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U. S. Nuclear Regulatory Commission
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SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NO. 50-445
UNIT 1 THIRTEENTH REFUELING OUTAGE (1RF13) STEAM GENERATOR
180 DAY REPORT

Dear Sir or Madam:

By means of the enclosure to this letter, Luminant Generation Company LLC (Luminant Power) submits the steam generator tube in-service inspection 180 Day Report as required by Technical Specification 5.6.9 for the Unit 1 thirteenth refueling outage (1RF13).

This communication contains no new licensing basis commitments regarding Comanche Peak Unit 1. Should you have any questions, please contact Mr. Jack Hicks at (254) 897-6725.

Sincerely,

Luminant Generation Company LLC

Mike Blevins

By: Fred W. Madden
Fred W. Madden
Director, Oversight & Regulatory Affairs

Enclosure - SG-SGMP-08-4, Comanche Peak Unit 1 Steam Generator Cycle 13 Condition Monitoring and Cycles 14, 15, and 16 Operational Assessment

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A047
URR

Westinghouse

SG-SGMP-08-4

Comanche Peak Unit 1
Steam Generator Cycle 13 Condition Monitoring and Cycles 14, 15, and 16 Operational Assessment

October 2008

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Westinghouse Electric Company LLC

Comanche Peak Unit 1 (CPNPP)
Steam Generator Cycle 13 Condition Monitoring and Cycles 14, 15, and 16 Operational Assessment

1.0 INTRODUCTION

Per Reference 1 (NEI 97-06), a condition monitoring assessment that evaluates structural and leakage integrity characteristics of SG eddy current indications is to be performed following each inspection. Condition monitoring is "backward looking" and compares the observed EOC-13 steam generator tube eddy current indication parameters against structural and leakage integrity commensurate with Reference 2 (EPRI 1012987, Tube Integrity Assessment Guidelines, Revision 2). Additionally, an operational assessment, or "forward looking" evaluation is used to project the inspection results and trends to the next inspection to determine primarily if tube structural or leakage integrity will be challenged at the next scheduled steam generator eddy current inspection at EOC-16. This report herein documents the condition monitoring assessment of the CPNPP Unit 1 replacement steam generators (RSGs) based on the NDE results from the 1RF13 Refueling Outage inspection at EOC-13 conditions. This report also documents the operational assessment of the CPNPP Unit 1 RSGs up to the next scheduled inspection at EOC-16.

The CPNPP Unit 1 RSGs are Westinghouse Model Delta 76 SGs with 5532 Alloy 690 thermally treated (TT) U-tubes. The nominal tube dimensions are OD of 0.750 inch with 0.043 inch wall thickness. The Row 1 and Row 2 tubes have a nominal wall thickness of 0.044 inch. The tube pitch is triangular with a leg dimension of 1.03 inch. The tubesheet thickness is 24.315 inches, including a nominal primary side cladding thickness of 0.25 inch. All tubes are hydraulically expanded through the tubesheet thickness. Tubes are supported by ten (10), 1.125 inch thick, trefoil broached hole tube support plates (TSPs). In the U-bend region the tubes are supported by four (4) sets of type 405 stainless steel anti-vibration bars (AVBs) with a 0.48 inch width and 0.14 inch thickness. AVB insertion depth is staggered with alternating AVBs to provide for increased vertical flow through the AVB region. The first Delta-style RSG which entered service were installed at V. C. Summer in 1994. To date, there has been no reported tube plugging in these RSGs due to operational degradation (Reference 3).

The CPNPP Cycle 13 operating period was 520.12 EFPD, or 1.424 EFPY. No eddy current inspection is planned for the 1RF14 and 1RF15 outages; the next scheduled eddy current inspection is the 1RF16 outage. Operating cycle lengths of 1.43 EFPY will be assumed for Cycles 14, 15, and 16 within the operational assessment portion of this evaluation.

One tube was plugged in the shop as a result of a manufacturing related issue. This tube location is R32 C90 in SG3. Thus the active tube count upon Cycle 13 startup was 5532 in SG1, SG2, and SG4, and 5531 in SG3. No tubes were plugged at the 1RF13 inspection.

