ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-361/95-14
50-362/95-14

Licenses: NPF-10
NPF-15

Licensee: Southern California Edison Co.
P.O. Box 128
San Clemente, California

Facility Name: San Onofre Nuclear Generating Station, Units 2 and 3

Inspection At: San Clemente, California

Inspection Conducted: July 10 through August 8, 1995, onsite and in-office review through August 30, 1995

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

J. Medoff, Chemical Engineer
Materials and Chemical Engineering Branch
Office of Nuclear Reactor Regulation

J. Russell, Resident Inspector, Project Branch F
Division of Reactor Projects

K. Weaver, Reactor Inspector, Maintenance Branch
Division of Reactor Safety

Accompanying Personnel: Dr. C. Dodd, NRC Consultant

Approved: Ken E. Brockman 9-21-95
Ken E. Brockman, Deputy Director Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 2 and 3): Regional initiative, announced inspection to review the history and material condition of steam generator tubing; to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube

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degradation; and, to assess the effectiveness of licensee programs and training in regard to detection of and response to steam generator primary-to-secondary tube leakage. The inspection additionally included observation of inservice inspection work and work activities.

Results (Units 2 and 3):

- San Onofre Nuclear Generating Station, Units 2 and 3, utilize two Combustion Engineering Model 3410 recirculating steam generators per unit. Each steam generator contains 9350 high-temperature mill annealed U-tubes with a nominal diameter and wall thickness, respectively, of 0.75 and 0.048 inches (Section 2.1).

- San Onofre Nuclear Generating Station, Units 2 and 3, were initially operated with a hot-leg temperature of 609°F. To compensate for a reduction in steam generator heat transfer capability that occurred during service as a result of fouling, the licensee has implemented turbine governor valve modifications in both units during the respective 1995 refueling outages. Subsequent operation of Unit 2 has demonstrated restoration to 100 percent power with a reduction of hot-leg temperature to 607°F (Section 2.2).

- The mechanical properties of the Units 2 and 3 steam generator tubing were noted by the inspectors to be typical for a high-temperature mill annealed condition, with the mean 0.2 percent yield strength and ultimate tensile strength values for samples of Unit 3 tubing observed to be approximately 6000 psi lower than the mean strength values of samples of Unit 2 tubing. The property differences were considered by the inspectors to be related to the lower mean carbon contents of the Unit 3 material (Section 2.3).

- The predominant degradation mode in both Units 2 and 3 during commercial operation was wear at upper tube bundle batwing supports. Other contributors to tube plugging were: wear at upper tube bundle vertical supports; denting of tubes located adjacent to tie rods; improper annealing of tubes by the tubing manufacturer, which resulted in through-wall primary water stress corrosion cracks in three tubes early in commercial operation; and, in the case of Unit 3, damage from loose parts due to degradation of the feedwater distribution box and feedring. (Sections 2.5.1 and 2.5.2).

- Limited circumferential stress corrosion cracking was initially detected at the top of the tube sheet in the Unit 2 steam generators during Refueling Outage RF6, and again in Refueling Outage RF7. The majority of these cracks were at the inside diameter of the tubes and were thus believed to be primary water stress corrosion cracking. One tube in each Unit 3 steam generator was plugged during Refueling Outage RF7 as a result of the initial identification of circumferential stress corrosion cracking at the top of the tube sheet (Sections 2.5.1 and 2.5.2).

Plant Operations

- Equipment and procedures used for the detection of tube leaks and mitigation of tube ruptures were considered adequate, and valid equations were used for quantifying leakage based on grab samples and radiation monitor readings (Section 6.2).

- Alarm setpoints were sufficiently low to alert operators if they did not notice an increasing leakage trend (Section 6.3).

- Operator training and the emergency operating procedures were adequate to mitigate a steam generator tube rupture (Section 6.4).

Maintenance

- The February 1995 discovery of chain segments in Unit 2 Steam Generator 2ME088 was viewed, primarily, as a human performance issue. Management actions taken in response were successful in improving steam generator foreign material exclusion performance during the subsequent August 1995 Unit 3 refueling outage (Section 3.1).

Engineering

- The eddy current examination program requirements were found to be generally consistent with the criteria contained in Electric Power Research Institute EPRI NP-6201, Revision 3. An exception noted was the absence of criteria for handling noisy data. An inspection followup item was identified pertaining to review of the conformance of the eddy current examination procedures with the requirements of Appendix H of Electric Power Research Institute EPRI NP-6201, Revision 3 (Section 4.2.1).

- The use by the licensee of two separate companies to perform independent primary and secondary analysis was considered commendable in terms of attempting to optimize the quality of eddy current data analysis results (Section 4.2.1).

- The reliability of the methodology used to determine whether some eddy current tube data were, or were not, indicative of the presence of shallow inside diameter circumferential defects was considered questionable (Section 4.3).

- Licensee and contractor nondestructive examiner personnel were knowledgeable and performance was good. Nondestructive examination procedures were complete and well written. The licensee's controls over inservice inspection contractors were also good (Sections 8.3, 8.4, and 8.5).

- One weakness was noted pertaining to the absence of documented instructions for the use of a newly created ultrasonic report form (Section 8.4.2).

- The absence until July 1995 of steam generator secondary side inspection requirements was considered a weakness (Section 3.1).

- A lack of rigor in the evaluation review process used by the independent safety evaluation group was noted during a limited review of the handling of steam generator and primary-to-secondary leak detection generic communications (Sections 4.2.2 and 6.1).

Plant Support

- More permissive sodium and chloride blowdown limits were included in the initial licensee secondary side chemistry program requirements than those included in the Electric Power Research Institute guidelines. Since February 1986, secondary water chemistry requirements have conformed with the Electric Power Research Institute secondary water chemistry guidelines as they have evolved (Section 7.1).

- The chemistry program activities and controls were found to be noteworthy, and reflecting favorably on the knowledge and involvement of chemistry staff (Section 7.1).

- Overall, the historical Units 2 and 3 data were considered by the inspectors to reflect progression to excellent current secondary water chemistry performance. However, an increasing trend in sludge removal amounts was also noted. Feedwater iron content (i.e., corrosion product transport to the steam generators) was, thus, considered to currently be the only secondary chemistry issue requiring continued management attention (Section 7.2).

- Extensive efforts have been made by the licensee to upgrade the in-line and laboratory instruments that are used to perform secondary water chemistry analyses (Section 7.4).

- Nine chemistry transients in Unit 2 and 13 in Unit 3 have occurred during commercial operation, with the majority occurring prior to installation of full-flow condensate polishers 1986 (Section 7.5).

Management Overview

- The development of a comprehensive steam generator strategic management plan was considered to be both proactive and of great potential value to management in the determination of needed program actions for maintaining the integrity of the San Onofre Nuclear Generating Station, Units 2 and 3, steam generators (Section 5.1).

- The 1993 decision to restrict hot-leg temperature, despite an accompanying reduction in power, was viewed as an indicator of management awareness of and support for initiatives which could be helpful in limiting the initiation and propagation of stress corrosion cracking (Section 2.2).

- The performance of comprehensive eddy current examinations in both units in 1993 and 1995 was viewed as an appropriate management response to the industry notification of the identification of stress corrosion cracking at the top of the tube sheet at another Combustion Engineering unit (Section 4.1).

Summary of Inspection Findings:

- Inspection Followup Item 361/9514-01; 362/9514-01 was opened (Section 4.2.1).

- Violation 362/9501-02 was closed (Section 9.1).

Attachments:

- Attachment 1 - Licensee Information Furnished in June 30, 1995, Meeting.
- Attachment 2 - Persons Contacted and Exit Meeting.

DETAILS

1 STEAM GENERATOR TUBE INTEGRITY REVIEW (73755, 79501, 79502, 42001)

The objectives of this part of the inspection were: (a) to ascertain the history and material condition of the Units 2 and 3 steam generator tubing; (b) to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation; and (c) to assess the effectiveness of licensee programs and training in regard to detection of and response to steam generator primary-to-secondary tube leakage. The inspection scope and findings are documented in Sections 2 through 7 below.

2 STEAM GENERATOR MATERIALS AND TUBE DEGRADATION HISTORY

2.1 Steam Generator Description

San Onofre Nuclear Generating Station, Units 2 and 3, are Combustion Engineering-designed 1100 megawatt electric pressurized water reactors, which commenced commercial operation on August 18, 1983 (Unit 2) and April 1, 1984 (Unit 3). The San Onofre Nuclear Generating Station design utilizes two Combustion Engineering Model 3410 recirculating steam generators. This model of steam generator contains 9350 Inconel 600 (ASME Material Specification SB-163) U-tubes with a nominal diameter and wall thickness, respectively, of 0.75 and 0.048 inches. Secondary side tube support structures consist of seven horizontal full eggcrate supports, three horizontal partial eggcrate supports, and upper bundle supports (i.e., two batwing diagonal supports and seven vertical supports). The materials used for fabrication of the steam generator vessels and internals (including tube supports) are, respectively, low alloy and carbon steels.

2.2 Hot-Leg Temperature

The inspectors were informed by licensee personnel that the current primary side inlet hot-leg temperature (i.e., T-Hot) for Unit 2 was approximately 607°F. The corresponding T-Hot value for Unit 3 prior to the current Cycle 8 refueling outage was indicated to be approximately 606°F.[1] The inspectors noted that, based on available Electric Power Research Institute information, the San Onofre Nuclear Generating Station, Units 2 and 3, T-Hot values were in the middle of the range of values used by pressurized water reactors. Licensee personnel informed the inspectors that an original T-Hot value of 609°F was used for Units 2 and 3. This value was raised to a maximum of 611°F

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[1]Note: The licensee identifies a refueling outage by the number of the operating cycle which follows the refueling outage, rather than by the more usual number of the operating cycle that has just been completed. To avoid confusion, subsequent references in this inspection report to refueling outages utilize the number of the operating cycle that has just been completed. For example, the Cycle 8 refueling outage is referred to as Refueling Outage RF7.

(by adjusting the cold-leg temperature, T-Cold, to the high end of the allowed range of 551°F to 555°F), to compensate for the loss in steam generator heat transfer capability that was observed to occur during operational service as a result of fouling. On September 7, 1993, the licensee administratively restricted the T-Cold value to 553°F, which reduced the T-Hot values and resulted in a reduction of power to approximately 98 percent. The decision to reduce T-Hot values, despite an accompanying reduction of power output, was viewed by the inspectors as an indicator of management awareness of and support for initiatives which could be helpful in limiting the initiation and propagation of stress corrosion cracking. A modified turbine governor valve design was subsequently developed to reduce the pressure drop through the turbine governor valves, and thereby, provide for an increase in power output by allowing more steam to flow into the high pressure turbine. This design modification was implemented in Unit 2 during Refueling Outage RF7 in March 1995 and resulted in restoration to approximately 100 percent power with a 607°F T-Hot value. A corresponding modification was scheduled to be implemented in Unit 3 during the current Refueling Outage RF7.

2.3 Tubing Material

The inspectors requested to see the procurement requirements for the San Onofre Nuclear Generating Station, Units 2 and 3, steam generator tubing that had been imposed by Combustion Engineering on its tubing vendor. In response to the licensee's request, ABB Combustion Engineering furnished: Combustion Engineering Purchase Specification P43B2(e), "Purchase Specification for Nickel-Chromium-Iron Alloy Tubular Products, ASME Section III," dated June 5, 1968, for the Unit 2 materials; and Combustion Engineering Purchase Specification P43B2(h) dated October 30, 1973, for the Unit 3 materials. These documents were marked as containing proprietary information.

The inspectors noted from review of the purchase specifications that ASME Material Specification SB-163 (i.e., Inconel 600) tubing was required to be furnished in the bright annealed condition, with test requirements including a hydrostatic test, ultrasonic examination, and eddy current examination. The inspectors observed that the Combustion Engineering purchase specifications placed an additional requirement to that imposed by the ASME material specification and the ASME Section III Code. This requirement consisted of a maximum value for the yield strength of the tubing materials. An "aim for" yield strength value was also noted to be included in the purchase specifications. Conformance to the "aim for" and maximum yield strength values was considered by the inspectors to effectively require the tubing manufacturer, Sawhill, to perform a high-temperature annealing cycle. The inspectors ascertained, however, that the requirements of the purchase specifications did not specifically include either a minimum annealing temperature, or a stipulation for the tubing to be furnished in a high temperature mill annealed condition. It was noted during review of samples of certified material test reports for each steam generator, that the tubing manufacturer also did not identify the actual annealing temperature used.

Comparison by the inspectors of Purchase Specifications P43B2(e) and P43B2(h) identified that Purchase Specification P43B2(h) contained a limited number of additional requirements to those identified in Purchase

Specification P43B2(e). The most significant additions noted in Purchase Specification P43B2(h) were the establishment of grain size criteria and requirements for, on a sample basis, determination of microstructure and performance of a corrosion test to ascertain resistance to intergranular attack.

The inspectors noted from review of samples of Units 2 and 3 steam generator tubing certified material test reports that the reported chemical composition values and mechanical properties conformed to the requirements of ASME Material Specification SB-163 and the applicable Combustion Engineering purchase specification. This review indicated that, for the samples reviewed (i.e., the sample size from each steam generator ranged from 63 to 81 certified material test reports), the ranges of reported 0.2 percent yield strength values for the Unit 2 and Unit 3 steam generator tubing materials were, respectively, 37,000-51,000 psi and 35,000-48,000 psi. The respective ranges of ultimate tensile strength values for the Unit 2 and Unit 3 steam generator tubing materials were 92,000-102,000 psi and 86,000-102,000 psi. The inspectors considered these mechanical property values to be typical for high-temperature mill annealed Inconel 600 tubing. (Note: As discussed in Section 2.5 below, three tube leaks occurred during 1984 in Units 2 and 3, one in Unit 2 and two in Unit 3. The leak paths were subsequently confirmed by laboratory examination to be primary water stress corrosion cracks which resulted from the use of improper annealing practices by the tubing manufacturer. Accordingly, the inspectors viewed the data as not necessarily being totally representative of the properties of the Units 2 and 3 steam generator tubing).

During the review of the certified material test report samples, the inspectors also observed that the strength properties and carbon content of the Unit 3 steam generator tubing heats appeared to be generally lower than those reported for the Unit 2 steam generator tubing heats. To verify this observation, the inspectors calculated the mean value and standard deviation for carbon content, 0.2 percent yield strength, and ultimate tensile strength for the individual samples of certified material test reports. In addition, the mean value and standard deviation were calculated for the chromium values reported in the Units 2 and 3 samples of certified material test reports and the grain size values reported in the Unit 3 samples of certified material test reports. The results obtained from these calculations are listed below in Table 1. The inspectors noted from these results that the Unit 3 steam generator tubing material mean 0.2 percent yield strength and ultimate tensile strength values were approximately 6000 psi lower than the corresponding values obtained from the Unit 2 data. The mean carbon content of both Unit 3 steam generator samples was also noted to be 0.025 weight percent versus 0.039 weight percent and 0.037 weight percent for the two Unit 2 steam generators.

Table 1

STEAM GENERATOR (SG) TUBING CHEMICAL COMPOSITION AND MECHANICAL PROPERTY DATA

Parameter	Unit 2				Unit 3			
	SG 2ME088		SG2ME089		SG3ME088		SG3ME089	
	Mean	σ[1]	Mean	σ[1]	Mean	σ[1]	Mean	σ[1]
0.2 % Yield Strength (KSI)	46.0	4.0	45.8	3.0	39.0	3.3	41.6	3.3
Ultimate Tensile Strength (KSI)	98.4	2.4	98.3	2.4	92.3	3.3	92.0	2.7
% Carbon (Ladle Analysis)	0.039	0.008	0.037	0.009	0.025	0.007	0.025	0.007
% Carbon (Check Analysis)	0.032	0.008	0.031	0.007	NI[2]		NI[2]	
% Chromium (Ladle Analysis)	15.31	0.33	15.27	0.46	15.42	0.51	15.40	0.50
%Chromium (Check Analysis)	15.61	0.27	15.50	0.32	15.58	0.54	15.57	0.53
Longitudinal Grain Size[3]	NR[4]		NR[4]		5.5	0.8	5.5	0.8
Transverse Grain Size[3]	NR[4]		NR[4]		5.5	0.8	6.0	0.8

[1] Standard deviation.
[2] No data noted in record sample reviewed.
[3] Mean grain sizes calculated by summing the mid-point values of the grain size ranges reported by the vendor, dividing by the sample size, and rounding off the resulting values to the nearest 0.5.
[4] Not required by Combustion Engineering Purchase Specification P43B2(e).

The mean strength property differences between the Units 2 and 3 steam generator certified material test report samples were considered by the inspectors to be significant and attributable to the differences in mean carbon contents. Although insufficient information was available to meaningfully assess whether the property differences would result in differences in susceptibility to primary water stress corrosion cracking in the expansion transition region of tubing, the inspectors considered that there was a potential for the Unit 3 tubing material to exhibit a lower susceptibility.

2.4 Tube-to-Tube Sheet Expansion

The inspectors requested the licensee to obtain the applicable tube-to-tube sheet expansion procedure from ABB Combustion Engineering that was used in the manufacture of the San Onofre Nuclear Generating Station, Units 2 and 3, steam generators. ABB Combustion Engineering furnished Combustion Engineering Nuclear Fabrication Practice FAB-9287-1-1, "Explanding Steam Generator Tubes into Tubesheets," dated March 24, 1971, in response to the licensee's request. This document was stamped to indicate it contained proprietary information. The inspectors ascertained from review of Combustion Engineering Nuclear Fabrication Practice FAB-9287-1-1 that the explosive expansion process, which was termed "explansion" by Combustion Engineering, had been used to expand the steam generator tubes in the tube sheet holes. The document indicated that the primary quality verification activities pertained to assuring the correct placement of explosives in the tubes, with the only inspection activity performed subsequent to completion of expansion being verification of actual detonation of charges in individual tubes.

2.5 Steam Generator Tube Degradation History

2.5.1 Unit 2 Tube Repairs

Prior to operational service, the Unit 2 steam generators contained a total of 21 plugged tubes (i.e., Steam Generator 2ME088, 11; and Steam Generator 2ME089, 10). An additional 12 tubes (Steam Generator 2ME088, 7; and Steam Generator 2ME089, 5) were plugged during Refueling Outage RF1 for what were characterized as preservice type defects. Table 2 below provides the tube plugging history for the two Unit 2 steam generators as a function of the effective full-power years of operation at the time of repair.

A tube leak in Steam Generator 2ME088 was identified in May 1984 after approximately 9 months of Unit 2 commercial operation. The defect was subsequently confirmed to be located in Tube 89-151 (i.e., Row 89, Column 151) at a distance of 9 to 9.5 inches above the tube sheet on the hot-leg side of the steam generator. The defect was determined by eddy current examination to be less than 0.5 inches in axial length and less than 0.3 inches in the circumferential direction. Eddy current examinations were performed of 62 tubes in the vicinity of the leaking tube, without additional defects found. Tube 89-151 was plugged on June 28, 1984, and Unit 2 was returned to service.

