APS

Palo Verde Nuclear
Generating Station

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U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN 50-528, 50-529, and 50-530
Response to NRC Request for Additional Information Regarding PVNGS Units 2 and 3 Steam Generator Tube Inspections

By letter dated December 22, 2005, the NRC provided to Arizona Public Service Company (APS) a request for additional information (RAI) regarding the results of the steam generator tube inspections for the PVNGS Unit 2 spring 2005 and Unit 3 fall 2004 refueling outages. APS' response to the RAI is enclosed.

No commitments are being made to the NRC by this letter. If you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

David Mauldin

CDM/TNW/GAM/ca

Enclosure: APS Responses to NRC Request for Additional Information Regarding PVNGS Units 2 and 3 Steam Generator Tube Inspections

cc:	B. S. Mallett	NRC Region IV Regional Administrator
	M. B. Fields	NRC NRR Project Manager
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS

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ENCLOSURE

ARIZONA PUBLIC SERVICE COMPANY RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING PVNGS UNITS 2 AND 3 STEAM GENERATOR TUBE INSPECTIONS

Questions for PVNGS Unit 2

NRC Question 1 (Unit 2)

In Section 4.0 of your October 24, 2005 letter, you indicated that for steam generators 21 and 22, tubes were detected with abnormal dent indications. Were these indications present since the pre-service inspection? If so, please discuss whether they have changed since the pre-service inspection and the reasons for any change. If they were not present in the pre-service inspection, please discuss the cause of the dents. Please discuss whether these dents are considered "abnormal" since they are similar to the dent indication that was the cause of your 2004 primary-to-secondary leak.

APS Response 1 (Unit 2)

All of the dent indications listed in Section 4.0 of the October 24, 2005 letter were present during the pre-service examinations (PSE). No changes were noted in any of the dent rotating coil examinations. The source of these abnormal dents was most likely the product of the initial steam generator assembly. All four abnormal dent indications (three in SG 21 and one in SG 22) appear to be directly associated with a vertical strap support bar. Note the NDE graphic in attached Figure 1 which indicates that the location of the rotating coil dent indication is at the vertical strap (VS2).

These dents were considered "abnormal" by APS because they exhibited vertical amplitudes higher than typical dent indications. This condition/classification is one of the lessons learned during the 2004 midcycle (leaker) outage and subsequent dent evaluations. The PVNGS Analysts' Technique Sheet for the +Point examination of dents requires the analysts to record any dent with a vertical amplitude over 0.2 volts with the +Point 300 kHz channel. These are then reviewed by the APS Level III for location, appearance, and the potential for masking of other types of flaw indications.

The abnormal dent indications were similar to the dent indication in SG 21 Row 156 Column 143 that leaked during Cycle 12 in that they had higher vertical voltage than other typical dent indications. Using the +Point 300 kHz channel, the vertical amplitude of the leaking tube was 0.94 volts compared to voltages of 0.29, 0.30, 0.67 and 0.92 for the tubes listed in Section 4.0. As indicated above, the four tubes in U2R12 were associated with a support bar, whereas the dent in the leaking tube was not directly associated with a support bar and the dent in the leaking tube was attributed to damage caused by a packing crate screw.

Although it is unlikely that these dents were caused by crate screw damage, APS took the conservative action and removed the affected tubes from service by plugging.

NRC Question 2 (Unit 2)

In Section 4.0 of your October 24, 2005 letter, you indicated that a volumetric indication was detected and plugged. In addition, you detected several other volumetric indications. Please discuss the nature, cause, and severity of these indications.

APS Response 2 (Unit 2)

The following table identifies each of the various volumetric indications and associated evaluation/comment:

SG 21	Evaluation	Comment
2 SVI	PIT	Similar to a small pit or nick type indication. No change was detected since pre-service inspection (PSE), and each are located within the tubesheet.
1 SVI	Lap	Very small tube mill manufacturing indication, no change noted since PSE.
SG 22	**Evaluation**	**Comment**
1 SVI	PIT	Similar to a small pit or nick type indication. No change was detected since PSE, and this was located within the tubesheet.
2 SVI	Lap	Very small tube mill manufacturing indications, no change noted since PSE.
1 SVI	MIG	Evaluated as a manufacture induced gouge (MIG) or nick. No change was detected since PSE, however the indication was **plugged**. It was determined that the size of the indication may mask future service related degradation should any appear.

NRC Question 3 (Unit 2)

Discuss whether a foreign object search and retrieval was performed and whether the loose parts were removed from the steam generators. If any loose parts were not removed, please discuss whether you assessed the impact the loose part could have on tube integrity during the interval between inspections.

APS Response 3 (Unit 2)

APS conducted a foreign object search and retrieval (FOSAR) during U2R12 at both the tubesheet (hot and cold leg) and at the cold leg flow distribution plate. A summary of the findings is provided below.

Tubesheet FOSAR Activities

A tubesheet FOSAR was conducted in both steam generators using a power cart mounted with a remotely operated camera and retrieval tooling. As expected, little sludge was observed in either of the steam generator's tubesheet annulus. The annulus was inspected twice in each steam generator. Once before sludge lancing and again after sludge lancing was completed.

