Palo Verde Nuclear Generating Station

Status of PVNGS Steam Generator Activities

August 1994

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF FIGURES

I. EXECUTIVE SUMMARY

The objective of this report is to provide a status of current activities undertaken by APS to address the two major corrosion mechanisms present in the PVNGS steam generators - ARC Region Outside Diameter Stress Corrosion Cracking (ODSCC) and tubesheet transition zone circumferential ID and OD cracking. Specifically, the USNRC Staff has requested information regarding the following items

- Results of Unit 2 and 3 Metallurgical Tube Examinations
- Transportability of ARC Region ODSCC in Unit 1 including an operating cycle length evaluation
- Results of Probabilistic Regulatory Guide 1.121 Assessment for Unit 2 - ARC Region ODSCC
- Results of Probabilistic Regulatory Guide 1.121 Assessment for Unit 1 - Circumferential Primary Water Stress Corrosion Cracking, PWSCC
- Integrated Outage Assessment Program

The Unit 2 and 3 metallurgical examination programs have been completed, and confirm the upper bundle mode of degradation to be OD initiated Intergranular Attack (IGA) and Stress Corrosion Cracking (SCC). Crack crevice chemistries indicate a tendency toward near neutral conditions indicating improved secondary side chemistry control. Contaminants, such as sulfate, are still believed to be contributing to the degradation. However, the new PVNGS sulfate action limits are expected to help mitigate the corrosion effects associated with reduced sulfur species. Chemical cleaning proved to be effective in removing tube scale and nearly all ridge deposit locations. Laboratory examinations also found that field eddy current calls were generally accurate with few exceptions. All tubes burst tested in the laboratory significantly exceeded the limits specified in Regulatory Guide 1.121. The Unit 3 tube examination specifically found that the detected volumetric indication in Unit 3 was not related to the ARC Region IGA/SCC found predominantly in the Unit 2 steam generators

Probabilistic models were developed by ABB-CE, Packer Engineering, APTECH and APS. These analyses support the current operating cycle lengths for Units 1 and 2 in accordance with the criteria specified in Regulatory Guide 1.121. The tube examination results from U2R4 and U2M5-1 were utilized to develop crack growth rate and probability of detection (POD) distributions. A standard full operating cycle of 425 effective full power days was demonstrated for Unit 1 for both PWSCC and ARC Region ODSCC. For Unit 2, an upper bound probabilistic

analysis was performed. Due to the considerable effort associated with incorporating all the relevant data from the U2M5-1 tube examinations, and the desire to incorporate additional post-chemical cleaning data sets via implementation of the integrated outage assessment program, APS elected to perform the Unit 2 analysis based on tube pull data from U2R4 and bobbin coil rather than MRPC detection capability. Therefore, credit for enhanced MRPC detectability, reduced temperature operation, and chemical cleaning was not taken due to the current commitment to inspect after six months. The analysis conservatively concluded that a six month run time at original design conditions would meet the required safety margins specified in the Reg Guide. APS considers the analysis conducted for Unit 2 to conservatively bound the current commitment to operate Unit 3 for six months.

Finally, the safety significance associated with the operating plans for all the PVNGS units has been evaluated by APS. The results of comprehensive inspection programs have been assessed statistically to determine the impact of leaving undetected defects through a full cycle of operation in Unit 1 and six month cycle lengths in Units 2 and 3. The analyses concluded with high confidence that the conservative safety margins established in Regulatory Guide 1.121 are maintained. Since probabilistic models contain a degree of uncertainty associated with the upper tail of the crack growth rate distribution, APS has taken additional actions to assure safe plant operation. An improved leak rate monitoring program and administrative limits on primary to secondary leakage provide additional assurance that an orderly shutdown will be conducted prior to a leak propagating to a rupture. Training of operations personnel for tube rupture events and upgrades to the Emergency Operating Procedures permit faster identification and isolation of the affected steam generator. An analysis was performed by APS to demonstrate that in the unlikely event of a main steam line break with consequential multiple tube ruptures, with the current administrative limits on reactor coolant system dose equivalent iodine, the resulting offsite doses are less than 10CFR100 guidelines.

APS believes that this "defense in depth" approach, provides reasonable assurance that the PVNGS Units can be safely operated until the next scheduled shutdowns for further steam generator inspections

II. PROBLEM DESCRIPTION AND SAFETY ASSESSMENT

The purpose of this report is to describe the current status of efforts undertaken by APS to address the two major corrosion mechanisms present in the PVNGS steam generators - ARC Region[1] Outside Diameter Stress Corrosion Cracking (ODSCC) and transition zone circumferential ID and OD cracking. Although no ARC Region ODSCC defects were found in the most recent steam generator inspection in Unit 1, APS elected to assess the potential for undetected axial defects to exceed Regulatory Guide 1.121 structural limits given the possible transportability of this condition to Unit 1 based on inspection results from Units 2 and 3 steam generators (SGs). Likewise, APS was requested by the USNRC Staff in Reference 1 to analyze allowable operating cycle length given the presence of circumferential defects detected during U1R4. In Reference 2, APS had demonstrated via a tiered inspection program of 100% MRPC, UT examination and in-situ pressure testing, that none of the detected defects exceeded Reg Guide structural limits during the previous cycle of high temperature operation. Finally, APS committed in Reference 4 to provide a probabilistic analysis for the current six month operating cycle in Unit 2.

A. ARC Region ODSCC Transportability - Unit 1

The ARC Region freespan ODSCC phenomenon was first recognized in PVNGS Unit 2 during the Eddy Current (ECT) inspections conducted in the Spring of 1993 during the fourth refueling outage (U2R4). This mechanism resulted in the rupture of a tube during power operation at the end of Cycle 4. This event and the subsequent analysis was discussed in depth in the "Unit 2 Steam Generator Tube Rupture Analysis Report" submitted to the NRC staff as enclosure (2) to William Conway's letter 102-02569-WFC/JRP dated July 18, 1993. Briefly, the report concluded that free span axial cracks had occurred in the upper bundle of the SGs in Unit 2 as a result of Intergranular Stress Corrosion Cracking (IGSCC) initiated at the outer diameter due to a combination of contributing factors including: tube-to-tube crevice formation, ridge deposits, increased sulfate levels probably due to a resin intrusion and mildly caustic crevice pH. Additional factors which played a part in some of the tubes analyzed included, substandard microstructure and cold working from manufacturing scratches.

The complex synergistic effect of these causal factors did not allow APS to conclude the relative weights of these factors to the tube failure, and led to a concern that the corrosion mechanism might be transportable to Units 1 and 3. The scope of ECT inspections for U1R4, U3M4 and U3R4 were adjusted to ensure that if the phenomenon was at work in a manner similar to Unit 2, it would be discovered. Neither bobbin nor Motorized Rotating

1. For brevity, the axial free span and support defects found in the upper bundle of the Units 2 and 3 steam generators at PVNGS are referred to as ARC Region ODSCC. The area of interest in the tube bundle has been previously defined in References 3 and 4.

Pancake Coil (MRPC) ECT methods discovered any free span axial cracking in the Unit 1 steam generators. In Reference 2, APS concluded that the accelerated ARC Region cracking phenomenon was not at work in Unit 1, and therefore no cycle length restrictions were imposed. However, defects exhibiting the same characteristics of bundle location, deposition and tube-to-tube crevice (bowing) were observed in Unit 3 during the U3R4 inspection.

During post-outage discussions, the USNRC staff requested a more quantitative evaluation to justify full cycle operation with respect to ARC Region ODSCC based on the Unit 3 findings. Consequently a Unit 1 analytical model was developed by Packer Engineering to address the potential for new and/or undetected ARC Region ODSCC defects in the Unit 1 steam generators.The analysis, described in Section V and provided in Appendix A, determines the probability of axial ODSCC defect(s) in Unit 1 leading to the exceedance of Regulatory Guide 1.121 structural limits. The probability of structural limit exceedances is estimated as function of run time using a conservative approach. The recently completed laboratory results of the tubes removed from Units 2 and 3 were utilized to support the probabilistic model for Unit 1. The analysis concluded that Reg Guide safety margins are maintained for full cycle operation in Unit 1

B. Circumferential Cracking - Unit 1

The circumferential cracks observed in Unit 1 during the U1R4 ECT inspections occurred at the hot leg tubesheet transition zone initiating from both the inside (PWSCC) and outside (ODSCC) of the tubes. Both corrosion mechanisms have been observed throughout the industry, and did not represent new corrosion mechanisms. A tiered inspection program of 100% MRPC inspection of the tubesheet transition zone followed by UT inspection and in-situ pressure testing of the largest defects, demonstrated that none of the detected defects exceeded the structural limits required by Regulatory Guide 1.121 after a full operating cycle at a T_{hot} of 621 °F.

Steps have been taken by APS to mitigate crack initiation and growth of PWSCC, during Cycle 5, by a reduction of primary coolant temperature to take advantage of the industry demonstrated temperature dependence shown by SCC rates. Secondary side corrosion at the tubesheet transition was addressed by sludge lancing, changes in chemical environment, as well as the benefit realized from temperature reduction. Many of the actions, described in this report, to prevent free span axial cracking have a similar benefit on the circumferential cracking mechanism.

Additionally, APS, in Reference 6, submitted the results of a Regulatory Guide 1.121 analysis for PWSCC defects identified in Unit 1. The analysis demonstrates that full cycle operation is justified in Unit 1 with respect to crack initiation and growth. ECT results indicate that the ID defects bound the OD defects with respect to defect size and crack growth rate.

C. ARC Region ODSCC - Units 2 and 3

Unit 2

In Reference 4, APS committed to provide the USNRC Staff with the results of a probabilistic analysis for Unit 2 based on the inspection results from the U2M5-1 midcycle inspection. In the submittal, APS stated that the ECT current results from the midcycle inspection appeared to indicate that crack growth rates were lower than previously estimated following the steam generator tube rupture event. As a result, APS considered the assumptions which formed the basis for six months of safe operation as calculated in Reference 3 and supported in the subsequent SER (Reference 7) to remain valid.

In this report, APS has provided the results of a recent statistical assessment of operating cycle length in Unit 2. The analysis demonstrates that a six month run time, at original design conditions, satisfies the criteria specified in Reg Guide 1.121. The six month operating interval was previously committed by APS plant management, and Unit 2 is currently scheduled for a second midcycle inspection (U2M5-2) starting mid-September 1994.

Due to the considerable effort associated with incorporating all the relevant data from the U2M5-1 tube examinations and incorporation of additional post-chemical cleaning data sets via implementation of the integrated outage assessment program, APS elected to perform the Unit 2 analysis based on tube pull data from U2R4, and bobbin coil rather than MRPC detection capability. Credit for enhanced MRPC detectability, reduced temperature operation, and chemical cleaning was not taken due to the current commitment to inspect after six months.

Unit 3

The extent and results of MRPC inspections conducted in U3R4 are described in detail in a separate report (Reference 14) to be submitted to the USNRC Staff. Upon completion of the inspection program, a total of 17 ARC Region defects were identified. The defects are considered to be bounded by the analyses performed for Unit 2, and a six month operating interval was committed to by APS plant management (Reference 30).

D. Safety Assessment

The safety significance associated with the operating plans specified in Section VI for all the PVNGS units has been evaluated by APS. The results of comprehensive inspection programs have been assessed statistically to determine the impact of leaving undetected defects through a full cycle of operation in Unit 1 and six month cycle lengths in Units 2 and 3. The analyses concluded with high confidence that the conservative safety margins established in Regulatory Guide 1.121 are maintained. Since probabilistic models contain a degree of uncertainty associated with the upper tail of the crack growth rate distribution, APS has taken additional actions to assure safe plant operation. An improved leak rate monitoring program and administrative limits on primary to secondary leakage as described in Section VII provide additional assurance that an orderly shutdown will be

conducted prior to a a through-wall leak propagating to a rupture. Training of operations personnel for tube rupture events and upgrades to the Emergency Operating Procedures also permit faster identification and isolation of the affected steam generator.

APS is in the process of finalizing a risk analysis associated with Unit 1 Cycle 5 operation with PWSCC and/or ARC Region defects. The analysis methodology provides for comparison of the core damage risk associated with Unit 1 continued plant operation versus mid-cycle shutdown for steam generator tube inspection. This analysis estimates the risk resulting from the following scenarios: 1) Continue power operation through the current 15 month run time, and 2) Conduct a mid-cycle shutdown to perform SG tube inspections (requiring mid-loop operations). The evaluation also provides analysis of public safety impact/consequences for at-power conditions. Based on results of preliminary analysis for Unit 1, it is expected that final results will indicate approximately equivalent core damage risk for Unit 1 full-cycle operation verses mid-cycle shutdown. In addition, it is expected that the public safety impact analysis will indicate that Palo Verde would not exceed SECY 89-102 Safety Goal Objectives for continued full cycle operation.