During Cycle 13 the NSSS power level was 3458 MWt. CPNPP Unit 1 will operate at an uprated NSSS power level of 3628 MWt upon Cycle 14 startup. This power level is expected to remain constant through the operational period to the next scheduled eddy current inspection.

2.0 OVERALL CONCLUSIONS

During the CPNPP 1RF13 steam generator tube inspection, no indications exceeding the structural integrity limits for either axial or circumferential degradation (i.e., burst integrity ≥ 3 times normal operating primary to secondary pressure differential across SG tubes) were detected. Delta 76 SGs are not subject to adjustment of the structural integrity performance criterion due to secondary loading effects thus the performance criterion is based on application of a safety factor of 3 upon the normal operating primary to secondary pressure differential. Therefore, no tubes were identified to contain eddy current indications that could potentially challenge the tube integrity recommendations of Reference 1. Similarly, all operational assessment structural and leakage integrity requirements are predicted to be satisfied at EOC-16 for the degradation mechanisms observed at EOC-13.

2.1 Impact of Industry Events Upon Conclusions of Operational Assessment

The ability of CPNPP Unit 1 to operate up to the 1RF16 outage without eddy current inspection of the SGs is partly dependent upon operating experience of similar units. For example, if a plant utilizing similar SGs should experience an unexpected degradation mechanism which causes a performance criterion to be compromised, it may be advisable that an eddy current inspection be performed prior to the 1RF16 outage. Based on current operating experience for Alloy 690 TT tubing, it is highly unlikely that an industry event involving corrosion of Alloy 690 TT tubing would be experienced prior the 1RF16 outage, thus the likelihood that eddy current inspections will be required prior to 1RF16 is exceptionally low.

2.2 Trackable Anomalies (TRA)

The pre-service inspection (PSI) identified a condition suggestive of reduced tube-to-tube clearance in the U-bend region. These locations were identified with a bobbin TRA code. Such indications are reported from the ¼ prime absolute channel. None of the TRA signals at 1RF13 contained bobbin signals suggestive of degradation, i.e., tube-to-tube contact wear. All TRA signals at 1RF13 were examined using the +Pt coil; none were reported to contain volumetric degradation.

An evaluation was performed for a similar plant. This evaluation concluded that signal amplitude of 3.50 volts in the ¼ prime absolute channel represents a contact condition. The largest TRA bobbin amplitude reported at 1RF13 was 1.87 volts in channel 6. The voltage normalization process applied at 1RF13 varied slightly from the voltage normalization used in the other program. A comparison of the normalization processes was performed and concluded that the 1RF13 amplitudes need to be increased by a factor of 1.25 to be consistent with the other data. Thus the largest TRA signal amplitude is adjusted to 2.34 volts for comparison with the 3.50 volt contact threshold. At 2.34 volts the gap is estimated at 0.026 inch. Twenty such tubes were identified in SG1; two in SG2, four in SG3, and two in SG4. Figure 1 presents a plot of the upper bundle TRA signals for all SGs.

Three other tubes were identified with TRA signals in non-U-bend regions; the TRA code is applied for tracking purposes. These TRA signals are not associated with a reduced tube-to-tube clearance condition. In SG3, R69 C19 and in SG4, R7 C99, were identified in the PSI with TRA signals in the expanded tube-in-tubesheet region just below the bottom of the expansion transition. These signals were examined with +Pt at 1RF13; no signal change was noted. As these signals were reported in the baseline they are an artifact of manufacture, possibly a scratch or gouge. Alternatively, these signals may be a resultant of foreign material, such as machine chip, from tubesheet hole drilling which became trapped between the tube and tubesheet during tube expansion. In the PSI, SG1, R56 C94 was identified with a TRA signal at 03H +21.98 inch. The TRA signal was applied as the bobbin signal parameters exist within the reporting window for freespan ODSCC. This signal was examined with +Pt in the PSI; no degradation was reported. This signal was again identified as a TRA by bobbin at 1RF13. There is no signal change in the bobbin coil data between the PSI and 1RF13 thus suggesting that degradation is not present. The +Pt data is representative of a ding signal. A common phenomenon of Alloy 690 TT tubing is that small ding signals can rotate into the flaw plane after the first cycle of operation but consistently have been shown to not include degradation by RPC examination. This signal included bobbin signal rotation in the PSI and at a consistent phase angle reporting at 1RF13. These three tubes remain in service. The next scheduled eddy current inspection at 1RF16 will include bobbin and +Pt inspection of these tubes.