During Refueling Outage RF1, a section of Tube 89-151 containing the defect was removed from Steam Generator 2ME088 for metallographic examination. The examination scope and results were documented in a licensee report entitled, "Metallurgical Defects in Steam Generator Tubes," dated April 3, 1985. The inspectors ascertained from review of the report that the examination found that: (a) a cold worked microstructure was present at the failure location, (b) the failure mechanism appeared to be intergranular stress corrosion cracking, (c) the failure appeared to have originated at the inside diameter of the tube, and (d) there was an absence of any aggressive species. It was accordingly concluded that the leak resulted from primary water stress corrosion cracking of a highly susceptible microstructure. The inspectors concurred with this conclusion. Bobbin coil eddy current examination using 100 KHz absolute frequency demonstrated the ability to reliably detect locations where a cold worked microstructure was present. A 100 percent scope bobbin coil examination was performed during Refueling Outage RF1, which resulted in the preventive plugging of an additional 15 tubes in Steam Generator 2ME088 and 46 tubes in Steam Generator 2ME089 due to the identification of the presence of regions of susceptible cold worked microstructure. The specific reason(s) for tubes, which were required to be furnished in the annealed condition, containing locations with a cold worked microstructure could not be defined in the absence of information from the tubing manufacturer. The licensee postulated that the most likely cause was a failure to repeat the heat treatment cycle for tubes that were in the annealing furnace at the time of an unscheduled furnace shutdown. The inspectors concluded that the licensee comprehensively addressed the problem and implemented appropriate actions to identify and remove improperly annealed tubes from operational service.

As noted below in Table 4, the greatest contributor to Unit 2 steam generator tube plugging during commercial service has, to date, been tube wear in the upper bundle at batwing supports. The current tube plugging totals due to batwing wear were, respectively, 218 for Steam Generator 2ME088 and 247 for Steam Generator 2ME089, with the majority of the degradation occurring in the first four operating cycles. Only 7 and 16 tubes, respectively, in Steam Generators 2ME088 and 2ME089 have been identified as exhibiting batwing wear since Refueling Outage RF4 in November 1989, with 0 tubes plugged for this degradation mechanism during the March 1995 Refueling Outage RF7. The inspectors considered the declining incidence of this type of degradation to be expected, due to the inherent limits in number of susceptible locations.

A small amount of upper bundle tube wear at vertical supports has been identified in both steam generators during commercial service. Six tubes were plugged in Steam Generator 2ME088 because of this type of degradation, with the plugging occurring in Refueling Outages RF1, RF4, and RF6. The corresponding vertical support wear total for Steam Generator 2ME089 was nine tubes, with the plugging occurring in Refueling Outages RF3, RF5, RF6, and RF7.

A total of three tubes have been plugged in Steam Generator 2ME088, two during Refueling Outage RF1 and one during Refueling Outage RF3, as a result of wear from loose parts. No repairs have been required in Steam Generator 2ME089 as a result of damage from loose parts.

Denting of tubes located adjacent to tie rods, at a location just above the secondary surface of the tube sheet, was initially identified in both steam generators during Refueling Outage RF4 in November 1989. The denting was ascribed by the licensee to result from the compressive forces imparted to the sludge by the corrosion and resulting growth of the tie rods. These forces, in turn, exerted forces on the adjacent tubes which resulted in instances of tube denting. Seven and 28 tubes, respectively, have been plugged in Steam Generators 2ME088 (Refueling Outages RF4, 1; RF5, 4; RF6, 1; and RF7, 1) and 2ME089 (Refueling Outages 4, 17; and RF5, 11) as a result of tie-rod denting. The inspectors ascertained from licensee information that there were a total of 14 tie rods (7 on the hot-leg side, 7 on the cold-leg side) which were adjacent to tubes in each steam generator. This represented a total of 42 tubes in each steam generator that were potentially vulnerable to this type of degradation (i.e., 3 tubes are adjacent to a tie rod in the Combustion Engineering Model 3410 steam generator design).

Table 2

UNIT 2 STEAM GENERATOR (SG) TUBE REPAIR HISTORY			
Time of Repair Refueling Outage (RF)	Effective Full Power Years of Operation	SG 2ME088	SG 2ME089
		Tubes Plugged	Tubes Plugged
Preservice	0.00	11	10
6/1984[1]	0.79	1	0
RF1 (1/1985)	1.00	146[2]	184[3]
RF2 (5/1986)	1.73	5	12
RF3 (9/1987)	2.85	62	80
RF4 (11/1989)	4.31	31	31
RF5 (9/1991)	5.72	10	31
RF6 (6/1993)	7.16	11	21
RF7 (3/1995)	8.62	22	23
Total Repairs		299	392
% Repairs (Inservice, Total)		3.00, 3.20	4.03, 4.19

[1] This outage resulted from the identification of a primary-to-secondary tube leak in Steam Generator 2ME088.

[2] This plugging total included seven tubes that were characterized as containing preservice type defects.

[3] This plugging total included five tubes that were characterized as containing preservice type defects.

Circumferential primary water stress corrosion cracking and circumferential outside diameter stress corrosion cracking were first identified in both Unit 2 steam generators during Refueling Outage RF6. All of the tube cracks were located in the vicinity of the secondary side surface of the tube sheet (i.e., expansion transition region) on the hot-leg side of the steam generators. Additional circumferential stress corrosion cracking was detected in both steam generators at this location during Refueling Outage RF7. The number of tubes plugged in Steam Generator 2ME088, as a result of the detection of circumferential stress corrosion cracking, was 2 during Refueling Outage RF6 and 15 during Refueling Outage RF7. The eddy current data analysts determined that the defects originated at the inside diameter in 15 of the tubes and at the outside diameter in 2 tubes. The majority of the defects were, thus, believed to be primary water stress corrosion cracking, with only a limited incidence of secondary side stress corrosion cracking. A total of 22 tubes (10, Refueling Outage RF6; 12, Refueling Outage RF7) have been plugged in Steam Generator 2ME089 as a result of the detection of circumferential stress corrosion cracking. The defects in 17 of the 22 tubes were determined to have originated at the inside diameter, with the remainder originating at the outside diameter. The predominant mode was, thus, again believed to be primary water stress corrosion cracking.

2.5.2 Unit 3 Tube Repairs

Prior to operational service, the Unit 3 steam generators contained a total of 35 plugged tubes (i.e., Steam Generator 3ME088, 24; and Steam Generator 3ME089, 11). Table 3 below provides the tube plugging history for the two Unit 3 steam generators as a function of the effective full-power years of operation at the time of repair.

A tube leak in Steam Generator 3ME089 was detected in June 1984 after approximately 2 months of Unit 3 commercial operation. The defect was subsequently confirmed to be located in Tube 66-64 at a distance of approximately 3 inches below the third horizontal eggcrate support on the hot-leg side of the steam generator. Eddy current examination determined the defect size to be less than 0.3 inches in both length and in the circumferential direction. Two other indications, 79 and 73 percent through wall, were detected by eddy current examination in Tube 66-64 at 10.9 and 16.9 inches above the third support. Eddy current examinations were performed of 61 tubes in the vicinity of the leaking tube, without additional defects found. Tube 66-64 was plugged on July 28, 1994, and Unit 3 was returned to service. A second tube leak was detected in Steam Generator 3ME089 in September 1984, which was subsequently confirmed to be located in Tube 79-15. Six defect indications, all greater than 80 percent through wall, were found by eddy current examination in Tube 79-15. These defect indications were grouped in the vicinity of the second horizontal eggcrate support (i.e., up to 12 inches above and 12 inches below) on the cold-leg side of the steam generator. An additional 109 tubes were examined by eddy current examination in the vicinity of the leaking tube, without additional defects found. Tube 79-15 was plugged and Unit 3 was again returned to service. During Refueling Outage RF1 for Unit 3, the 100 percent bobbin coil examination scope identified 5 tubes in Steam Generator 3ME088 and an additional 15 tubes in Steam Generator 3ME089 which contained regions of susceptible cold worked microstructure. The licensee removed these tubes from operational service by plugging.

The greatest contributor to Unit 3 steam generator tube plugging during commercial operation has been, as it was for Unit 2, tube wear in the upper bundle at batwing supports. The current plugging totals due to batwing wear for Steam Generators 3ME088 and 3ME089 were, respectively, 233 and 236. The majority of this plugging was performed through Refueling Outage RF3 in May 1988, with only 31 and 8 tubes, respectively, plugged in Steam Generators 3ME088 and 3ME089 since that time.

Table 3

UNIT 3 STEAM GENERATOR (SG) TUBE REPAIR HISTORY			
Time of Repair Refueling Outage (RF)	Effective Full Power Years of Operation	SG 3ME088	SG 3ME089
		Tubes Plugged	Tubes Plugged
Preservice	0.00	24	11
7/1984[1]	0.34	0	1
11/1984[1]	0.55	0	1
2/1985[2]	0.69	116	116
RF1 (11/1985)	1.02	6[3]	20[3]
RF2 (1/1987)	1.74	9	11[3]
RF3 (5/1988)	2.81	77	100
RF4 (5/1990)	4.33	11	23
RF5 (2/1992)	5.74	18	11
RF6 (11/1993)	7.13	42	17
RF7 (8/1995)	8.49	23	8
Total Repairs		326	319
% Repairs (Inservice, Total)		3.22, 3.49	3.29, 3.41

[1] This outage resulted from the identification of a primary-to-secondary tube leak in Steam Generator 3ME089.

[2] This outage resulted from the previous identification in Unit 2 of batwing support location wear problems.

[3] This plugging total included one tube which was characterized as containing a preservice type defect.

Thirty-seven tubes (Steam Generator 3ME088, 24 tubes; Steam Generator 3ME089, 13 tubes) were plugged as a result of the identification of upper bundle wear at vertical supports. The plugging was performed in Steam Generator 3ME089 during Refueling Outages RF4, RF5, RF6, and RF7, and in Steam Generator 3ME088 during Refueling Outages RF5, RF6, and RF7.

A total of 19 tubes have been plugged in Steam Generator 3ME088, 15 during Refueling Outage RF4 and 4 during Refueling Outage RF6, as a result of wear from loose parts. Nineteen tubes have also been plugged in Steam Generator 3ME089 because of wear from loose parts, with the plugging of all

19 tubes occurring during Refueling Outage RF6. The inspectors considered these numbers to be unusually high for this type of degradation mechanism. (See Sections 2.5.3 and 3 below for additional information on this subject.)

Four and ten tubes, respectively, have been plugged in Steam Generators 3ME088 (Refueling Outages RF5, 3; and RF6, 1) and 3ME089 (Refueling Outages RF4, 1; RF5, 2; and RF6, 7) as a result of tie-rod denting.

Tube 101-25 in Steam Generator 3ME088 was classified during the inspection as containing a single inside diameter circumferential indication at the top of the tube sheet. The defect indication, thus, appeared to be primary water stress corrosion cracking. (Further information regarding the eddy current examination results for this tube is discussed below in Section 4.3.) The eddy current data obtained from this tube was the first potential indicator of stress corrosion cracking becoming an active degradation mechanism in the Unit 3 steam generators. The inspectors were informed during a second exit meeting held telephonically on August 30, 1995, that one tube was also plugged in Steam Generator 3ME089 because of the identification of a single circumferential indication at the top of the tube sheet.

2.5.3 Tube Degradation Differences Between Units 2 and 3 Steam Generators

The licensee furnished to the inspectors a compilation of Units 2 and 3 plugging history for each active degradation mode. A summary of this information is listed below in Table 4. The inspectors concluded from review of this data that there were some differences between the Units 2 and 3 steam generators with respect to degradation history. Three specific degradation modes (i.e., loose part wear, improper annealing, and circumferential stress corrosion cracking) appeared to show a different rate of occurrence between the two units.

2.5.3.1 Loose Part Wear

A total of 38 tubes in the Unit 3 steam generators have been plugged through Refueling Outage RF7 as a result of wear from loose parts, versus a corresponding plugging total of only 3 tubes for the Unit 2 steam generators. The inspectors questioned licensee personnel about the incidence of damage from loose parts that had occurred in the Unit 3 steam generators, and were informed that the loose parts originated primarily as a result of erosion of the feedwater distribution box and feedring. Licensee personnel additionally provided to the inspectors a document entitled, "Evaluation of Foreign Objects in the SONGS Unit 3 Steam Generators," which was originally transmitted to the NRC by letter dated December 3, 1993. The inspectors ascertained from review of this evaluation that pieces of carbon steel were found on the secondary side of Steam Generator 3ME089 in July 1990 during Refueling Outage RF4. Subsequent detailed inspection of both Unit 3 steam generators revealed that the bottom portions of three of the four Schedule 40, 9 inch-long pipe stubs (which connected the Schedule 120 feedring and the center distribution box) were missing and the other was cracked. The 3-inch vents on the distribution box were also missing.

Table 4

UNITS 2 AND 3 STEAM GENERATOR (SG) TUBE INSERVICE DEGRADATION MODES				
Tube Degradation Mode	Unit 2 Tubes Plugged		Unit 3 Tubes Plugged	
	SG 2ME088	SG 2ME089	SG 3ME088	SG 3ME089
Batwing Wear	218	247	233	236
Vertical Support Wear	6	9	24	13
Loose Part Wear	3	0	19	19
Improper Annealing	16	46	5	19
Circumferential SCC[1]	17	22	1	1
Tie Rod Denting	7	28	4	10
Other Causes	14	25	15	8

[1] Circumferential stress corrosion cracking at tube sheet in the tube expansion transition area.

The failure of the feedring resulted in through-wall cracking at the welded connection of the distribution box and the establishment of severe erosion conditions within the distribution box. These erosion conditions led, in turn, to separation of the vents and excessive metal loss from the inside of the distribution boxes, with the resulting creation of additional foreign objects on the secondary side of the steam generators. As a result of the findings in the Unit 3 steam generators, Unit 2 was shut down in July 1990 for secondary side inspections. Much less severe degradation was found to have occurred in the Unit 2 steam generators. Accessible loose parts were removed from the steam generators in both Units 2 and 3, tubes exhibiting wear were plugged, and repairs were made to the feedrings and distribution boxes. Distribution box replacement was subsequently performed in 1995 in both units during the respective Refueling Outage RF7. Prior to shutdown for the Unit 3 Refueling Outage RF6, a small gradually increasing leak was detected in Steam Generator 3ME088. Following shutdown, one tube was identified as leaking and the cause determined to be wear from a foreign object. The licensee developed special retrieval tools to facilitate removal of foreign objects. Those tubes which exhibited wear, and were in contact with foreign objects that could not be removed, were plugged and stabilized together with adjacent tubes.

2.5.3.2 Improper Annealing

A total of 62 tubes were plugged in the Unit 2 steam generators (i.e., Steam Generator 2ME088, 16 tubes; Steam Generator 2ME089, 46 tubes) as a result of improper annealing by the tube manufacturer. A significantly smaller number of tubes, 24, were plugged in the Unit 3 steam generators because of this problem (i.e., Steam Generator 3ME088, 5 tubes; Steam Generator 3ME089, 19 tubes). Due to a certain amount of switching of tubing materials during steam generator manufacture (i.e., Unit 2 tubing materials used in Unit 3 steam generators and vice versa), the inspectors were unable to conclude whether the annealing process problems were either confined to Unit 2 tube manufacture, or had occurred at a reduced frequency during Unit 3 tube manufacture.

2.5.3.3 Circumferential Stress Corrosion Cracking

A total of 39 tubes were plugged because of identified circumferential stress corrosion cracking in the Unit 2 steam generators (Steam Generator 2ME088, 17 tubes; Steam Generator 2ME089, 22 tubes) through Refueling Outage RF7, versus a total of 2 tubes through the corresponding outage in the Unit 3 steam generators (Steam Generator 3ME088, 1 tube; Steam Generator 3ME089, 1 tube). The accrued effective full-power years of operation for Units 2 and 3 were almost the same at the time of the respective 1995 Refueling Outage RF7 (i.e., Unit 2, 8.62; Unit 3, 8.49). The inspectors concluded that insufficient information was currently available to determine whether there was a relationship between the strength property differences of the Units 2 and 3 tubing and the current difference in incidence of circumferential stress corrosion cracking in the steam generators.

3 VISUAL EXAMINATION OF THE SECONDARY SIDE OF THE STEAM GENERATORS

3.1 Review of Program Requirements and Inspection Data

The inspectors reviewed Procedures SO23-XVII-9, "Steam Generator Secondary Side Upper Internals Visual Examination Program," Revision 0; SO23-XVII-7.3, "Feedwater Distribution Box and Feedring J Nozzle Monitoring Program," Revision 0; SO123-I-1.18, "FME-Foreign Material Exclusion Control During Maintenance, Testing and Inspection Activities," Revision 2, Temporary Change Notice 2-16; and SO123-XVII-6, "Evaluation and Reporting of Foreign Objects Found in the Secondary Side of Steam Generators," Revision 0. The inspectors noted that the secondary side examination procedure, SO23-XVII-9, became effective on July 7, 1995, and was to be used for the first time during the Unit 3 Refueling Outage RF7. The inspectors were informed by licensee personnel, in response to questions on this subject, that Procedure SO23-XVII-9 was the first licensee secondary side inspection procedure and was not a replacement for another procedure. The inspectors also ascertained that the only secondary side inspections that were performed prior to the discovery of the foreign objects created by the Unit 3 feedring and feedwater distribution box degradation in 1990, were accomplished by Combustion Engineering in the respective Units 2 and 3 Refueling Outage RF1. The inspectors considered the absence until 1995 of steam generator secondary side inspection requirements to be a weakness. The inspectors informed licensee personnel that the performance of such a program could have led to the detection of the feedring and feedwater distribution box degradation at an earlier damage state.

The inspectors performed an additional review (to that documented in NRC Inspection Report 50-361/95-02; 50-362/95-02) of licensee information pertaining to the discovery of lengths of metal chain in Unit 2 Steam Generator 2ME088 during Refueling Outage RF7. The discovery was made on

February 17, 1995, during preparation for steam generator cleaning and documented in Nonconformance Report 95020054. The inspectors ascertained from review of the nonconformance report that four removable chain links and two pieces of chain, 3 feet and 2-1/2 feet in length, were removed from the blowdown lane on the cold-leg side of the steam generator. It was additionally reported that a 12-inch length of No. 9 wire was removed from the periphery of the tube bundle. The nonconformance report discussed the four barriers that were utilized up to Refueling Outage RF6 to prevent foreign objects dropping down the annulus during upper vessel work activities. The nonconformance report also noted that chains and No. 9 wire are not currently used and postulated that the items were most probably left in the steam generator during repair activities in an outage performed prior to Refueling Outage RF6. The failure to detect the chains after they dropped was ascribed to their becoming draped over lugs that are present in the steam generator annulus area. The inspectors considered it probable that the chains were temporarily trapped by lugs in the steam generator annulus, but considered it unlikely that the chains were present in the steam generator prior to Refueling Outage RF6.

Evaluation by the inspectors of the barrier methods and practices that were indicated by the nonconformance report to have been used, suggested that, if implemented as stated, they should have been adequate to preclude dropped chain segments from entering the steam generator annulus. Also of concern to the inspectors was that, from the nature of the work activities, it appeared probable that craft personnel were aware of, but did not report that chain segments had entered the steam generator annulus. The inspectors, thus, viewed the discovery of chain segments as primarily a human performance issue.

The inspectors reviewed with licensee construction management the actions taken to improve the effectiveness of steam generator foreign material exclusion controls, including the human performance aspects. The inspectors were informed that an inflatable seal was now used to seal the steam generator annulus during upper vessel work. Option 3 of Procedure SO123-I-1.18 (i.e., logging of items entering the vessel) was invoked until the seal was installed in the annulus and lead blankets were installed. All craft personnel were stated to have been briefed at the beginning of the Unit 3 Refueling Outage RF7 on management expectations regarding foreign material exclusion, including the importance of personnel immediately reporting problems that had occurred. Inspections at the tube sheet of the tube bundle periphery, the annulus, and the blowdown lane, after completion of work activities, were now supplemented by a top to bottom inspection of the annulus. This inspection was performed using a high powered lamp to detect any objects that were present on lugs.