In Steam Generator 21, an 18" long, ¼" diameter piece of weld wire was found vertically lodged in the divider plate slot. The part was retrieved. The weld wire was not adjacent to any tubes and, as such, would not have been detected by eddy current. No other loose parts were identified visually. An additional review was performed to identify the source of the part. The wire had an identification number (DMO IG 1.5424) stamp. The source was tracked to a German (Bohler) manufactured weld wire used by the steam generator manufacturer, Ansaldo. As such, the wire was not introduced operationally or through any maintenance activity performed by APS.

In Steam Generator 22, a 2.5" long, ¼" diameter piece of tungsten (TIG electrode) was found in the hot leg blowdown lane near tube R1C38. It was retrieved/removed from the steam generator. APS Engineering review concluded that the part was a remnant from the fabrication process conducted by Ansaldo. The NDE data was reviewed at this location to determine if this object was observed by ECT or if any wear was present in the vicinity of tube R1C38. The result of this review confirmed that there was no indication of wear and therefore had not been an impact to steam generator tube integrity. No other loose parts were identified in the FOSAR inspection.

Flow Distribution Plate FOSAR

The flow distribution plate (FDP) has been identified by APS Engineering as a critical region within the feedwater box (economizer) for the introduction of loose parts. A FDP FOSAR inspection was conducted using a video probe through a piece of conduit around the outer tube periphery. As expected, little sludge was observed on either of the steam generator's flow distribution plate. No loose parts were identified in either steam generator.

NRC Question 4 (Unit 2)

> Appendices C and D of your October 24, 2005 letter, list several distorted support signals. Regarding these indications, please discuss whether these indications can be traced back to the baseline inspection? If so, have they shown any change? If change has been observed, please explain what has caused these indications to change.

APS Response 4 (Unit 2)

Several distorted support indications were identified during the bobbin examination program; 60 in SG 21 and 57 in SG 22. All of these indications were also examined with the +Point coil for confirmation and classification. With the +Point examination, all of these indications were classified as NDF (no discontinuity found) or as wear. The actual number of bobbin calls classified as NDF is 31 in SG 21 and 32 in SG 22. The remainder of the indications (29 and 25 in SG 21 and 22 respectively) was classified as wear.

None of these indications were either previously identified or could be traced back to the pre-service examination (PSE). The indications that were +Point examined and classified as NDF are most probably caused by small amounts of deposit or wear below the +Point calling criteria (10%).

NRC Question 5 (Unit 2)

> In Section 3.0 of your October 24, 2005 letter, you indicated that an operational assessment will document your tube integrity assessment as required by Nuclear Energy Institute (NEI 97-06). Please discuss the results of this assessment (i.e., whether it confirms that the tube integrity will be maintained until the next steam generator tube inspections).

APS Response 5 (Unit 2)

The Operational Assessment for U2C13 confirmed that tube integrity, in accordance with the performance criteria in NEI 97-06, will be maintained until the next refueling outage. As Cycle 12 was the first operating cycle for these replacement steam generators (RSGs), all identified wear indications were evaluated with respect to tube integrity and cause.

Due to certain historically observed wear phenomena, APS has employed conservative administrative plugging criteria related to support wear mechanisms (APS letter no. 102-04094, dated March 13, 1998, *Response to Generic Letter 97-05, "Steam Generator Tube Inspection Techniques"*). For example, support wear indications are removed from service for abnormal wear rate greater than or equal to 35% for a normal operating cycle if no previous wear is identified. In addition, for the original steam generators (OSGs), tubes with Batwing Stay Cylinder (BWSC) and Cold Leg Corner (CLC) wear damage are removed from service for wear greater than or equal to 20%. This administrative plugging criterion is designed to ensure that Regulatory Guide 1.121 and NEI 97-06 structural and accident leakage performance criteria are not exceeded in the subsequent operating cycle. It was expected, based on RSG redesign, that the conditions necessary to generate high wear rates in the BWSC and CLC regions were eliminated. While this was clearly the case for CLC wear, the U2R12 inspection did reveal similar wear conditions and patterns within the BWSC region. As such, APS conservatively applied plugging and evaluation criteria

that have been successfully demonstrated and presented to the NRC for the OSGs (APS letter no. 102-03931, dated May 9, 1997, *Operational Assessment*, and APS letter no. 102-04040, dated November 18, 1997, *Response to Request for Additional Information Regarding Monitoring and Operational Assessment for Palo Verde Unit 2 and Continued Operability for Steam Generators for Palo Verde Units 1 and 3*).

All tubes classified within the Batwing Stay Cylinder Wear (BWSC) region during U2R12 were evaluated for wear greater than or equal to 20% as called by bobbin coil. During the inspection, ten tubes were identified with wear meeting this criteria within the defined Unit 2 BWSC region and were removed from service by plugging The largest BWSC wear call was 40% found in SG22 tube R44C111 at BW1 -0.96". The remaining nine tubes had wear ranging from 20% to 38% during this cycle.