Finally, an analysis was performed by APS in Reference 5 to demonstrate that in the unlikely event of a main steam line break with consequential multiple tube ruptures, with the current administrative limits on reactor coolant system dose equivalent iodine, the resulting offsite doses are less than 10CFR100 guidelines.

APS believes that this "defense in-depth" approach, provides reasonable assurance that the PVNGS Units can be safely operated until the next scheduled shutdowns for further steam generator inspections

III. OPERATING HISTORY

A. Operation and Inspection Timeline

To understand the initiation and progression of defects in the ARC region of the PVNGS steam generators, it is important to review the operational and inspection differences among the three PVNGS Units. It is recognized that the design of the System80 steam generators creates an environment in the upper region of the tube bundle susceptible to ODSCC if other contributing factors such as chemistry, crevice formation and material susceptibility are present. In developing probabilistic models of steam generator tubing degradation, it is important to incorporate normalized inspection results, temperature history and secondary chemistry events. Figure III-1 depicts inspection and secondary chemistry milestones with plant effective full power hours. From the perspective of these key parameters, ARC Region ODSCC has either not initiated in Unit 1 or is progressing at a substantially slower rate than Units 2 or 3. This assumption is best demonstrated by a detailed description of the results of the inspection program conducted in Unit 1 at the end of Cycle 4, as well as generally observed secondary chemistry differences between Unit 1 and Units 2 and 3. This position is further supported by detailed statistical treatment of the results given in Section V.

1. Unit 1R4 NDE Inspection Program

The scope of ECT inspection during the U1R4 outage was designed to ensure that if the ARC Region ODSCC mechanism existed in Unit 1, it would be discovered. The program included an inspection of 100% of the entire tube bundle using the bobbin coil probe, a sample inspection of bobbin indications associated with the 07H eggcrate support through the first vertical support structures with the MRPC probe, an MRPC inspection of approximately 1800 tubes per steam generator from the 08H support through the first vertical support encompassing the area where almost all of the free-span axial indications were found in U2R4, and a checkerboard MRPC inspection sample of approximately 500 tubes from the 08H support through the first vertical support (See Figures III-2 and -3). A larger MRPC pancake coil (0.115") with demonstrated increased sensitivity during U2R4 and U2M5-1 was utilized in the inspection program conducted during U1R4. Additional improvements in ECT techniques and analyst training discussed previously with the USNRC Staff enabled the ECT analysts to locate axial defects more effectively, and determine the extent of bowing and ridge deposit formation in Unit 1. Reference 2 provided the location of possible deposits as determined by ECT, as well as locations of tube bowing, a mechanism which may promote the formation of free span crevices and deposit sites.

[illegible]

[illegible]

[illegible]

Upon completion of the ECT inspection program, ***no axial indications*** (ODSCC) were found in the areas inspected from the 08H eggcrate to the vertical support area of the Unit 1 steam generators. However, as stated in Reference 2, the inspection results indicated that slight freespan corrosion damage may be present on a small number of tubes in the form of volumetric indications. One tube in SG 1-2 (R122L101) was also inspected by UT examination to confirm that the SVI defect (identified by ECT) was volumetric and not SCC. The UT examination confirmed the ECT disposition of the defect. Based on the inability to confirm the exact nature of these volumetric indications, tubes with SVIs were removed from Units 2 and 3 during U2M5-1 and U3R4, respectively. Results of the laboratory examination of these defects indicate that the SVIs are not related to the IGA/IGSCC indications found in the ARC Regions in Units 2 and 3.

Reference 2 provided ECT summary tube maps of PDPs (deposits) and BOW (reduced tube spacing). No conclusions could be drawn with respect to tube deposits in Unit 1, as there does not appear to be a significant difference between the PVNGS Units with regard to the general location and number of tubes with deposits prior to chemical cleaning. APS has committed to perform chemical cleaning in Unit 1 during U1R5.

APS considers the NDE results to be statistically significant with regard to possible crack initiation and crack growth in Unit 1. After the same operating interval in Unit 2 (U2R4) with ECT equipment and techniques not regarded to be as efficient, a total of 122 defects were found. During U3R4, with a smaller MRPC inspection extent (see Figures III-4, -5, -6 and -7), a total of 17 ARC Region defects were identified. These results will be treated statistically in the cycle length evaluation discussed in Section V.

2. Unit 1 Operating Chemistry

APS has reviewed the operating chemistry experience in Unit 1 compared to Units 2 and 3 to determine if distinct differences in secondary chemistry could explain the absence of ARC Region ODSCC and the greater number of tubesheet indications in Unit 1. The secondary chemistry history and the current chemistry program in the PVNGS Units will be described in the following section, however, the following items form the basis of a general conclusion of better overall operating chemistry in Unit 1, and consequential reduced secondary side attack

- Unit 1 has always maintained the lowest molar ratio values of the PVNGS units.
- For recorded data from 1988-1993, Unit 1 has maintained lower sodium levels than Units 2 and 3.

- Unit 1 has had the lowest condenser leak rate average of the three PVNGS units, pointing to lower contaminant ingress from the condensers
- Historically, Unit 1 has, by a factor of two, lower condensate dissolve oxygen values. This condition can translate into lower electrochemical potential (ECP) and lower corrosion product transport.
- Unit 1 has always maintained the highest overall INPO rankings of the PVNGS units. The INPO CPI Index considers sodium, dissolved oxygen and cation conductivity. Table III-1summarizes the PVNGS INPO rankings for PWRS from 1990-1993.

Table III-1 National PWR INPO Rankings

Year	INPO Ranking			
	Unit 1	Unit 2	Unit 3	Total Plants
1990	5	28	16	47
1991	1	2	3	40
1992	3	29	30	38
1993	11	33	30	33

It should also be noted that Unit 2 pulled tube metallurgical studies indicated less than favorable metallurgical structures relative to caustic IGSCC. Upon review of certified material test reports (CMTRs) for the PVNGS units there is an indication the steam generator tubing in Unit 1 may be more resistant to caustic IGSCC/IGA as five percent of the tubes in Unit 2 exhibit flow strengths higher than the highest strength tube in Unit 1. This condition was also observed by NRC inspectors in Reference 8.

In summary, there are chemical and possible metallurgical factors which are consistent with superior resistance to upper bundle corrosion degradation of Unit 1.

With regard to tubesheet circumferential SCC, there is indication that pre-1993 hot leg sludge piles were larger in Unit 1 than in either Units 2 and 3. As can be seen by comparing defect location with sludge pile depths in Figures III-8 through III-13, there is a consistent sludge pile/defect relationship. This relationship has been observed in other Combustion Engineering units. The insulating effect of the sludge pile may contribute to the initiation and propagation of primary initiated defects within the sludge pile. APS sludge lanced Unit 1 during U1R4 in an effort to minimize this condition.

[illegible]

B. Corrective and Preventative Actions

Although the inspection results indicate that accelerated ARC Region cracking is not presently at work in Unit 1, APS has taken a number of corrective and preventative actions based on a mechanistic understanding of the phenomenon. Despite the positive inspection results, APS elected at the start of Cycle 5 to operate Unit 1 at reduced power in an effort to eliminate region susceptibility as defined by the ATHOS model of the PVNGS steam generators (Reference 2). This interim measure was taken until industry demonstrated mitigative actions could be implemented including primary temperature reduction and stricter secondary chemistry controls. APS formed an industry panel of experts to review these actions and to assess the impact of returning the PVNGS units to 100% power. This panel of experts known as the PVNGS Steam Generator Steering Committee was comprised of:

Dr. Jacques-Philippe Berge - Edf

Dr. Kenneth R. Craig - Florida Power and Light

Dr. Solomon Levy[1] - Levy and Associates

Dr. Geoffrey R. Egan - APTECH

Mr. Chuck Welty - EPRI

Mr. Donald F. Streinz - ABB-Combustion Engineering

Mr. Michael P. Short - Southern California Edison

Mr. Richard T. Begely[2] - Consultant, Former Vice President Westinghouse

Notes:

1. Dr. Solomon Levy is also a member of the PVNGS Oversite Safety Review Committee (OSRC)
2. Mr. Richard Begely is a recent addition to the Steering Committee

A discussion of the actions evaluated by the Steering Committee is provided below:

1. Secondary Water Chemistry Control

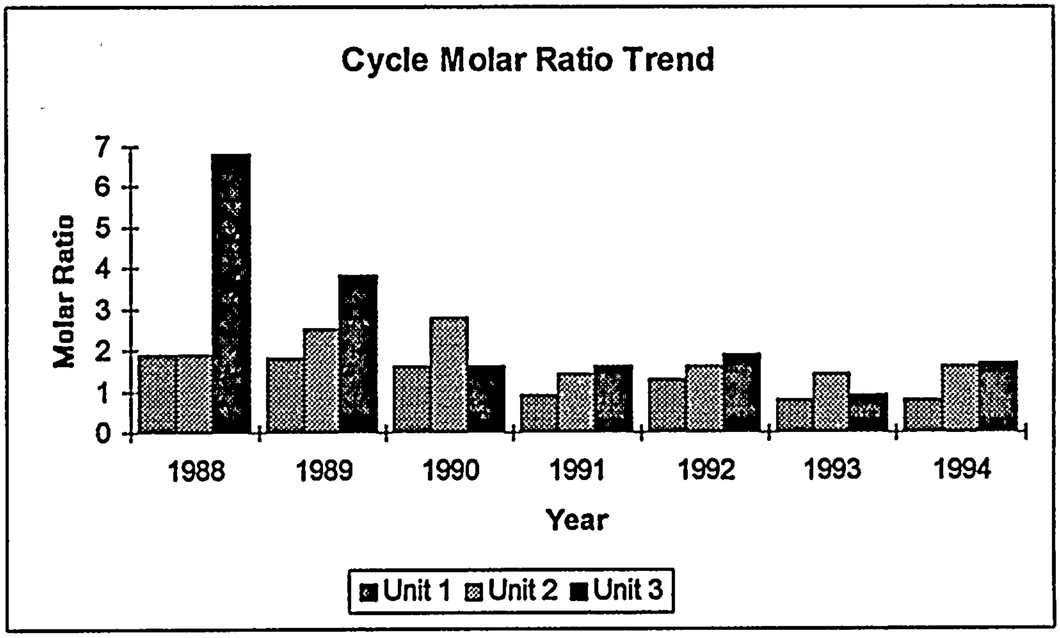
Molar Ratio Control

Molar ratio control has been developed in response to the industry data suggesting highly caustic or acidic crevice conditions promote rapid intergranular attack of Alloy 600. IGSCC affects Alloy 600 steam generator tubes at more than 50 units around the world. EPRI recently reported the results on the correlation of steam generator hideout return data from the secondary side of steam generators from about 30 units utilizing the MULTEQ-REDOX computer code. MULTEQ code results indicate that in the majority of cases studied, crevice solutions are caustic. Examinations of steam generator tubes removed from service and results from laboratory programs sponsored by EPRI and others, have identified the principle causes of this corrosion.

The primary factor is the ability of a boiling crevice to concentrate liquid corrodents to a level limited only by the locally available superheat (primary water temperature less pressure limited secondary water temperature in the local environment).

The objective of molar ratio control is to promote a near-neutral crevice pH environment by developing a relationship between bulk water chemistry and crevice chemistry which can be monitored and controlled on a daily basis. By promoting a near neutral environment, the rate of intergranular attack is expected to be reduced. Figures III-14 and III-15, reproduced from Reference 9, illustrate the effect of high temperature pH on crack growth rate for IGA and IGSCC as shown crack growth rates are reduced as pH approaches neutral; this beneficial effect should be realized by an effective molar ratio control program. Molar ratio, as defined at Palo Verde, is simply the ratio of sodium divided by chloride.

Due primarily to the complex physical laws governing the hideout of sodium and chloride, molar ratio control has been difficult to achieve for most utilities, including Palo Verde. Sodium has a much greater tendency to hideout due to its restricted mobility as compared to the more volatile chloride ion. Therefore attempts at molar ratio control at PVNGS have been primarily by partial or full condensate demineralizer bypass to minimize sodium ingress to the steam generators. The following graph not only indicates a downward trend in molar ratio at PVNGS, but also indicates that Unit 1 has consistently had more success in maintaining lower molar ratio values.