To evaluate the effects of management actions, the inspectors compared the results from Unit 3 Steam Generator 3ME089 foreign object search and retrieval inspections that were performed during Refueling Outages RF6 and RF7. Nineteen foreign objects were identified at the tube sheet in Refueling Outage RF6 versus a total of 4 during Refueling Outage RF7. The 19 objects included 6 pieces of No. 9 tie wire (used in scaffolding assembly), which suggested that the annulus seal that was in use in Refueling Outage RF6 was less than effective. The four objects observed in Refueling Outage RF7 included two that were present during earlier outages, with the remaining two consisting of a small piece of tape (or plastic) and a flat metallic object (3 inches by 3/4 inch by approximately 1/32 inch thick). The inspectors concluded that management actions were successful during Refueling Outage RF7 in improving previous weak steam generator foreign material exclusion performance.

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

4.1 Review of Tube Examination History

Review of the steam generator tube eddy current examination history for San Onofre Nuclear Generating Station, Units 2 and 3, identified that 100 percent of the unplugged tubes in both Units 2 and 3 were examined by the bobbin coil method during the respective first refueling outage. More limited scope bobbin coil examinations were conducted during Refueling Outages 2 and 3. In Unit 2, the respective approximate tube sample sizes during these two refueling outages were 6 percent and 4 percent in Steam Generator 2ME088 and a 9 percent sample in Steam Generator 2ME089 during Refueling Outage RF3. The only examination performed in Steam Generator 2ME089 during Refueling Outage RF2 was monitoring progress of previously identified wear. The approximate bobbin coil sample sizes in Unit 3 during Refueling Outages 2 and 3 were, respectively, 9 percent and 10 percent in Steam Generator 3ME088 and 3 percent and 13 percent in Steam Generator 3ME089.

During Refueling Outage RF4, approximately 23 percent of the Units 2 and 3 steam generator tubes were examined by the bobbin coil method. Similar scope bobbin coil examinations were performed in the Units 2 and 3 steam generators during the respective Refueling Outage RF5. The inspectors noted that the examination reports to the NRC made reference for the first time to the use of motorized-rotating pancake coil examinations for evaluation of bobbin coil indications. The inspectors additionally ascertained from licensee personnel, as discussed in Section 4.2.2 below, that limited use was made of the motorized-rotating pancake coil examination method in both units during Refueling Outage RF5 for examination of tube expansion transition areas at the top of the tube sheet.

During Refueling Outage RF6, the Units 2 and 3 bobbin coil examination sample sizes were significantly increased to, respectively, 66 percent and 73 percent of active tubes. The inspections included all active tubes in the central cavity region of the tube bundle where the batwing wear mechanism, discussed in Sections 2.5.1 and 2.5.2 above, was active. The examinations also included all tubes not examined during the previous 4 years. Comprehensive use was made for the first time of the motorized-rotating pancake coil examination method, with top of the tube sheet examinations performed in both units of all active tubes on the hot-leg side and of a 6-percent tube sample on the cold-leg side. During the respective Refueling Outage RF7, all active Unit 2 tubes were examined full-length by the bobbin coil method and motorized-rotating pancake coil examinations were performed at the top of the tube sheet of all active tubes on the hot-leg side and 6 percent of the tubes on the cold-leg side. The Unit 3 examination scope was the same as Unit 2, with the exceptions of the 6-percent cold-leg sample at the top of the tube sheet being increased to 20 percent and a plus point coil being added to the probe containing the motorized-rotating pancake coil. The inspectors considered the examination program scope adopted by the licensee for these two outages as an appropriate response by management to industry notification of the potential for stress corrosion cracking at the top of the tube sheet.

4.2 Review of Examination Program Requirements

4.2.1 Current Program and Process

The inspectors reviewed the eddy current examination program requirements which were contained in: (1) "Data Analysis Guidelines, San Onofre Nuclear Generating Station," Revision 5; (2) Procedure SO23-XXVII-23.1, "Multifrequency Eddy Current Procedure Steam Generator Tubing, MIZ-30 Digital Eddy Current System, SONGS," Revision 4, Temporary Change Notice 4-3; (3) Procedure SO23-XVII-4.2, "Steam Generator Tube Inspection and Corrective Action," Revision 2, Temporary Change Notice 2-2; (4) Procedure SO123-XXVII-23.1, "Working Instructions for Installing, Operating, and Removing the SM-10/20/22 Fixture Using the LAN Acquisition System," Revision 1, Temporary Change Notice 1-1; (5) Procedure SO23-XXVII-25.3, "BWNT Steam Generator Quality Control Process Matrix Procedure," Revision 0; and (6) Procedure SO23-XXVII-25.4, "Field Procedure for Steam Generator Closeout," Revision 0. The inspectors also compared the current program against the recommendations contained in Electric Power Research Institute EPRI NP-6201, "PWR Steam Generator Examination Guidelines," Revision 3.

It was ascertained during this review that the data analysis guidelines were generally consistent with the recommendations contained in Electric Power Research Institute EPRI NP-6201, Revision 3. The most significant discrepancy noted was the absence of any program guidance concerning the Electric Power Research Institute EPRI NP-6201 recommendation for establishment of criteria for noisy data. Other areas noted where improvements could be made in the data analysis guidelines were providing a more detailed description of examination history and improving the quality and identification of some of the figures.

Site-specific training and testing of primary and secondary eddy current data analysts were ascertained by the inspectors to have been performed by personnel from Anatec International, the company performing secondary eddy current data analysis for the licensee. Although the inspectors considered it less than optimal for a contractor to be administering site-qualification tests to its own personnel, no specific problems were noted. Overall, the training material was considered to be satisfactory, but was noted to be lacking any description of the instrument, MIZ-30-4, being used during the Unit 3 Refueling Outage RF7 for eddy current data acquisition. It was additionally noted by the inspectors that the training material did not include drawings of the probes that were being used, or discuss the use of the plus point coil examination method which was being used for the first time during the Unit 3 Refueling Outage RF7. The NRC consultant reviewed the tapes used for training and testing eddy current data analysts and concluded that there was a good mix of hard and easy-to-find defects.

The NRC inspectors and consultant reviewed the process and equipment that were being used for Unit 3 Steam Generator 3ME088 eddy current data acquisition and analysis. Data acquisition and primary eddy current analysis were performed by Rockridge Technologies (formerly Conam), with secondary eddy current data analysis performed by Anatec International. The inspectors considered the use by the licensee of two separate companies to perform independent primary and secondary analysis to be commendable in terms of attempting to optimize the quality of eddy current data analysis results. The primary analysis was performed remotely at the Rockridge Technologies facility in Benicia, California, using a dedicated telephone line for data transmission. Secondary analysis and resolution analysis (by the Rockridge Technologies and Anatec International Level III lead analysts for differences in "calls" between the primary and secondary analysts) were performed onsite.

It was ascertained that Zetec SM-22 fixtures were used for data acquisition by bobbin coil probes and probes which contained both a 0.115-inch diameter unshielded rotating pancake coil and a plus point coil. In addition, a probe containing a high frequency 0.080-inch diameter shielded rotating pancake coil had been brought to site. This probe was used, as of the end of the onsite inspection, to examine only one tube (i.e., Tube 101-25) which had been identified by the eddy current data analysts to contain an inside diameter circumferential indication at the top of the tube sheet. The NRC consultant ascertained that the extension coaxial cable, which is used to transmit the signal from the instrument to the probe pusher-puller unit, was of lower capacitance than that used previously and was thus beneficial in terms of data quality. Similarly, low capacitance slip rings were used at the pusher-puller unit. The NRC consultant noted that the probe cable, which transmits the signal to the probe and is pushed up the bore of the steam generator tubing, is normally a higher capacitance type than the extension cable. The probe cable lengths used by Rockridge Technologies at San Onofre Nuclear Generating Station were 83 feet for the rotating probes and 110 feet for the bobbin coil probes. The NRC consultant considered that the use of a reduced probe cable length would have been beneficial to the rotating probe examinations, and was feasible since the main application for the probes was for tube examination at the top of the tube sheet.

An additional review of eddy current equipment criteria was performed by the inspectors after the onsite inspection. The inspectors noted that Appendix H, "Performance Demonstration for Eddy Current Examination," of Electric Power Research Institute EPRI NP-6201, Revision 3, defined qualification requirements for eddy current examination techniques and equipment. The essential variables for equipment that were listed in this document were ascertained to include probe and extension cable type and length. Industry qualification criteria thus existed that provided limits to allowed variation in process equipment and methodology. The status of conformance of the Rockridge Technologies eddy current examination procedures to the qualification criteria contained in Appendix H of Electric Power Research Institute EPRI NP-6201, Revision 3, was not ascertained during the onsite inspection. The licensee purchase order, 6M223901, that was applicable to Rockridge Technologies eddy current examination activities, was noted by the inspectors to not invoke any specific Electric Power Research Institute EPRI NP-6201 requirements. A second exit meeting was held by telephone on August 30, 1995, to inform the licensee that review of the conformance of the eddy current examination procedures to Appendix H of Electric Power Research Institute EPRI NP-6201, Revision 3, was considered an inspection followup item (361/9514-01; 362/9514-01).

4.2.2 Response to Generic Communications

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

The review indicated that the licensee had appropriately responded to Bulletin 89-01, with the last remaining Westinghouse Inconel 600 mechanical plugs removed and replaced with Inconel 690 mechanical plugs during the respective Units 2 and 3 Refueling Outage RF7.

The inspectors questioned licensee personnel, however, regarding the independent safety evaluation group evaluations of Information Notices 90-49 and 91-67, in that the evaluations exhibited an apparent lack of rigor. Two statements, in particular, in the evaluations were found by the inspectors to be questionable. These statements pertained to: (a) the indicated routine use of the rotating pancake coil at the San Onofre Nuclear Generating Station since 1980 for improving examination capabilities in known or suspected problem areas such as roll transition areas, and (b) the development of a high degree of confidence in bobbin coil signal analysis techniques based on the results of metallographic examination of pulled tubes in Unit 1.

The inspectors questioned licensee personnel on the scope of utilization of the motorized-rotating pancake coil method and were informed that the method was used initially for evaluation of Unit 1 steam generator tube degradation. No information was seen by the inspectors which would indicate routine use in Units 2 and 3 of the motorized-rotating pancake coil in the time period prior to the issue of Information Notice 90-49. The specific number of examinations performed in this time period was not requested, in that the current use of the method was high and the value of the information was not considered sufficient to warrant the licensee effort. The inspectors did request information on the specific Units 2 and 3 usage of the motorized-rotating pancake coil method for a 2-year period following the August 1990 issue of Information Notice 90-49. The licensee provided Refueling Outage RF5 (Unit 2, 1991; Unit 3, 1992) data in response to the request, which showed the number of motorized-rotating pancake coil tube examinations performed was 70 in Unit 2 (Steam Generator 2ME088, 43; Steam Generator 2ME089, 27) and 133 in Unit 3 (Steam Generator 3ME088, 78; Steam Generator 55). Of these motorized-rotating pancake coil examinations, 62 in Unit 2 and 116 in Unit 3 were performed at the top of the tube sheet on the hot-leg side of the steam generators. The inspectors considered this scope of examination to offer only a limited probability of detection of the presence of circumferential stress corrosion cracking.

The inspectors considered the statement made in the evaluations regarding the high degree of confidence in bobbin coil analysis signals to be in conflict with the text of Information Notices 90-49 and 91-67 regarding the limitations of the bobbin coil method. To gain an understanding of the reasons for the licensee statement, the inspectors reviewed a licensee report of metallurgical results for Unit 1 pulled tube samples. These results indicated that degradation of Unit 1 tubes at the tube sheet was primarily related to intergranular attack. The inspectors informed licensee personnel that the ability of the bobbin coil to successfully detect some magnitude of intergranular attack did not appear germane to the discussion in Information Notice 90-49 regarding the limited ability of the method to detect circumferential cracking.

The inspectors additionally noted that the licensee subsequently implemented a comprehensive motorized-rotating pancake coil examination program at the top of the tube sheet after evaluation of an August 1992 industry notification regarding circumferential cracking at Arkansas Nuclear One, Unit 2.

4.2.3 Eddy Current Program Oversight

The inspectors observed that oversight of the eddy current examination contractors during the Unit 3 Refueling Outage RF7 was performed by a steam generator engineer from the site technical services organization. The engineer was ascertained to hold a Level III eddy current examiner certification. No documentation was seen during the outage that would allow an assessment of the scope of the oversight activities. The scope of oversight of eddy current data acquisition and analysis activities by the licensee nuclear oversight division was not reviewed during the inspection.

4.3 Review of Tube Examination Data

The NRC consultant reviewed: (a) the motorized-rotating pancake coil data for tubes that were identified during the Unit 2 Refueling Outage RF7 to exhibit circumferential cracking at the top of tube sheet, and (b) a sample of plus point coil and motorized-rotating pancake coil data that was obtained during the corresponding Unit 3 Refueling Outage RF7 from the top of the tube sheet in Steam Generator 3ME088. The data from a total of 114 tubes were included in this review. In addition, the NRC consultant also reviewed Refueling Outage RF7 bobbin coil data for four tubes from Steam Generator 3ME088. The bobbin coil data quality was considered to be good. The motorized-rotating pancake coil data was also considered to be of fairly good quality when it was taken into account that lift-off signals and signals from deposits are much larger for this type of probe. The plus point coil data were found by the NRC consultant to be much cleaner and easier to analyze than the motorized-rotating pancake coil data.

Although the NRC consultant did not differ with the "calls" made by the analysts, a question was raised concerning the reliability of the resolution methodology that was used to overrule some initial "calls" on plus point data by primary or secondary analysts of circumferential indications. Only one inside diameter circumferential indication "call" was allowed to stand in Unit 3 Steam Generator 3ME088 (i.e., Tube 101-25). This determination was based on use of a screening process which required the phase shift to rotate at all frequencies in a manner similar to the response from the electric discharge machined circumferential notch on the calibration standard. The phase-shift rotations from Tube 101-25 were the only ones in Steam Generator 3ME088 to meet this criteria. The NRC consultant questioned the reliability of this approach, in that it was believed to have resulted elsewhere in tubes containing defects being left in service. The NRC consultant also concluded, however, from review of eddy current data for which "calls" were overruled, that the signals, if they were truly indicative of degradation, appeared to be shallow inside diameter defects that were not of current concern.

The NRC consultant also reviewed the eddy current data that were obtained from a high frequency motorized-rotating pancake coil examination of Tube 101-25. This type of probe concentrates the signals near the tube inner surface and provides for better sizing of defects, due to there being greater phase spread between inside diameter and outside diameter defects. The data collected from both the calibration standards and Tube 101-25 were, however, observed to be quite noisy, which resulted in there not being any improved resolution of inside diameter defects.

5 STEAM GENERATOR STRATEGIC MANAGEMENT PLAN

5.1 Document Review

Prior to the onsite inspection, a preliminary meeting was held with licensee personnel on June 30, 1995, in the Region IV office to review licensee steam generator activities and initiatives. Written information furnished by the licensee during this meeting is provided in Attachment 1. During the inspection, the inspectors reviewed the licensee "Steam Generator Strategic Management Plan, San Onofre Nuclear Generating Station, Units 2 and 3," Revision 0 dated August 1994. The inspectors noted that the plan had been prepared by an inter-disciplinary team. The plan was found to contain: detailed information on tube degradation status, mechanisms, and predictions; detailed chemistry history; a discussion of potential remedial measures; a review of heat transfer degradation and response options; a discussion of primary and secondary side inspections and maintenance; recommendations; and a discussion of candidate steam generator research activities. The inspectors were informed that the strategic management plan would be updated to reflect the additional knowledge that had been gained through the Units 2 and 3 Refueling Outage RF7. Overall, the inspectors considered the approach used by the licensee to be outstanding, in that the plan integrated multi-disciplinary activities into a single program and provided a vehicle for effective management assessment of steam generator program activities and status. The inspectors concluded that the steam generator strategic management plan, if maintained as a living document, should prove to be a valuable tool to management in terms of determining both the status of and needed program actions for maintaining the integrity of the San Onofre Nuclear Generating Station, Units 2 and 3, steam generators.

6 PRIMARY-TO-SECONDARY LEAKAGE MONITORING AND RESPONSE

During this part of the inspection, the inspectors performed an evaluation of the effectiveness of licensee programs and actions concerned with monitoring of and response to steam generator tube leakage and rupture. The areas reviewed included handling of generic communications related to steam generator tube integrity, the adequacy of procedures and equipment to provide real-time information on leak rate and rate-of-change of leak rate, the adequacy of alarm set points on radiation monitors used for detection of leakage and for alerting operators to any increasing leak rate, and operator training.

6.1 Licensee Response to Generic Communications

The inspectors reviewed the licensee's evaluation of NRC Information Notices 93-56, 88-99, and 91-43, as well as industry information which pertained to Information Notice 93-56. These evaluations were performed by the licensee's independent safety evaluation group. The inspectors considered that the overall conclusions of the evaluations of the information notices were correct and that the associated actions taken by the licensee were appropriate. However, the inspectors found that two of the three information notice evaluations by the licensee contained erroneous statements in the justification for the conclusions, which indicated a lack of thoroughness in the reviews. The third information notice evaluation suggested a further evaluation by the licensee's nuclear engineering design organization, which was not documented as having been completed. However, based on interviews, the inspectors concluded that an evaluation had taken place. Specifics are given below:

- Information Notice 93-56 - The licensee evaluation stated that if the operators were in the functional recovery emergency operating procedure and failed to meet a safety function, they could transition to the appropriate optimal recovery emergency operating procedure. The inspectors determined that they would instead remain in the functional recovery procedure until the safety function was met. This was standard owners group philosophy.

- Information Notice 88-99 - The licensee evaluation stated that the Units 2 and 3 air ejector effluent exhausted to the plant vent stack. The inspectors determined that this was erroneous in that the air ejectors have a separate exhaust and the two systems cannot be cross tied.

- Information Notice 91-43 - The licensee evaluation stated that the nuclear design engineering organization would be forwarded the information notice because the NRC recommended use of nitrogen-16 main steam line monitors. The nuclear engineering design organization did an informal cost benefit analysis, decided that the costs were prohibitive for the benefits, but did not document the evaluation in the context of the information notice response.

Overall, the inspectors concluded that the evaluations of the three information notices by the independent safety evaluation group were appropriate, but the errors noted were indicative of a lack of rigor in the evaluation review process.

6.2 Procedures and Equipment Adequacy for Leak Rate Information

The inspectors reviewed: (a) the installed radiation monitors which could alert operators to a steam generator tube leak or rupture, (b) the various licensee procedures for determining leak rate, (c) the abnormal operating instruction for a tube leak, (d) the emergency operating procedures in regard to tube ruptures, and (e) procedures for controlling contaminated water. The inspectors also walked down the condenser offgas system, visually inspected the grab sample points, and interviewed cognizant personnel. In addition, the inspectors reviewed the guidance contained in Electric Power Research Institute Report TR-104788, "PWR Primary to Secondary Leak Guidelines," dated May 1995. The inspectors compared licensee leak estimation equations to the equations contained in the Electric Power Research Institute report. The inspectors concluded, overall, that the licensee had adequate equipment and procedures to detect leaks and mitigate ruptures, and that the licensee equations to quantify leakage based on grab samples and radiation monitor readings were valid.