The largest bobbin wear indication outside the BWSC region was observed in SG21 tube R161 C132 at VS1 + 0.88 (14 %). This flaw was well below the plugging and structural limit. As such, no wear outside the BWSC region is considered to result in an integrity concern for U2C13.

As indicated above, the largest wear growth in U2C12 was observed in tube R44C111 located in SG 22. As this was the first cycle of operation, the tube degradation grew from 0% to 40% in one operating cycle. For growth rate analysis of wear indications, APS assumes a constant volume loss rate versus wall thickness reduction. This is due to the fact the wall thickness depletion diminishes as the tube continues to wear due to the increase in the volume of material on a cylindrical surface. To validate that an appropriate plugging criterion was applied and that tube integrity for Cycle 13 is maintained, this rate was computed and added to the Cycle 13 Beginning of Cycle (BOC) condition and then assessed for structural and leakage integrity at the End of Cycle (EOC).

The basic structural assessment equation used for the evaluation:

EOC = BOC + NDE uncertainty + Growth Rate

The Cycle 13 Operational Assessment was performed deterministically in accordance with the EPRI *Steam Generator Integrity Assessment Guidelines*. All factors were applied at 95/50 confidence bounds (or higher) as required by NEI 97-06. The limiting volumetric growth rate approach specified in the previously referred to APS letters was applied. The largest indication left in service was an 18% wear indication at tube R43C112 in SG 22. The limiting EOC condition was computed to be 48% through-wall. This value was then compared to the structural limit of 76% through-wall based on plant and defect specific burst testing. As such it was concluded that tube integrity will be maintained for the Unit 2 steam generators for Cycle 13.

Based on the conditions identified during U2R12, APS has declared the wear mechanism in Unit 2 as "active" in the PVNGS Degradation Assessment. In

accordance with EPRI *PWR Steam Generator Examination Guidelines*, steam generator eddy current inspections are planned in U2R13.

NRC Question 6 (Unit 2)

Several tubes were identified as being plugged (R141C102, R141C112, R154C91 and R106C117); however, the information in Appendices C and D contain no information concerning the nature of the indications in these tubes. Please discuss the reason for plugging these tubes (e.g., abnormal dents).

APS Response 6 (Unit 2)

All four of these tubes were plugged due to the abnormal dent indications discussed in the response to Unit 2 RAI Question Number 1.

NRC Question 7 (Unit 2)

It is the NRC staff's understanding that the Palo Verde, Unit 2, replacement steam generators have an economizer with a similar set screw configuration as that in Unit 3 (which experienced degradation). As a result, please discuss whether any inspections were performed to confirm the integrity of these locations. In addition, please discuss whether any other secondary side inspections were performed during the outage.

APS Response 7 (Unit 2)

No specific inspections of the set screws were conducted in U2R12. APS, with support from Westinghouse and Ansaldo, conducted an evaluation of the specific design differences and similarities. Other than the FOSAR inspections reported in the response to Unit 2 RAI Question 3, no other secondary side inspections were performed. The results of the replacement steam generator (RSG) set screw evaluation were inputted into the PVNGS Degradation Assessment as summarized below.

The main design differences between the original steam generators (OSGs) and RSGs with respect to the feedwater box include; the set screw length exposed to feedwater flow, the gap setting against the shell and the set screw installation technique. The difference in set screw material (SAE Gr.5 vs. SA-193 Gr. B7) was not judged to be a significant difference.

The increased set screw length exposed to feedwater flow was evaluated with respect to the possible negative effect of increased flow forces on the set screw. The increased force on the set screw was calculated to negligibly increase by approximately 3% in the RSGs. Alternatively, the increased length permitted setting the gap between the set screw and the shell at 0.06 inches in the RSGs vs. 0.25 inches in the OSGs. This was evaluated to have a positive effect during accident

conditions. Although not likely to help limit the erosion or wear of the feedwater box at the set screw location, if erosion does occur, the combination of the smaller gap and the seal plate on tube side of the feedwater box would limit the movement of the set screw. As a result, it is less likely that the same amount of erosion as seen in the Unit 3 OSGs would lead to a set screw failure.

The most significant difference between the OSGs and the Unit 1 and 2 RSGs is the installation of a seal plate. In the OSGs the set screws were welded to the tube-side face of the feedwater box then ground flush. Because of the hardness of the set screw material, very little of the weld metal adhered to the set screw. As a result, there was a small leak path through the threads that allowed water to leak from the feedwater box to the economizer region of the steam generator. Conversely, the Units 1 and 2 RSGs have a 0.25-inch carbon steel plate that is groove-welded flush to the tube-side face of the feedwater box (see attached Figure 2). This seal plate is a significant design improvement in the RSGs. Although the primary purpose of the seal plate was to avoid welding to hardened bolting material, it has the secondary effect of eliminating the jetting flow through the set screw hole if the set screw falls out. While this change might not significantly affect the probability of a set screw failure in Units 1 and 2, it will have a significant effect on the consequences of a failure.

