Technical Specification 5.6.8

APS

Palo Verde Nuclear Generating Station

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U.S. Nuclear Regulatory Commission
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References: 1) Letter dated May 1, 2003, "Special Report 3-SR-2003-003 Steam Generator Tube Plugging," from G. R. Overbeck, Arizona Public Service Company, to USNRC

2) Letter dated October 15, 2003, "Special Report 3-SR-2003-003-01," from G. R. Overbeck, Arizona Public Service Company, to USNRC

Subject: Palo Verde Nuclear Generating Station (PVNGS) Unit 3
Docket Nos. STN 50-530
Unit 3, Refueling 10, Outage (U3R10) Steam Generator Tube Inspection Request For Additional Information (RAI) Response

Dear Sirs:

Pursuant to PVNGS Technical Specification 5.6.8, Arizona Public Service Company (APS) provided Special Report 3-SR-2003-003 on May 1, 2003 (Reference 1) which discussed the steam generator tube plugging associated with Unit 3 Refueling 10 Outage (U3R10). Additionally, a supplement report to Special Report 3-SR-2003-003 was provided on October 15, 2003 (Reference 2). On August 11, 2004, the NRC sent electronically a request for additional information concerning the U3R10 steam generator tube inspection report (Reference 2). The enclosure to this letter lists the NRC questions along with APS' response to the questions.

No commitments are being made to the NRC by this letter.

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

Sincerely,

David Mauldin

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CDM/TNW/JAP

Enclosure: Arizona Public Service Company's Response to Unit 3, Refueling 10, Outage (U3R10) Steam Generator Tube Inspection Request For Additional Information (RAI)

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

ENCLOSURE

Arizona Public Service Company's Response to Unit 3, Refueling 10, Outage (U3R10) Steam Generator Tube Inspection Request for Additional Information (RAI)

REQUEST FOR ADDITIONAL INFORMATION FOR
ARIZONA PUBLIC SERVICE
PALO VERDE UNIT 3 STEAM GENERATOR TUBE
INSPECTION REPORT FOR THEIR 2003 OUTAGE
DOCKET NO. 50-530

By letters dated May 1, 2003 (ML031280157), and October 15, 2003 (ML032960550), Arizona Public Service (APS), the licensee, submitted the steam generator tube inspection summary reports for the Spring 2003 outage at the Palo Verde Nuclear Generating Station Unit 3 in accordance with the plant's Technical Specifications.

The staff has reviewed the information the licensee provided and determined that additional information is required in order to complete the evaluation. The additional information below is being requested.

1. Rotating coil (RC) examinations were performed in the upper cold leg (arc) region based on the results from U1R10. Please discuss the results of the examinations performed in this region during the 10th refueling outage at Unit 3 (U3R10).

APS Response:
An upper cold leg (arc) region supplemental inspection with Plus Point was performed in Unit 3 based on a Palo Verde Nuclear Generating Station (PVNGS) Degradation Assessment (DA) of U1R10 findings. In the U1R10 inspection, 26 tubes were found to have Stress-Corrosion Cracking (SCC) indications at support locations on the cold leg side of the upper bundle (See Figure 1 - tube supports 07C-VS5). All indications were detected by bobbin coil. These indications represented a first time discovery of cold leg side SCC in the upper bundle region at PVNGS. Hot leg side (07H-VS3) ARC Region degradation has been detected in all three units for 10 years.

An Eddy Current Testing (ECT) expansion using rotating coil (Plus Point) was conducted in the length of tubing from 07C-VS5 to determine if freespan axial SCC defects existed in the same region. The inspection revealed no indications within the freespan. As such, the bobbin coil inspections were considered adequate for detecting Outside Diameter Stress-Corrosion Cracking (ODSCC) at vertical strap and eggcrate support locations.