During the inspection period, the inspectors noted that Unit 2 Radiation Monitor 7870, the condenser offgas wide range monitor, was reading higher than grab samples of the condenser offgas taken three times a week for a known tube leak in Unit 2 Steam Generator 2ME089. The inspectors reviewed historical data which revealed an approximate average activity of 3 E-6 microcuries per cubic centimeter (7870 reading) versus 8 E-8 microcuries per cubic centimeter (grab samples). The licensee had chosen not to calibrate the radiation monitor to the grab sample, which was Electric Power Research Institute guidance. This was because of the detector differences between the grab sample and the radiation monitor, with the radiation monitor being probably more accurate. The inspectors considered this appropriate. The inspectors also noted that the leak was small and anticipated that, as activity increased, the monitor and grab samples would agree more closely. In response to the inspector concern that the radiation monitor was reading high, the licensee decontaminated the 7870 screen on August 4, 1995, which brought the readings closer together.

6.3 Alarm Setpoints on Radiation Monitors

The inspectors reviewed the licensee's setpoint rationale and documentation for all radiation monitors associated with detecting a tube leak or rupture. The inspectors noted that the licensee was unable to establish its desired alarm setpoint corresponding to a 30 gallons per day (gpd) leak on Unit 2 Radiation Monitor 7870, because as described above, the monitor was indicating high compared to grab samples. Also, the analytical methods used for establishing the 30 gpd leak would set the alarm close to the actual reading, which would provide spurious alarms. The actual alarm during the inspection period was 6.3 E-4 microcuries per cubic centimeter. The inspectors considered this appropriate and also considered that this setpoint was sufficient to alert operators to an increasing leak rate. The inspectors concluded that the setpoints were sufficiently low for alerting operators if they did not notice an increasing leakage trend.

6.4 Adequacy of Emergency Operating Procedures and Operator Training

The inspectors observed operators as they operated the plant-referenced simulator during a tube rupture scenario, reviewed the emergency operating procedures with respect to a tube rupture, calculated transport time for radioactive liquid and gas from the steam generator to the condenser offgas radiation monitor, reviewed a similar licensee calculation, and reviewed the owners group guidance and deviation document for the emergency operating procedures. Overall, the inspectors concluded that the procedures and training were adequate. Operator performance during the scenario is described in NRC Inspection Report 50-361/95-09; 50-362/95-09.

The inspectors did identify that the operators were being trained with a transport time of about 1 - 2 minutes for the condenser offgas radiation monitors to detect elevated steam generator activity, while the actual plant response was established to be around 4 minutes. The inspectors determined that the operating crews would probably not reach the diagnostic portion of the emergency operating procedures (providing them with the elevated readings on the condenser offgas radiation monitor that they would need to diagnose a tube rupture) until after the 4-minute delay time. The licensee was reevaluating radiation monitor response in the simulator at the end of the inspection period. The resident inspectors will, during the course of routine inspection activities, review the new simulator model to ensure the transport time is lengthened.

The inspectors also identified some minor differences between the owners group guidance and the licensee's emergency operating procedures that were not identified in the deviation document. The inspectors considered these differences as meeting the spirit of the owners group guidance, and not deviations from it, and consequently concluded that the differences did not require a formal justification for deviation.

Overall, the inspectors concluded operator training and the emergency operating procedures were adequate to mitigate a steam generator tube rupture.

7 REVIEW OF SECONDARY WATER CHEMISTRY CONTROLS AND HISTORY

Many impurities that enter the secondary side of steam generators can contribute to corrosion of steam generator tubes and support plates. While the concentration of impurities needed to cause corrosion problems is normally much higher than that present in steam generator bulk water, concentration of impurities to aggressive levels is possible in occluded areas where dryout occurs. Typical areas where dryout and resulting concentration of impurities can occur are tube sheet crevices, tube support plate crevices, and sludge piles. Impurities known to contribute to tube denting (i.e., squeezing of tubes at tube supports or tube sheets as a result of the pressure of corrosion products) are chlorides, sulfates, and copper and its oxides. Pitting of steam generator tubes has been attributed to the presence of copper and concentrated chlorides. Concentrated sulfates and sodium hydroxide are believed to be major causes of intergranular stress corrosion cracking and intergranular attack in steam generator tubes. Iron oxide deposits and sludge promote local boiling and concentration of impurities, leading to these damage mechanisms.

7.1 Program Evolution

The inspectors reviewed the licensee's secondary water chemistry control program requirements and initiatives for Units 2 and 3. It was ascertained that secondary water chemistry controls have utilized all volatile treatment with hydrazine, and ammonia for pH control, throughout commercial operation. The inspectors compared the San Onofre Nuclear Generating Station historical secondary water chemistry program requirements against the criteria contained in the Electric Power Research Institute "PWR Secondary Water Chemistry Guidelines." These guidelines were initially issued as Electric Power Research Institute NP-2704-SR in October 1982, with a different document number assigned for each issued revision (i.e., Revision 1, Electric Power Research Institute NP-5056-SR; Revision 2, Electric Power Research Institute NP-6239; and the current Revision 3, Electric Power Research Institute TR-102134). To accomplish this task, the inspectors compared the following revisions of Procedure SO123-III-2.1.23, "Units 2/3 Steam Generator and Condensate/Feedwater Chemistry Control and Sampling Frequencies," against the applicable Electric Power Research Institute document that was in effect at the time: (a) Revision 0, which was effective on July 22, 1983, against Electric Power Research Institute NP-2704-SR; (b) Revision 9, which was effective on August 9, 1990, against Electric Power Research Institute NP-6239; and (c) Revision 12 through Temporary Change Notice 12-4, which was effective on May 24, 1995, against Electric Power Research Institute TR-102134.

The inspectors determined that more permissive sodium and chloride blowdown limits were included in the initial licensee secondary side chemistry program requirements than those included in the Electric Power Research Institute guidelines (i.e., Procedure SO123-III-2.1.23, Revision 0, 50 ppb Level 1 Action Limit; Electric Power Research Institute NP-2704-SR, 20 ppb Level 1 Action Limit). Additional review established that Procedure SO123-III-2.1.23 fully conformed to the Electric Power Research Institute guideline recommendations on issue of Revision 3 in February 1986. Subsequent revisions to the procedure have remained in conformance with the Electric Power Research Institute secondary water chemistry guidelines as they have evolved. The inspectors were informed that the initial plant design did not include condensate polishers. A design modification was subsequently performed to incorporate condensate polishers, with installation completed in 1986 in Units 2 and 3. As shown by the data in Section 7.2 below, the installation of condensate polishers made a significant contribution to development of a capability to maintain very high quality secondary water chemistry.

A review was performed of basic condensate polisher design features and capabilities with licensee chemistry staff. The inspectors found that both cation and mixed bed condensate polishers were used in San Onofre Nuclear Generating Station, Units 2 and 3, with the cation polishers placed upstream of the mixed bed polishers. The effluent from the mixed bed polishers passed through 5 micron filters which precluded passage of resin fines from the polishers and possible ingress to the steam generators. Use of these filters was believed by licensee personnel to be possibly unique in domestic plants. The functions of the cation polisher were to remove NH_4^+ ions and heavy metal cations, which created an acidic influent to the mixed bed polishers and resulted in reduced metal fouling of the mixed bed polishers and enhanced kinetic performance. Other features which eliminated the typical inability with mixed bed polishers to completely separate anion and cation resins for regeneration, and resultant relatively poor performance and high effluent sodium contents, were stated by licensee personnel to be: use of a unique design of resin separation tank that optimized backwash flow, retention of the resin interface region to the next bed to be regenerated, and rinsing of the anion resin with weak ammonium hydroxide to exhaust any cation resin that was carried over with anion resin during separation. The current typical quality of water leaving the full flow condensate polishers was indicated by licensee staff to be: cation conductivity, 0.055 μS/cm; sodium, < 2 ppt; chloride, < 3 ppt; and sulfate, < 6 ppt. The inspectors considered these chemistry values to be outstanding.

The inspectors noted from review of the steam generator strategic management plan and from discussions with licensee staff that the chemistry staff had been both thorough and proactive in its efforts to improve secondary water chemistry and reduce iron transport to the steam generators. To date, initiatives have included: (a) a study of optimum pH in 1991, with a value of 9.3 found to reduce corrosion product transport to the steam generators by 50 percent (without an accompanying increase in copper transport); (b) relocation of the chemical feed point after identification of 500 feet of secondary piping, that was installed as part of the condensate polisher design modification, not receiving chemical treatment; (c) adoption in 1991 of morpholine additions to the steam generators during layup, in an attempt to improve heat transfer; (d) implementation of actions to assure bulk chemicals were not contaminated, as a result of the discovery of high sodium concentrations in ammonium hydroxide; (e) evaluation of the effects of elevation of hydrazine additions above 100 ppb on corrosion product transport; (f) comprehensive review of molar ratio history; and (g) evaluation of use of ethanolamine to reduce iron transport to the steam generators. Although the inspectors considered the time frame for studying the adoption of ethanolamine additions was protracted, it was noted that the review was extremely thorough and had identified that some supply sources were furnishing ethanolamine which contained ethylene glycol, a contaminant that would impair resin performance.

Overall, the inspectors considered chemistry program activities and controls to be noteworthy, and reflecting favorably on the knowledge and involvement of chemistry staff.

7.2 <u>Secondary Side Chemistry History</u>

The inspectors reviewed the history of the San Onofre Nuclear Generating Station, Units 2 and 3, steam generators with respect to significant chemistry events and compliance with the Electric Power Research Institute secondary water chemistry guidelines. Details on off-normal chemistry are discussed below in Section 7.5. As part of this review, the inspectors requested available historical information from the licensee for annual average blowdown and condensate/ feedwater chemistry values. The information provided in response by the licensee for Units 2 and 3 is listed below in Tables 5 and 6. The inspectors considered the ready availability of this historical chemistry performance information by operating cycle was a further indicator of a strong chemistry program and effective program management.

Table 5

UNIT 2
AVERAGE STEAM GENERATOR BLOWDOWN AND CONDENSATE/FEEDWATER CHEMISTRY VALUES

Parameter[1]	Current Limit	Operating Cycle						
		1	2	3	4	5	6	7[2]
CC, μS/cm	< 0.8	1.24	0.32	0.15	0.10	0.08	0.08	0.07
Cl^-, ppb	< 20	59.6	10.4	3.8	1.4	0.3	0.3	0.16
$SO4^-$, ppb	< 20	29.4	12.0	4.2	0.6	0.3	0.1	0.05
Na^+, ppb	< 20	30.0	4.4	2.0	0.9	0.3	0.1	0.12
CON DO, ppb	< 5	16.3	12.3	10.3	8.1	7	-	-
POL DO, ppb	< 5	-	-	6.8	5.9	5	4.2	4.3
FW Cu, ppb	< 1	9.9	1.0	2.2	0.8	0.2	0.3	0.12
FW Fe, ppb	< 5	16.3	6.5	7.2	9.8	12.8	6.2	5.4
Molar Ratio[3] Na^+/Cl^-+SO4^-	0.7-1.0[5]	0.57	0.35	0.45	0.75	0.89	0.41	-
Molar Ratio[4] Na^+/Cl^-	0.7-1.0[5]	0.78	0.65	0.81	0.99	1.54	0.51	0.83

1 CC (cation conductivity), Cl^- (chloride), $SO4^-$ (sulfate), Na^+ (sodium) CON DO (condensate dissolved oxygen), POL DO (Polisher effluent dissolved oxygen), FW Cu (feedwater copper), FW Fe (feedwater iron).
2 Reported values are averages for the final 3 months of Cycle 7.
3 Determined from the ratio of molar concentration of sodium ⌄ the sum of molar concentrations of chloride and sulfate.
4 Determined from the ratio of molar concentration of sodium to molar concentration of chloride.
5 Initial goal, not a limit.

Cycles 1 and 2 in Unit 2 were characterized by high contaminate (i.e., chloride, sulfate, and sodium) concentrations in the blowdown. These concentrations were assumed by the inspectors to be related to condenser tube leakage problems during early operation, with the absence of condensate polishers precluding condensate cleanup prior to passage to the steam generators. The iron and copper contents of the feedwater were also noted to be high in Cycle 1. The inspectors were informed that the condenser tube sheet and five out of six feedwater heaters in each train were tubed with copper alloys, which explained the source of the copper. Overall, the data was considered by the inspectors to reflect progression to excellent secondary water chemistry performance. Exceptions noted were condensate dissolved oxygen and, in particular, feedwater iron content. The latter value, with its significance in terms of corrosion product transport, was considered by the inspectors to currently be the only secondary chemistry issue requiring continued management attention. The historical molar ratio values were noted by the inspectors to be lower than values seen at other facilities, thus, raising the possibility that crevice conditions in the San Onofre Nuclear Generating Station, Unit 2, steam generators may have been less alkaline than elsewhere. Insufficient information was available to determine whether the lower molar ratio values would result in a lower incidence of secondary side stress corrosion cracking than encountered at other plants.

Table 6

UNIT 3
AVERAGE STEAM GENERATOR BLOWDOWN AND CONDENSATE/FEEDWATER CHEMISTRY VALUES

Parameter[1]	Current Limit	Operating Cycle						
		1	2	3	4	5	6	7[2]
CC, μS/cm	< 0.8	0.70	0.31	0.14	0.10	0.09	0.08	0.07
Cl^-, ppb	< 20	26.5	9.6	2.8	2.0	0.3	0.3	0.18
$SO4^-$, ppb	< 20	25.8	11.7	1.5	0.5	0.2	0.1	0.06
Na^+, ppb	< 20	14.2	2.8	2.0	0.7	0.3	0.2	0.17
CON DO, ppb	< 5	17.1	11.4	10.2	7.4	5	5.8	-
POL DO, ppb	< 5	-	-	6.7	5.4	4.5	4.7	5.4
FW Cu, ppb	< 1	7.6	2.0	0.6	0.5	0.2	0.3	0.2
FW Fe, ppb	< 5	19.5	9.4	12.0	14.1	11.0	6.5	6.4
Molar Ratio[3] Na^+/Cl^-+SO4^-	0.7-1.0[5]	0.48	0.24	0.79	0.46	1.03	0.83	-
Molar Ratio[4] Na^+/Cl^-	0.7-1.0[5]	0.83	0.45	1.10	0.54	1.54	1.03	1.07

[1] CC (cation conductivity), Cl^- (chloride), $SO4^-$ (sulfate), Na^+ (sodium) CON DO (condensate dissolved oxygen), POL DO (polisher effluent dissolved oxygen) FW Cu (feedwater copper), FW Fe (feedwater iron).

[2] Reported values are averages for the final 3 months of Cycle 7.

[3] Determined from the ratio of molar concentration of sodium to the sum of molar concentrations of chloride and sulfate.

[4] Determined from the ratio of molar concentration of sodium to molar concentration of chloride.

[5] Initial goal, not a limit.

The historical chemistry performance in Unit 3 was indicated by the data to be very similar to Unit 2, with higher contaminant concentrations in the first two cycles followed by progression to excellent overall secondary water chemistry following installation of condensate polishers. The molar ratio, feedwater copper and iron, and dissolved oxygen historical data also reflected similar performance to that noted in Unit 2.

The inspectors requested historical information from the licensee for each steam generator pertaining to the weight of sludge removed by sludge lancing during refueling outages. The data provided by the licensee are listed below in Table 7.

Table 7

WEIGHT (LBS) OF SLUDGE REMOVED FROM UNITS 2 AND 3 STEAM GENERATORS (SGs)						
Outage	Unit 2 SGs			Unit 3 SGs		
	2ME088	2ME089	Total	3ME088	3ME089	Total
RF3	120	86	206	170	137	307
RF4	185	219	404	307	249	556
RF5	299	278	577	263	211	474
RF6	309	384	693	397	804	1201
RF7	682	903	1585	595	438	1033
Total	1595	1870	3465	1732	1839	3571

The data indicated to the inspectors that similar total sludge quantities had been removed from each steam generator, and that corrosion product transport was essentially the same in Units 2 and 3. The inspectors were informed by licensee personnel that variations occurred in recent outages in the number of sludge lancing passes that were used for individual steam generators. The inspectors acknowledged that changes in practice would be expected to cause some variation in sludge removal amounts, but still considered the data indicated an overall increasing trend. The inspectors considered that the sludge quantities being removed were a further reason for continued management attention to feedwater iron content and program actions to reduce corrosion product transport.

The inspectors also reviewed the results of chemical analyses that were performed on sludge samples that were removed from the Unit 2 steam generators during Refueling Outage RF7. These analyses showed that the major element in the sludge was, as would be expected, iron. X-ray diffraction indicated that the iron was primarily present in the form of magnetite (i.e., Fe_3O_4), with a small amount present as hematite (i.e., Fe_2O_3). Approximately 8 percent by weight copper was found to be present in the sludge, with X-ray diffraction indicating that the copper was present in the metallic form. The inspectors noted that X-ray fluorescence also found silicon, zinc, and nickel to be present in the sludge. The approximate respective quantities, in the assumed oxide form, were 2 percent zinc oxide, 4 percent silica (i.e., SiO_2), and 0.6 percent nickel oxide. The high copper content in the sludge resulted, as discussed above, from the use of copper alloys for the feedwater heater tubes and condenser tube sheet. The zinc and nickel quantities were also believed by the inspectors to originate from feedwater heater tubes, in that two feedwater heaters in each train were tubed with 90-10 cupronickel tubes and three feedwater heaters in each train were tubed with arsenical Admiralty brass, a copper-zinc alloy. Leachate samples demonstrated the ability of impurities to concentrate in sludge piles, with approximately 19 ppm of sodium measured versus the 0.1-0.2 ppb values shown above in Table 5 and 6 for current sodium levels in the blowdown.

7.3 Self Assessment of Primary and Secondary Water Chemistry

The inspectors performed a limited review of the licensee audit and surveillance history pertaining to the primary and secondary water chemistry control programs. In review of the audit and surveillance findings, the inspectors observed no findings which would bring into question the quality of the water chemistry programs.

7.4 Chemistry Laboratory Instrumentation

The inspectors toured the secondary water chemistry laboratory and reviewed the in-line process capabilities with licensee staff. The inspectors verified from the review that the necessary instrumentation was installed in the process lines, or available in the laboratory, for the analysis of the diagnostic and control parameters specified in the secondary water chemistry control program. The inspectors ascertained that analog in-line instruments were originally used to monitor the pH, conductivity, sodium, and oxygen content of feedwater. Within the last year, the licensee has replaced these instruments with in-line digital equipment which was indicated to have improved the sensitivity of detection by a factor of approximately 10. An example given by licensee personnel was the detection capability for sodium ion. The original in-line analog instruments for sodium were stated to not accurately measure concentrations below about 5 ppb, which necessitated the taking of grab samples and use of an ion chromatograph for sensitive measurements. The new digital equipment eliminated the need for sampling by providing an in-line detection capability of 0.1 ppb for sodium ion.

The inspectors also toured the room containing the condensate demineralizer panel and its adjacent laboratory, and observed the in-line analytical instrumentation used for monitoring condensate water chemistry. The condensate demineralizer panels provide a means of monitoring condensate flow and measuring cation and normal conductivities of condensate as it enters and discharges from the condensate polishers. The licensee originally installed in-line ion chromatographs into the secondary side design in 1986 after Units 2 and 3 were modified to include cation and mixed bed condensate polishers. These in-line ion chromatographs are located in a laboratory located adjacent to the condensate demineralizer panel room, and allow for a readily accessible, rapid means of monitoring condensate cation and anion chemistry. The inspectors verified that the secondary in-line ion chromatographs were used to monitor the key chemical ionic species in the Units 2 and 3 condensate systems.

The inspectors noted that extensive efforts have been made by the licensee to upgrade the in-process and laboratory instruments that are needed for monitoring and performing required secondary water chemistry analyses. In addition, the inspectors noted that the licensee is currently in the process of introducing a computerized chemistry data management system. When fully operational, the system should allow instantaneous retrieval of data, enhance trending capabilities, and significantly reduce paper generation.