Although significant improvement in molar ratio control as been achieved by minimizing sodium ingress, to achieve molar ratio control consistently within the recommended band, it was deemed necessary by APS to inject ammonium chloride at a known concentration and controlled rate into the feedwater system. Ammonium chloride injection began in Unit 1 on May 21, 1994. Implementation of a true molar ratio control strategy is two-fold with the limiting factor being procedural controls designed not to exceed the EPRI PWR Secondary Water Chemistry Guideline, Revision 3, Action Level 1 value for Chloride of 20 ppb and still remain within the molar ratio operating range of 0.2 to 0.6. Therefore, the following two step strategy is employed:

1. Maintain sodium ALARA, and control molar ratio with the addition of ammonium chloride as necessary.

2. Do not allow chloride levels to exceed 20 ppb. This implies that the sodium concentration cannot exceed 7 ppb to maintain the molar ratio within the operating range.

Loss of control of the ammonium chloride addition system is governed by the action levels established by EPRI for the chloride concentration. If the entire volume of chloride were injected into the steam generators, and there was no removal term (i.e. blowdown is secured), the maximum concentration that would be achieved would be approximately 0.22 ppm.

Significant improvements have been realized in molar ratio, primarily through polisher bypass operation. Recent results indicate that Unit 1 with the use of ammonium chloride has achieved a molar ratio of 0.4 based on INPO reported monthly averages

Elevated Hydrazine

In accordance with the EPRI PWR Secondary Water Chemistry Guidelines (Reference 9), Palo Verde increased the feedwater hydrazine concentration to greater than 100 ppb hydrazine in January 1993. The recommended increase in hydrazine was based upon industry data indicating that increased hydrazine concentrations promoted a reduction in electrochemical potential (ECP). ECP can significantly effect the rate of intergranular attack as illustrated in Figure III-15. EPRI sponsored laboratory testing, and empirical data obtained from St. Lucie 2 indicate that increasing the feedwater hydrazine concentration to 100 ppb reduces the ECP value by about 300 mV (Reference 10). Additionally, data from Reference 11 states that the plants on boric acid and high hydrazine have a lower Weibull slope (average 2.3) than units with boric acid and low hydrazine (average of 5). Weibull slopes from Reference 11 are a measure of the rate of increase of tube plugging due to IGA/IGSCC defects.

Prior to implementation, Units 1 and 2 increased hydrazine concentration from the previous 50 ppb to 75 ppb in December, 1992, to ensure secondary chemistry control would not be adversely effected. Unit 3 remained at 50 ppb hydrazine to provide baseline data correlations if required. Based upon the trial runs, there were no noticeable effects on condensate polisher operations or any secondary chemistry parameter other than feedwater iron concentrations.

A decrease in condensate influent (CDI) and final feedwater iron concentrations were noted at the higher hydrazine concentrations. Unit 2, which was operating with full flow condensate polishing, did not observe a decrease in feedwater iron concentrations.

In addition to the reduction in iron transport (which is considered a supplemental benefit since the purpose of increasing hydrazine is to reduce ECP), initial sample sets analyzed under an EPRI-funded project, indicated a reduction of hematite concentrations while operating at the higher hydrazine concentrations. The composite samples sent to EPRI for Mossbauer Spectroscopy showed steam generator blowdown hematite concentrations were reduced from 11% by weight hematite at the lower hydrazine concentration, to 2% by weight hematite while operating at 100 ppb hydrazine. Since hematite can raise the ECP by + 100 mV, the reduction in hematite concentration (reduced to magnetite) is considered a benefit. Unit 2 metallurgical results also show that copper is plated out on the tube surfaces confirming that the tubes are seeing a reducing environment. Testing is currently being arranged to provide both additional Mossbauer analyses, and to provide direct measurement of final feedwater ECP.

ETA

In April 1993, Unit 1 converted from ammonia to ethanolamine (ETA) for secondary system pH control with the goal of reducing corrosion product transport to the steam generators. Because of its lower volatility relative to ammonia, ETA has significantly reduced flow assisted corrosion of the wet steam piping, which has been the primary source of corrosion products that deposit on heat transfer surfaces of the steam generator. These deposits are the building blocks for the formation of the upper bundle crevices and the aggressive alkaline-sulfate environment observed.

It has been well established that erosion/corrosion of carbon steel can be minimized at a room temperature pH of approximately 10.0. This pH is above that which can be achieved with ammonia and hydrazine. The site specific upper pH which Palo Verde could operate with, and maintain full flow condensate polishing, has been 9.15 with ammonia as the pH control additive. Iron transport to the steam generators under these conditions has been 10 ppb or greater. ETA was adopted to reduce the iron transport rates to less than 5 ppb without having an adverse effect on condensate polishing. This is possible since:

1) ETA is a stronger base at higher temperatures. It is the high temperature pH which is most important when determining the

system's corrosion rate (as opposed to the 25 °C pH).

2) ETA has a lower volatility and therefore partitions more into the water phase. This not only results in a higher pH in the water phases and therefore lower corrosion, but also results in less amine removed by the condensate polishers since a significant amount of ETA is pumped forward via the heater drains.

3) ETA is very thermally stable which ensures the advantageous properties of base strength and low volatility are not nullified.

4) EPRI funded studies designed to evaluate the effects of ETA on condensate demineralizer operation has not shown any physical effects such as bead fracture on ion exchange resins.

Prior to implementation of ETA in Unit 2 during May 1994, only Unit 1 had been converted to ETA at PVNGS (Figure III-1). To achieve feedwater iron goals, Units 2 and 3 have been able to operate with pHs elevated to approximately 9.8 due to bypassing their condensate polishers. Consequently, similar reductions in iron transport have been observed in these units. However, in the event of a small condenser tube leak, the units on ammonia could not operate with full flow polishing and still maintain the reduced iron transport rates. ETA operation therefore provides more flexibility to the units during an operating cycle.

Since the use of ethanolamine (ETA) for secondary pH control has been implemented in Units 1 and 2, feedwater iron concentrations have been reduced from nominally 5 ppb to about 2 to 4 ppb. Significant reductions were also observed in the heater drain samples with iron concentrations being reduced from about 32 ppb to approximately 5 ppb.

Electrochemical Potential Monitoring

Palo Verde is considering performing Electrochemical Potential (ECP) measurements of the final feedwater utilizing equipment and procedures similar to previous ECP monitoring programs conducted by EPRI. ECP measurements of an at-temperature feedwater stream will provide trend data for Alloy 600, carbon steel, and stainless steel. For testing purposes, plant feedwater hydrazine and oxygen concentrations are varied to determine their effect on ECP. This information can be used to optimize operating feedwater hydrazine and oxygen concentrations and to ensure that ECP is reduced to appropriate levels.

In addition to the measurements of ECP for the various alloys, dissolved oxygen, corrosion product transport and Mossbauer measurements are currently scheduled to be performed at the same sample location. An oxidation/reduction potential (ORP) electrode will also be installed in the secondary chemistry laboratory wet rack to

determine if a correlation can be made between the ECP and ORP probes. If the ORP electrode correlates with the ECP measurements, it could be used as an alternate to ECP for routine monitoring. The ORP electrode is less expensive than is the ECP probe.

Condensate Polisher Operation
To provide maximum protection for the steam generators from ionic and particulate ingress, the ideal configuration at PVNGS would be operation with full flow condensate polishing and as high a system pH as practical. To satisfy the pH requirement monoethanolamine (ETA) has been chosen as the pH additive, as it is compatible with full flow polishing. However, due to sodium leakage from the condensate polishers, a caustic environment in the steam generator crevices prevails when operating in a full flow polishing configuration. Additionally, it is known that potential resin and resin fine leakage from the vessels is another source of sulfate in the steam generators. For these reasons, the condensate polisher regeneration process and equipment have been identified as requiring upgrading to minimize or preclude these conditions.

With the replacement of the Unit 1 condensate polishing resin during the first quarter of 1994, all three units are now utilizing Dow 650C cation, and Dow 550A anion resin in the condensate polishing systems. During the first quarter of 1994, a task team was formed within APS to address condensate polisher issues. This team works closely with both PVNGS Site Chemistry, and a PVNGS Secondary Chemistry Control Task Team to establish the optimum polisher configuration.

In February, 1994, APS issued a Site Issues Plan addressing operational and design problems with the condensate polishers. This plan was formulated with the help of EPRI, consultants, and experts from other utilities. Actions were identified in three major areas. These area are 1) condenser integrity, 2) regeneration upgrades and 3) minimization of resin intrusion.

<u>Condenser Integrity</u>
Condenser integrity was identified as the first line of defense for impurity ingress into the steam generators. Leak detection capabilities were evaluated to ensure that leak detection methodology in use at PVNGS is in keeping with best industry practices and leak detection limits are as low as possible. Review of the PVNGS capabilities determined that the helium leak detection methodology in use at PVNGS has previously found leaks as small as 1 gallon per day.

When a tube leak has been verified, plant power is reduced to 45% and the suspect circulating water train is isolated and drained This evolution can take up to 6 hours. During this time, full flow polishing operation is maintained if possible. All EPRI action levels are adhered to during this time frame, and increased monitoring of steam generator, condensate and condensate polisher chemistry is implemented.

Regeneration Upgrades

Enhancements/modifications for resin regeneration were identified in the areas of the regeneration process, regeneration equipment, training, and maintenance.

Although sodium leakage from individual vessels has never been quantified at PVNGS, the polishers have been identified as the largest single source of sodium by source term studies. The goal of the actions on the polishers is to reduce sodium leakage from the polishers to levels of less than 3 ppt. As the quantity of sodium is a direct contributor to the caustic conditions in the steam generator crevices, minimization of the sodium reduces the caustic environment, and minimizes the amount of ammonium chloride that is required to be injected for molar ratio control.

Regeneration process upgrades under consideration include methods to reduce resin cross contamination during resin separation, ammonium hydroxide rinse of the anion resin, replacement of process control valves, evaluation of impurity limits for regeneration and secondary addition chemicals, routine evaluation of resin performance and evaluation of alternate resin separation/regeneration systems. The primary focus of the process upgrades is to reduce sodium leakage from the polishers.

Cross contamination is being reduced by the implementation of the Graver SEPREX process, modification of the resin transfer laterals in the cation vessel and anion vessel, and relocation of the air control solenoids for the separation water flow. The ammonium hydroxide anion rinse was performed after an anion regeneration. The rinse was intended to convert any cation resin or fines trapped in the anion resin from the sodium form to the ammonia form which will preclude sodium leakage from this resin. Some plants have demonstrated that performance of this rinse is able to reduce sodium leakage from mixed bed polishers from approximately 0.1 ppb to less than 0.003 ppb.

Replacing the process control valves could allow consistency to be achieved in the regeneration process. Currently valve positions will vary with sequential openings, causing varying flow rates resulting in inconsistent regenerations. Process valves to be replaced control resin transfer, cleaning, separation, and chemical concentrations.

Resin performance monitoring has not been routinely performed at PVNGS due to the radioactive contamination of resin from primary to secondary leakage. PVNGS is in the process of establishing the capability of onsite resin analysis. This will allow monitoring the performance characteristics of the resin and the quality of the regeneration process. This information can be used to assist in optimization of the regeneration process and predict resin replacement.

APS Engineering, Site Chemistry and Operations are continuing to evaluate

alternate separation/regeneration processes to determine the most practical options for PVNGS to pursue. Equipment upgrades under consideration include replacing the process controller, rerouting the pre-service rinse water to waste instead of the hotwell, installation of resin sampling capabilities, installation of continuous analyzers for the individual service vessel effluent, and replacement of acid and caustic piping, valves and pumps as required. The primary focus of the equipment upgrades is to ensure the regeneration process is executed as desired and an optimum regeneration performed. Additionally, training issues are being evaluated by the task force at the operator, chemist, and engineer level. New training requirements are being identified and training will be developed to address these areas. Vendor training is being presented onsite to supplement existing training and to address the areas of resin theory, regeneration principles, and equipment operation. Finally maintenance practices are being reviewed to ensure that routine inspections are being performed and that process controls are calibrated to maintain an optimum regeneration process.

Resin Intrusion

Resin intrusion is being addressed through the redesign of the resin traps located downstream of the condensate polishers. The micron rating of these traps will be reduced to the smallest practical size while meeting the design criteria for the system and traps. Testing will be performed on traps of approximately 100 and 170 micron size. Installation of the test traps is expected to occur by the end of 1994 and testing is expected to take up to 60 days.