The subsequent Unit 3 DA, performed in preparation for U3R10, determined that this first time discovery of Unit 1 axial ODSCC on the cold leg was limited to an area of the steam generator found to contain a higher level of deposits as indicated via a scale profiling technique licensed through Westinghouse (see Figure 2). Although, Unit 3 was not expected to have similar deposition profiles, based on the extent of steam generator modifications designed and implemented in Unit 3 to limit dryout in the upper bundle region of the steam generator, as a conservative measure the U3R10 inspection plan included a freespan upper bundle cold leg exploratory sample program with Plus Point.

The sample program concentrated on tube locations based on an assessment of the Unit 1 data which considered a potential region comprising about 1800 tubes as being the most heavily affected. A representative Plus Point inspection pattern was selected using an eight (8) tube pattern spaced every fifth tube. Because Unit 3 had not experienced upper cold leg axial flaws, and given the demonstrated benefit of the design modifications, the Plus Point sample program was considered reasonable, in combination with 100% bobbin coil, to determine the possible presence of upper bundle cold leg axial flaws. The U3R10 Plus Point inspection included 203 tubes tested from supports VS5-07C in each SG. If any SCC had been detected by either bobbin or Plus Point, the program would have been expanded. No indications of ODSCC were detected by either the bobbin or supplemental Plus Point inspections.

2. In Section 3.0 of your 10/15/03 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. In addition, please discuss whether you performed any in-situ pressure testing during this outage. If so, please discuss the results of these tests.

APS Response:
The Operational Assessment for Unit 3 Cycle 11 was performed for all SCC mechanisms using a multi-cycle 'Monte Carlo' simulation analysis contained within the OPCON 3.01 computer code developed by APTECH. The analysis, performed in accordance with NEI 97-06 and the EPRI SG Integrity Assessment Guidelines, demonstrated that all inservice Unit 3 steam generator tubing meets the NEI 97-06 (PVNGS specific) steam generator (SG) performance criteria for all corrosion related mechanisms. The minimum acceptance criteria for PVNGS are three times normal operating differential pressure (3NODP) and an accident leakage limit of 0.5 gallons per minute (gpm) per SG. Additionally, all corrosion related indications found in U3R10 were removed from service upon detection as indicated in PVNGS response to Generic Letter 97-05.

The Unit 3 Cycle 11 Operational Assessment also contained deterministic evaluations of detected wear degradation to validate PVNGS Administrative Plugging Criteria and demonstrate that structural and leakage integrity is assured. The wear assessment for Unit 3 Cycle 11 relied on various engineering studies and assumptions associated with Combustion Engineering (CE) System 80 design. The areas under consideration are separated into the three (3) groups: Cold Leg Corner, Eggcrate/ Vertical strap, Batwing Stay Cylinder regions. The wear assessment results confirmed that PVNGS plugging criteria are conservative and operational wear rates remain within bounding assumptions. As such, the operational assessment indicated that Unit 3 can operate a full cycle with respect to steam generator tube integrity.

Using the EPRI In Situ Pressure Test Guidelines to screen detected flaws, one (1) circumferential flaw located within the tubesheet in tube R75 C30 in SG32 was selected to be in situ pressure tested. The flaw had a measured maximum depth of 100% through-wall (TW) and a Percent Degraded Area (PDA) of 76.18% and was located more than six inches below the secondary face of the tubesheet. The flaw, because of its location, is restricted from burst and pullout. Additionally, analysis indicated that it is highly unlikely to leak at accident pressures. However, as a conservative measure, the tube was leak tested at accident pressures using EPRI guidelines and exhibited zero leakage. No other circumferential flaws met the screening criteria for in situ pressure testing. All detected circumferential cracks were removed from service by plugging and staked as required. No other forms of tube degradation, (e.g., Axial SCC, wear, volumetric) were of a sufficient size or extent to require in situ pressure testing.

3. In Section 4.0 of your 10/15/03 letter, you indicated that you expanded your RC examinations to include a five tube buffer zone around a tube with a lower bundle freespan axial indication. Please provide additional information regarding the type of indication identified (size, etc.) and how was it identified (bobbin, RC). In addition, please discuss the technical basis for the five tube buffer zone (e.g., why is the degradation limited to the region surrounding the identified flaw).