7.5 Off-Normal Secondary Chemistry History

The inspectors requested licensee personnel to provide available information regarding significant out-of-specification conditions which have occurred during commercial service. The criteria used by the inspectors to define significant were exceeding Action Levels 2 and 3 values in the Electric Power Research Institute secondary water chemistry guidelines. The number of occurrences identified by the licensee for Units 2 and 3 are listed in Tables 8 and 9 below. The inspectors noted from review of the supporting information provided by the licensee that the actual number of Unit 2 chemistry transients were two in 1983, three in 1984, three in 1985, and one in 1986 (i.e., more than one limit was exceeded during some of the transients). The majority of the problems encountered by the licensee in the early years of commercial operation were related to sea water intrusion events, with the immediate pass through of sodium and chloride ions to the steam generators. The effects of installation of full-flow condensate polishers are illustrated by the absence of any violation of Action Level 2 sodium and chloride limits subsequent to 1986. The inspectors considered that the nine Unit 2 chemistry transients were potential contributors to tube degradation, with the chloride excursions expected to promote pitting. Eddy current examination has detected a limited number of volumetric indications which could possibly be pits. Tube samples were not, however, removed by the licensee, thus, precluding verification of the degradation mechanism.

Table 8

UNIT 2 OFF-NORMAL SECONDARY WATER CHEMISTRY HISTORY						
Year	Action Level 2 Occurrences				Action Level 3 Occurrences	
	COND DO[1]	SG Na^{+} [2]	SG Cl^{-} [3]	SG CC[4]	SG Na^{+} [2]	SG CC[4]
1983		2	2			1
1984		1	3		1	2
1985	2	1	1	1		
1986			1			

1 Condensate dissolved oxygen
2 Steam generator blowdown sodium
3 Steam generator blowdown chloride
4 Steam generator cation conductivity

Table 9

UNIT 3 OFF-NORMAL SECONDARY WATER CHEMISTRY HISTORY						
Year	Action Level 2 Occurrences				Action Level 3 Occurrences	
	COND DO[1]	SG Na^{+} [2]	SG Cl^{-} [3]	SG CC[4]	SG Na^{+} [2]	SG CC[4]
1984	1		4			
1986	1	1	4	1		1
1987	1					
1988			2			1
1993	1					

1 Condensate dissolved oxygen
2 Steam generator blowdown sodium
3 Steam generator blowdown chloride
4 Steam generator cation conductivity

The inspectors noted from review of the supporting information provided by the licensee that the actual number of Unit 3 chemistry transients were 4 in 1984, 5 in 1985, 1 in 1987, 2 in 1988, and 1 in 1993. The number of chemistry transients, 13, was greater than the corresponding number experienced by Unit 2, and some problems had occurred after installation of full-flow condensate polishers. The later problems were observed to be related to a heater drain tank pump and loss of condenser vacuum and, thus, were not specifically related to the condensate polishers. The inspectors considered overall that the Unit 3 steam generators had been exposed to somewhat worse chemistry transient conditions than what the Unit 2 steam generators had experienced. The most significant condition noted in the Unit 3 data occurred in August 1984. Steam generator chloride peaked at 35 ppm and necessitated shutdown of the unit to minimize degradation.

8 INSERVICE INSPECTION-OBSERVATION OF WORK AND WORK ACTIVITIES (73753)

The objectives of this part of the inspection were to determine whether: (a) the performance of inservice inspection examinations, and any repair or replacement of Class 1, 2, and 3 pressure retaining components, were accomplished in accordance with the applicable ASME Code; and (b) the licensee had appropriately satisfied industry initiatives. This part of the inspection and the followup activities documented in Section 9 of this report were performed by a single inspector during August 2-8, 1995.

8.1 Inservice Inspection Program

The licensee's inspection program incorporated the requirements of the 1989 Edition of the ASME Code with no addenda. This was the second 10-year inservice inspection program plan for San Onofre Nuclear Generating Station, Unit 3. The program's initial use was scheduled for the current refueling outage. During this inspection period, NRC review of the plan continued.

8.2 Contract Personnel Qualifications and Certifications

The initial inservice inspections were performed by three Lambert-MacGill-Thomas, Inc., examiners, one of whom was the designated contractor supervisor.

The inspector reviewed the qualification files of the three nondestructive examination personnel who performed the observed examinations. The files contained certifications for the examination methods that the inspector observed. The contractor supervisor was certified as a Level III examiner in all methods except radiography; however, the inspector did not observe this individual perform any examinations. Of the two individuals who were observed by the inspector performing examinations in the field, one was certified as a Level III examiner for all methods except radiography, and the other was a Level II examiner in magnetic particle, liquid penetrant, and ultrasonic examination methods and a Level I in visual testing. The records showed that all three individuals observed by the inspector in the performance, evaluation, and supervision of nondestructive examinations had met the qualification and certification requirements in the applicable supplement of American Society of Nondestructive Testing Recommended Practice SNT-TC-1A and ASME Section XI.

8.3 Inservice Inspection Procedures Review

The inspector reviewed the nondestructive examination procedures used during the performance of the observed examinations. These procedures were in a Lambert-MacGill-Thomas, Inc. procedural format, but assigned a licensee procedure identification number. The procedures reviewed included the following:

- Procedure SO23-XXVII-20.47, "Magnetic Particle Examination," Revision 0 (this procedure was applicable to examinations using fluorescent or color contrast and wet or dry ferromagnetic particles);

- Procedure SO23-XXVII-20.48, "Liquid Penetrant Examination," Revision 0; and

- Procedure SO23-XXVII-20.55, "Ultrasonic Examination of Nuclear Coolant System Austenitic Piping," Revision 1.

The inspector verified that the procedures had been appropriately reviewed and approved by the appropriate licensee personnel, and were consistent with the requirements of the 1989 Edition of the ASME Code.

8.4 Observation of Nondestructive Examinations

The performance of inservice examinations was authorized and controlled by construction work orders. The inspector observed the licensee's contractor employees perform nondestructive examination activities in the field. These observed examinations were conducted using the liquid penetrant, ultrasonic and magnetic particle examination methods on Class 1, 2, and 3 piping and components. The inspector observed the contract examiners from the start of the examinations until the result determinations were made. The inspector noted that the examiners performed inspections to verify correct weld identification and cleanliness prior to all examinations.

8.4.1 Dye Penetrant Examinations

The inspector observed the performance by contract personnel of liquid penetrant examinations on the following system piping welds:

Code Class	ISI Design No.	System and Piping Size
1	03-021-160	Shutdown Cooling - 18 inches
1	03-021-140	Shutdown Cooling - 18 inches
1	03-021-130	Shutdown Cooling - 18 inches

The inspector noted that the contract examiners performed thorough pretest inspections for adequacy of surface preparation and cleanliness prior to start of liquid penetrant examinations. After pretest inspections, the examiners applied approved cleaner to assure the surface area was clean prior to application of the penetrant fluid. The surface temperature of areas to be tested was measured by the examiners with a thermometer to verify that the surface temperatures were within the required examination range. The inspector verified that the thermometer was within the calibration period. The inspector also noted that the examiners allowed for the appropriate dwell times for the liquid cleaner, liquid penetrant, and developer in accordance with the procedure.

8.4.2 Ultrasonic Examinations

The inspector observed the performance by contract personnel of ultrasonic examinations using both shear and longitudinal wave forms on the following system piping welds:

Code Class	ISI Design No.	System and Piping Size
2	03-073-1850	Safety Injection - 8 inches
2	03-073-1860	Safety Injection - 8 inches
2	03-073-1870	Safety Injection - 8 inches

The inspector noted that contract personnel performing the observed examinations adhered to procedural requirements and were very knowledgeable of the examination and procedural requirements. The inspector reviewed the examination results that were documented on a form, "SONGS Inservice Inspection Ultrasonic Examination Report Unit 3 395-08IUT-018."

This report form had been created by the licensee especially for this outage. During the review, the inspector identified numerous instances of a lack of (1) clarity concerning what information was required, (2) familiarity by licensee personnel concerning form usage, and (3) guidance from procedures or directions.

The licensee representatives indicated that instructions had not yet been written because the new report form was still in the development process. The inspector considered (a) not having instructions or identification of the acronyms used on the newly created report form and (b) that the contract supervisor was not knowledgeable of what the acronyms represented was a weakness. The licensee representatives indicated that prior to the next outage instructions would be created that would appropriately identify all acronyms.

8.4.3 Magnetic Particle Examinations

The inspector observed the performance by contract personnel of magnetic particle examinations on the following system piping and components:

Code Class	ISI Design No.	System and Piping Size
1	03-013-003P	Reactor Vessel, Pipe Longitudinal Weld, Pump End
1	03-013-004P	Reactor Vessel, Pipe Longitudinal Weld, Pump End

In addition the inspector observed magnetic fluorescent particle examinations on the No. 1 and No. 5 reactor pressure vessel studs.

The inspector noted that contract personnel used an AC yoke and appropriately verified that it was capable of lifting a 10 pound weight prior to the examinations. The inspector verified that approved color contrast magnetic particles were used and observed contract personnel appropriately verify magnetic flux lines prior to examinations in accordance with the procedure.

During the wet fluorescent magnetic particle examinations of the No. 1 and No. 5 reactor pressure vessel studs, the inspector noted that contract personnel appropriately adhered to the procedure. Licensee personnel had erected a tent on the Unit 2 spent fuel pool area floor for the examinations. The inspector noted that no outside lighting was visible inside the tent. The inspector observed the examiner appropriately adhere to the 5-minute stay time inside the dark tent prior to the examinations. Contract personnel appropriately determined the fluorescent wet oxide concentration using a centrifuge tube and verified that the concentration was in accordance with the procedure. The contract examiners measured the intensity of the black light used during the examinations to ensure the procedural required minimum of 800 microwatts/square cm was met.

8.5 Licensee's Controls over Inservice Inspection Contractors

During the observed examinations, the inspector noted that the licensee's engineer in charge of inservice inspection activities independently verified each of the applicable weld locations for each examination, as well as monitored all of the contract personnel activities. Based on the observations, the inspector concluded that: licensee personnel were involved in ensuring the quality of examinations, and that the effectiveness of the licensee's controls over inservice inspection contractor personnel were good.

8.6 General Condition of Containment

During the inspection, most of the Unit 3 inservice inspection activities observed by the inspector were performed inside the containment. The inspector noted that the general material condition of the Unit 3 containment and housekeeping were good, and that tool and component laydown areas were adequately marked. No evidence of boric acid leakage was noted in the areas of the observed examinations. The inspector also noted, while travelling to and from the inservice inspection examination sites inside containment, that plant personnel appeared to be adhering to good radiological practices.

8.7 Section XI Repair and Replacement

Licensee nondestructive examination personnel were responsible for the nondestructive examination of ASME Section XI Code repair and replacement welding activities. The inspector observed licensee examination personnel perform liquid penetrant, magnetic particle, and visual testing in the field during repair and replacement welding activities. In addition, the inspector reviewed radiographs taken by licensee for ASME Section XI Code repair and replacement activities. The inspector reviewed the qualification records of the licensee individuals observed and the licensee personnel responsible for the radiographs that were reviewed. The qualification records met the qualification and certification requirements of American Society of Nondestructive Testing Recommended Practice SNT-TC-1A and the ASME Section XI Code.

The inspector did not directly observe licensee personnel perform welding activities in the field. However, the inspector did review two welding maintenance order packages and the associated weld records and repair specifications. The inspector questioned licensee welding personnel at the specific job sites to ascertain whether licensee welding personnel were knowledgeable of ASME Section XI welding practices and licensee procedural requirements. In addition, the inspector verified that licensee welding personnel, associated with the two maintenance order packages reviewed, were qualified for those types of welding activities.

8.7.1 Boric Acid Line Replacement (Maintenance Order No. 95061075000)

This maintenance order involved the replacement of a damaged section of boric acid line piping. This piping was previously reviewed by another inspector and documented in NRC Inspection Report 50-361; 50-362/95-13. The piping that required replacement was a Code Class 3 spool piece. The inspector reviewed Weld Record WR3-95-454 which documented the welding process instruction, weld joint data, ASME Code requirements, and the weld location drawing. The inspector also reviewed Repair Specification 152-95, Revision 1, which documented the appropriate ASME Code required nondestructive examinations. The replacement spool piece was fabricated in the maintenance shop, while the damaged spool piece was being removed in field.

The inspector observed a licensee nondestructive examiner perform liquid penetrant examinations on three new welds on the new boric acid line spool piece. The inspector noted Procedure NDEP-PT-001, Revision 6, "Liquid Penetrant Examination" was used for this activity. The inspector verified that the procedure had been reviewed and approved by the appropriate licensee personnel, and was consistent with the requirements of the 1989 Edition of the ASME Code. The inspector noted that the licensee examiner responsible for the performance of these examinations was knowledgeable of the procedure requirements and the examination process. No indications were identified during the three examinations and the welds were accepted. During this inspection, the inspector was unable to observe actual replacement of the boric acid line spool piece, because licensee personnel were still in the process of removing the damaged spool piece.

8.7.2 High Pressure Safety Injection Header No. 2 Check Valve Replacement (Maintenance Order 93121777000)

This maintenance order required the replacement of the High Pressure Safety Injection Header No. 2 Check Valve S31204MU152, which was leaking by and pressurizing the hot-leg injection line resulting in the line having to be drained several times per shift. The new weld on the hot-leg injection line associated with the replacement check valve was Code Class 1 and required radiographs be taken to satisfy ASME Code requirements. The inspector reviewed Nondestructive Examination Procedure NDEP-RT-004, which was used for the radiograph examinations. The procedure complied with the requirements of ASME Code Case N-416-1, Code Section III, and ASME Code Section V. The inspector reviewed the six radiographs taken of the new weld and the associated documentation. While viewing the radiographs taken of the new weld, the inspector interviewed two of the licensee radiographic specialists to ascertain their knowledge of the procedure and radiograph examination requirements. The two licensee technicians were knowledgeable of both the procedural and ASME code requirements. During review of the radiographs, the inspector noted that the appropriate 12 penetrameter was used and the essential 4T hole was visible. The inspector also reviewed Radiograph Report 3RT-018-95 which documented the results of the radiographs. The inspector noted that the penetrameter was appropriately placed and verified that the geometric upsharpness calculation was within Code requirements. The inspector concluded that all information, diagrams, and results were appropriately documented. No defects were identified by the licensee's radiographic examiners or the inspector while viewing the six radiographs.

8.7.3 Snubber Removal (Maintenance Order 95011093000)

This maintenance order involved a snubber that was removed and replaced with a rigid strut located in the Unit 3 Radwaste Building Tunnel 31, and was part of the licensee's snubber reduction efforts that were ongoing throughout the refueling outage.

The inspector observed a licensee examiner perform visual tests and magnetic particle testing on two new welds associated with the maintenance order. The inspector noted that the examiner followed procedures and was knowledgeable of the procedure requirements. The examiner had identified during visual testing that one of the welds did not satisfy the procedural requirements for undersize leg length. This observation was appropriately documented and the weld was rejected. The examiner's observation required welding personnel to make another pass on the undersized leg. The latter weld passed both the visual and magnetic particle examinations and was accepted by the licensee examiner.

8.7.4 Component Cooling Water Check Valve S31203MU269 Replacement (Maintenance Order 95040549000)

This maintenance order involved the replacement of the currently installed check valve with a new 3-inch, 150 lb swing check valve on the component cooling water line in the Unit 3, safety equipment building. This component was ASME Code Class 3. The inspector reviewed the work package and observed a portion of the work being performed.

The inspector noted that two weld records were associated with the maintenance order. Weld Record WR3-94-445, Revision 1, was for the weld joint for the 3-inch Schedule 40, 0.216-inch valve body and the 3-inch, stainless steel Schedule 10 piping. The other Weld Record WR3-94-446 was for the valve body and carbon steel piping. The inspector noted that the weld record contained all pertinent information such as component data, weld joint data, welding process instructions, and the weld location drawings. The inspector noted that two licensee welding personnel performed the welds on the valve. The inspector verified that the welding personnel were qualified for the job. The inspector also questioned the licensee welding supervisor in charge of the job concerning the required maximum interpass temperatures for both the stainless steel piping and the carbon steel piping. The supervisor was cognizant of the maximum interpass temperature of 350°F for the stainless steel and the 600°F for the carbon steel, and appeared cognizant of the required nondestructive examinations. The inspector also questioned one of the two welders associated with the work order to ascertain the welder's knowledge of procedural welding requirements. The welder appeared appropriately knowledgeable of procedural requirements.

9 FOLLOWUP - MAINTENANCE (92902)

9.1 (Closed) Violation 362/9501-02: Prohibited Switchyard Entry

9.1.1 Original Violation Summary

This violation involved Edison's maintenance personnel who entered the switchyard to perform maintenance without obtaining prior authorization from either the common control operator or the shift superintendent as required by procedure.

9.1.2 Licensee Action In Response to the Violation

As part of the licensee's corrective action, locks were placed on the switchyard vehicle access gates. The keys for these locks were now controlled by San Onofre Operations and Security Divisions. A letter was sent to the Edison Transmission and Substation Department by the San Onofre Operations Manager notifying them of the locks and access controls. The letter also emphasized the requirement to request access authorization prior to entering the switchyard. Procedure SO23-6-30, "Switchyard Inspection and Operation," Revision 1, was revised to provide enhanced switchyard access controls during both normal operations and high-risk evolutions.

9.1.3 Inspector Action During the Present Inspection

During this inspection, the inspector reviewed Procedure SO23-6-30 to verify that enhanced access controls were included for high-risk evolutions. The revised procedure required control room personnel to remain cognizant of all activities in the switchyard. It also required authorization prior to switchyard entry from either the common control operator or the shift superintendent. In addition, the revised procedure required the switchyard to remain locked at all times except for during entry.

The inspector visually verified that locks had been placed on the switchyard access gates and that the gates were locked. The inspector also observed personnel who were operating vehicles and machinery compiling with the procedure by waiting for appropriate personnel to unlock the access gates.

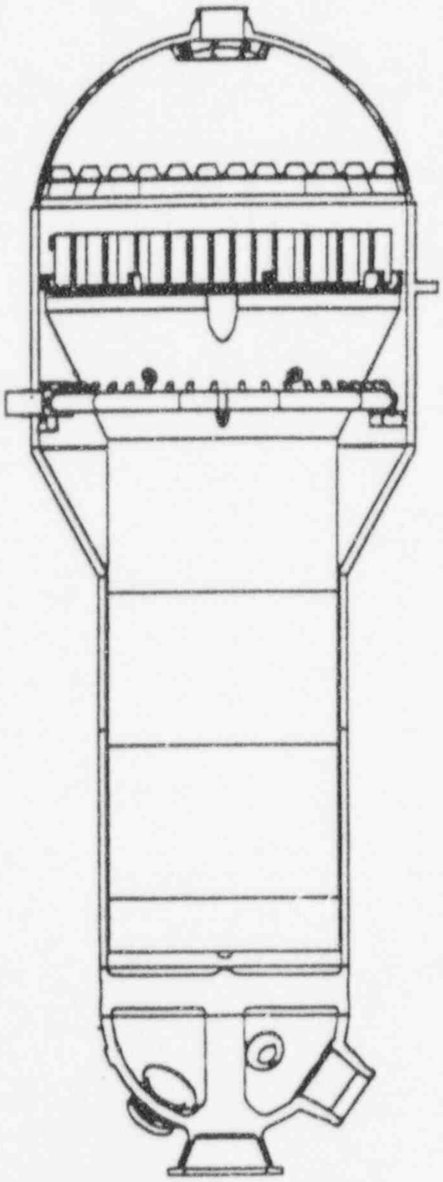
ATTACHMENT 1

LICENSEE INFORMATION FURNISHED IN JUNE 30, 1995, MEETING

Steam Generator Strategic Management Plan

San Onofre Nuclear Generating Station

Units 2 and 3



Southern California Edison Company

August 1994 (Revision 0)

Steam Generator Strategic Management Plan

Mission:

The Strategic Management Plan and Team was established to evaluate the health of the San Onofre Steam Generators and to develop a strategy to help ensure they can be satisfactorily operated throughout the licensed lifetime of the plant.

