface. Any roughness appears to be along the line of axial scratches lengthwise for entire extent of the engagement area.

This visual evidence, as well as communication with Combustion Engineering personnel associated with the test program, provides high confidence that the solidification did not occur and that the use of MDM provided conservative results.

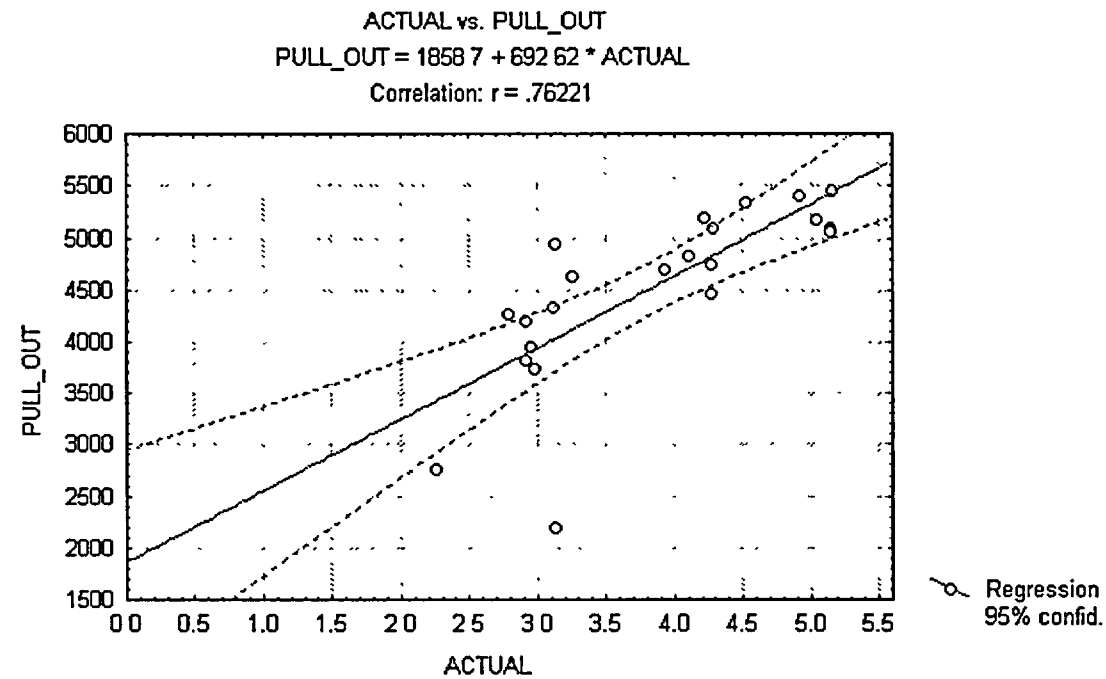
NRC Question 18

The tables in Sections 4.0 and 5.0 of WCAP-15947-P list Target Length and/or Actual Length. Explain what the Actual Length signifies. Why are actual lengths not provided for all data points? The Actual Length for Specimen number 21, which had an unexpectedly low pull out force, is not provided. Provide the Actual Length for this specimen, if possible, as it is the data point driving the 3.0 inch joint length depicted in Figure 11 of the Supplemental Report to WCAP-15947-P. It would be particularly in helping the staff understand whether the recorded pull out force for Specimen 21 is conservative or non-conservative.

APS Response

A review of the test records indicates that actual lengths are available for Specimens 20 and 21. These are provided in Table 12-1 of APS response to *NRC Question 12.* A few actual lengths of the BE steam generator samples were located and entered in Table 12-1 as well. Also, the third column in WCAP 15947-P, Appendix B, entitled ***Position (in) @ Force = 0*** is the distance the tube was pulled before the load cell reading decreased to essentially zero. This should be a number close to the actual joint length, limited by the accuracy of the MDM head positioning and the data acquisition rate. APS evaluated these results with for a comparison with Figure 2-1 of APS Response to *NRC Question 2.* The results (Figure 18-1) indicate little change in the regression fit. The correlation improves somewhat, and the results continue to support the conclusions of WCAP 15947-P and indicate that the minimum engagement length of three (3) inches conservatively bounds the 95% confidence fit. Although, the actual length of Specimen 21 failed to provide any additional insight as to why the pullout load deviated significantly from the other data, APS believes that the discussion provided in APS responses to *NRC Questions 4, 5, and 12*, provide substantial evidence that the CEOG test data from the BE steam generator is the most applicable to PVNGS Unit 1. However, APS elected to include the results from all testing, including Specimen 21 in specifying minimum engagement length

Figure 18-1



NRC Question 19

In Table 5-1 and Figure 5.1 of WCAP-15947-P the expected trend (increase in joint length results in a decrease in leak rate) does not appear to have occurred. Discuss the need for additional testing to explain the lack of a trend. Do you believe that the testing already completed has bound the largest potential leak rate?