Operating Chemistry Specifications

PVNGS has previously operated based on the sodium and sulfate specifications outlined in Table III-2. These are the current guidelines set forth in Section 2 of the EPRI Secondary Water Chemistry Guidelines, Revision 3. The existence of the ARC region in the upper bundle of the steam generators increases the propensity for contaminants to concentrate in that region. In order to mitigate the effects of this phenomena, the steam generator specifications outlined in Table III-3 have been implemented by PVNGS. These specifications would ensure appropriate action at lower contaminant levels than the current specifications, including a requirement to reduce power to below the threshold for dryout at levels as low as 20 ppb.

Table III-2: EPRI Chemistry Specifications

LEVEL	ACTION
> 20 ppb sodium or sulfate	Reduce sodium and sulfate to < 20 ppb within 7 days or reduce power to 30%
> 100 ppb sodium or sulfate	Reduce power to 30% within 8 hours. Reduce sodium to < 100 ppb within 100 hours or shutdown the Units to at least Mode 3
> 500 ppb sodium	Shutdown the Unit to at least Mode 3 as quickly as safe plant operations permit

Table III-3: PVNGS Chemistry Specifications

LEVEL	ACTION
> 20 ppb sodium or sulfate	If these values are exceeded reduce power to 86% within 8 hours and meet all Action Level 1 requirements
> 100 ppb sodium or sulfate	Reduce power to 30% within 8 hours. Reduce sodium or sulfate to < 100 ppb within 100 hours or shutdown the Units to at least Mode 3
> 500 ppb sodium or sulfate	Shutdown the Unit to at least Mode 3 as quickly as safe plant operations permit

In addition to the new chemistry specifications, an Abnormal Occurrence Checklist procedure is utilized to respond to off-normal chemistry conditions. This procedure addresses power changes, primary to secondary leaks, impurity ingress, secondary system resin intrusion, and condenser tube leaks. A checklist is provided for each of these considerations and direct sampling and analysis actions.

[illegible]

Boric Acid Treatment

Due to the presence of caustic steam generator crevices, Palo Verde has implemented a boric acid treatment program in all three PVNGS Units. Boric acid has been proven effective in both laboratory studies and actual field use to reduce denting in steam generators. Since denting occurs in generators with ferrous support plates, Palo Verde is not susceptible to this damage mechanism. Laboratory studies using model boilers have shown that continuous on-line addition of boric acid also significantly inhibits IGA/SCC. As a result of the successful use of boric acid in the field to control denting, and the inhibition shown in laboratory tests, utilities have recently employed boric acid in an attempt to control IGA/SCC caused by caustic environments within steam generators. Boric acid was first used as an on-line intergranular corrosion inhibitor in the field in 1985. Since then, the data base for plants using boric acid has increased. EPRI report NP-5558 "Boric Acid Guidelines for Intergranular Corrosion Inhibition" (Reference 12), recommends that boric acid be applied in plants having IGA/SCC. The EPRI PWR Secondary Water Chemistry guidelines states that virtually all U. S. PWRs where IGA/SCC is a serious problem have adopted boric acid treatment.

The reasoning behind boric acid's effectiveness is threefold:

1) Boric acid reduces the pH of alkaline environments by reaction with NaOH to form borate.

2) Boric acid dilutes the OH^- concentration, thereby lowering the chemical activity and reducing the probability that OH^- is present at the actively corroding grain boundary.

3) Boric acid forms a passive borate layer on Alloy 600 tubing. It is hypothesized that a salt film of MeB_4O_7 is formed on the metal substrate, and, this film protects the metal by restricting the movement of the OH^- ion. The boric acid chemisorbs on the surface, raising the activation energy for dissolution, leading to a reduction in dissolution rate.

Considerable effort has been made by the industry to quantify the influence of boric acid remedial measures. The most recent compilation of data is included in EPRI TR-101010 "Correlation of Secondary-Side IGA/SCC Degradation of Recirculating Steam Generator Tubing With the On-Line Addition of Boric Acid" (Reference 11). The report states that corrosion growth decreased notably for the five units with statistically valid corrosion data from the periods both before and after the application of boric acid. For several units for which data were deemed "not reliable," boric acid apparently had no significant effect. The report recommends on-line boric acid addition combined with an increase in hydrazine concentration and an increase in secondary system pH.

Based upon hideout return chemistry data indicating caustic crevice chemistry, and the subsequent appearance of IGA/IGSCC indications at the tubesheet and flow distribution plate in Units 1 and 2 respectively, Palo Verde began preparations in 1992 to implement secondary system boric acid treatment. A cross-disciplined team was assembled to develop an implementation process to address the tubesheet indications, and the team selected a series of high boron concentration crevice flushes to be performed at the lower tube supports. Based upon the Unit 2 (March 1993) steam generator tube rupture and the determination of upper bundle fouling and crevice formation, the team changed the focus of the crevice flushes to address the 07H - 09H eggcrate supports. The process which was determined to provide the best chance for mitigating caustic crevice chemistry consisted of 4 steps:

1. Ambient soak with 50 ppm boron for 4 days in Mode 5
2. Crevice flushes with 2000 ppm boron at 300 F in Mode 4
3. Low power soak with 300 ppm boron
4. On-line continuous addition at 5 to 10 ppm boron

Boric acid treatment was initially implemented in Unit 1 following U1R4 in November 1993. The unit successfully implemented the 300 ppm boron low power soak and is currently maintaining 5 - 10 ppm boron on-line addition. Unit 2 initially implemented boric acid treatment during the U2M5-1 outage in March, 1994, with the exception of Step 1 above. The boric acid program in Unit 3 was implemented following U3R4 in May of 1994.

2. Summary

Based on review of PVNGS operating history, tube pull examinations, industry review and thermal hydraulic modelling, APS believes a mechanistic understanding of the causal factors involved with ARC Region ODSCC has been established. Figure III-16 provides a simplified illustration of the synergistic effects which if present can result in an aggressive environment and accelerated IGA/IGSCC in the upper bundle of the PVNGS steam generators. Figure III-17 illustrates the comprehensive spectrum of corrective and preventative actions taken or planned by APS to mitigate SCC damage mechanisms. Aggressive crevice chemistry control is expected to reduce the rate of corrosion within the ARC Region to manageable levels to permit full cycle operation in Units 2 and 3. APS believes that these actions combined with the good operating and inspection history in Unit 1 support full cycle operation for the present cycle (Cycle 5).

IV. UNIT 2 AND 3 TUBE PULL RESULTS

A. Background - Unit 2

Twenty-one (21) tube bend sections from Unit 2 Steam Generator 2-2 were removed for metallurgical examinations during the U2M5-1. A description of the tube removal process was provided in Reference 4. Of the 21 tube sections, 13 contained eddy current indications, while the remaining 8 tubes were removed as part of the tube harvesting effort. A sketch of the removed tube bend sections is provided in Figure IV-1. A complete listing of all eddy current calls for the removed tubing is shown in Table V-7 of Reference 4. The scope of metallurgical examinations intended for steam generator bend section tube analysis was developed by APS..The purpose of the examinations were as follows:

1) Evaluate field eddy current testing (ECT) correlation to actual defect size and location
2) Validation of ECT detectability thresholds
3) Characterization of various ECT probe capability to probe bend section tubing;
4) Burst test data correlation for defect structural integrity analysis;
5) Probability of detection (POD) database development
6) Identification of mode of degradation

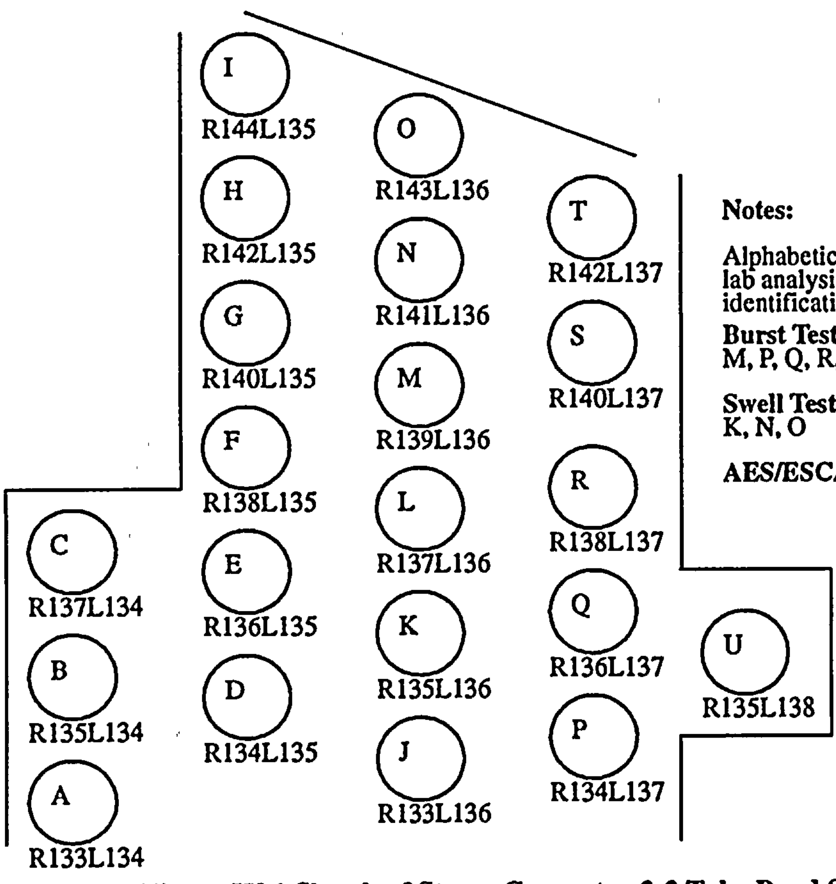
The tube examinations were conducted at ABB-CE in Windsor, CT. Independent laboratory microstructure evaluations for all 21 tube sections and corrosion analysis for one crack indication (tube R137L134 (C)) was performed by Westinghouse in Pittsburgh, PA. Burst testing procedure review and witnessing was performed by an APS independent consultant to ensure consistency with industry standards. All laboratory work was performed under the direction of APS Metallurgists.

Nondestructive tests were performed on bend section tubing to characterize tube condition received at the laboratory, identify defect areas and other areas of interest, and characterize deposit appearance and chemical composition. Tubes examined were chemically cleaned in the field and thus deposit observations were limited to remaining ridge deposits not completely removed by the cleaning. The scope of nondestructive tests included the following:

- Receipt Inspections
- Visual Inspection and photography
- NonDestructive testing (Bobbin and MRPC, ultrasonic (UT) characterization)
- Dimensional Measurements (bend section radius, tube ovality)
- Deposit chemical analysis

Following the nondestructive work, destructive testing was performed. Destructive testing included the following:

- Swell testing of tubes without ECT corrosion indications
- Burst testing
- Scanning electron microscopy (SEM) of burst and crack extension areas
- Low Optical Microscopy of material cross sections
- Radial metallography to characterize surface intergranular corrosion
- Auger electron spectroscopy (AES) to determine crack tip chemistry
- X-Ray photoelectron microscopy to determine crack tip chemistry
- Dual etch metallography to characterize tube microstructures
- Modified Huey testing to determine degree of tube sensitization
- Mechanical testing for tensile and yield strength properties
- Base metal chemical analysis



Notes:

Alphabetical notation used during lab analysis to simplify tube identification

Burst Test Tubes: A, B, C, G, J, L, M, P, Q, R, S, T, U

Swell Test Tubes: D, E, F, H, I, K, N, O

AES/ESCA Tube samples: C, D, P

Figure IV-1 Sketch of Steam Generator 2-2 Tube Bend Section Locations

B. Laboratory Test Results

1. Visual Inspection

Visual examination of post-chemically cleaned tube bend sections revealed tube surfaces to be generally clean and free of deposits. Localized areas of remaining ridge deposits were detected. Deposits appeared to be black with white and orange areas. Close examination of remaining ridge deposits showed deposit removal was in process but was likely slowed by insoluble species. Deposit analysis indicated a primary constituent of SiO_2 with small percentages of iron oxide. Typical deposit chemical analysis data are provided in Table IV-1.

Further laboratory chemical cleaning testing on remaining ridge deposits indicated continued cleaning with longer exposure times of 20 - 40 hours to the EPRI SGOG process. A summary of this testing is provided in Reference 13. The results of this testing prompted APS to increase the exposure of the Unit 3 chemical cleaning iron solvent from 40 hours to 80 hours.