Based on this evaluation, APS concluded that the probability of a set screw failure is marginally lower in the Unit 1 and 2 RSGs than in the OSGs. It should be noted that the erosion/corrosion that led to the set screw failure in the Unit 3 OSG occurred after 11 operating cycles. As such, the mechanism is not considered to be a near term issue. To ensure that the condition does not manifest itself in the Units 1 and 2 RSGs, a routine Preventative Maintenance Task to inspect the RSGs in this region on a 6Y (six year) frequency has been implemented for Units 1 and 2, and the condition has been incorporated into the PVNGS Degradation Assessment.

Based on the set screw discovery and root cause evaluation, APS was able to implement additional changes in the Unit 3 RSGs currently being fabricated. The Unit 3 RSGs, to be installed in fall 2007, have changed the material of the seal plate (carbon steel to nickel-alloy 690) and added a nickel-alloy 690 washer where the set screws contact the ID surface of the feedwater box. These changes essentially eliminate the possibility of erosion of the feedwater box near the set screw threads. As a result, a set screw failure in the Unit 3 RSG feedwater box will not be a credible event.

NRC Question 8 (Unit 2)

Discuss the scope and results of your dent examinations including a discussion of whether all dents have been examined with a rotating coil since the fabrication of the steam generators. In addition, please discuss whether any dents have changed since the pre-service inspection.

APS Response 8 (Unit 2)

Bobbin coil examinations were utilized to call all dent signals down to a 0.5 volt level. 100% of these dent indications were examined with the +Point rotating coil during U2R12. The numbers examined were 894 in SG 21 and 696 in SG 22. Based on re-review of the historical data from the PSE, the APS Level III concluded that none of the dents identified exhibited change.

NRC Question 9 (Unit 2)

Please clarify the scope and results of your U-bend and square bend examinations.

APS Response 9 (Unit 2)

100% of the tubing was examined with the bobbin coil through the full length. This included all U and Square bend areas. In addition, the following table identifies the numbers of +Point examinations performed in U or square bends. It should be noted that these were performed either due to bobbin indication calls or bobbin dents and the examination extent was typically associated with or inclusive of a tube support in the bend areas. There was not a scoped program for sampling short radius or other bends this outage. 100% of the Row 1 and 2 short radius U-bends were inspected with +Point during the PSE.

Because these examinations were required to disposition bobbin indications, the results were classified into NDF, SVI or wear (also see the responses to Unit 2 RAI Questions 2 and 4).

SCOPE DESCRIPTION		SG 21	SG 22
Exam Description	**Extents**	**Scope**	**Scope**
U BEND	VARIOUS	319	122
SQUARE BEND	VARIOUS	90	93

NRC Question 10 (Unit 2)

General information concerning the design of your replacement steam generators was provided in the submittal. In order for the staff to better understand the design of your replacement steam generators, please provide the following information: model number, heat transfer surface area, flow distribution baffle design (e.g., circular holes) and thickness, tube support plate thickness, batwing and vertical strap thickness, and the smallest U-bend radius.

APS Response 10 (Unit 2)

The replacement steam generators were designed by ABB/CE (now Westinghouse) and manufactured in Italy by Ansaldo, and are considered a modified System 80 design (no specific model number). The tube bundle consist of 12,580 – ¾ inch OD Alloy 690 thermally treated tubes with a nominal wall thickness of 0.042 inch and an average heated length of 63.9 feet and 157,838 ft^2 of heat transfer area. The tubes are hydraulically expanded into the tubesheet for the entire tubesheet thickness of 25 inches. The tube support system is similar to the original design, and like the original design is fabricated from 409 ferritic stainless steel.

The tubes are arranged in rows, with all tubes in a given row having the same length. The rows are staggered, forming a triangular pitch arrangement. The shorter tubes, which have 180° bends, are located in the first 17 rows at the center of the tube bundle. All tubes in the subsequent rows have double 90° bends. To minimize the potential for stress corrosion cracking, in addition to the tubing material change, the U-bend region, which is limited to the first 17 rows, was stress relieved after bending. The smallest U-bend radius (Row 1) is three inches.

The horizontal tube supports located along the vertical section of the tubes are of an eggcrate design. The eggcrates are comprised of alternating one and two inch strips, 0.090 inch thick, arranged in two directions that intersect at 60°. The bend and horizontal regions of the tubes are supported by batwing and vertical lattice supports, respectively. The primary difference from the OSG design are that the batwing and vertical lattice supports are perforated to improve thermal-hydraulic conditions in the upper bundle region to prevent crevice dryout and reduce secondary fouling. The batwing and vertical support structures are now unitized and fabricated from two inch wide, 0.090 inch thick 409 SS strips. The batwing supports which minimize out-of-plane movement have been relocated to bisect the tube bends.

The tube supports are designed to provide support during operation or combined seismic and accident conditions while offering minimum restrictions to steam/water flow in the tube bundle. The large flow area in the RSG support design provides better irrigation, and reduces the potential for steam blanketing, and therefore are less likely to be blocked by crud, boiler water deposits and corrosion products.

The RSG design also differs from the OSG in terms of the flow distribution plate(s). The RSGs do not have a hot leg flow distribution plate, which was eliminated to improve hot-side circulation. The cold leg flow distribution plate is an approximately one inch thick, 405 stainless steel plate with 0.776 inch circular holes.