Background:

Prior to the Cycle 7 refueling inspections, our steam generator experience had been generally favorable with fouling as the only significant concern.

Unfavorable industry trends combined with the detection of an active cracking mechanism in Unit 2 in the summer of 1993 resulted in the formation of the Team and the development of the Strategic Plan.

The Plan was to be developed primarily with in-house resources as a means of broadly acquiring and maintaining the expertise needed for a long term commitment to the existing steam generators.

Outside consultant input would be obtained to serve as an independent confirmation of the team's findings and to supplement the team's work with the best available methods for predicting steam generator performance.

The team would report periodically to the Executive Forum as a means of facilitating senior management participation and input into the Plan. The Plan would serve to focus the Nuclear Organization's efforts in support of steam generator life-cycle management and assist in allocation of resources as a part of the Nuclear Organization's Business Plan. Appropriate portions of the Plan would be incorporated into the Business Plan.

The Plan was to be a living document periodically updated as new information became available. The first update was planned for the end of 1995, following the SO3 Cycle 8 refueling outage.

Implementation of the Plan will be the responsibility of the Manager, Site Technical Services.

Preparation and initial implementation:

Perform an interdisciplinary examination of the issues

Team was formed in fall 1993

Re-assess the steam generator situation

Evaluate industry trends

Develop models to forecast future technical and economic performance

Analyze and categorize appropriate measures to correct and/or mitigate degradation

Apply the models to the spectrum of corrective and mitigative measures

Develop and secure approval of Plan's recommendations

The Plan was issued in August 1994

Implement during the Cy 8 refueling outages in 1995

Monitor results and feedback into the Plan

First update to the Plan is forecast for December 1995

Communication:

Plan presented at the May 1995 EPRI Strategic Management Workshop

Copies of the Plan have been provided to all CE plants

INPO evaluated the Plan as a strength during 1994 E&A

The Plan and results achieved to date have been discussed extensively with supervisors and managers and described in newsletters provided to all employees.

Steam Generator Strategic Management Team:

Reports to Executive Forum

Management sponsors from Chemistry, Design Engineering and Site Technical Services

Steam generator design and inspection engineers

Secondary plant systems engineer

Plant chemistry engineer

Senior consulting engineer

Research engineer

Cost analyst

NSSS representative

Consulting assistance from:

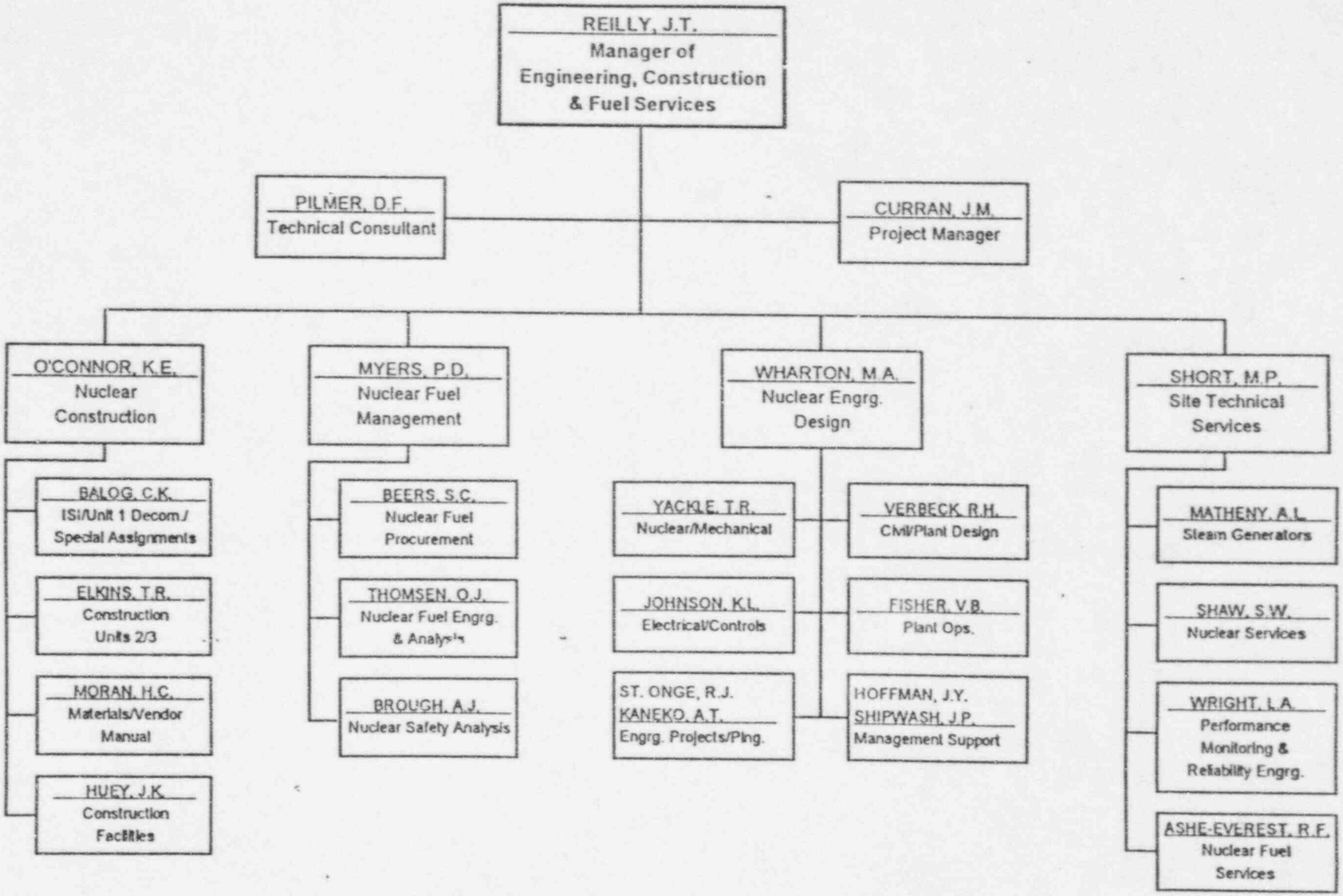
Overview	EPRI
SG Model	Dominion Engineering
Uncertainties	PLG, Inc.
Chemistry	GEBCO Engineering
	NWT Corporation

NUCLEAR ORGANIZATION

- **HAROLD B. RAY** — Senior Vice President
  - **KRIEGER, R.W.** — Vice President Nuclear Generation
    - WALDO, R.W. — Operations
    - KNAPP, P.J. — Health Physics
    - BREIG, D.P. — Technical
    - HARBERTS, C.N. — (Acting) Outage Management
    - SPEER, M.J. — Security
    - ZINTL, W.G. — Emergency Preparedness
    - FEE, J.F. — Maintenance
    - CLARK, J.R. — Chemistry
  - **KATZ, B.** — Manager of Business and Financial Services
    - FRANZ, P.M. — NIS Station Systems
    - SANCHEZ, G.J. — NIS Computer Network & Support Services
    - HONLEY, P.A. — Personnel Resources & Development
    - BAUERN, D.R. — Nuclear Business & Admin. Services
    - BREVIG, L.D. — Nuclear Rate Regulation
    - COX, D.L. — PVNGS Project
    - HEINICKE, D.R. — Prjt. Mgmt. & SONGS Participant Services
  - **ROSENBLUM, R.M.** — Vice President Eng./Tech. Services
    - SLAGLE, K.A. — Nuclear Oversight
    - REEDER, J.L. — Training
    - NEWTON, H.W. — Support Services
    - MARSH, W.C. — Nuclear Regulatory Affairs
    - REILLY, J.T. — Engineering, Construction and Fuel Services
    - BELLIS, K.M. — Emergency Planning & Public Affairs

4/95

ENGINEERING, CONSTRUCTION & FUEL SERVICES DIVISION



4/95

Steam Generator Situation (Section 2):

Tubing Degradation Issues

Improper annealing - no evidence it is continuing

Support wear - on-going but relatively minor concern

Tie-rod denting - on-going but very limited in extent

Circumferential cracking at top of tubesheet - primary area of concern

Other cracking mechanisms - potential area of concern

Other Concerns

Steam pressure decay has led to reduced unit output

Internal component wear from erosion

Chemistry Assessment (Section 6.3):

Continue operating the steam generators as done historically, so as not to upset the molar ratio without careful evaluation of the resulting crevice chemistry

Continue with efforts to remove impurities, primarily sodium, from additives

San Onofre Steam Generator Tube Plugging History

6/9/95

2ME088				Vertical	Loose	Circ	Tie-			
		Batwing	Improper	Support	Part	SCC	Rod	Other	Pre-	Outage
Date	EFPD	Wear	Annealing	Wear	Wear	at TSH	Denting	Causes	service	Total
Preservice	0	0	0	0	0	0	0	0	11	11
Jun-84	289	0	1	0	0	0	0	0	0	1
Jan-85	366	117	15	2	2	0	0	3	7	146
May-86	632	5	0	0	0	0	0	0	0	5
Sep-87	1039	60	0	0	1	0	0	1	0	62
Nov-89	1574	29	0	1	0	0	1	0	0	31
Sep-91	2087	4	0	0	0	0	4	2	0	10
Jun-93	2613	3	0	3	0	2	1	2	0	11
Mar-95	3146	0	0	0	0	15	1	6	0	22
Total		218	16	6	3	17	7	14	18	299

San Onofre Steam Generator Tube Plugging History

6/9/95

2ME089 Date	EFPD	Batwing Wear	Improper Annealing	Vertical Support Wear	Loose Part Wear	Circ SCC at TSH	Tie-Rod Denting	Other Causes	Pre-service	Outage Total
Preservice	0	0	0	0	0	0	0	0	10	10
Jun-84	289	0	0	0	0	0	0	0	0	0
Jan-85	366	130	46	0	0	0	0	3	5	184
May-86	632	12	0	0	0	0	0	0	0	12
Sep-87	1039	75	0	1	0	0	0	4	0	80
Nov-89	1574	14	0	0	0	0	17	0	0	31
Sep-91	2087	14	0	5	0	0	11	1	0	31
Jun-93	2613	2	0	2	0	10	0	7	0	21
Mar-95	3146	0	0	1	0	12	0	10	0	23
Total		247	46	9	0	22	28	25	15	392

San Onofre Steam Generator Tube Plugging History

6/9/95

3ME088 Date	EFPD	Batwing Wear	Improper Annealing	Vertical Support Wear	Loose Part Wear	Circ SCC at TSH	Tie-Rod Denting	Other Causes	Pre-service	Outage Total
Preservice	0	0	0	0	0	0	0	0	24	24
Jul-84	126	0	0	0	0	0	0	0	0	0
Nov-84	202	0	0	0	0	0	0	0	0	0
Feb-85	252	116	0	0	0	0	0	0	0	116
Nov-85	374	0	5	0	0	0	0	0	1	6
Jan-87	636	9	0	0	0	0	0	0	0	9
May-88	1025	77	0	0	0	0	0	0	0	77
May-90	1580	11	0	0	0	0	0	0	0	11
Feb-92	2094	11	0	2	0	0	3	2	0	18
Nov-93	2603	8	0	8	19	0	1	6	0	42
Total		232	5	10	19	0	4	8	25	303

San Onofre Steam Generator Tube Plugging History

6/9/95

3ME089										
Date	EFPD	Batwing Wear	Improper Annealing	Vertical Support Wear	Loose Part Wear	Circ SCC at TSH	Tie-Rod Denting	Other Causes	Pre-service	Outage Total
Preservice	0	0	0	0	0	0	0	0	11	11
Jul-84	126	0	1	0	0	0	0	0	0	1
Nov-84	202	0	1	0	0	0	0	0	0	1
Feb-85	252	116	0	0	0	0	0	0	0	116
Nov-85	374	2	17	0	0	0	0	0	1	20
Jan-87	636	10	0	0	0	0	0	0	1	11
May-88	1025	100	0	0	0	0	0	0	0	100
May-90	1580	2	0	4	15	0	1	1	0	23
Feb-92	2094	5	0	3	0	0	2	1	0	11
Nov-93	2603	0	0	3	4	0	7	3	0	17
Total		235	19	10	19	0	10	5	13	311

TABLE 2-1 S.O.N.G.S. UNIT 2/3 CHEMISTRY SUMMARY AVERAGE DATA (>30 % POWER)

PARAMETER	CURRENT LIMIT	OPERATING CYCLE					
		I	II	III	IV	V	VI
UNIT TWO STEAM GENERATOR Cation Cond. (uS)	DATES EFPDs < 0.8	7/82-11/84 (365.9) 1.24	2/85-4/86 (266.4) 0.32	4/86-9/87 (407.6) 0.15	10/87-9/89 (407.6) 0.10	12/89-5/91 (513) 0.08	11/91-6/93 (525.3) 0.08
Chloride (ppb)	< 20	59.6	10.4	3.8	1.4	0.3	0.3
Sulfate (ppb)	< 20	29.4	12.0	4.2	0.6	0.3	0.1
Sodium (ppb)	< 20	30.0	4.4	2.0	0.9	0.3	0.1
CONDENSATE/POLISHER Effluent Dissolved Oxygen (ppb)	< 5/5	16.3/---	12.3/---	10.3/6.8	8.1/5.9	7/5	-/4.2
FEEDWATER Copper (ppb)	< 1	9.9	1.0	2.2	0.8	0.2	0.3
FEEDWATER Iron (ppb)	< 5	16.3	6.5	7.2	9.8	12.8	6.2
Molar Ratios	$\dfrac{\frac{Na}{23}}{\frac{Cl}{35.5} + \frac{SO_4}{48}}$ (0.7 - 1.0)	0.57	0.35	0.45	0.75	0.89	0.41
	$\dfrac{\frac{Na}{23}}{\frac{Cl}{35.5}}$ (0.7 - 1.0)	0.78	0.65	0.81	0.99	1.54	0.51
UNIT THREE STEAM GENERATOR Cation Cond. (uS)	DATES EFPDs < 0.8	11/82-10/85 (374.8) 0.70	11/85-1/87 (262.2) 0.31	2/87-5/88 (389.1) 0.14	7/33-4/90 (554.5) 0.10	7/90-1/92 (513.5) 0.09	1/92-10/93 5.09 0.08
Chloride (ppb)	< 20	26.5	9.6	2.8	2.0	0.3	0.3
Sulfate (ppb)	< 20	25.8	11.7	1.5	0.5	0.2	0.1
Sodium (ppb)	< 20	14.2	2.8	2.0	0.7	0.3	0.2
CONDENSATE/POLISHER Dissolved Oxygen (ppb)	< 5/5	17.1/---	11.4/---	10.2/6.7	7.4/5.4	5/4.5	5.8/4.7
FEEDWATER Copper (ppb)	< 1	7.6	2.0	0.6	0.5	0.2	0.3
FEEDWATER Iron (ppb)	< 5	19.5	9.4	12.0	14.1	11.0	6.5
Molar Ratios	$\dfrac{\frac{Na}{23}}{\frac{Cl}{35.5} + \frac{SO_4}{48}}$ (0.7 - 1.0)	0.48	0.24	0.79	0.46	1.03	0.83
	$\dfrac{\frac{Na}{23}}{\frac{Cl}{35.5}}$ (0.7 - 1.0)	0.83	0.45	1.10	0.54	1.54	1.03

Development of Tube Degradation Model (Appendix A):

Model input was based on experience

- San Onofre
- Other ABB-CE units
- Other PWRs

Weibull method of forecasting was selected

- Weibull parameters were estimated based on similar units for each mechanism
- Weibull parameters were applied to each unit's actual experience
- Where mechanism had not be detected, it was assumed to begin with the next inspection
- Cracking mechanisms were adjusted for temperature
- Several temperature cases were run to assess benefits

Uncertainty assessment was performed

- Substantial uncertainty exists particularly for mechanisms with limited plant specific data. This reinforced the need to feedback future inspection results into the model.

Model Results:

Acceptable (12-15%) tube plugging without reliance on sleeving by 2013 (licensed end of life)

Comparison with SO2 Cycle 8 inspection results:

Degradation Mechanism	Cycle 8 Plan Forecast	SO2 Cycle 8 Results
Circumferential at top of tubesheet, hot leg	12-36	27
Axial sludge pile related	3-9	6
Axial support related	2-6	4
Wear and Miscellaneous	less than 25	8
Total	42-76	45

Forecast for SO3 Cycle 8:

Degradation Mechanism	Cycle 8 Plan Forecast
Circumferential at top of tubesheet, hot leg	12-36 (1)
Axial sludge pile related	3-9
Axial support related	2-6
Wear and Miscellaneous	less than 25
Total	42-76

Note 1: Forecast is under review to reflect use of improved ECT technology (Plus Point)