2.3 Upper Bundle Deposits

Bobbin data analysis for SG1 identified PLP reports on 6 tubes (R9, 15, 17, 19, 21, and 23 in Column 83) in the 09H to 10H span, at approximately 14 to 17 inches above 09H. Subsequent RPC testing did not identify a PLP but suggested the presence of axially oriented deposits on the tube OD. These deposits generally increase with proximity to 10H, and in some cases, extend through the TSP at the trefoil lobe. Figure 2 provides a visual inspection photograph of these deposits.

3.0 PRE-OUTAGE EVALUATION OF SG DEGRADATION STATUS

Pre-Outage Degradation Assessment

A pre-outage degradation assessment (Reference 3) pursuant to Reference 2 (EPRI 1012987), was performed for CPNPP 1RF13. This degradation assessment (Reference 3, SG-CDME-08-30, "Steam Generator Degradation Assessment for CPNPP 1RF13") identified the degradation modes which could occur at CPNPP Unit 1 and evaluated the adequacy of the eddy current techniques applied for detection and sizing of these mechanisms.

Per Reference 2, two modes of degradation are considered, existing, and potential. An existing mechanism is described by its name; any degradation mechanism which has been observed at CPNPP Unit 1. A potential mechanism is a mechanism not previously reported at CPNPP Unit 1, but has a realistic likelihood of occurrence based on inspection results at similar units or based on laboratory studies. As the 1RF13 inspection is the first in-service inspection of the CPNPP Unit 1 RSGs there are no existing degradation mechanisms.

The degradation assessment concluded that the following degradation mechanisms were potential in the CPNPP Unit 1 RSGs based on similar plant experience:

- Tube wear at anti-vibration bar (AVB) intersections
- Tube wear due to loose parts/foreign object interaction

CPNPP 1RF13 Initial Inspection Plan

The CPNPP 1RF13 initial inspection plan exceeded both the Technical Specification minimum requirements as well as the recommendations of Reference 4 (EPRI TR-1003138). The 1RF13 initial inspection plan included:

1) 100% full length 0.610 inch bobbin inspection (Row 4 and higher)
2) 100% 0.610 inch bobbin inspection of hot and cold leg straight sections in Rows 1, 2, and 3
3) 100% Rows 1, 2, and 3 small radius U-bend +Pt inspection in each SG using a mag-biased, mid-range Plus Point (+Pt) coil
4) 20% hot leg TTS +Pt inspection in each SG from 3 inches above to 3 inches below TTS
5) 100% +Pt inspection of all dents/dings ≥ 5 volts (from bobbin analysis)
6) 100% +Pt inspection of trackable anomaly signals* (TRA) from the pre-service inspection (PSI) and/or 1RF13
7) Special interest RPC (freespan signals without historical resolution, bobbin I-code indications, etc)
8) 100% tube plug video inspection (1 tube in SG3)
9) Top of tubesheet secondary side video inspection including FOSAR
10) Upper bundle video inspection in one SG (SG1)

(*): TRA signals are believed to be associated with tube proximity conditions in the U-bend region. Based on a comparison of the TRA signal amplitudes from the PSI with other data developed for similar SGs, no tubes are believed to be in physical contact with each other.

CPNPP 1RF13 Eddy Current Inspection Expansion

There was no scope expansion at the 1RF13 inspection.

Degradation Structural Limits

Reference 3 (CPNPP 1RF13 SG Degradation Assessment) identified length and depth based structural limits for freespan axial and circumferentially oriented degradation and volumetric degradation. The degradation assessment provides the structural limits and NDE uncertainties to support the condition monitoring and operational assessments of this report.