The steam generators are of a stayed design to support the tubesheet, and as a result, the center of the bundle contains a cylindrical cavity. The stay cylinder is a hollow tube that supports the primary plenum plate, the divider plate separating economizer and evaporator region on the secondary side and provides rigidity to the tubesheet to minimize tubesheet bowing.

See attached Figure 3 for a simplified depiction of the support system for the PVNGS RSG design.

Questions for Palo Verde Unit 3

NRC Question 1 (Unit 3)

> In Section 3.0 of your October 18, 2005 letter, you indicated that an operational assessment will document your tube integrity assessment as required by NEI 97-06. Please discuss the results of this assessment (i.e., whether it confirms that the tube integrity will be maintained until the next steam generator tube inspections).

APS Response 1 (Unit 3)

The Unit 3 Cycle 12 Operational Assessment concluded that tube integrity, in accordance with the performance criteria in NEI 97-06, will be maintained until the next refueling outage. Depending on the damage mechanism (e.g., wear, stress corrosion cracking, etc.), the assessment was performed using either a deterministic approach or a more sophisticated Monte Carlo simulation analysis using the OPCON 3.02 computer code developed by APTECH. OPCON 3.02 is a suite of software packages developed by APTECH. OPCON 3.02 has been developed in accordance with APTECH's Quality Assurance Program, which meets the requirements of 10 CFR 50 Appendix B and ANSI N45.2. The OPCON code has been successfully used and benchmarked by APS for condition monitoring and operational assessment of all three units since 1999.

All indications found during U3R11 were removed from service or dispositioned in accordance with PVNGS Administrative Plugging Criteria and were within pre-outage predictions with respect to the severity of the degradation. No in-service tubes were found to contain degradation exceeding the threshold values for structural and leakage integrity. As such, all steam generator performance criteria were satisfied for Unit 3 Cycle 11.

The operational assessment for Cycle 12 contained an evaluation of all damage mechanisms observed in the Unit 3 steam generators in U3R11 inspection. These included

- Axial ODSCC at eggcrate tube supports and flow distribution plates.
- Axial ODSCC in upper bundle (ARC) regions including vertical strap, and bat wing tube supports.
- Axial ODCSS near top of tubesheet and within tubesheet crevice.
- Axial IDSCC below top of tubesheet.
- Circumferential SCC near top of tubesheet hot side and within tubesheet hot side.
- Loose Part Wear evaluation (set screw).
- Support Wear.

The analytical predictions for Cycle 12 show that all performance criteria are satisfied. The combined probability of burst, including circumferential cracking, predicted for the Unit 3 steam generators in Cycle 12 is approximately 0.012 at 3NODP, which demonstrates assurance that the structural performance criteria will be satisfied for a full operational cycle. The combined 95/95 leakage at main steam line break (MSLB) condition is predicted at 0.102 gpm, which is less then the acceptance criteria of 0.4 gpm per steam generator. As such, APS concluded that the planned cycle length for operation of U3 in Cycle 12 is not limited from a steam generator tube integrity perspective.

NRC Question 2 (Unit 3)

In Table 1 of your October 18, 2005 letter, you indicated that rotating coil examinations were performed on bobbin indications from the previous outage and from the current outage. Please clarify what types of indications (e.g., wear, manufacturing burnish marks, free span differentials, etc.) were included in this sample and whether the sample represented 100% of the bobbin indications

Please confirm that rotating coil examination was performed on any distorted support indications (DSIs) or non-quantifiable indications identified by either the primary or secondary eddy current data analyst.

APS Response 2 (Unit 3)

The rotating coil examinations included 100% of all the bobbin flaw or degradation type indications. This includes all bobbin "I" code type indications from current inspection and "H" codes from historical data (i.e., "I" code indications from a previous outage), bobbin percent calls, bobbin PVN (permeability variation), and historical NTE (No Tubesheet Expansion) calls. In addition, a sample of MBM (Manufacturing Buff Mark), BLG (Bulge), and 100% all the bobbin identified dents on the hot leg straight

section up to the Batwing were included. The bobbin dent calling threshold for the hot leg straight section of tubing is 2 volts.

The resolution training and instructions for PVNGS include a requirement to keep all of the upper bundle NQI calls and all the hot leg eggcrate and vertical strap DSI calls. This instruction includes all DSI and NQI calls from both primary and secondary.

NRC Question 3 (Unit 3)

> Regarding the volumetric indications detected during the 2004 (U1R11) inspections and reported in Table 2 of your October 18, 2005 letter, please clarify whether any of the indications are a result of corrosion (i.e., volumetric indications other than manufacturing burnish marks, pit-like indications (not corrosion related), tube-to-tube wear, wear at tube supports). If any volumetric indications attributed to corrosion (e.g., intergranular attack) were left in service, please discuss your basis for leaving them in service. With respect to the volumetric indications that were plugged, please clarify the reason for plugging these indications. Specifically address whether any of the flaws previously attributed to manufacturing related reasons (e.g., manufacturing burnish marks) have changed with time. If they have changed, please discuss why and whether this has led to any changes in how you classify indications (since the change may imply an active degradation mechanism at this location).