Figure 1

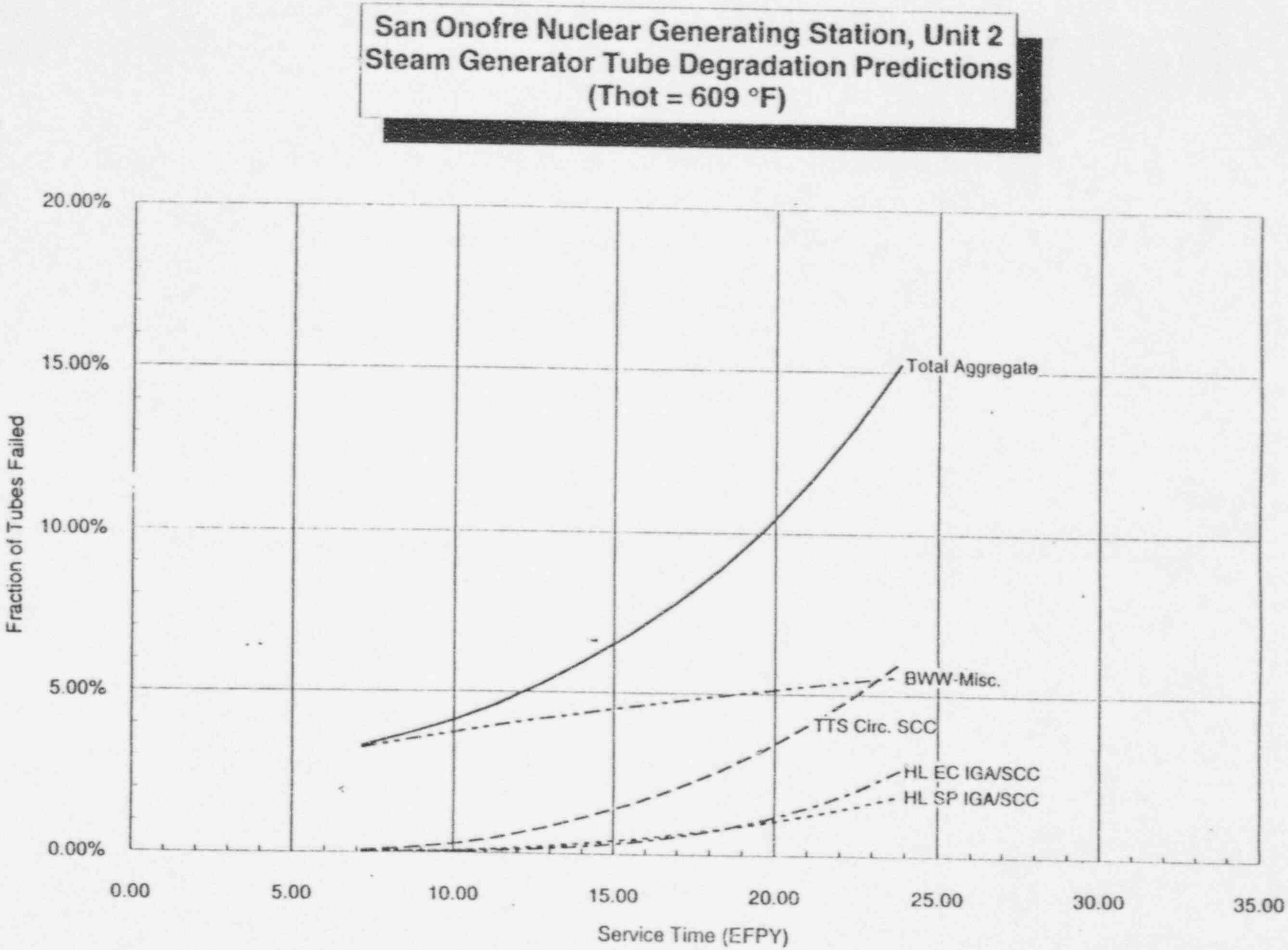
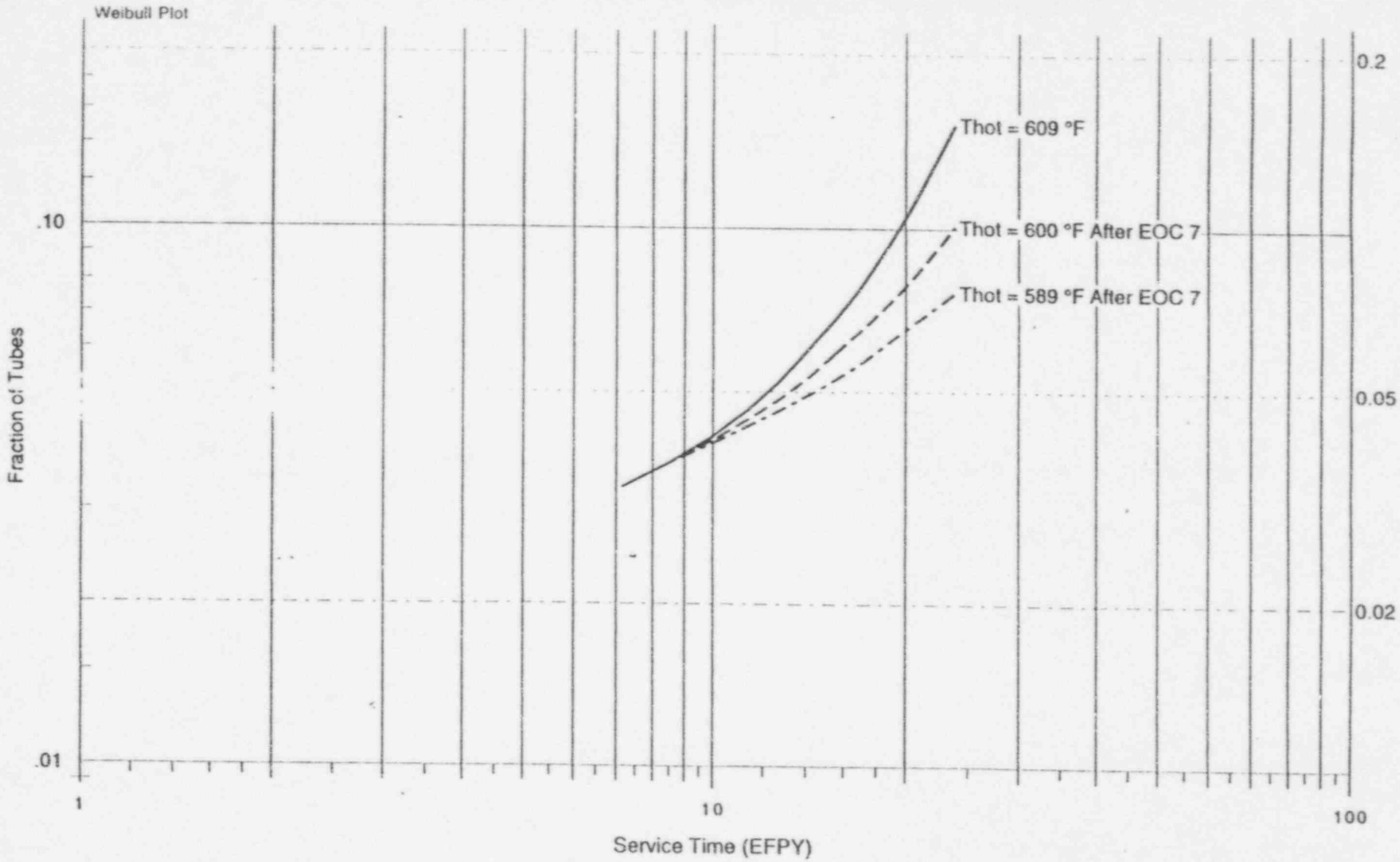

San Onofre Nuclear Generating Station, Unit 2
Steam Generator Tube Degradation Predictions
(Thot = 609 °F)
20.00%
15.00%
10.00%
5.00%
0.00%
Fraction of Tubes Failed
0.00
5.00
10.00
15.00
20.00
25.00
30.00
35.00
Service Time (EFPY)
Total Aggregate
BWW-Misc.
TTS Circ. SCC
HL EC IGA/SCC
HL SP IGA/SCC

Figure 3

San Onofre Nuclear Generating Station, Unit 2
Aggregate Steam Generator Tube Degradation Prediction



Management Plan - Section 6.6

Action	Status	F/C
Strategy 8: Implement corrective and mitigation actions categorized as either "Safe" or "Modest". Consider actions categorized as "Aggressive' should experience indicate adverse trends (SG Model). Continue to study actions categorized as "Questionable".		
Safe Actions:		
A. Reduce Tcold to valves wide open	Complete	
B. Reduce Tcold to low in normal operating band	Complete	
C. Continue with historical chemistry control	On-going	
D. Reduce bulk chemical impurities	Complete	
Modest Actions:		
A. Mechanical scale removal	Complete	
B. Enhanced sludge removal	Complete	
C. Iron filtration	Pilot study	
D. Tcold reduction in conjunction with turbine valves modification	Planned after Cy 8	
E. Molar ratio management (impurity reduction in chemicals)	On-going	
Aggressive Actions:		
A. Molar ratio control (via chloride injection)	Hold	
B. Large reduction in Tcold	Hold	
C. Copper replacement in feedwater heaters	Hold	
D. Carbon steel tube replacement in MSR's	Hold	
E. Tube repair in lieu of plugging	Hold	
Questionable Actions:		
A. ETA addition	Under review (2)	
B. Boric acid addition	Monitor	
C. Chemical cleaning	Monitor	
Tabled Actions:		
A. Shot Peening	Hold	

Notes:

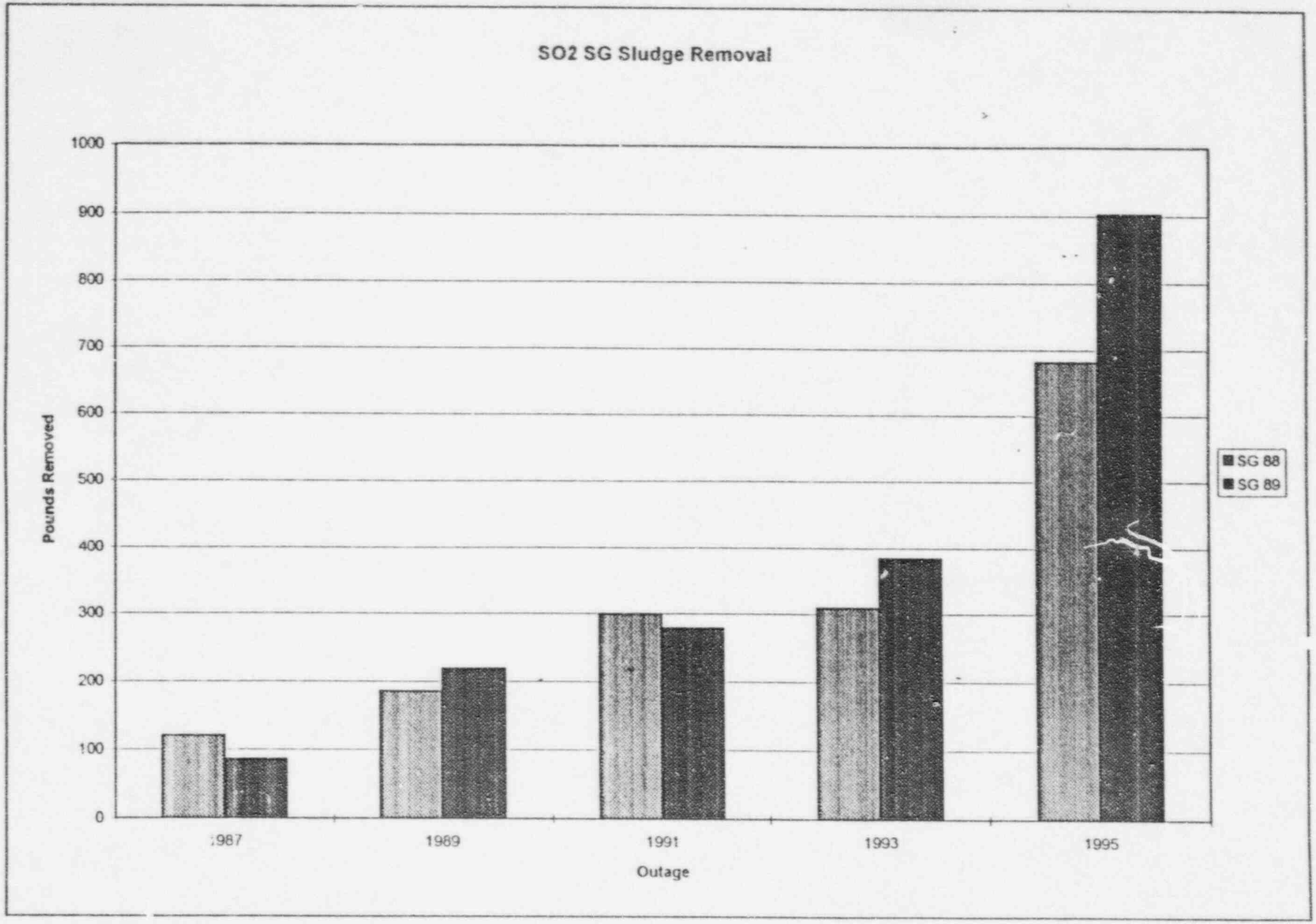
(1) Westinghouse tube plug issues emerged in December 1994 and replacement of all W-I600 plugs is complete in SO2 and planned for SO3. Replacement of PIP'd W-I600 plugs is under review.

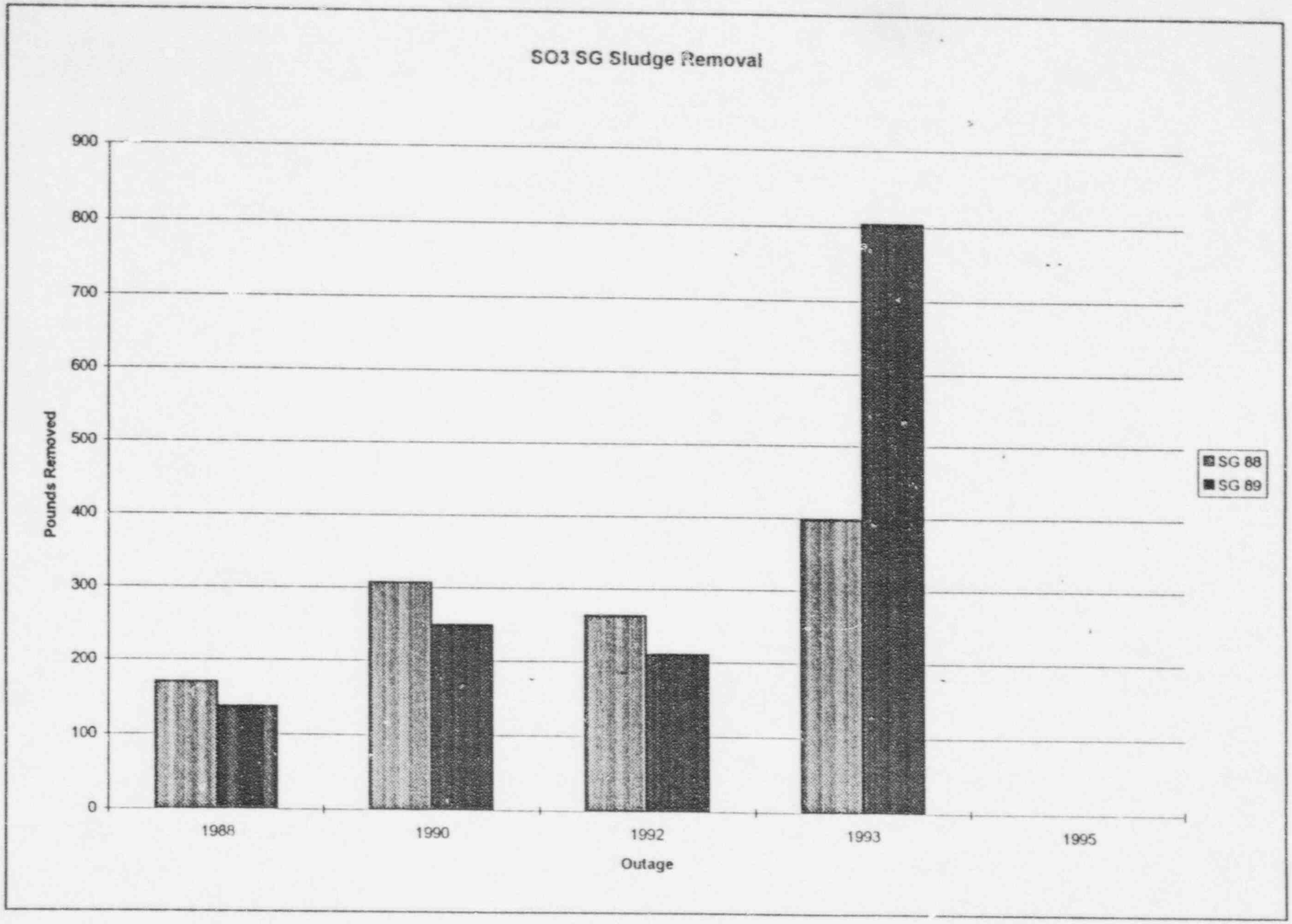
(2) ETA compatibility with FFCPD's has been addressed. With discovery of turbine cracking, a turbine compatibility study is underway.

Action	Status	F/C
Strategy 1: Minimize the effects of corrosion product transport on the steam generators.		
A. Reduce corrosion product transport to the steam generators		
1. Increase hydrazine concentration	Complete	
2. Evaluate the use of iron filtration	Pilot study in-progress	8/95
3. Continue to study ETA	On-going, turbine effects assessment in-progress	8/95
4. Follow EPRI work with alternative amine chemistry	On-going	
5. Replace condensate, drain and feedwater piping components with corrosion resistant materials based on cost/benefit assessments	SO 2 Complete SO 3 Planned	Cy 8
B. Increase removal of sludge from steam generators		
1. Increase duration of sludge lancing during outages	SO 2 Complete SO 3 Planned	Cy 8
2. Evaluate use of bi-directional sludge lancing	Deferred	12/95
3. With EPRI, support the R&D of deep bundle hard sludge removal (CECIL)	Under review	12/95
C. Remove scale from steam generator tubing		
1. Develop and implement techniques for mechanical removal of scale and deposits	SO2 Complete SO3 Deferred	12/95
2. Follow use of chemical cleaning and implement if mechanical methods are ineffective	On-going	
3. Consider R&D effort to improve understanding of scale and deposit formation, including impact on tubing corrosion and heat transfer	Working on proposal with EPRI	9/95

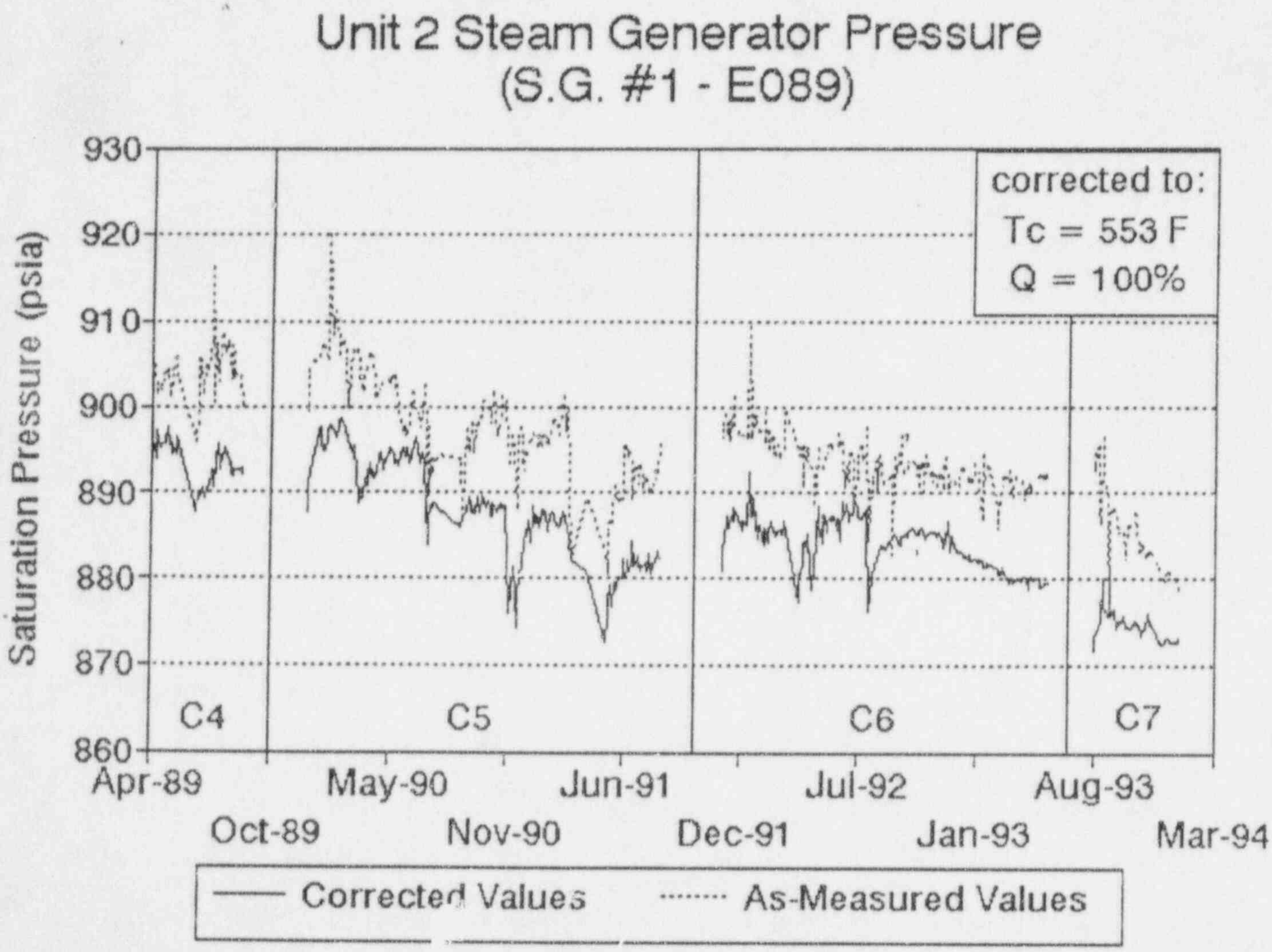
Action	Status	F/C
Strategy 2: Optimize steam generator chemistry to improve crevice chemistry conditions		
A. Reduce impurities in bulk chemicals to improve molar ratio	Complete	
B. Optimize FFCPD operation to reduce sodium impurities and improve molar ratio	In-progress	12/95
C. Utilize hideout-return studies to monitor and feedback the impact molar ratio has on crevice conditions	In-progress	12/95
Strategy 3: Reduce RCS operating temperatures as allowed by turbine plant adjustments and modifications		
A. Modify turbine plant to maximize unit output under reduced temperature conditions	Turbine Valves FWHtrs	Cy 8 Cy 9 under review
B. Develop and validate (ASME test) analytical models of turbine plant to allow development of optimal design conditions	In-progress	12/95
C. Evaluate and adjust control systems to enable operation with reduced RCS temperature	Complete	
D. Revise safety analysis, coincident with routine updates, to allow operation with reduced RCS temperature	On-going	
Strategy 4: Communicate the SG strategic plan to the organization and affected parties		
A. Incorporate strategic plan into appropriate training programs	Complete	
B. Develop briefings for appropriate nuclear organization employees	Complete	
C. Communicate the plan in employee newsletters	Complete	
D. Develop briefings for participant owners	Complete	