Reference 3 (CPNPP 1RF13 SG Degradation Assessment) established a conservative $3\Delta P_{NormOp}$ value of 3762 psi to be applied to the condition monitoring and operational assessment process. This value is based on steam pressure measurement during Cycle 13.

3.1 CPNPP 1RF13 Identified Degradation Mechanisms

Indications suggestive of the following degradation mechanisms were detected in the CPNPP 1RF13 inspection:

- Freespan volumetric degradation not associated with a corrosion mechanism

One tube in SG2 (R13 C01) was reported to contain a bobbin DFI signal at the 01H +8.08 inch elevation (eight inches above FDB). There was little change in the bobbin signal parameters between the PSI and 1RF13. RPC (+Pt) inspection of the location identified a shallow volumetric signal. The depth of the indication was measured at <10%TW using the ETSS 21998.1 sizing technique. The axial and circumferential involvement lengths were approximately 0.14 inch and 26 degrees arc. This location is likely attributed to a lap. The indication was sized at <40%TW and justified for continued operation.

AVB wear was not reported at the 1RF13 inspection. This observation is not uncommon for Delta style RSGs. The nominal tube-to-tube dimension along the 1.03 inch pitch dimension is 0.142 inch while the nominal AVB width is 0.140 inch. The limited tube-to-AVB gap effectively reduces the potential for relative motion between the AVBs and tubes, thus effectively reducing the potential for tube wear.

PLP Signals

Possible loose part (PLP) signals were reported by bobbin between 09H and 10H on six tubes in column 83 in SG1. Subsequent +Pt examination did not confirm the presence of a PLP but did confirm the presence of OD deposits on column 82, 83, and 84 tubes. These tubes were left in service. Figure 2 presents a photograph of the deposits. One tube in SG4, R8 C38, was reported to contain a PLP signal from RPC at 0.1 inch above the top of tubesheet. This location was visually inspected following sludge lancing; no PLP was observed. RPC testing of R8 C38 and surrounding tubes following the visual examination did not identify PLP signals.

In SG2 hot leg, a small metallic object was observed by FOSAR and removed from the top of tubesheet. The object appears to be a remnant of manufacture, approximately 1 inch long, approximately 0.03 to 0.06 inch high, with width much less than height. No eddy current signal was associated with this object. A pre-sludge lance foreign object search (FOS) was performed in SG2 only; the FOS was performed post-lancing in the other SGs. The pre-sludge lance FOS of SG2 identified pieces of tube scale and small wire bristle brush wires. The scale and bristle brush wire was not found in the post-sludge lance FOS. No other foreign objects were observed by FOSAR in SG2 or the other SGs.

Disposition Techniques for Identified Degradation Mechanisms

Depth measurement of AVB wear indications by bobbin is accepted as a method for evaluation against the 40% depth repair criteria.

All crack-like indications in the tubesheet region, expansion transition, sludge pile region, freespan, and TSP intersections are repaired upon detection since depth sizing technique uncertainties are not an acceptable method for evaluation against the 40% depth repair criteria. No crack-like indications were reported at 1RF13.

Volumetric degradation in the freespan with no bobbin signal change from the PSI is evaluated for repair against the 40% repair criterion as such signals do not represent a corrosion related degradation mechanism. In the event that volumetric signals are reported with change from the PSI, the tube would have been plugged.

Reference 3 provides guidance related to assessing tube operability for observed permeability variations. The reporting criteria for PVN is >1 volt by bobbin with no voltage reporting threshold by RPC. No PVN signals were reported during the 1RF13 inspection.

4.0 Degradation Mechanism Classification for 1RF16

Based on the CPNPP 1RF13 inspection results and prior inspection results for similar SGs, no mechanisms are considered existing per Reference 3, for the 1RF16 inspection.

Based on the CPNPP 1RF13 inspection results and prior inspection results for similar SGs, the following mechanisms are considered potential per Reference 3, for the 1RF16 inspection:

- Tube wear at anti-vibration bar (AVB) intersections
- Tube wear due to loose parts/foreign object interaction
- Freespan volumetric degradation not associated with a corrosion mechanism

As the freespan volumetric degradation not associated with a corrosion mechanism is attributed to an artifact of manufacture this category is not associated with a result of operation and thus is categorized as potential as no growth can be incurred.