APS Response 3 (Unit 3)

As indicated in APS's response to Generic Letter 97-05 (APS letter 102-04094, dated March 13, 1998) and per PVNGS Administrative Plugging Criteria, any SVI/MVI that indicates evidence of corrosion is removed from service regardless of size. When SVI/MVI indications are detected/called, a historical review is performed to assess any evidence of change. Change is considered any amount of signal difference from either RPC or bobbin that is not attributed to ECT process tolerances. This evaluation is based on present data compared to a minimum of two (2) cycles of historical data.

With the exception of the tube-to-tube wear (TTW) indications, all of the remaining RPC called volumetric (SVI or MVI) indications did not change outside the repeatability limits of eddy current examinations. As such, none of the volumetric indications were determined to be from a corrosion related degradation. Additionally, none of the indications attributed to manufacturing related reasons showed evidenced of change.

As also indicated in APS's response to Generic Letter 97-05, the characteristics of tube-to-tube wear (TTW) are well understood based on tube pull results and operating experience. The PVNGS Administrative Plugging Criteria requires that TTW indications are removed from service if the indication exceeds 35% through-wall depth as measured by rotating coil techniques or as recommended by the APS

Level III. A total of eleven indications were plugged due to tube-to-tube wear (three in SG 31 and eight in SG 32). The largest indication was measured at 29% through-wall.

Four additional SVIs (three in SG 31 and one in SG 32) were plugged in U3R12. These indications were classified as PIT (pit or nick-like indications). These SVI calls were reviewed for voltage changes which may indicate progressive corrosion. Although none of these indications were found to be progressive in nature, APS elected to conservatively plug these tubes due to future flaw masking potential.

NRC Question 4 (Unit 3)

In Table 2 of your October 18, 2005 letter, you indicated that various tubes were preventatively plugged due to dents. Please discuss whether there is active denting occurring or whether these tubes were plugged for dents whose characteristics (e.g., voltage) may not have changed but that might limit the effectiveness of the eddy current examination. If active denting is occurring, please discuss the cause.

APS Response 4 (Unit 3)

The three dent indications were plugged due to their characteristic of being able to mask a flaw if present. No active denting is or has occurred at PVNGS. The large flow area in the System 80 support design provides better irrigation, and reduces the potential for steam blanketing, and therefore are less likely to be blocked by crud, boiler water deposits and corrosion products. Since the support material is Type 409 ferritic stainless steel, it is not susceptible to magnetite corrosion which has resulted in active denting and lockup at plants with carbon steel supports.

The following table illustrates the number of dents examined with the +Point probe in each of the steam generators. No indications of cracking were associated with any of these dents.

Dent BOBBIN Voltage	SG 31	SG 32
2 to 4.99	327	411
5 to 9.99	139	178
10 to 14.99	36	56
15 to 19.99	13	17
> 20	5	21
Largest Bobbin Voltage Dent	24.12	59.81

NRC Question 5 (Unit 3)

Please discuss the results of the rotating coil examination of your dents/dings. Please include the voltage of the dents/dings and the nature of any indications in your response. If any flaw like indications were detected in your dents/dings, please discuss the nature of the indication and the voltage of the dent/ding.

APS Response 5 (Unit 3)

The requested information is contained in the table provided in response to Unit 3 RAI Question 4. As indicated previously, there were no crack-like indications detected in any of these dent locations.

NRC Question 6 (Unit 3)

> Please discuss the results of the rotating coil examinations of the U-bend region in rows 1-18.

APS Response 6 (Unit 3)

The +Point examinations included 100% of the Row 1 thru 5 U-bend areas. The examinations included both a high frequency and mid-frequency +Point probe for the Row 1 thru 3 U-bends. There were three tubes identified in SG 31 with geometry (GEO) type signals that were plugged. These are geometric anomalies that are preventatively plugged due to their potential to mask flaw signals. No crack-like or corrosion related degradation was identified.

In addition, a 20% sample of the U-bends in Rows 6 thru 18 were examined with the +Point probe. The inspection sample included 100% of all apex anomalies (manufacturing defects). There were no crack-like or corrosion related indications detected in the bend areas with these examinations.

NRC Question 7 (Unit 3)

> Regarding the set screw degradation found in steam generator 32, please discuss the results of your final analysis (e.g., was it consistent with your initial analysis summarized in the NRC letter dated February 23, 2005). In addition, please discuss your plans to address the potential for continuing degradation of these set screws (including inspections and integrity assessments).

APS Response 7 (Unit 3)

APS has reviewed the information summarized by the NRC in their February 23, 2005 letter (ADAMS ML050490197) and the information attached to the February 23 NRC letter that was provided by APS to support the summary (ADAMS ML050490053 and ML050490124). With respect to the analysis to support Unit 3

Cycle 12 operation, no changes in the information provided were made. The actions and analysis completed to support condition monitoring and the operational assessment are as indicated in the information provided. The only additional actions were to document the findings and integrity evaluation in the PVNGS Corrective Action Program (CRDR 2746969) and to finalize review of the potential impact to the Unit 1 OSG and determine any compensatory measures for the RSGs and for U3R12. The following information is a summary of the findings.