APS Response

As indicated in WCAP 15947-P, leak rate is a function of differential pressure. Empirical data is necessary for understanding the leak rate as a function of joint length, but the Poiseuille equation provides an expression that approximates the fundamental relationship between the length of the tubesheet joint and leak rate:

$$dP = \frac{64}{R_e} \frac{L}{D} \frac{\rho v^2}{2 g_c}$$

Where:

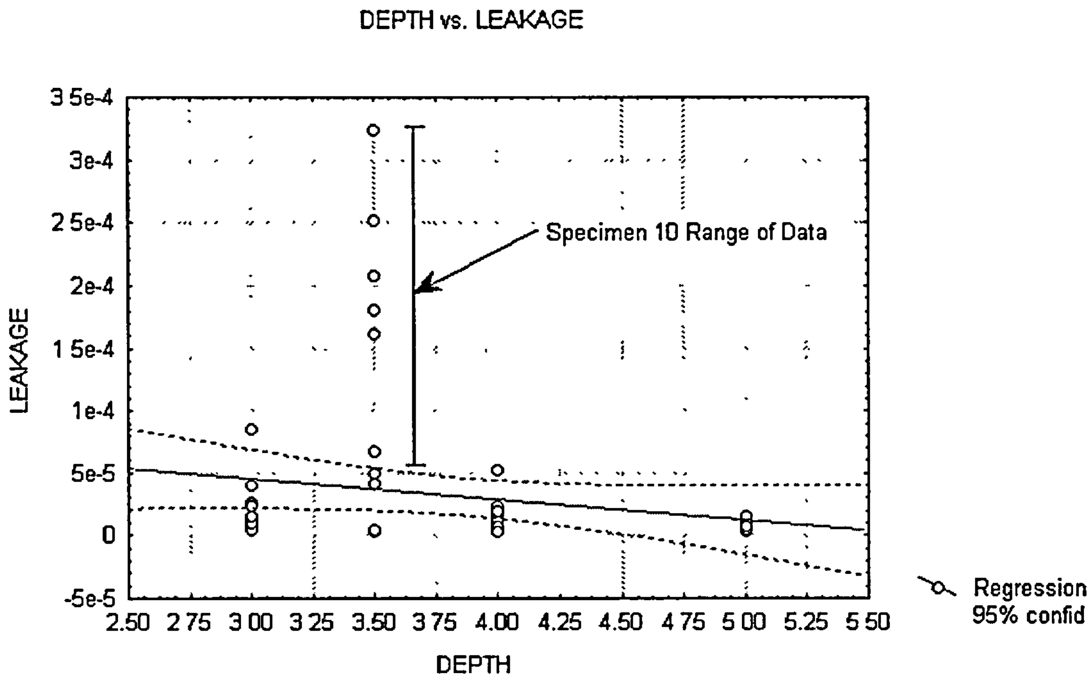
R_e = Reynolds number
D = in this case, the diameter difference between the tube and tubesheet
ρ = fluid density
g_c = gravitational constant
L = joint length
v = fluid velocity or flow rate
dP = differential pressure at MSLB

For the leak rate tests conducted in the CEOG project, all of the terms in the equation are essentially constant except the joint length and flow rate. Therefore, it can be stated that the flow rate varies inversely as the square root of the joint length. This relationship indicates that flow rate should reduce quickly over a very short joint length and then flatten out over longer joint lengths. As indicated in the WCAP, the set of tests performed by Westinghouse did not attempt to establish experimentally or analytically the knee of the curve or a usable formulation to cover all joint lengths. As reflected in Tables 12-1 and 13-1, a decision was made after early trials with the program scoping mockup (described in APS response to *NRC Question 13*) not to leak test 2" specimens. However, in Figure 12 of the PVNGS supplemental report, APS included 2, 3 and 4" data points from this pre-testing mockup in an attempt to show this relationship.