FOSAR inspection of the top of tubesheet region has established that no foreign objects are present at the top of tubesheet region.

4.1 Summary of Eddy Current Signal Reports

Table 1 presents a pivot table numerical summary of all eddy current signal reports for the 1RF13 inspection. The data of Table 1 is for a signal basis, not a tube basis, thus the number of affected tubes can be less than the number of signals.

Table 1

Signal	Description	Probe	SG1	SG2	SG3	SG4	Total
ADS	Absolute Drift Signal	Bobbin	0	0	0	2	2
DFI	Differential Freespan Indication	Bobbin	0	1	0	0	1
DFS	Differential Freespan Signal (RPC NDF)	Bobbin	1	2	0	0	3
DNG	Ding	Bobbin	54	34	72	22	182
INF	Indication Not Found	Bobbin / RPC	9	1	2	11	23
INR	Indication Not Reportable	Bobbin / RPC	233	83	299	85	700
NDD	No Detectable Degradation	Bobbin / RPC	6868	6937	6866	6967	27638
NDF	No Degradation Found	RPC	32	4	5	7	48
PCT	Percent Throughwall	Bobbin / RPC	0	1	0	0	1
PLP	Possible Loose Part	Bobbin / RPC	6 (1)	0	0	1 (4)	7
TRA	Trackable Anomaly	Bobbin / RPC	21 (2)	2	5 (3)	3 (5)	31
VOL	Volumetric	RPC	0	1	0	0	1
Total			7224	7066	7249	7098	28637 (6)

(1): Signals are attributed to deposits in freespan region. Visual examination showed no PLP.
(2): Includes one signal in the vertical straight section above 03H.
(3): Includes one signal in the expanded tube-in-tubesheet region.
(4): Visual examination showed no PLP. RPC post visual examination did not include a PLP report.
(5): Includes one signal in the expanded tube-in-tubesheet region.
(6): Does not include RBD, RND, RIC, or RRT reports as all retests of such tubes included complete, analyzable data.

5.0 Operational Assessment

5.1 General Discussion

As no degradation mechanisms challenged structural or leakage integrity at 1RF13, and SGs with Alloy 690 TT tubing have operated in excess of 10 EFPY without reporting of stress corrosion degradation, the likelihood of an indication posing a challenge to structural or leakage integrity at the end of the Cycle 16 operating period is considered negligible.

5.2 Detailed Growth Evaluation

5.2.1 AVB Wear

AVB wear in Delta style RSGs has only been reported at one plant; ANO-2. These RSGs replaced C-E original SGs, and are significantly larger than Delta style RSGs which are installed in Westinghouse plants. AVB wear has not been reported at V. C. Summer, Shearon Harris, or South Texas Units 1 and 2. Thus, while AVB wear was identified as a potential mechanism for the 1RF13 inspection, observation of AVB was not anticipated based on the results of the other Delta style Units of similar size.

Application of ANO-2 AVB wear growth rates will represent an extremely conservative assessment. The first ISI of the ANO-2 RSG was performed in 2002. No AVB wear was reported in SG1; two AVB wear reports of 8 and 12%TW were reported in SG2. Eddy current inspection was not performed at the 2003 outage. At the 2005 outage, nine indications ranging from 9 to 21%TW were reported in SG1 while thirteen indications ranging from 5 to 26%TW were reported in SG2. The 26%TW indication had the 12%TW report in 2002. For the two indications with reports in 2002 the growth values are 5.2 and 1.9%/EFPY. If a 5%TW detection threshold is applied to the 2002 data, the largest growth rate is 5.9%/EFPY. This value also represents the 95th percentile growth rate based on 22 growth data points.

Therefore, for the operational period to 1RF16 (4.29 EFPY), the maximum AVB wear growth allowance is 25.3%TW.