<u>Table IV-1: Semi-Quantitative X-ray Fluorescence Analysis for Tube R144L135 (I)</u>

Assumed Oxide Form	Concentration (%)
SiO_2	48.0
MnO	23.0
MgO	6.8
Fe_3O_4	5.1
CaO	4.6
Al_2O_3	4.3
Cu	2.6
NiO	1.5
SO_3	1.7
Cr_2O_3	1.2
TiO_2	0.6
ZnO	0.4

Tube measurement data showed that, with few exceptions, tube bend sections were found to be in conformance with specification requirements for tube bend radius and tube ovality requirements. Lab visual documentation of pre- and post swell/burst testing was provided in tube section maps. A typical tube map for tube R133L134 (A) is provided in Figure IV-2. This figure may be used to determine typical tube defect locations as noted in this report. These sketches were used by corrosion engineers to determine areas for further examination and development of tube sectioning maps. As was observed and reported in Reference 3, tube bowing or reduced tube spacing appears to result in freespan tube-to-tube crevices in the PVNGS steam generators. Some of the pulled tube sections were found to be bowed and exceeded bend radii specification requirements. Figure IV-3 shows a photograph of tube R139L136 (M) bend section demonstrating an out-of-tolerance condition.

2. Swell Test Results

Tube swelling was performed for tubes which had no reported field eddy current defect signals. The procedure consisted of pressurizing and holding at approximately 1375, 2650 and 4450 psi to check for potential leakage, pressuring to 8000 psi and then stopping the procedure. All tubes designated for swell testing in Figure IV-1 were successfully swelled with the exception of tube R135L134 (B). This tube (B) burst at 7820 psi and was subsequently investigated as a burst tube and is reported in the following sections. The tube burst at the intrados (inner bend) in a ridge deposit at the batwing elevation. Subsequent review of field and platform eddy current data revealed the tube was NDD in the field but detected as a SAI in the steam generator platform after tube removal. This data point was included in the probability of detection database as a field ECT undetected defect and characterized via fractography.

Tube swell test examinations revealed varying degrees of shallow IGA and SCC. Some tube batwing contact areas associated with ridge deposits were sites for localized IGA. Complete tube surfaces were also found to be affected by shallow IGA and SCC. Some tube sections were found to contain up to 30 percent throughwall attack, however, completely around the circumference of the tube. These areas were further examined to determine the actual extent of surface attack.

3. Burst Test Results

Tube burst testing was performed per a quality controlled procedure under supervision by APS and its consultant. The procedure was the same for swell testing except the tubes were pressurized until failure. Burst opening average and maximum depths were measured using SEM montages of the burst face and taking depth measurements every 0.025 inches. Test data indicated that tube burst pressures were significantly above 3ΔP (3810 psi) and 1.4 times main steam line break pressure (3500 psi). Table IV-2 provides a summary of tube burst data. Tube burst pressures are at room temperature.

Table IV-2: Steam Generator Tube Bend Section Burst Data

Tube ID	Burst Pressure (psi)	Burst Location	Length (in), Depth	Field ET call
R133L134 (A)	7320	Extrados[1], 0-degree, lower tangent of bend	1.44", 51% avg, 73% max through-wall (TW)	BW+3.95" SAI
R135L134 (B)	7820	Intrados, 180 degree,	1.25", 51% avg, 73% max TW	NDD
R137L134 (C)	8500	Extrados, top of bend	1.3", 32% avg, 41% max TW	BW+16.0" SAI
R140L135 (G)	7540	Extrados, top of bend	1.15", 47% avg, 66% max TW	BW+16.4" SAI
R133L136 (J)	6020	Intrados, 180 degree, below Batwing	1.5", 45% avg, 85% avg TW	09H+16.6" SAI
R137L136 (L)	8860	Extrados, top of bend	1.3", 38% avg, 53% max TW	Plugged tube (1993)
R139L136 (M)	6860	Extrados, upper tangent of bend	0.95", 51% avg, 84% max TW	Plugged tube (1993)
R134L137 (P)	8640	Extrados, upper tangent of bend	1.3", 41% avg, 60% max TW	BW1+16.2" SAI
R136L137 (Q)	9180	Extrados, upper tangent of bend	1.24", 32% avg, 45% max TW	BW1+16.60" SAI
R138L137 (R)	8020	Extrados, upper tangent of bend	1.25", 39% avg, 55% max TW	BW1+16.30" SAI
R140L137 (S)	8960	Extrados, upper tangent of bend	1.36", 31% avg, 48% max TW	BW1+17.37"
R142L137 (T)	9860	Vertical section, 45 degrees, 8" below batwing	1.48", 0% avg, 0% max TW	NDD
R135L138 (U)	8520	Intrados, at batwing elevation	1.25", 38% avg, 59% max TW	BW1+1.51" SAI

1. Extrados refers to the outer surface of the tube bend, whereas intrados is the inner side or 180° point per Figure IV-2.

[illegible]

[illegible]

[illegible]

4. **SEM Fractography Evaluation**

Results from SEM examination of defect burst surfaces confirmed the mode of corrosion degradation to be outside diameter initiated intergranular attack (IGA) with stress corrosion cracking (SCC). Surface IGA of a cellular form with both axial and circumferential extents was detected on most tubes examined. No transgranular cracking was detected. Secondary cracking extending from burst openings was observed and subsequently sized. Tube scratches were identified as being favored sites for crack propagation under ridge deposits. Shallow tube wear was identified at batwing support contact areas and in some cases were associated with crevice deposits and subsequent IGA and SCC. Apparent tube-to-tube contact wear was observed on at least one tube (M) as shown in Figures IV-5 and IV-6.

5. **Eddy Current Detectability Evaluation**

Burst tube openings and general surface areas were examined in detail and defects identified were sectioned, sized and compared to field bobbin and MRPC eddy current calls. The results showed a generally excellent correlation of field eddy current detectability and sizing to actual defect size and locations. Eddy current MRPC was found capable of identifying average wall corrosion of 35%-45%, with a few instances where 31% average degradation was found. Tube R135L134 (B) burst defect was not detected in the field by either bobbin or MRPC. This tube had an average wall loss due to corrosion of 49%. Detectability of this defect may have been hampered by the surrounding IGA, which was 20%-30% deep. Note that the burst pressure of this defect was 7820 psi, significantly higher than Reg. Guide 1.121 requirements. This eddy current data was subsequently used to develop POD curves which are presented and discussed in a later section of this report.

6. **Eddy Current Chemical Cleaning Sensitivity Tests**

Additional testing was performed on a sample tube crack to determine if the modified EPRI SGOG chemical cleaning process caused a suspected change in defect signal response by oxidation of the crack face. This condition was postulated after ECT signal voltages changed in a number of tubes in SG 2-2 which were eddy current tested before and after chemical cleaning. A discussion of this field ECT observation and potential reasons for the changes was provided in Reference 4.

The procedure called for exposing tube R134L137 (P) SAI indication to a series of chemical reducing and oxidizing steps and performing eddy current bobbin and MRPC tests at baseline, between chemical exposure steps, and at test completion, each time comparing the signal response. Tube P contained an SAI with the following voltage history: 1993 - 0.54V, 1994 before chemical cleaning - 0.77V, 1994 after chemical cleaning - 1.61V and 1994 after cleaning, platform ECT - 1.79V.

After separate exposures to 100 ppm hydrazine, 0.5% hydrazine, and 3% hydrogen peroxide solution with ECT readings conducted after each step, the results showed no noticeable change in signal response. Therefore, the chemical cleaning process applied in Unit 2 did not result in a defect conductivity change.

7. Crack Surface Oxide Analysis

Tube metal crack oxides from tubes R137L134(C), R134L135(D) and R134L137(P) were characterized using Electron Spectroscopy for Chemical Analysis (ESCA) and Auger Electron Spectroscopy (AES). It is important to note that these tubes were chemical cleaned in the field prior to examination, with tube P undergoing further testing for eddy current response changes after exposure to reducing and oxidizing environments. Therefore, the ESCA and AES results may have been affected by contaminants associated with the chemical cleaning solutions and corrosion inhibitor.

Tube surface, crack mouth, mid-crack and crack tip were examined. Tube surface ESCA results showed high amounts of silicon, suggesting that the chemistry was controlled by deposition of secondary side contaminants. Some chromium depletion was noted, indicating that an alkaline chemistry environment was present during crack initiation. Surface analysis also detected high amount of zinc, along with lead, copper, iron and magnesium.

Crack face oxide chemical analysis noted irregular, but sometimes high, amounts of lead, sulfates and sulfides, which were detected in noticeable amounts of 1 to 6 atomic percent. Other elements detected included Na, K, Cu, Ca, C (possibly organic forming from the steam generator secondary water and the chemical cleaning process), and Cl. The presence of lead without chrome depletion is also indicative of possible lead influenced SCC. However, further evidence of lead influence, such as consistently high lead levels and indications of transgranular crack growth, was not observed.

The crack face Ni/Cr ratios were typical of the base metal composition or lower, indicating nickel depletion and negligible chromium depletion. In some areas the surface Ni/Cr ratio was significantly lower than base metal. Crack oxide thicknesses were found to be very thin, especially in the crack tip regions. For example, tube R134L135 (D) AES results identified a range of thin oxide thickness of 120-300 Angstoms at the crack face.

8. Material Analysis

Material microstructure investigations of 21 bend section tube samples found the microstructures to exhibit random carbide distributions with low preferential tendency towards grain boundaries. The average percent carbides at the grain boundaries was found to be 13% which is considered low for optimum resistance to crack initiation and growth. It is generally agreed, that caustic IGSCC resistance is improved with Alloy

600 microstructures which have continuous or semi-continuous grain boundary coverage (Reference 21).

Grain size evaluations found the material to be fine grained with ASTM grain sizes ranging from 8 to 9. The results were generally consistent with microstructures observed during the 1993 Unit 2 steam generator tube pull examinations. Steam generator tubing for Combustion Engineering steam generators was procured to a specification aimed at producing tube material with relatively coarse grains (ASTM 5 to 8) and a semi-continuous intergranular carbide network (Reference 22).

Room temperature tensile tests were performed. The data shows an average yield strength of 49 ksi. The material specification for Palo Verde steam generator tubing required a maximum yield strength of 55 ksi, with a desired yield strength of 45 ksi. Chemical analysis of tube samples concluded that the tubing conformed to the material specification. Modified huey testing concluded that the tubing material would have a very low susceptibility to acidic attack (not sensitized), averaging 0.12% weight loss. Material susceptible to acidic attack would have a weight loss of at least 5.0%. These results were comparable to the 1993 Palo Verde tube pull metallurgical results (0.06-0.44 wt% loss)

9. Evaluation of Probable Corrosion Mechanism

The results of the U2M5-1 tube examinations support previous conclusions that ARC Region tube deposit contaminants are required to cause the resulting IGA and SCC. Examinations of bend section tubing showed outside diameter initiated IGSCC and IGA located in batwing supports and apparent freespan locations. Corrosion attack in freespan locations was associated with long narrow ridge-like deposits, which act as crevice sites. These results confirm findings from the 1993 tube pull metallurgical examinations.

The results also show a potential favorable change in crack crevice chemistry tending towards neutral-alkaline and in some places neutral-acidic. This crevice chemistry is considered to be improved over the more alkaline-caustic crevices observed during the 1993 Unit 2 steam generator tube metallurgical analysis. The increased IGA character of the tube degradation indicates a slow growth factor which is further supported by the thin oxide thickness layers found on the crack surfaces (Reference 20). Studies published by EPRI (Reference 23) have shown that under the same stress IGSCC propagation is approximately 10 times faster than the IGA propagation rate.

The presence of sulfates and reduced sulfide species are concluded be an important factor in the tube degradation. Sulfur was detected in all areas examined on crack surfaces, and therefore, is suspected in aggravating the IGA and SCC in the tubing. However, the amount of sulfates deposited, and subsequently detected on the crack faces may have been influenced by the chemical cleaning corrosion inhibitor.

Sulfur attack is typically associated as a low temperature phenomenon resulting in IGA of sensitized Alloy 600 in oxygenated environments, i.e., plant shutdown conditions. Under these conditions, sensitized or partially sensitized Alloy 600 has been shown to be highly susceptible to reduced sulfur species attack (Reference 24). This form of corrosion attack has been reported in three operating plants, all of which have once through steam generators with sensitized Alloy 600 tubing (Reference 25). High temperature sulfur attack is generally associated with oxidizing, bulk acid sulfate conditions and results in rapid wastage, IGSCC, and pitting. Neither of the above conditions are applicable to PVNGS steam generators.