As indicated by the NRC Staff, Figure 5.1 of WCAP 15947-P does not indicate a leak rate vs. joint length trend. However, APS believes that several observations can be made through a review of all the leakage data. Figure 5.1 of the WCAP and Figure 12 of the PVNGS Supplemental Report plot the average leak rate for the three (3) tests performed on each specimen. Additionally, APS in Figure 19-1 included the results of all the BE steam generator leak tests, as well as all the leakage test data from the single tube mockups. Although the 0.048 inch single tube mockup data is not considered applicable without adjustment for pullout criteria, the differences in tube wall thickness should not impact the leakage results. Plotting all the test data provides little improvement for relationship of joint length vs. leakage for the range of joint lengths tested. However as opposed to Figure 5.1, the test results illustrate that the leakage trend is flat for three (3) inch joints or longer with most values near the minimum level of detection for the CEOG test program.

Figure 19-1 also provides strong evidence that the data from Specimen 10 is not consistent with the rest of the data from over 60 data points. Additionally, as indicated the data spread for Specimen 10 ranges from a low of 4.13e-5 gpm to a high of 3.24e-4 gpm. An explanation for this anomaly could not be identified, although it was noted that the lower values were observed during a later test date. The most likely explanation for the outlier behavior is a bore surface finish that is uncharacteristic of the rest of the BE and rough bore mock-up samples. However, pull test data was not available for Specimen 10. Based on the outlying, variable and inconsistent nature of Specimen 10 results, APS concludes that the evidence supports removal of the ambient temperature test data for Specimen 10 from consideration.

Figure 19-1



The data presented in Figure 19-1 indicates that the contact forces due to explansion and internal pressure provide a satisfactory leak limiting joint at a three (3) inch joint length. As shown, the data is fairly flat for the 3, 3.5, 4 and 5 inch test samples, and most of the results are near the minimum level of detection for the test program. Furthermore, the major variability in the results is believed to be due to the test procedure itself. The test flow rates as described in Section 3.1.2 of WCAP 15947-P relied on counting pump strokes of a small capacity positive displacement pump over a minimum 40 minute test period. If no pump strokes were observed, a single pump stroke was assumed in order to include a flow rate in the dataset. Additionally, pump strokes were evaluated over the entire test period with no consideration as to when the positive displacement pump stroked during the test period. With most of the test data based on 0-4 pump strokes, considerable variability is introduced for such low leak rates.

Based on these factors, APS believe the most appropriate prediction of leak rate is to simply assess the statistics for all the BE and single mockup test (excluding Specimen 10), by combining the results of all four joint lengths. With this approach, the mean leak rate is calculated to be 1.28e-5 gpm. This value yields the results in Table 19-1 with respect to the total number of active tubes in Unit 1. The mean value is considered appropriate for the Table 19-1 calculation based on the fact that the variability is test process driven and since no credit was taken for leakage reduction due to the thermal expansion. This reduction was observed in a limited basis in the CEOG test program. The effect was also analyzed specifically for W* and the corresponding benefit was reviewed and is considered applicable to the CE explansion joint. As indicated in APS response to *NRC Question 10*, an upper bound leak rate will be used in the operational assessment per the requirements of NEI 97-06.

Table 19-1
Estimated Leakage for 100% TW/360° Flaw in All Active Tubes

SG	Active Tubes	Mean Leakage rate (gpm)	Predicted Leakage
1-1	10350	1.28e-5	0.132 gpm
1-2	10150	1.28e-5	0.13 gpm

With respect to the effect on thermal expansion, for the CEOG test program, two (2) specimens were tested at MSLB pressures at a temperature of 585°F. The testing is described in WCAP 15947-P. The specimens tested were single mockup Specimens 7 and 10. Conduct of the high temperature tests was not feasible on the BE samples. Despite the fact that Specimen 10 has been excluded from the ambient leakage tests, the observed trend of the high temperature testing is not considered to be impacted. The amount of benefit assumed was evaluated from the lowest ambient pressure test result.

Four (4) high temperature leakage tests were performed on Specimen 7. Three out of the four tests exhibited no pump strokes for the test period. The fourth test yielded one (1) pump stroke. Using the previously described leakage procedure the average leak rate was computed as 5.151e-6 gpm. The ambient tests for Specimen 7 had two (2) tests with zero pump strokes, one with three (3) strokes and four (4) tests with four (4) pump strokes yielding an average test rate of 1.15e-5 gpm. Nearly a 50% reduction in leakage rates at these low leakage levels is considered supportive of the thermal expansion effect.

For Specimen 10, three (3) high temperature tests were conducted with two (2) tests reporting zero pump strokes and the third test generating only one (1) stroke for an average test result of 5.617e-6 gpm. The lowest ambient pressure test for Specimen 10 was an order of magnitude less at 4.136e-5 gpm. The average ambient test result for Specimen 10 was 1.6e-4 gpm, nearly a two orders of magnitude change. APS regards the test data to be sufficiently conclusive of the expected benefit of differential thermal expansion between the tube and tubesheet.