5.3 Operational Assessment for Cycle 14, Cycle 15, and Cycle 16

The tube logs for the CPNPP Unit 1 RSGs were used to develop the mean plant specific room temperature flow stress value of 143.49 ksi. The standard deviation on flow stress is 2.37 ksi. At 650^{o}F the mean flow stress is 124.77 ksi with a standard deviation of 2.06 ksi.

The AVB width is 0.48 inch. Considering the angles that AVBs cross the tubes a maximum effective contact width of 0.60 inch is developed.

The operating temperature flow stress, standard deviation of flow stress, and maximum effective length were input to a Monte Carlo simulation of burst pressure for axial thinning, consistent with equation 5.33 of Reference 5. At the lower 95th percentile the flaw depth which provides for burst capability of 3.762 ksi using the above inputs is 66.3%TW.

Thus the difference between the structural limit of 66.3% and maximum growth allowance of 25.3% can be used to define the maximum permissible flaw depth at the beginning of Cycle 14 condition which would satisfy the structural integrity performance criterion at EOC-16 of 41%TW.

This BOC-14 depth of 41%TW would readily be detectable, thus it can be established that the CPNPP Unit 1 RSGs can operate up to the 1RF16 inspection without challenging the structural integrity performance criterion.

To assess the detection capabilities of AVB wear at 1RF13, a sampling of 40 AVB wear locations per SG was performed to develop a distribution of noise values at AVB locations. The 95th percentile P2 channel noise value is 0.06 Vvm.

This distribution was compared with the expected flaw amplitudes for various depth AVB wear scars, developed from the average of one calibration standard for each SG. Assuming a signal to noise ratio of 1.5 will result in high probability of detection. This implies that flaw signal amplitudes of 0.09 volt will be reliably detected. Based on the AVB wear calibration curves a 0.09 volt signal represents an AVB wear depth of 5%TW.

If a BOC-14 depth of 5%TW is assumed the expected maximum depth at EOC-16 is estimated to be bounded by 30%TW, which is well below the structural limit of 66.3%TW, and the structural integrity performance criterion is satisfied. It should be noted that wear mechanisms are a constant energy process. Thus, as the volume of the wear scar as a function of depth increases at a rate greater than associated with a linear relationship, the apparent depth growth is then decreased with increasing wear depth. For example, the volume removed for a 40%TW wear scar is more than double the volume removed for a 20%TW wear scar. As the rate of volume removal rate is constant, the apparent depth growth is decreased. This has been observed at numerous plants with large numbers of wear scars. The increase in reactor power (and steam flow rate) could increase wear growth rates. An evaluation (Reference 6) has concluded that the best estimate increase in wear growth rates due to operation at 3628 MWt is approximately 10%, thus, a bounding end of Cycle 16 wear depth of 33%TW could be experienced if the power uprate negatively affects wear growth rates.

6.0 Operational Assessment Summary

This operational assessment has established that CPNPP Unit 1 can operate for at least 4.29 EFPY up to the EOC-16 period without significant probability of observed indications at the 1RF16 inspection exceeding the structural or leakage integrity performance criteria.

7.0 References

1) NEI 97-06 Revision 2, "Steam Generator Program Guidelines" Nuclear Energy Institute

2) "Steam Generator Integrity Assessment Guidelines: Revision 2," EPRI, Palo Alto, CA: July 2006, 1012987

3) SG-CDME-08-30, "Steam Generator Degradation Assessment for Comanche Peak 1RF13 (October 2008)," August 2008

4) "PWR Steam Generator Examination Guidelines: Revision 7,Requirements," EPRI, Palo Alto, CA: October 2007, 1013706

5) "Steam Generator Degradation Specific Management Flaw Handbook," EPRI, Palo Alto, CA: January 2001, 1001191

6) LTR-SGMP-08-22, Revision 1, "Uprate Factor for Tube Wear at Comanche Peak Unit 1 Following an Uprate to 3628 MWt NSSS Power," Westinghouse Electric Co., LLC, October 2008