The effect of IGA and SCC attack of Alloy 600 in sulfur contaminated near-neutral and caustic environments have also been investigated. These conditions are more typical for Palo Verde steam generators. MULTEQ code results indicate that in the majority of cases studied, crevice solutions are caustic. This data was supported by 1993 U2R4 tube pull metallurgical results. As discussed in Reference 26, caustic IGA and SCC of Alloy 600 has been shown to occur due to a film rupture mechanism followed by anodic dissolution at the grain boundary and subsequent repassivation. Paine et al. have reported in Reference 27 that mechanisms which make grain boundaries susceptible to attack include:

- Segregation of Alloy impurities
- Formation of Nickel Sulfide
- Selective dissolution of Cr and Fe
- Anodic potential shifts by oxides

Paine also concluded that for IGA to occur, either the tubing oxide film is limited in its ability to protect against attack or no film is present. The ability of the Alloy 600 tubing to re-form its protective oxide layer is therefore important in its ability to protect against corrosion. Grain boundary chemistry effects on IGA and SCC have been investigated and it has been shown that surface passivation occurs more rapidly in the presence of precipitated carbides at grain boundaries than in the absence of carbides at the grain boundaries (Reference 21), which is more typically the case as observed for Palo Verde Unit 2 and 3 tubing material.

Recent studies by the French (References 28 and 29) have shown that sulfides or reducible sulfates can further inhibit the formation of a protective oxide film in deaerated caustic solutions but are not able to promote IGA in neutral solutions. The resultant nickel sulfide corrosion product is the most stable solid compound and thus no protective oxide layer can be developed. Therefore, in caustic environments, sulfates and reduced sulfate species can reduce or slow oxide film repair and enhance dissolution. These conditions are believed to have affected IGA growth rates for the Unit 2 steam generator tubing.

[illegible]

C. Findings / Conclusions

1) The corrosion detected on Unit 2 Steam Generator 2-2 bend section tubing was due to OD initiated axial orientated intergranular attack and intergranular stress corrosion cracking;

2) IGA and SCC were detected in tube freespan and batwing locations with the most severe attack associated with long narrow ridge deposits;

3) IGA was detected to have both axial and circumferential extent giving it a cellular nature;

4) The present chemical crevice conditions are considered to be near-neutral. However, caustic conditions with reduced sulfur species contributing to the corrosion attack are still considered to be primarily responsible for the degradation;

5) Additional contaminants such as lead, copper, silicon, sodium, magnesium and chloride, combined with a concentrating mechanism such as steam blanketing, contributed to the aggressiveness of the tube general and crevice deposits;

6) Burst test results showed burst pressures were substantially higher than $3\Delta P$ and 1.4 times MSLB pressures as specified by Reg. Guide 1.121 requirements;

7) Scratches and wear scars under concentrating ridge deposits were present and were often identified as preferential sites for IGA and SCC;

8) Tubing microstructures were found to contain random carbides with discontinuous or some semi-continuous grain boundary carbides, indicating less than optimum resistance to stress corrosion cracking.

D. Unit 3 Tube Examination Results

The scope and process description of the metallurgical examination and subsequent evaluation of tubes removed from the Unit 3 ARC Region during U3R4 are discussed in detail in References 14 and 19. Two (2) Unit 3 tube bend sections, tubes R152L73 and R154L73, were removed and delivered to ABB-CE for laboratory examination. Tube R152L73 contained a suspected volumetric indication (SVI) on the intrados of the tube just above the batwing support contact area, but below the bend tangent point. Tube R152L73 did not have an eddy current indication, but was removed to allow access to the tube of interest. As discussed in Reference 14, the results of the examination found that:

- There was no IGA or IGSCC in tube R152L73 which was called SVI by field ECT
- The SVI was approximately $2\frac{3}{16}$ inches long and 1/4 inch wide and had a depth of approximately 26%
- The SVI exhibited a general corrosion process under a ridge-like deposit which concentrated impurities in the bulk water
- There was no evidence of active wear caused by repeated tube-to-tube contact
- The microstructures of the tubes examined were not typical of Alloy 600 with good resistance to stress corrosion cracking

V. REGULATORY GUIDE 1.121 ANALYSIS

A. Introduction

In Reference 4 and subsequent discussions with the USNRC Staff, APS committed to provide analyses for Units 1 and 2 regarding operating cycle length based on Regulatory Guide 1.121 structural limits. In Reference 6, APS submitted the results of an evaluation of the circumferential PWSCC observed in Unit 1. In this section the results of analyses performed by Packer Engineering and APS to address the presence of ARC Region ODSCC in Units 1 and 2 respectively are provided. The completed report by Packer Engineering is provided as Appendix A. The analytical approach selected for Unit 1 utilizes an enhanced methodology similar to the Reference 6 report regarding PWSCC. Additionally, APS elected to conduct an independent statistical analysis of the Unit 1 inspection results utilizing the BALIFE computer code by APTECH.

Due to the considerable effort associated with incorporating all the relevant data from the U2M5-1 tube examinations, APS chose to perform the Unit 2 analysis based on tube pull data from U2R4 and bobbin coil rather MRPC detection capability. Credit for enhanced MRPC detectability, reduced temperature operation, and chemical cleaning was not taken due to the current commitment to inspect after six months.

B. Unit 1 Probabilistic Model - ODSCC ARC Region

As previously stated, the evaluation conducted by Packer Engineering (Begely et. al) is provided as Appendix A to this report. The following information summarizes the model description and results.

1. Model Description

The Unit 1 analytical model was developed by Packer Engineering to address upper bundle axial ODSCC as it applies to the Unit 1 steam generators. Based on past inspection results for Units 2 and 3 at Palo Verde, the detection of secondary side stress corrosion cracks in the ARC region of Unit 1 may occur at some future date. The following discussion provides a description analysis of the probability of axial ODSCC in Unit 1 leading to the exceedance of Regulatory Guide 1.121 structural limits. The probability of structural limit exceedances is estimated as function of run time using a conservative approach.

The approach selected by APS and Packer Engineering for Unit 1, models the historical development of cracks, crack growth, detection of cracks and subsequent removal from service and the initiation and growth of new cracks during a given cycle of operation. Past performance of all Palo Verde Units as well as the historical performance of other steam generators was considered in the development of cracking statistics for

[illegible]

application to Unit 1. Data in industry literature and the Unit 2 pulled tube examination results from U2R4 and U2M5-1 were used to construct probability of detection curves for the detection of axial IGSCC/IGA using an MRPC eddy current probe. Crack growth rates were estimated from Unit 2 eddy current inspection data combined with pulled tube examination results and corrosion data in industry literature.

2. Background

Although detailed information regarding the causal factors involved in ARC region ODSCC, as well as recent inspection results for all the PVNGS units are described in References 2,3,4, and 14 submitted to the USNRC Staff, a summary of these submittals as applied in the Unit 1 model is provided below.

Axial cracking of steam generator tubing in the upper bundle region of steam generators at PVNGS was first detected in 1991 in Unit 2 during the U2R3 outage. A 100% eddy current inspection of the upper bundle using a bobbin coil probe revealed a single axial indication, and two other indications which were later classified as axial crack like indications. In the U2R4 outage, following a tube rupture event, eddy current inspection of a total of 8000 tubes using MRPC eddy current probes revealed a total of 122 axial indications, with 104 in SG 2-2 and 18 in SG 2-1.

Examination of tubes pulled from Unit 2 following the steam generator tube rupture in U2R4 showed the degradation to be a combination of intergranular stress corrosion cracking and intergranular attack on the outer diameter of the tubing. IGSCC/IGA was observed in the vicinity of upper bundle eggcrate and batwing supports and in free span locations. Cracking at free span locations was typically associated with long narrow ridge deposits. Occasionally these deposits were observed to bridge adjacent tubes. Bridging/ridge deposits, apparently encouraged by diminished tube separation, are considered to act as crevice sites, capable of concentrating aggressive chemical species. Upper bundle IGSCC/IGA was also found to be confined to an analytically defined region of high mass flow and high quality where film boiling and dryout was indicated. These conditions favored deposit formation and concentration of chemical species.The root cause analysis performed by APS attributed the IGSCC/IGA degradation to caustic/alkaline environments in eggcrate, batwing and tube to tube crevices and similar conditions under bridging/ridge deposits. Reduced sulfur species, OD tube scratches, and less than favorable Alloy 600 metallurgical structures were found to be exacerbating factors.

Axial indications have also been found in the ARC region in Unit 3. After 4 cycles of operation, an MRPC inspection of a total of 1975 tubes revealed 17 axial indications. When normalized to the same inspection sample size as the Unit 2 inspection during the U2R4 outage, a total of 55 axial indications would have been expected. At comparable points in their operating histories, taking into account the learning curve for MRPC inspection procedures, Unit 3 has experienced about 25% of the extent of upper bundle IGSCC/IGA as Unit 2.

The midcycle MRPC inspection of Unit 2 after about 4.5 cycles of operation, U2M5-1, revealed additional axial indications. However, of the 86 axial indications detected prior to chemical cleaning, all but one (1) were determined to have been present at the end of the previous cycle. At this point, chemical cleaning was conducted. A combination of increased analyst experience and training, equipment improvements relative to the U2R4 outage and removal of deposits by chemical cleaning then led to the detection of a total of 330 axial indications. These confounding variables complicate the analysis of the rate of appearance of new indications. However, analysis of eddy current data in terms of crack growth rates points to the effectiveness of temperature and power reductions and elevated hydrazine levels in mitigating IGSCC/IGA degradation rates. As stated previously, analysis of pulled tube data (crack face oxide compositions) also point to a lessening of aggressive chemical conditions in the last 4.5 months of operation.

No axial indications have been observed in the ARC region of the Unit 1 SGs after 4 operating cycles. MRPC inspections of a total of 5038 tubes in the upper bundle ARC region did not reveal a single axial indication. In terms of the onset of upper bundle IGSCC/IGA, Unit 1 clearly is superior to Unit 2. The quantitative implications of the inspection results for Unit 1 are utilized in the Appendix A report. As discussed in a previously, Unit 1 has a consistently better record of molar ratio values compared to Units 2 and 3, with an obvious implication of less aggressive crevice chemistries. Although the three units have a similar history of sulfate levels, only Unit 2 experienced a significant resin intrusion. In terms of the expected behavior of Unit 1 for the present cycle, boric acid treatment of the secondary side was initiated at the beginning of the cycle, and molar ratio control via ammonium chloride injection was instituted five months into the operating cycle. Both of these factors are expected to mitigate the development of aggressive crevice chemistries. While Unit 2 pulled tube metallurgical studies indicated less than favorable metallurgical structures relative to caustic IGSCC, there is an indication the steam generator tubing in Unit 1 may be more resistant to caustic IGSCC/IGA. Five percent of the tubes in Unit 2 exhibit flow strengths higher than the highest strength tube in Unit 1.

In summary, there are chemical (as previously described) and possible metallurgical factors which are consistent with superior resistance to upper bundle corrosion degradation of Unit 1.

3. Statistical Approach

The probabilistic Reg Guide 1.121 model developed for the Unit 1 ARC Region ODSCC RG 1.121 analysis is similar to that developed by ABB-CE for circumferential cracking at the tube sheet and is designed to reflect four basis processes:

- Freespan Cracking
- Crack Growth
- MRPC Probability of Detection
- Repair-removal of defect from service

Each of these processes, with the possible exception of repair, has large components of associated uncertainty. This characteristic requires the implementation of a fully probabilistic overall model in order to realistically assess the permissible operating/ inspection periods for the Palo Verde Unit 1 generator. Enhancements to the probabilistic modeling include incorporation of material property distributional effects and flaw length distributional effects obtained from Unit 2 mid-cycle outage data analysis. In addition, an improved probability of detection function (POD) was incorporated into the model.

Crack Initiation and Growth Models

The crack initiation process is simulated by the well-known Weibull time-to-failure function given by:

$$F = 1 - exp\left[-\langle\frac{t}{\theta}\rangle^{\beta}\right]$$

Where

F - Fraction of the tube population that has failed at time t

θ - Characteristic Value: The characteristic value is an adjustable parameter of the Weibull Distribution and is measure of the typical time to failure, similar to the mean value of a normal distribution. The characteristic value is the time at which 63.2% of the population has failed. The characteristic value is selected to optimize the fit of the distribution to the existing failure data.