APS Response:
A free-span axial crack was found in Unit 3 Steam Generator #2 (SG32) in tube R102C143 at TSH +10.04 inches. At this location, there was evidence of a distinct sludge deposit which indicated a localized condition. There was no other evidence of denting, cold working or tube bowing. A review of ECT results for this region determined this was the only axial SCC call made. Typically, only volumetric and NQIs calls are made at this region/elevation of the steam generator.

This flaw was found using bobbin non-destructive examination (NDE) techniques and was very small, with a measured length of 0.2 inches and 0.23 volts. As such, this flaw was not considered to be a structural or leakage integrity issue. The Plus Point inspection was expanded covering a five (5) zone in all directions around the flaw. No other indications were identified. As no other indications either by Plus Point or bobbin coil were found, PVNGS concluded that the existing 100% bobbin coil program was sufficient in identifying this form of degradation and that this indication was an isolated occurrence which did not constitute a new damage mechanism.

As part of PVNGS steam generator tube integrity program, all bobbin indications regardless of location are further interrogated with a plus point probe. It has been PVNGS experience using a five (5) tube buffer zone provides reasonable assurance of detecting a local damage phenomenon and demonstrating the adequacy of the bobbin coil. This position has been previously provided to the NRC staff. A review of historical data confirmed that the tube was affected by a localized sludge deposit which was not removed during chemical cleaning. This is also the first indication of its kind and considered an isolated incident with minimal integrity impact. Finally, there is no evidence of signal masking and as such, bobbin coil is qualified for detection of this degradation and 100% bobbin coil inspections were performed, with no similar defects detected.

4. Please discuss the source of origin for the loose part detected in SG32. In addition, please discuss whether a foreign object search and retrieval (FOSAR) was performed and whether the loose part was removed from the SG. If the part was not removed, please discuss whether you assessed the impact the loose part could have on tube integrity.

APS Response:
The analysis of eddy current data detected an external anomaly and for conservatism was designated a potential loose part (PLP) in SG32. The inspection also indicated a small volumetric flaw (approximately 8% TW) as well and, as such, was designated as a loose part indication (PLI) in the affected tube (R150C63 at 01H +0.66 inches). This location is just above the hot leg flow distribution support (01H). Access to this area of the steam generator is severely limited and therefore visual inspection or retrieval was not considered feasible. As such, it was not possible to confirm whether the signal was attributed to a loose part or a deposit. From a program perspective, a more conservative approach is dictated for a loose part designation.

For example, as required by PVNGS steam generator program, a Plus Point probe inspection expansion was completed to bound and characterize the possible extent of any potential loose part and to determine if any other tubes were affected. The Plus Point probe expansion sample included eight (8) surrounding tubes, and did not find any other indications of a loose part or any detectable wear. As required by PVNGS steam generator program, and described in APS response to GL 97-05, tube R150C163 was preventatively plugged and staked at this location.

5. In Table 1 of your October 15, 2003 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. In addition, please discuss whether all wear indications were inspected with a rotating coil to verify that no cracking was associated with the wear indications. If all wear indications were not inspected with a RC, please discuss the technical basis for your sampling strategy. Please confirm that an RC examination was performed on any distorted support indications (DSIs) identified by either the primary or secondary eddy current data analyst (consistent with your practice in 2002 for Unit 2).

APS Response:
All bobbin flaw type indications that were called during U3R9 were programmed to be examined by Plus Point during U3R10. This includes all bobbin wear indications, as well as all previous Indication Codes or I-Codes (e.g., Category III per EPRI PWR Steam Generator Examination Guidelines).

All new wear indications and I-Codes are also RC examined. All dents >2volts located at supports from the 01H thru the 05H were also examined with Plus Point based on the PVNGS Degradation Assessment. A sample of manufacturing buff marks (MBMs) and bulges were also included. Further information regarding the classification and inspection of service induced and nonservice induced indications can be found in APS response to Generic Letter 97-05.