Figure 1

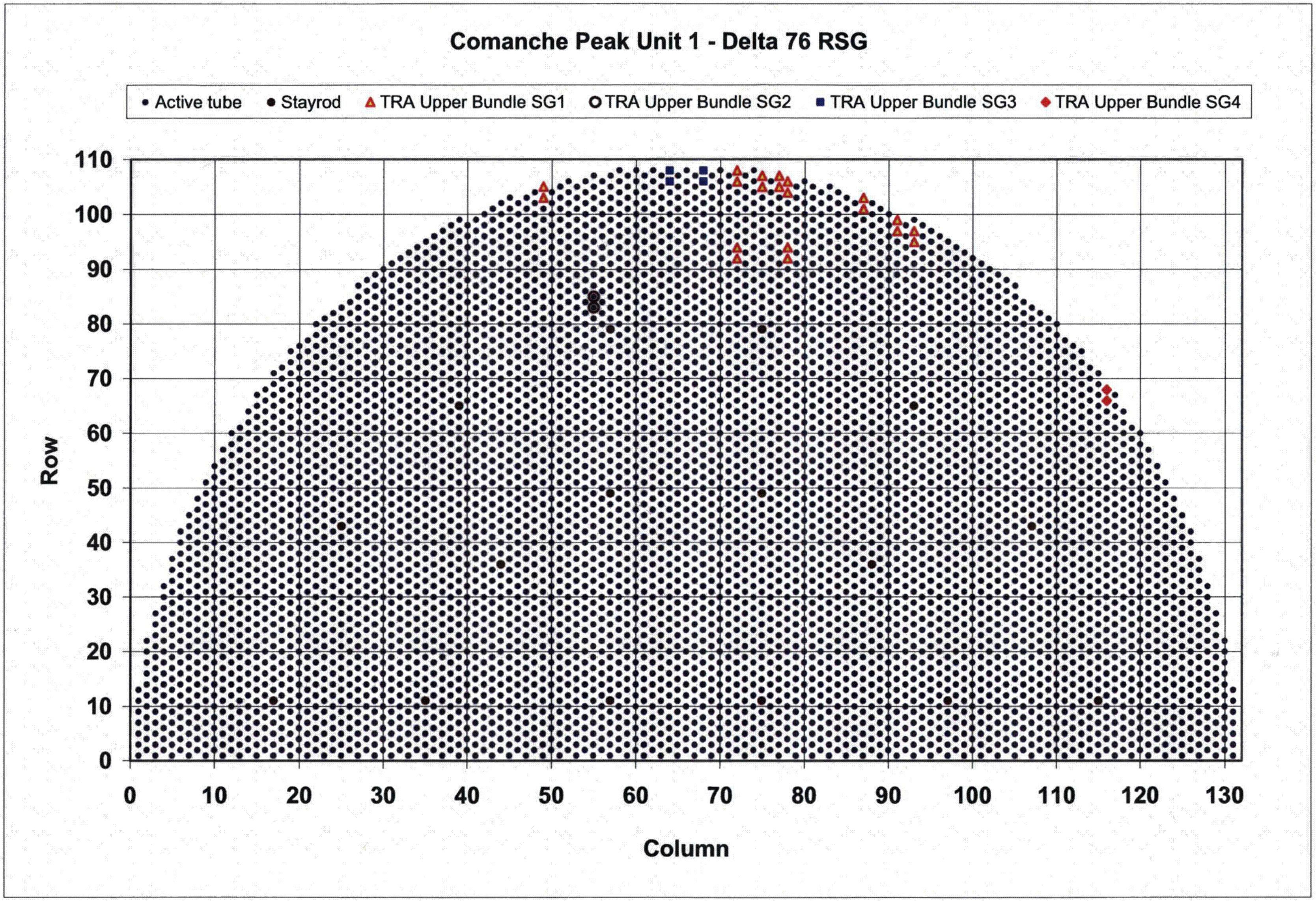
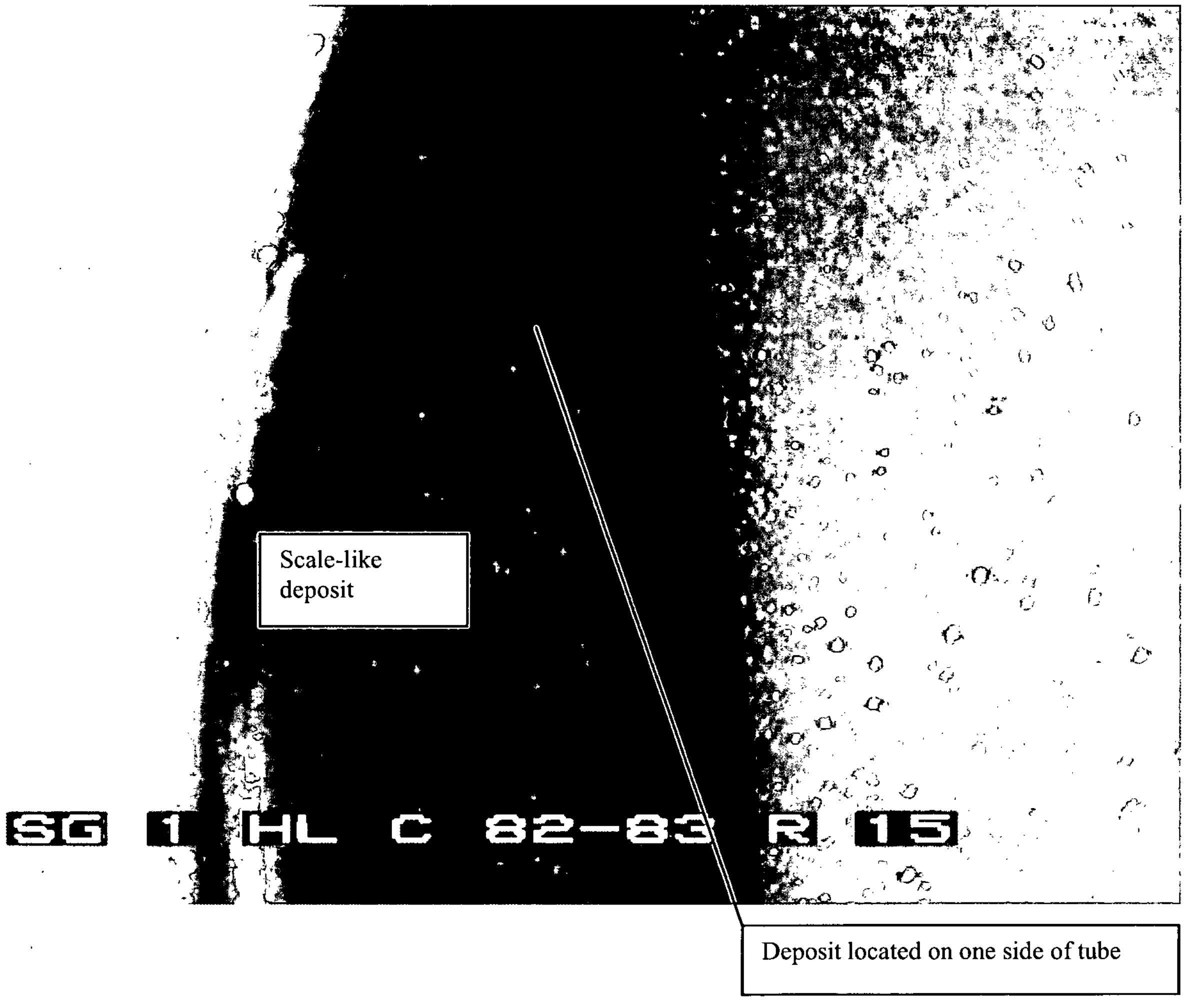

Comanche Peak Unit 1 - Delta 76 RSG
Active tube
Stayrod
TRA Upper Bundle SG1
TRA Upper Bundle SG2
TRA Upper Bundle SG3
TRA Upper Bundle SG4
Row
Column
0
10
20
30
40
50
60
70
80
90
100
110
120
130

Figure 2


SG 1 HL C 82-83 R 15
Scale-like deposit
Deposit located on one side of tube