β- Slope (Shape Parameter): The slope of a Weibull distribution is an adjustable parameter that is selected to make the distribution fit the failure data as well. The slope

parameter controls the slope of the cumulative distribution function. The slope is a measure of the dispersion or scatter in the failure times. Typical slopes for steam generator degradation range from $1<\beta<6$. Low slopes such as $\beta=1$ represents the case of a constant failure rate. This case indicates large dispersion in time-to-failure and no aging effect, whereas high slopes such as $\beta=5$ are indicative of low dispersion and rapid aging.

Reference 15 provides an extensive catalog of Weibull parameter estimates based on worldwide operating plant data. This of course represents data from cracks which have progressed well beyond initiation into the detectable regime. It can be experimentally shown, however, that this represents only a time delay function for reasonable crack growth rate distributions which can be easily accommodated by a minor adjustment to the scale parameter (θ).

For Palo Verde Unit 1, which has experienced no upper bundle axial cracking as of the most recent inspection, Weibull parameters were developed from Unit 2 behavior. The shape parameter (β)used in the analysis has a relatively conservative value of 5.5 typical of IGSCC/IGA phenomena in HTMA tubing. The scale parameter (θ) was developed on the basis of null inspection results for the U1R4 inspection outage. The value of the scale parameter ultimately chosen is in fact the lowest (most conservative) value for which the Weibull model would predict a zero incidence of axial cracks at reasonable probability (5%).

Inspection/Repair Model

Inspection results from U2R4, U2M5-1 and U3R4 have demonstrated that the MRPC probes represent an improvement in detection of ODSCC axial cracks. Therefore, simulation of the inspection/repair process requires the probabilistic implementation of a probability of detection function (POD) for MRPC. For this purpose, a new POD function developed by Mr. Steve Brown of Packer Engineering was included in the simulation. Implementation of the inspection process is straightforward. At a given inspection time, each of a group of active cracks is subjected to a probability of detection function. Corresponding to each crack is a POD based on the function. A uniformly distributed random number is chosen to decide if a given crack is detected. If the crack is detected, it is removed from further service or subsequent inspection.

Material Properties and Crack Length Effects

The most significant differences between the axial and the circumferential cracking simulations performed in Reference 6 involve the inclusion of material and crack length effects. The material property effects are included by obtaining randomized flow stress values specific to Unit 1 tubing based on Certified Material Test Reports (CMTRs) from the original tubing manufacturer. The crack length effects are included by sampling from Unit 2 MRPC measurements. In both cases, the probabilistic effects are reflected as distributional terms in the implementation of Reg Guide limits for axial cracks.

Operating Cycle Length Evaluation

The Palo Verde Unit 1 operating cycle length evaluation consists of a simulator case run for Unit 1 operating conditions of 611 °F for periods varying from 200 day operation to 425 day operation. Specific newly implemented model capabilities included:

- Improved POD function for axial cracks
- Unit 1 specific tube material property distribution
- Axial crack length distribution (from Unit 2)

All cases were run with a POD function which permitted detection of no cracks with average depths less than 5% through wall and permitted detection of all cracks with average depths greater than 75% through wall. For the purposes of crack initiation, a temperature correction was performed using an activation energy of 50 Kcal/mole. For crack propagation an activation energy of 30 Kcal/mole was used. The allowable operating cycle length can be obtained from the case set results using a probabilistic acceptance criterion. For each case set the following example acceptance criterion was applied:

> ***There must be a 90% probability that one or fewer tubes will be expected to violate RG 1.21 limits for axial cracks during the current operating period.***

The results given in the Appendix A report show an acceptable full cycle operating period of 425 days for Palo Verde Unit 1 based on the above criterion. These results are specific to axial cracking in the upper bundle area.

C. Independent Evaluation - Unit 1

Currently, APS utilizes the BALIFE computer code developed by APTECH to perform long term statistical analyses for evaluating the effects of repair and remedial measures on steam generator life. The BALIFE code applies rigorous Bayesian reliability estimation methods to the prediction of failure frequencies from life- or age-to-failure data. The code allows the user to develop a "prior" distribution such as a Weibull curve to establish a baseline for a typical industry damage mechanism. Plant specific data can then be used to calculate a "likelihood" function which allows APS to estimate the probability of a specific value of the Weibull slope in light of PVNGS specific failure data. Finally, a "posterior" distribution is calculated as the product of the "prior" and "likelihood" functions. The code has been verified by APTECH by comparing the BALIFE and exact solutions for several "textbook" classical and Bayesian problems.

The BALIFE code has also been utilized by APS for assessing the probability of Reg Guide exceedances as a self-check of more detailed analyses. Such an analysis was performed by APTECH for ARC Region ODSCC in Unit 1. The key assumptions developed for this analysis are summarized below.

- Weibull scale and shape parameters for SG 2-2 were utilized in the Unit 1 analysis. This assumption is considered conservative based on past operating and inspection history from Unit 1

- Credit was taken for operating Unit 1 at a T_{hot} of 605 °F during the first seven months of Cycle 5 operation. However, no credit for temperature reduction was taken for the remainder of cycle. The analysis was performed for the original design temperature of 621 °F.

- Instead of treating the U1R4 inspection as a null data set based on the fact that no ARC Region ODSCC defects were found. APTECH followed a classical statistical estimation method which amounts to pessimistically assuming that one (1) MRPC detected defect existed.

- The MRPC POD curve developed by Packer Engineering was utilized in the analysis to obtain a 95% confidence interval estimate. The POD Curve (Figure V-1) indicates that there exists a 40% chance of finding a 25% average through-wall flaw with MRPC. APTECH then determined the number of such cracks which could have been present during U1R4 such that there was a 5% chance of missing all the defects.

That number is approximately six (6) (since $(1-0.4)^6 \cong 0.05$. Therefore, the assumed 95% upper confidence forecast allows for six 25% through-wall defects at the U1R4 even though none were found.

The results of the analysis are presented in Table V-1. The BALIFE forecasts are probabilities for 64+% cracks over the next two cycles. As a comparison to the results for the Packer Engineering analysis, the 95% confidence bound indicates that there is a 92% probability of one or fewer Reg Guide exceedances for full cycle operation in Unit 1.

Table V-1: Results of BALIFE Analysis

Type of Analysis	% Chance of Zero 64+% Cracks	% Chance of Exactly One 64+% Crack	Chance of more than one 64+% Cracks
Best Estimate for Current Operating Cycle	94	<6	0.3
95% Confidence Bound Estimate for Current Operating Cycle	73	19	8
Best Estimate for Next Two Operating Cycles	80	16	4
95% Confidence Bound Estimate for Next Two Operating Cycles	41	24	35

[illegible] [illegible] [illegible] [illegible]

D. Unit 2 Upper Bound Probabilistic Model

In Reference 4, APS committed to provide a probabilistic assessment of the Unit 2 operating cycle based on the results of the U2M5-1 ECT inspection. The analysis is intended to demonstrate that the structural limits specified in Regulatory Guide 1.121 are met for the six month operating period currently underway in Unit 2. Prior to restart of Unit 2, APS committed to a six month run time based on the premise that the indications found in the U2M5-1 inspection are bounded by the crack growth rate established from the inspection following the rupture of tube R117L144 (U2R4). This assumption requires that the corrosion environment and eddy current inspection criteria are constant or improving. This assumption can be verified via a statistical treatment of the results.

Due to the considerable effort associated with incorporating all the relevant data from the U2M5-1 tube examinations and incorporation of additional post-chemical cleaning data sets via implementation of the integrated outage assessment program, APS elected to perform the Unit 2 analysis based on tube pull data from U2R4 and bobbin coil rather than MRPC detection capability. Credit for enhanced MRPC detectability, reduced temperature operation, and chemical cleaning was not taken due to the current commitment to inspect after six months.

1. Model Description

Regulatory Guide 1.121 provides the requirements for evaluating the structural integrity of degraded steam generator tubing. The requirements are designed to maintain specific margins for degraded tubing against rupture. In the Unit 2 Cycle 5 evaluation, analyses are performed, considering crack growth rate and eddy current bobbin coil detection thresholds, to determine the length of the current operating interval such that the safety margins specified in Regulatory Guide 1.121 will continue to be maintained. The results of the analysis indicate that a six month operating interval can be supported.

<u>Acceptance Criteria</u>
A statistical analysis to determine the duration of the current operating interval requires quantification of the acceptance criteria specified in Regulatory Guide 1.121 to determine the maximum allowable crack size. APS provided the results of this evaluation in Reference 3. The calculation utilized a burst correlation developed for EPRI by Framatone described in EPRI report NP-6865-L "Steam Generator Tube Integrity, Volume 1" (Reference 16). Using this correlation, the maximum allowable crack depth as a function of crack length can be determined as illustrated in Figure V-2. The Framatone correlation was selected since it has been shown to provide the best comparison with available burst test data for long cracks. Figure V-2 also shows the 90% confidence interval confidence bands on the R.G. 1.121 acceptability criteria; the confidence bounds are based on an analysis performed using experimental data correlating observed burst pressure

[illegible]

vs. the Framatome model predicted burst pressure. It should be noted that the Framatome correlation has been shown to be overly conservative for short cracks, i.e., less than approximately 0.349 inches long that approach through-wall depth. Therefore, APS uses an EPRI correlation developed in EPRI Report NP-6864-L "PWR Steam Generator Tube Repair Limits" (Reference 17) for determining RG 1.121 compliance for short flaws. This correlation indicates a through wall flaw less than 0.349 inches long will maintain the required safety margins against rupture.

<u>Statistical Analysis To Determine Length of Current Operating Interval</u>

As recommended by the USNRC Staff in their Safety Evaluation Report (SER) dated August 19, 1993 of the Unit 2 Steam Generator Tube Rupture Evaluation Report, APS has evaluated statistical methodologies to evaluate uncertainties and to provide a more realistic assessment of tube integrity margins than what can be achieved through a deterministic approach alone. A deterministic approach was used by APS to determine the length of the first Cycle 5 operating interval.

The following paragraphs describe the basic methodology used in the statistical analysis developed to define the current operating interval in Unit 2.

<u>Crack Distribution and Crack Growth Rate Determination</u>

The distribution of cracks (i.e. the number of cracks at any given depth or length) that exists in a steam generator can be determined by statistically combining the as-detected crack distribution, in terms of depth and length, with the probability of detection (POD). This resulting statistical distribution describes the number of "real" cracks, at any given depth or length, both detected and undetected. If distributions are determined for successive inspections, the crack growth rate distribution and the rate at which new cracks are being initiated can be determined.

The length distribution of the as-detected cracks is formed by obtaining the length, as measured by MRPC, of each bobbin detected crack. The depth distribution is formed by first obtaining the depth information for all cracks in which bobbin depth calls can be made. These depth calls are then converted to average crack depths using a correlation developed from the U2R4 pulled tube samples. However, the large majority of cracks in Unit 2 which were detected by bobbin are not measurable (NQI). The NQIs within each discrete length interval are then distributed amongst the discrete depth intervals.

Having determined the length and depth distributions of the as-detected cracks in this manner, the real cracks distributions are determined by combining with the appropriate bobbin POD curve. The real crack distribution, thus, consists of both the detected and undetected by bobbin crack populations. This analysis uses a POD curve derived from Fig. 3.39 in NUREG/CR-5117.

This process of forming the length and depth crack distributions is performed using the results of the U2R4 and the current Cycle 5 mid-cycle inspection (U2M5-1). The U2R4 distribution is then updated by removing from the distribution those tubes that have been plugged, including the large population of tubes which have defects detected by the more sensitive MRPC technique. Thus, the number of tubes removed from service is greater than the number of tubes with defects detected by the bobbin coil technique.

Sufficient information has now been developed to estimate the initiation rate (cracks/month) at which new crack sites are being produced on the SG 2-2 tubes. This is done by comparing the number of estimated "real" cracks at successive inspection. For example, comparing the number of real cracks at U2M5-1 to the number of real cracks at EOC-4 following plugging provides an estimate of the number of new cracks that initiated during the operating interval. Dividing the number of new cracks initiated by the duration of the operating interval results in an estimate of the rate at which new cracks are formed. The new crack sites initially start at essentially zero depth and subsequently grow in depth and length based on the operating time and the through-wall depth and axial length crack propagation rates.