In summary, APS believes that testing described in WCAP 15947-P provides sufficient bounding information and no additional tests are required. The tests indicate that the joint is essentially leak tight, providing a basis for a three (3) inch engagement length for leakage for the proposed inspection extent. The adjustment for tube flexure effects is discussed in APS response to *NRC Question 2*. As indicated in Table 1 of the RAI Introduction, APS includes a 1.5 inch adjustment for test variability and NDE uncertainty. As described in APS response to NRC Question 5, the NDE uncertainty is only 0.25 inches. Therefore, 1.25 inches is conservatively applied to address any variability in the test results.

The use of this leakage value in an operational assessment is discussed in APS response to *NRC Question 10.* As reported in the PVNGS Supplemental Report, APS has also performed in situ pressure tests of detected 100% throughwall flaws with no evidence of leakage. Finally, it should be noted that APS employs a primary-to-secondary leakage monitoring program that is more conservative than the EPRI Primary-to-Secondary Leakage Guidelines. The administrative shutdown limit (in place since 1994) is 50 gallons per day (gpd) with action levels as low as 10 gpd. Since flaws in below the proposed inspection criteria are not at risk for burst and will not result in a sudden "pop-through", should any joint(s) develop leaking flaws in excess of the anticipated values, an orderly plant shutdown would occur.

NRC Question 20

A value of 4410 psid was used to correspond to the 3 times the normal operating differential pressure acceptance criteria. What was the secondary side pressure used in determining this value? Will the value assumed in this calculation bound (for the licensed period of operation) the lowest secondary side pressure? If not, discuss the need to modify the inspection criteria to include a limit on its applicability.

APS Response

As indicated on page 4 of the PVNGS supplemental report, the primary pressure at PVNGS is 2250 psia and the current secondary pressure is 980 psia resulting in a steady state operating differential pressure of 1270 psid. Consequently, the 3NODP value for PVNGS is 3810 psid, which is conservatively bounded by the 4410 psid used in the WCAP. The value of 4410 psid was used in the CEOG program to bound all CE designed plants.

In no scenario over the remaining life of Unit 1, does PVNGS expect to operate with a secondary pressure lower than 780 psia. Additionally, as required by PVNGS procedure 81DP-9RC01, and the EPRI *Steam Generator Integrity Guidelines*, changes in the NODP of greater than 50 psid require reassessment of the basis of the structural integrity performance criteria.

Attachment 1
Technical Specification 5.5.9 Revised Marked-up Page

5.5 Programs and Manuals (continued)

5.5.9.4 Acceptance Criteria (continued)

7. Preservice Inspection in the context of new steam generators means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection was performed prior to the field hydrostatic test and prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

   Preservice Inspection for steam generator tubes repaired by tube sleeving means an inspection of the full length of the pressure boundary portion of the sleeved area performed by eddy current techniques prior to service to establish a baseline condition of the sleeved area. The sleeved area includes the pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

8. Sleeve Inspection for sleeves selected in accordance with table 5.5.9-3 means an inspection of the sleeved area, including the pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

9. Tube or Tubing means that portion of the tube that forms the primary system to secondary system pressure boundary.

10. Tube Inspection for tubes selected in accordance with Table 5.5.9-2 means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg, excluding sleeved areas. *

* For Unit 1 only, the portion of the tube within the tubesheet below 7 inches from the bottom of the expansion transition (BET) is also excluded. The portion of the tube below the BET that is not excluded shall be free of detected degradation.

(continued)

Attachment 2
Technical Specification 5.5.9 Re-Typed Page

5.5 Programs and Manuals (continued)

5.5.9.4 Acceptance Criteria (continued)

7. Preservice Inspection in the context of new steam generators means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection was performed prior to the field hydrostatic test and prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

   Preservice Inspection for steam generator tubes repaired by tube sleeving means an inspection of the full length of the pressure boundary portion of the sleeved area performed by eddy current techniques prior to service to establish a baseline condition of the sleeved area. The sleeved area includes the pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

8. Sleeve Inspection for sleeves selected in accordance with table 5.5.9-3 means an inspection of the sleeved area, including the pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

9. Tube or Tubing means that portion of the tube that forms the primary system to secondary system pressure boundary.

10. Tube Inspection for tubes selected in accordance with Table 5.5.9-2 means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg, excluding sleeved areas. *

   * Unit 1, only the portion of the tube within the tubesheet below 7 inches from the bottom of the expansion transition (BET) is also excluded. The portion of the tube below the BET that is not excluded shall be free of detected degradation.

(continued)