Finally, it should be noted that a section was included in the Resolution Training that documented APS's expectation to "keep" all bobbin DSIs called by either the Primary or Secondary Analyst on hot leg eggcrates and vertical strap locations.

6. Please clarify the "Row 1 thru 5" entries in Table 2 of your October 15, 2003 letter. For example, in steam generators 31 and 32, was one tube (in rows 1 through 5) plugged for a dent? If so, discuss the size of the dent, whether it has changed with time, and the reason for plugging these particular dents.

APS Response:
For clarification purposes, tube R2 C27 was plugged for dent indications located at the BW1 +4.16" and at BW1 +8.68. The physical location of these is between the hot leg tangent and apex and the other between the apex and the cold leg tangent. These indications had not changed from U3R9; however, the tube was preventatively plugged due to the possible masking effect of the dent signals. This tube was examined with both the mid-frequency (MF) and high-frequency (HF) Plus Point coils. No crack indications were noted with either coil.

7. In Table 1 of your October 15, 2003 letter, you indicate that only certain inspections marked with a "TS" are those used to satisfy your technical specification requirements. Please clarify this statement. For example, please clarify the acceptance criteria used during the "non-technical specification" inspections and the technical basis for the acceptance criteria (e.g., was it the same as the technical specifications). In addition, please clarify that all indications detected during the "bobbin coil technical specification" inspections which could not be reliably sized or were greater than the plugging limit were plugged regardless of the results of the "non-technical specification inspections." Alternatively, please confirm that all inspections were performed in accordance with your Technical Specifications in conjunction with Appendix B to 10 CFR Part 50 and that the acceptance criteria in your Technical Specifications were applied to all indications detected as a result of these inspections.

APS Response:
The inspections designated "TS" are conducted to demonstrate that the section of tubing inspected satisfied Technical Specification (TS) Section 5.5.9.4.10, Tube Inspection (i.e., point of entry {hot leg side} completely around u-bend to the top support of the cold leg). The other inspections listed in Table 1 are supplemental inspections performed by APS to ensure 10 CFR 50, Appendix B requirements are satisfied for the required TS surveillance. The TS acceptance criterion for repair of defective tubing was applied to all indications detected by the PVNGS inspection program. Additionally, all information and commitments made in response to Generic Letter 97-05 are applied as well (e.g., all corrosion related degradation are plugged on detection). All bobbin indications that could not be reliably characterized by Plus Point, or were greater than plugging limit were plugged regardless of the results of the supplemental inspections.

Finally, the U3R10 inspections were performed in accordance with NEI 97-06 and the EPRI PWR Steam Generator Examination Guidelines.

8. Four tubes listed in Appendix G (R2C27 in SG31; R14C27, R15C63, R80C143 in SG32) were not listed in Appendices C and D, which provided the reason for tube plugging. Please clarify the reason for plugging these tubes.

APS Response:
SG 31 tube R2 C27 was the tube noted in Question 6 above. It was plugged for dents located in the bend region.

SG 32 tube R14 C27 was preventatively plugged for a deposit located above the TSH. This indication response from this deposit was large enough to possibly mask flaw indications. This type of signal is not typical of PVNGS data in any of the units, and is possibly the only one noted. Therefore, it was plugged due to possible masking effects.

SG 32 tube R150 C63 was plugged and staked due to a loose part with wear (note Question 4 above). Appendix E contains the summary of all loose part indications.

SG 32 tube R80 C143 was preventatively plugged due to a permeability variation that also could possibly mask flaw type indications.