Action	Status	F/C
Strategy 5: Forecast the steam generator performance and the effectiveness of potential corrective actions		
A. Develop a steam generator predictive model	Complete	
B. Assess the effectiveness of potential corrective and mitigation actions. Categorize actions to develop an implementation strategy.	Complete	
C. Maintain the model effectiveness current via periodic updates. (initially biennial)	Planned	12/95
Strategy 6: Plan inspections to support reliable operation and updates of the predictive model		
A. Baseline SG's with 100% bobbin ECT at next refueling outage	SO 2 Complete SO 3 Planned	Cy 8
B. Using inspection techniques, determine the most likely cause for on-going cracking mechanisms	On-going	12/95
Strategy 7: Optimize repair strategies		
A. Develop an optimal repair strategy for tube plugs to preclude on-line leakage	In-progress	Cy 8
B. Evaluate supporting development of improved tube repair methods (EPRI).	Complete-member EPRI partnership	

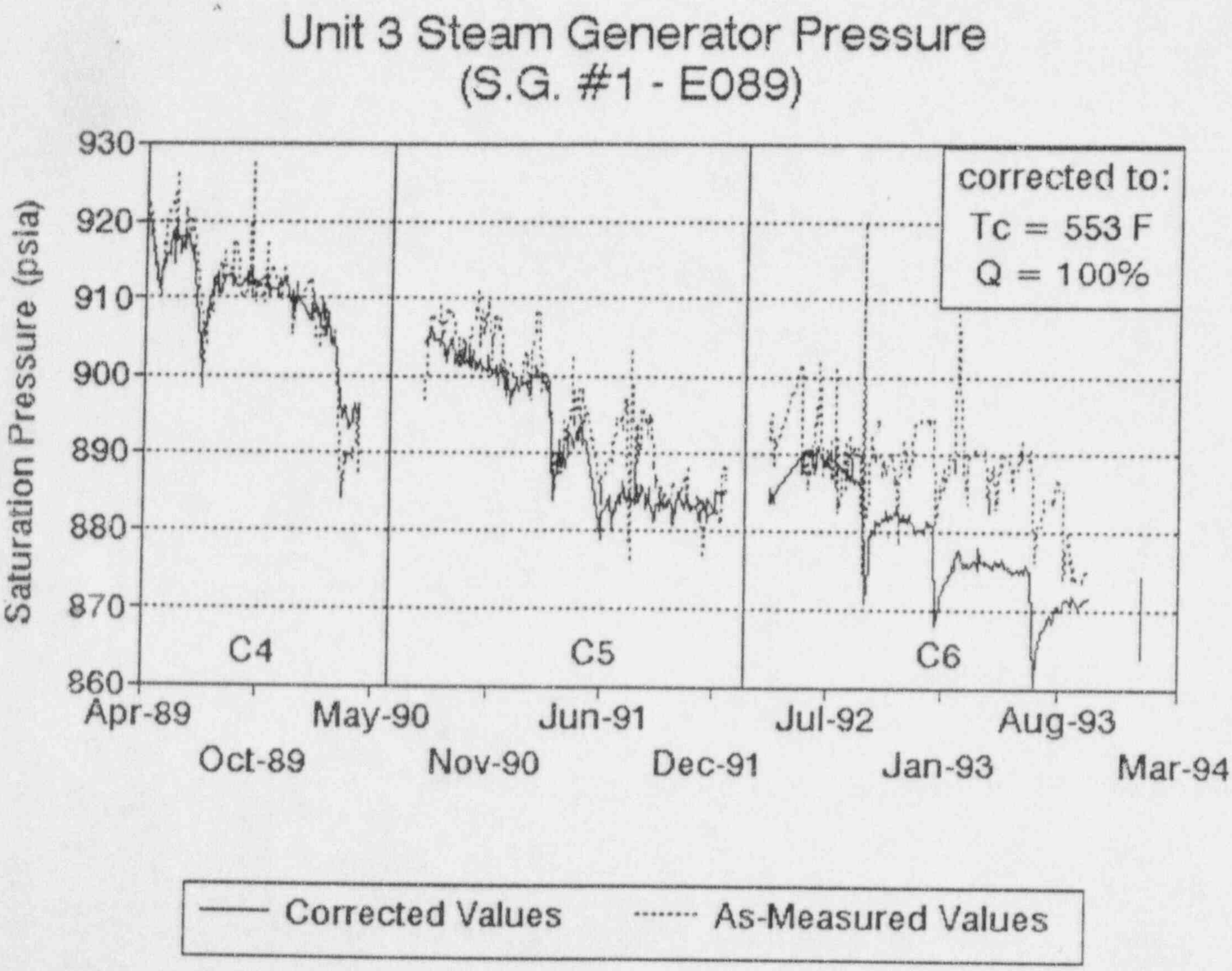

SO2 SG Sludge Removal
1000
900
800
700
600
500
400
300
200
100
0
Pounds Removed
1987
1989
1991
1993
1995
Outage
SG 88
SG 89

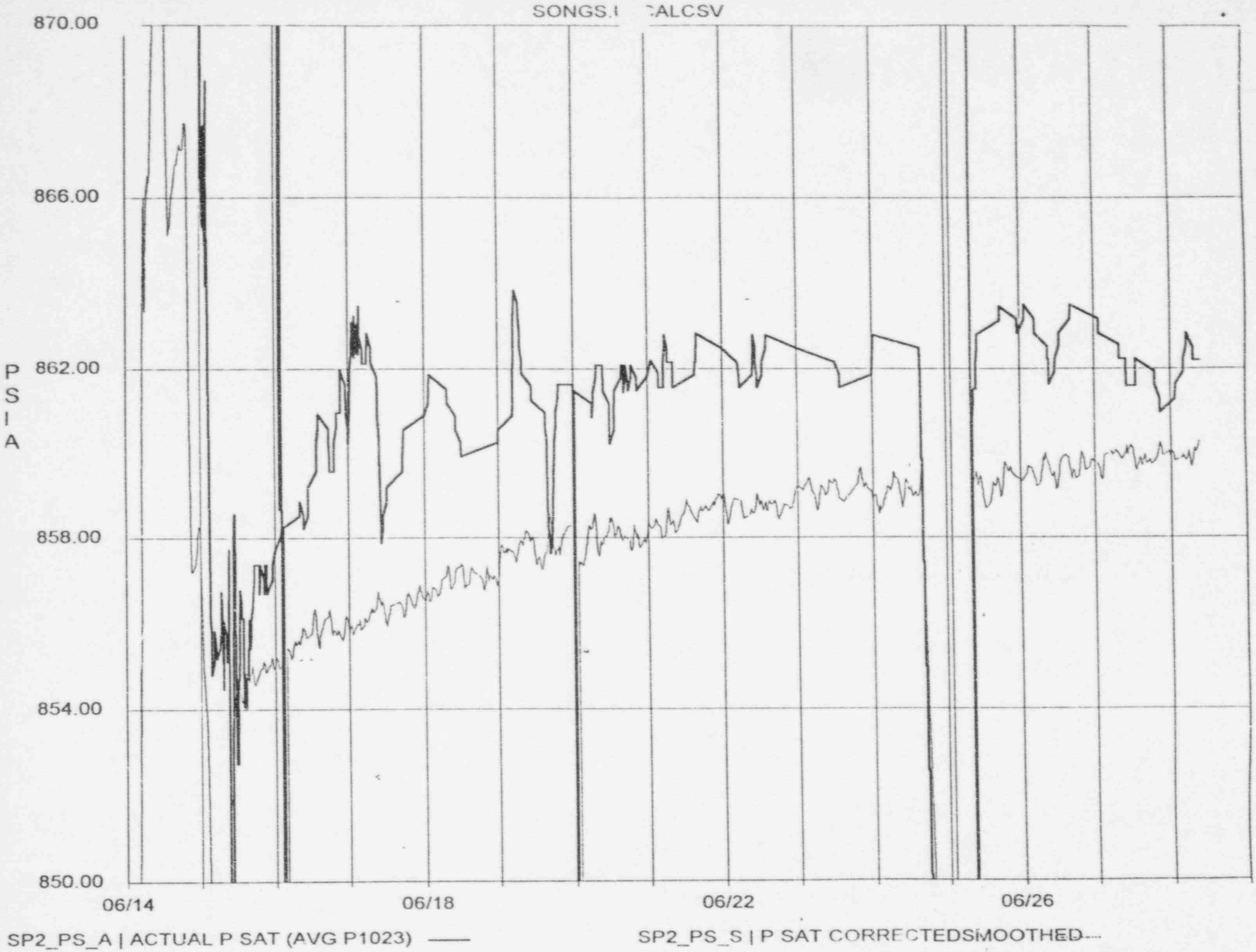

SO3 SG Sludge Removal
900
800
700
600
500
400
300
200
100
0
Pounds Removed
1988
1990
1992
1993
1995
Outage
SG 88
SG 89

Graphics item 2: Unit 2 Pressure Trend



Graphics item 3: Unit 3 Pressure Trend




SONGS.I CALCSV
870.00
866.00
862.00
858.00
854.00
850.00
PSIA
06/14
06/18
06/22
06/26
SP2_PS_A | ACTUAL P SAT (AVG P1023)
SP2_PS_S | P SAT CORRECTEDSMOOTHED

Improvements planned for Revision 1 (F/C 12/95):

Self-evaluation of plan's effectiveness, including comparison with materials from EPRI Strategic Planning Workshop

Tcold reduction contingency planning

Circumferential cracking detection issues

Update tube plugging issues

Update to R&D program

Cycle length optimization

Foreign material control and prohibited material control (i.e. lead)

Erosion-corrosion of SG internal components

Incorporate CEOG SG Task Force activities

SG leak rate monitoring and incorporation of recently issued EPRI leak rate guidelines

Table 7-1 Candidate Steam Generator RD&D Activities								
	Project	Priority	Time Frame	Focus	Objective	B/C Potential	RD&D Action	Status
1	Mechanical Scale Removal System Development	High	Near Term	SONGS/Industry	Performance	High	Research Working Group (RWG) approved 1994 funding	Contractors on schedule for demonstrations in Cycle 8 outages
2	Narrow Gap Sludge Lance Development	High	Mid Term	SONGS/Industry	Longevity	Medium	RWG approved 1994 funding for project	Proposed as 1995 EPRI TC Project
3	Permanent Magnetic Filter Assessment and Demonstration	High	Mid Term	SONGS/Industry	Performance	Mid to Low	RWG approved 1994 project funding	Proposal received from ABB/CE for an in-plant, single-tube, side-stream demo; contracting
4	Boric Acid Treatment Studies	High	Near Term	SONGS	Longevity	High	No defined RD&D project	No action
5	Reactor and FW Temperature Reduction Testing	High	Near	SONGS	Performance /Longevity	High	Limited testing to be performed in June	Scope of additional testing limited by existing safety analyses

Table 7-1 Candidate Steam Generator RD&D Activities

	Project	Priority	Time Frame	Focus	Objective	B/C Potential	RD&D Action	Status
6	Welded Tube Repair Technology Development	Medium	Long Term	Industry	Longevity	High	EPRI Proposal for TC project received	Participation contingent upon favorable assessment by utility review committee
7	Improved Instruments / Basic Water Chemistry Studies	Medium	Mid Term	SONGS	Longevity	High	RWG approved funding to purchase a precision IC	Instrument specs developed; RFP issued; test plan under development
8	Better Chemicals and Materials (alternate amines, better resins, etc.)	Medium	Mid Term	SONGS	Longevity	Unknown	No defined RD&D project	No action
9	ETA Utilization Analyses	Medium	Near Term	SONGS	Performance	Medium	No defined RD&D project	Chemistry Division evaluating impact of ETA on FFCPD
10	Tube Pulls	Medium	Long Term	Industry	Longevity	Low	No action	No current plans [illegible] ll tubes [illegible] pt for cause

	Table 7-1 Candidate Steam Generator RD&D Activities							
	Project	Priority	Time Frame	Focus	Objective	B/C Potential	RD&D Action	Status
11	Secondary Plant Material Replacement Optimization	Low	Mid Term	SONGS	Performance	Mid to Low	No defined RD&D project	No action
12	Basic Iron Transport and Fouling Studies (ECP Model)	Low	Long Term	Industry	Performance	High	University proposal under review	No action
13	Chemical Treatment Technology	Low	Mid Term	SONGS/Industry	Performance	High	Proposal in-hand. No action taken as yet	None

Case #1 -Base Case for Analysis

Start Date: 1/1/94
Data Basis: Start of Cycle 7
Base Plant Gross Output: 1180 MWe
Effective Plant Net Output at Start of Analysis: 1070 MWe
Effective Full Power Years Operated at Start of Analysis: Approx. 7.65 years
Production Factor Assumed During Operation: 92%
Refueling Outage Length: 75 days
Steam Generator Pertinent Factors:

- Assumed T-Hot for Analysis: 609 degrees Fahrenheit
- Percentage Tubes Plugged at Start of Analysis: 3.3%
- DEI 3/19/94 Projection for Aggregated Plugging
- Additional Fouling Losses of 10 MWe per cycle

CYCLE	6	7	8	9	10	11	12	13	14	15	16	17	18
EOC Plugging %	3.3	3.7	4.1	4.6	5.2	6.0	6.9	8.0	9.3	10.7	12.3	14.2	16.3
Plugging Delta %		0.4	0.4	0.5	0.6	0.8	0.9	1.1	1.3	1.4	1.6	1.9	2.1
BOC MWe Net		1070	1059	1048	1036	1024	1012	999	986	972	958	943	927
Plug MWe Loss		1.1	1.3	1.5	1.9	2.3	2.7	3.3	3.9	4.2	4.8	5.7	6.3
Fouling MWe Loss		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
EOC MWe Net		1060	1049	1038	1026	1014	1002	989	976	962	948	933	917
Avg. Cycle MWe	1070	1065	1054	1043	1031	1019	1007	994	981	967	953	938	922
Cycle Length (Days)		629	635	642	649	657	665	673	722	733	744	755	768
Cycle Start		Aug-93	Apr-95	Jan-97	Oct-98	Jul-00	May-02	Mar-04	Jan-06	Jan-08	Jan-10	Jan-12	Feb-14
Mid Cycle Outage		None	None	None	None	None	None	None	Jan/07	Dec/08	Dec/10	Jan/13	Jan/15
Refueling Start		Feb-95	Nov-96	Aug-98	May-00	Mar-02	Dec-03	Nov-05	Oct-07	Oct-09	Nov-11	Dec-13	Jan-16
End of Cycle		Apr-95	Jan-97	Oct-98	Jul-00	May-02	Mar-04	Jan-06	Jan-08	Jan-10	Jan-12	Feb-14	Mar-16

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End of Cycle		Apr-95	Jan-97	Oct-98	Jul-00	May-02	Mar-04	Jan-06	Jan-08	Jan-10	Jan-12	Feb-14	Mar-16

ATTACHMENT 2

PERSONS CONTACTED AND EXIT MEETING

1 PERSONS CONTACTED

1.1 Licensee Personnel

**D. Axline, Compliance Engineer, Licensing
C. Balog, Nuclear Construction Supervisor
J. Clark, Manager, Chemistry
*J. Fee, Manager, Maintenance
*O. Flores, Supervisor, Chemistry Engineering
*D. Franklin, Compliance Engineer, Licensing
#G. Gibson, Manager, Compliance, Licensing
*D. Herbst, Manager, Quality Assurance, Nuclear Oversight Division
*D. Irvine, Supervisor, Technical Support, Station Technical
K. Knight, Nuclear Construction Superintendent
*R. Krieger, Vice President, Nuclear Generation
M. Knowlton, Quality Assurance Engineer, Nuclear Oversight Division
*A. Mahindrakar, Inservice Inspection Engineer, Site Technical Services
**A. Matheny, Steam Generator Engineer, Site Technical Services
J. Mundis, Senior Engineer, Site Technical Services
K. O'Connor, Manager, Construction
S. Paranandi, Quality Assurance Supervisor, Nuclear Oversight Division
*T. Peterson, Engineer, Station Technical
***D. Pilmer, Technical Consultant, Engineering, Construction and Fuel Services
*G. Plumlee, Supervisor, Compliance, Licensing
*J. Schramm, Manager, Safety Engineering, Nuclear Oversight Division
*S. Shaw, Inservice Inspection Supervisor, Site Technical Services
##M. Short, Manager, Site Technical Services
*K. Slagle, Manager, Nuclear Oversight Division

1.2 Contractor Personnel

J. Barron, Quality Assurance Manager, Rockridge Technologies
M. Chambers, Level III Lead Analyst, Rockridge Technologies
M. Keneipp, Lead Task Coordinator, Rockridge Technologies
*R. Marlow, Vice President, Rockridge Technologies
A. Neff, Level III Lead Analyst, Anatec International

1.3 NRC Personnel

*J. Sloan, Senior Resident Inspector
*D. Solorio, Resident Inspector
#T. Gwynn, Director, Division of Reactor Safety

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

*Denotes personnel that attended the August 8, 1995, exit meeting.
**Denotes personnel that attended the August 8, 1995, and August 30, 1995, telephonic exit meeting.

***Denotes personnel that attended the August 30, 1995, telephonic exit meeting.
#Denotes personnel that attended the June 30, 1995, meeting prior to the onsite inspection.
##Denotes personnel that attended the June 30, 1995, and August 8, 1995, exit meeting.

2 EXIT MEETING

An exit meeting was conducted on August 8, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this report. A second exit meeting was held by telephone on August 30, 1995, to inform the licensee that, as a result of in-office review, an inspection followup item would be identified in regard to eddy current examination procedure conformance to Appendix H of EPRI NP-6201, "PWR Steam Generator Examination Guidelines," Revision 3. During the telephone call, licensee personnel also provided sludge lancing information for Steam Generator 3ME088 and the tube plugging information for Steam Generator 3ME089. Nuclear steam system supplier documents were reviewed during the inspection which had been marked to indicate they contained proprietary information. No information was included in the inspection report that was considered proprietary.