Unit 1 Original Steam generators (OSGs)

At the time of the evaluation in 2004, Unit 1 was operating in Cycle 12 (the last cycle prior to SG replacement – the OSGs were subsequently replaced in U1R12, fall 2005). The design of the feedwater box was identical to the Unit 3 steam generators, and as such, the potential for similar erosion/corrosion of the set screw locations adjacent to the feedwater deflector plates could not be ruled out. Therefore, the transportability evaluation focused on the conditions known at the end of Cycle 11 and the applicability of the analyses/evaluation performed for Unit 3 Cycle 12.

APS reviewed the eddy current data taken during U1R11. Since 100% ECT examinations were performed, there is data for all potentially affected tubes both at the tubesheet (with respect to loose part indications and wear) and at the tube support locations (01C-03C) for tube wear (to assess potential for flow jetting). There were no new or changed eddy current indications for the potentially affected tubes. There were no unaccounted for loose part indications (that is, no indications due to set screws) in either of the Unit 1 steam generators. Additionally a complete tubesheet visual examination (FOSAR) was performed during U1R11 and there were no indications of a set screw. As such, it can be concluded that no set screws were dislodged at the end of Unit 1 Cycle 11.

Therefore, it was APS's position that the evaluation supporting Unit 3 Cycle 12, regarding the tube and feedwater box damage potential of any dislodging of set screw(s) during Unit 1 Cycle 12 could be applied. Although the preventive plugging instituted in Unit 3 was not performed in Unit 1, the analyses indicated that the associated tube damage resulting from streaming flow or a loose part is not a structural concern for a single cycle of operation.

As stated above, the Unit 1 OSGs were removed and replaced during U1R12 in the fall of 2005.

Units 1 and 2 Replacement Steam Generators (RSGs)

The conclusions and actions for the replacement steam generators in Units 1 and 2 are provided in response to Unit 2 RAI Question 8.

Unit 3 (U3R12)

Based on the actions taken in U3R11, no additional actions or inspections are planned for U3R12 scheduled for April 2006 other than currently scheduled eddy current examinations and the FOSAR inspections of the tubesheet region. The basis for this position is as follows:

- The only set screw locations susceptible to erosion/corrosion were those locations adjacent to the feedwater deflector plates. The tubes in the proximity of those locations, should the affected set screws become dislodged and flow jetting occur, have been plugged and staked in U3R11.

- The most likely transport location for a dislodged set screw is the economizer feed ring. In this location there is no interaction with the tube bundle.

- The feedwater box (economizer) integrity analysis assumed that all affected set screws become dislodged. Structural integrity was demonstrated by analysis.

In the unlikely event that another set screw migrates to the tubesheet, the planned eddy current and FOSAR will identify the condition and appropriate actions will be taken. The effect of a set screw on active and inactive tubing was assessed in the Unit 3 Cycle 12 assessment. The Westinghouse analysis determined that no tube integrity concerns existed for active tubes. The potential for impact damage on an inactive, non-stabilized tube was considered by APS (Ginna experience). As such, all inactive tubes in the zone of influence were confined by plugging and staking surrounding tubes in U3R11.