Figures for U3R10 Steam Generator Tube Inspection Request for Additional Information (RAI) Response

(Letter 102-0524)

PVNGS Steam Generator Tube Supports

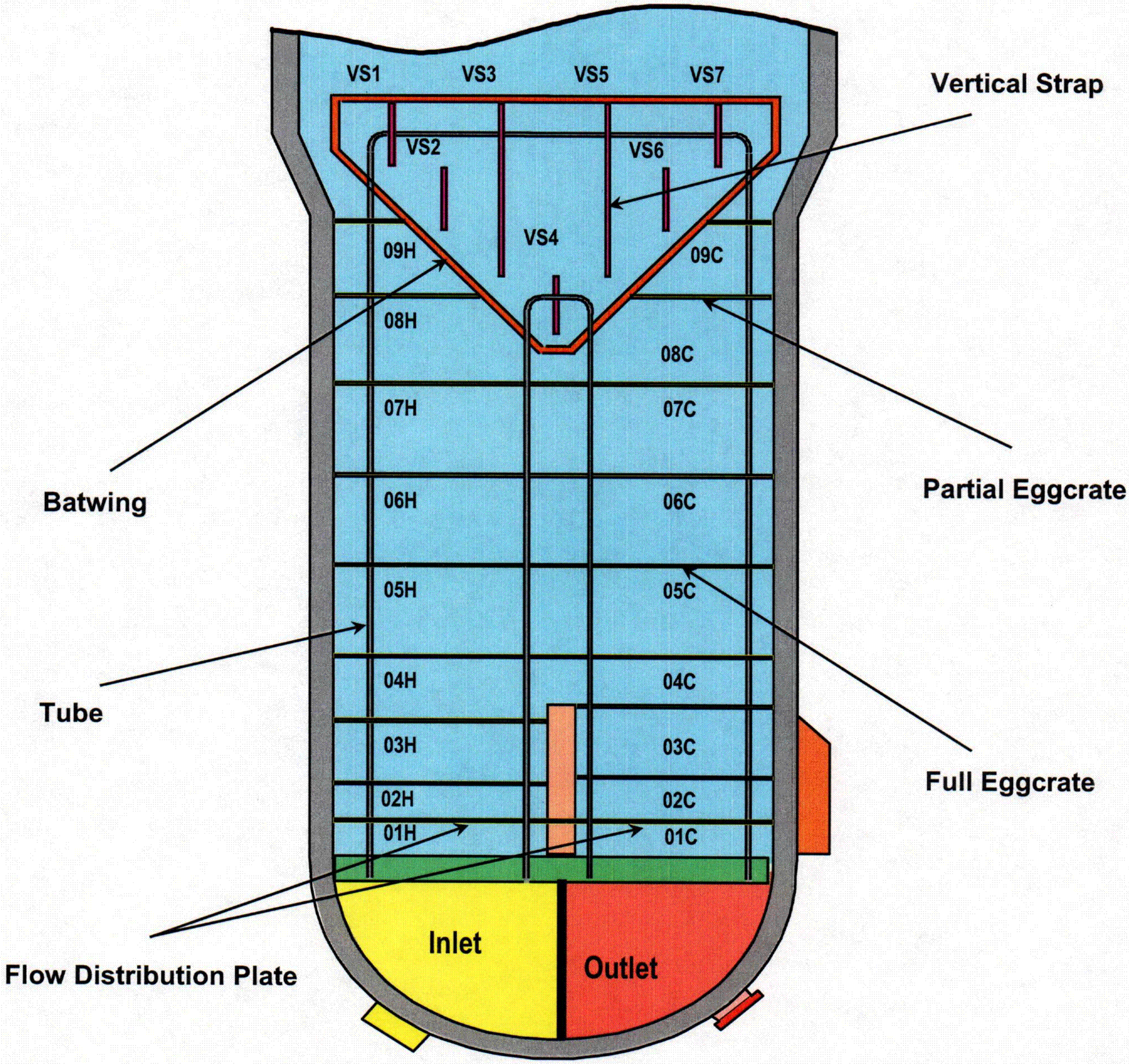

Figure 1

C01

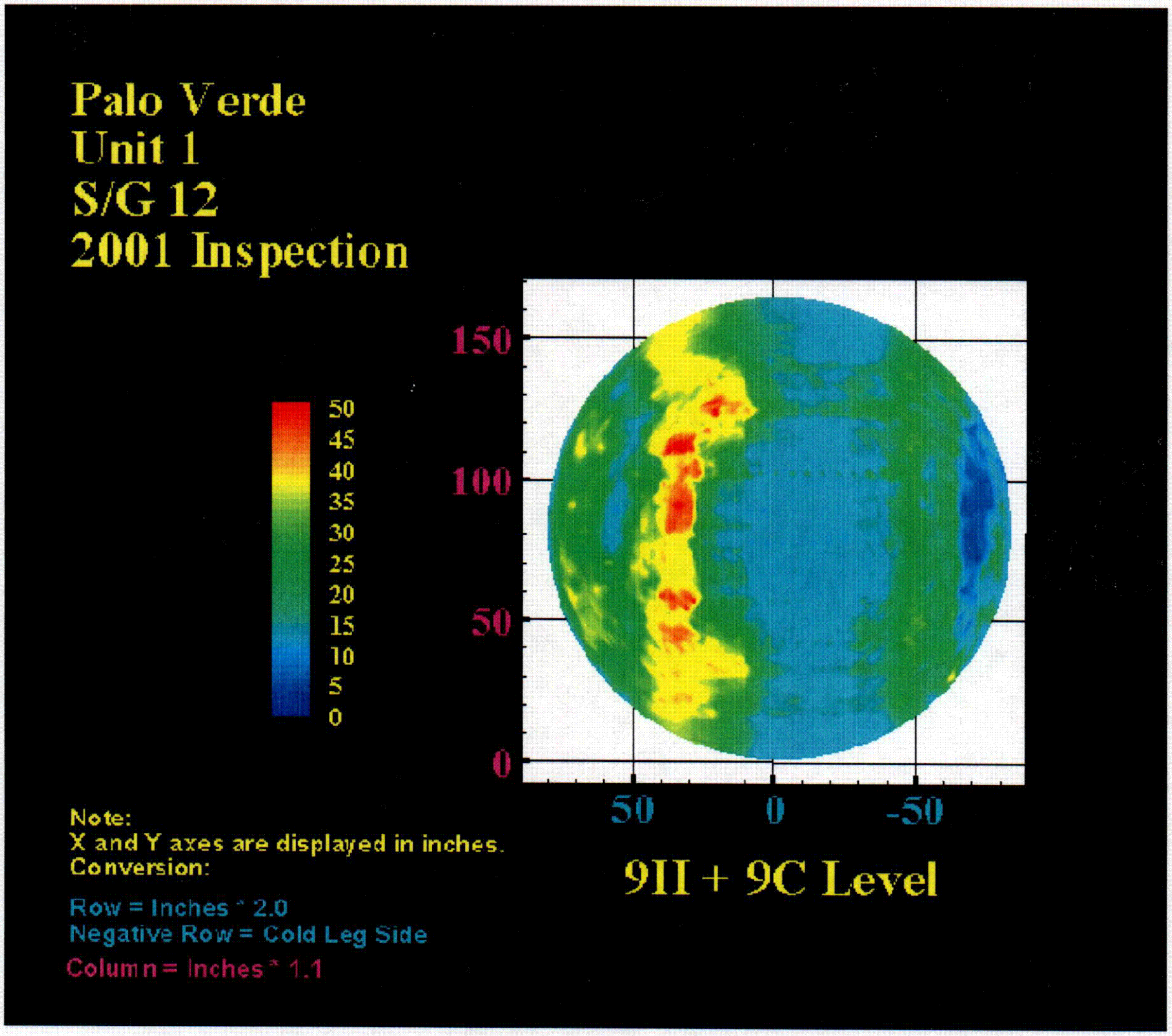

Figure 2

Note: Plot indicates region of deposition at the 09C support that corresponds radially with tubes with detected cold leg side degradation. Significant deposition on hot leg side corresponds with typical hot leg ARC region

C02