Figure 1
MRPC Graphic "Abnormal" Dent

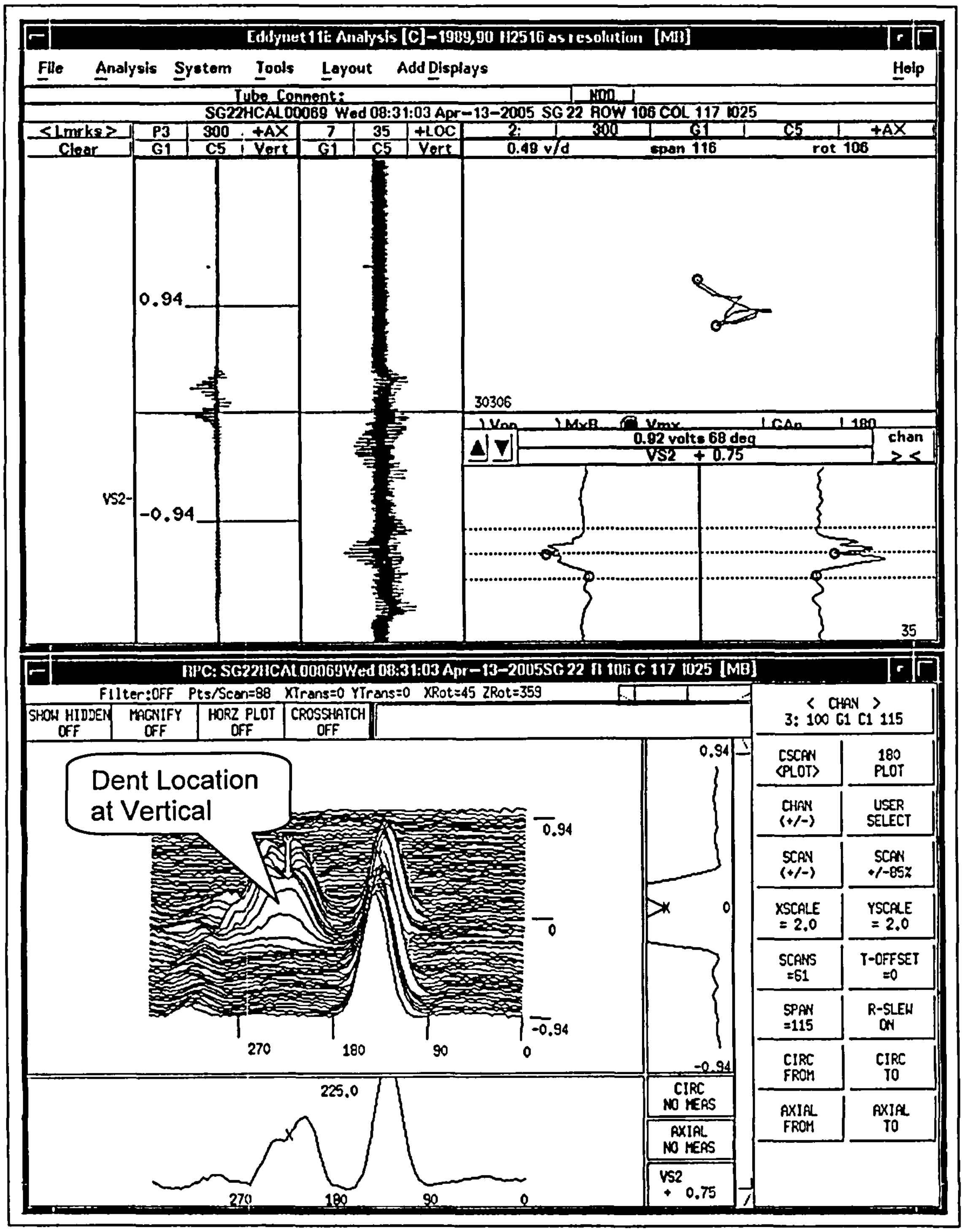

Figure 2
Set Screw Installation Unit 1 and 2 RSG

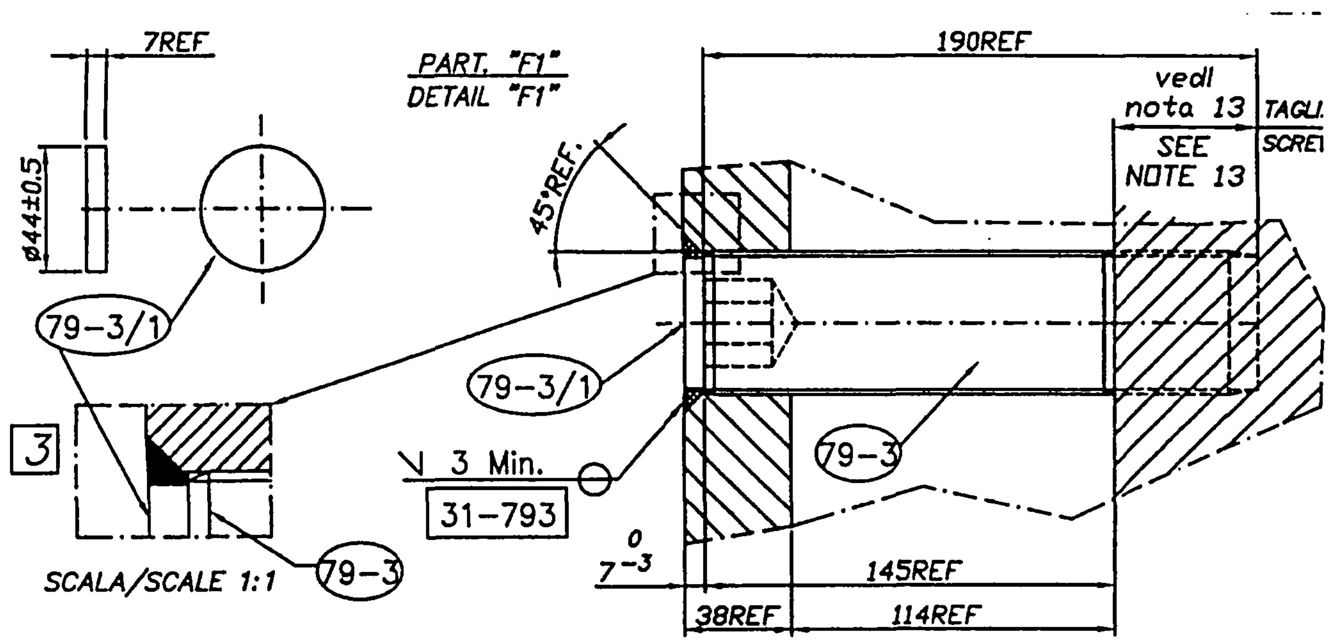

Figure 3
Support System - PVNGS Replacement Steam Generators

Design Changes

BW in center of Bends

3 Partial Eggcrates

No FDP on Hot Leg