The Monte-Carlo technique is then used for calculating the through-wall and axial crack propagation rate probability distributions. For the through-wall crack propagation rate, a correlation was developed from U2R4 pulled tube data which relates MRPC voltage to average crack depth. The regression analysis takes full account of the statistical uncertainties (see Figure V-3). The correlation is used to establish from the U2R4 and U2M5-1 MRPC voltage data of individual axial indications, the growth exhibited by these indications from U2R4 to U2M5-1. This information together with the correlation shown in Figure V-2 was used to perform a 50,000 histories Monte-Carlo simulation to determine the through-wall crack propagation rate. The resulting cumulative distribution function (CDF) shows a mean through-wall crack propagation rate of 0.61 mills/month, and a 95% confidence estimate of 1.60 mills/month.

The axial crack propagation rate was calculated differently than the through-wall rate. The real crack length distributions for U2R4 after plugging and U2M5-1 before plugging are arranged in a CDF. The U2R4 distributions are adjusted by adding additional "real" cracks to the first axial crack length intervals as necessary. This adjustment effectively amounts to adding cracks of zero length, in order to equalize the total "real" crack count between EOC-4 (following tube plugging) and M5 (before plugging). A Monte-Carlo simulation consisting of 50,000 histories samples the cumulative axial distribution function. As an outcome of these simulations the depth and length crack propagation rate probability distributions are generated.

Defect Population Considered In The Analysis

As can be seen by the above discussion, the process of determining the distribution of real cracks, both detected and undetected, is dependent somewhat on the applicability of the POD curve. However, a large percentage of the defects detected in the Unit 2 steam generators are located in the 90 degree square bends of the tubing. Industry experience indicates that bobbin coil detectability levels in the bend sections may be much less than the corresponding detectability levels for defects located in the vertical straight leg section of the tubing, therefore the POD curve is probably not applicable for defects located in the bends. Therefore, combining the as-detected distribution of defects, which contains the population of defects located in the bends, with a POD for which a large percentage of the population is not applicable would not be statistically meaningful.

To ensure that the population of defects included in the as-detected distribution is applicable to the POD curve used, only the defects located in the vertical straight leg sections of the tubing are utilized in the statistical analysis. This approach results in a more statistically meaningful analysis. This approach is considered acceptable if: (a) the beginning of cycle condition of the undetected defects in the tube bends is consistent with the straight sections; and, (2) the growth rates of defects located in the tube bends is consistent with the observed growth rates of defects located in the straight sections. APS believes that the beginning of cycle condition of the tube bends are consistent with the straight sections. Both the straight sections and the bends are inspected by MRPC techniques. An appreciable difference between MRPC detectability levels in the straight leg sections and the bend sections is not expected based on the mechanics of the rotating pancake coil probe. Therefore, cracks which go undetected (by MRPC) and are left in service at the start of the cycle in the bends are not any deeper than the undetected (by MRPC) defects left in the straight sections. Also, observation and field experience indicates that crack growth rates are not appreciably greater for defects located in the bends.

2. **Determination of the Unit 2 Operating Interval**

To determine the length of the current operating cycle, Monte-Carlo simulations were performed to propagate the "average depth real" cracks which remain following 2M5 tube plugging, or the beginning of cycle condition. In addition to these cracks, new crack sites of essentially zero depth were simulated to occur at the rate determined previously. All cracks were propagated both depth-wise and length-wise by using the crack propagation rate CDFs developed previously. In order to compile the required key results at each postulated Cycle 5 operating time, 50,000 Monte-Carlo histories are collected during each simulation; this large number of simulations minimizes the statistical uncertainty resulting from finite sampling. In this manner, the probability of a crack exceeding specific critical combinations of crack depth and length, based on the

Framatone burst correlation are used to determine the Unit 2 maximum allowable crack size. All results are determined at 50%, 90%, and 95% statistical confidence levels; the resulting mean is also determined.

The Monte-Carlo simulations performed by APS fully support a six month operating interval for Unit 2. The Reg Guide 1.121 safety margins are met for this operating interval, i.e. 90% confidence of less than 1 cracks exceeding 65% average through-wall depth following six months operation at full power. Since Unit 2 has been operated at a power levels below 100%, e.g., 85% to 89%, for most of the operating cycle, it is expected that this interval could be extended beyond six months as a result of lower tube temperatures and prevailing dryout conditions. This however has not been evaluated given that a commitment is already in place to perform an inspection at six months.

VI. PVNGS INTEGRATED OUTAGE ASSESSMENT PROGRAM

A. Background

Since the Unit 2 steam generator tube rupture in March 1993, APS has conducted two extensive ARC Region inspections in Unit 2 (U2R4 and U2M5-1), a single inspection in Unit 1 (U1R4) and two inspections in Unit 3 (U3M4 and U3R4). These inspections have provided considerable information on the behavior of ARC Region ODSCC. Additionally, APS has performed three (3) tube removal and examination activities of tubes from Units 2 and 3. Further midcyle inspections are planned in Units 2 and 3 during Cycle 5 operation. It is a reasonable expectation that the improvements in secondary chemistry, temperature reduction and the performance of chemical cleaning will permit a return to full cycle operation of all the PVNGS units. APS has reviewed the expected cycle and outage durations through 1996. The purpose of integrating planned outages, analytical evaluations, tube inspections and remedial/repair activities is to meet the following safety and economic objectives.

- In order to limit safety issues associated with equipment and personnel resources, APS plant management avoids conducting simultaneous outages of the PVNGS Units.
- Cycle lengths are dependent on demonstrating the structural integrity limits of steam generator tubing as defined in Regulatory Guide 1.121.
- An assessment of the safety consequences of performing midcycle outages
- An assessment of tube failure risk as a function of graduated increases in inspection interval

1. Outage Schedule

In order to meet these objectives the outage schedule depicted in Figure VI-1 is the expected operating cycle and outage lengths for the three PVNGS units through the end of 1996. Of special interest are the relationship of inspection results for all three units over the next nine months. As indicated, U2M5-2 midcycle inspection is scheduled to take place in September 1994. This inspection represents the first opportunity to evaluate post-operational benefits of chemical cleaning after six months of operation. The U2R5 inspection will be conducted in February 1995 representing nearly four additional months of operation. In an effort to meet the objectives describe above and to minimize the effect of the Cycle 5 inspections on future outage scheduling, APS elected to design the Unit 2 Cycle 6 core for a 12 month operating length rather than the typical 15 month designs.

Unit 3 will be shutdown in November 1994 for a midcyle inspection after six months of operation following chemical cleaning. Unit 3 also implemented a T_{hot} reduction program of 10 °F at 100% power during this period. It is expected that the results of this inspection will justify end of cycle operation until U3R5 in September 1995. This represents a nine (9) month operating cycle length.

Unit 1 resumed operation following U1R4 in November. The first seven months of operation Unit 1 was operated at 85% power at a T_{hot} of 605 °F. The unit was placed at approximately 100% power at a T_{hot} of 611 °F upon receipt of Technical Specification approval and implementation of setpoint changes. Based on the analyses provided in this report and in Reference 6, full Cycle 5 operation has been demonstrated. The timing of the U1R5 steam generator inspection in April 1995 will provide valuable data regarding the effectiveness of remedial measures implemented by APS.

This program of graduated operating cycles and integrated outages provides a significant database of operational effects and inspection results. This information is expected to demonstrate that full cycle operation can be safely justified and that the aggressive mitigating actions implemented at PVNGS are indeed effective.

2. Analytical Efforts

APS is continuing to refine and improve the analytical techniques as part of our integrated strategy. The laboratory tube examination results and aggressive inspection programs provide valuable input into the probabilistic models utilized in RG 1.121 structural assessments. Areas in which APS intends to incorporate upcoming inspection results with model enhancements include:

1. Development of MRPC Voltage/Length to Burst Pressure Correlation using approaches similar to the industry Defect Specific Management (DSM) effort.

2. Development of a multi-population model based on statistical treatment of ECT results which indicate that crack indications identified in U2R4 and U2M5-1 occur disproportionately among tubes within the ARC Region

3. Improvement of thermal/hydraulic models to demonstrate the effectiveness of steam generator modifications and the effects of repair/ remedial measures.

4. Assessment of the MRPC technology to accurately reflect crack profiles. This effort includes the use of additional UT examinations and crack discretization via deconvolution.

5. Assess tube failure risk reduction as a function of graduated increases in inspection interval, including further development of inspection uncertainty model to estimate the probability of missing cracks with a multiple level inspection program of bobbin and MRPC as well as primary and secondary analysis of both inspection techniques.

APS intends to incorporate the results of the U2M5-2 and U3M5 into these approaches; not only in the form of a self-check, but also to demonstrate adequate safety margin to support a nine (9) month operating cycle for the balance of Unit 3 Cycle 5 and 12 month Cycle 6 operation in Unit 2. The schedule for an updated submittal to the USNRC Staff is January 1995.

4. Unit 1 Midcycle Risk Analysis

The PVNGS Reliability and Risk Analysis group is currently performing a risk analysis associated with continued Unit 1 full-cycle operation. This analysis includes evaluation of Unit 1 core damage risk due to the potential for SG tube degradation in excess of Reg Guide 1.121 limits as indicated by the Unit 2 SGTR event.

Analysis methodology provides for comparison of the core damage risk associated with Unit 1 continued plant operation versus mid-cycle shutdown for steam generator tube inspection. This analysis estimates the risk resulting from the following scenarios: 1) Continue power operation through the current 15 month run time, and 2) Conduct a mid-cycle shutdown to perform SG tube inspections (requiring mid-loop operations). The study also provides analysis of public safety impact/consequences for at-power conditions.

The final analysis described above is in progress, awaiting input from independent sources related to expected SGTR frequency for single/multiple tube rupture events, as well as updated information on proposed Unit 1 outage schedule.

Based on results of preliminary analysis for Unit 1, it is expected that final results will indicate approximately equivalent core damage risk between Unit 1 full-cycle operation and mid-cycle shutdown. In addition, it is expected that the public safety impact analysis will indicate that Palo Verde would not exceed SECY 89-102 Safety Goal Objectives for continued power operation. These expectations are also supported by results of a similar analysis previously performed for PVNGS Unit 3 (Study: 03-NS-A49, January 1994). The completed results of the Unit 1 analysis will be available for presentation to the USNRC Staff in August 1994.

VII. OPERATIONAL RESPONSE

A. Leakage Monitoring and Procedural Control

APS has incorporated an integrated leakage monitoring program, utilizing equipment and procedure upgrades, to permit plant operators can detect and respond to changes in steam generator primary-to-secondary leakage, and shutdown the unit prior to a significant leak or steam generator tube rupture should unexpected tube degradation exceed expected values. The program is designed to provide clear and unequivocal plant management support to commence orderly shutdown to ensure leakage does not exceed very stringent administrative limits. APS has endeavored to ensure that adequate staff, equipment and organizational resources are in place to implement this program, using a combination of radiation monitors and laboratory radiochemical analyses. The program also includes outage activities which ensure that all detected SCC defects are removed from service. A summary of the integrated plan is provided below.

Inspection Program

A comprehensive steam generator inspection program reduces the risk of leaving a significant defect(s) in service. In the areas of interest at the tubesheet and the ARC region, 100% bobbin coil inspections have been conducted. In most cases a similar 100% MRPC inspection of the affected region has been conducted. As demonstrated in the probabilistic assessments performed in this report, this level of inspection is statistically significant in terms of preventing through-wall defects.

Plugging Criteria

Before the steam generators are returned to service, a review by APS Engineering of all eddy current indications is conducted. Regardless of size or depth, all tubes with detected cracks are removed from service. This action assures that any possible leakage is not a result of known defects left in the generator.

Equipment Upgrades

As reported in References 3 and 4, APS has implemented upgrades in leakage monitoring equipment to provide plant operators with enhanced diagnostic tools. These upgrades have now been implemented in all three PVNGS Units. They include:

Steam Generator Blowdown Radiation Monitors (RU-4 & RU-5)

The blowdown monitors currently monitor the downcomer flowstreams rather than hot leg blowdown to provide greater sensitivity for detection and response to primary to secondary leakage.

[illegible]

Condenser Vacuum Exhaust Monitor (RU-141)

The CVE Monitor has been changed to an in-line monitor, and a graph of monitor reading verses leak rate is trended.The alert setpoints for the CVE Monitor were decreased to four (4) times background to provide earlier alarms to plant operators in the event of increasing primary leakage.

N-16 Monitors

N-16 monitoring systems have been permanently installed in all three units to provide an additional diagnostic tool for primary-to-secondary leakage detection. The design incorporates sodium iodide crystal detectors connected to the existing radiation monitoring system. The detectors are located on the main steam lines (4 per unit) in the Turbine Building and are connected to the condenser exhaust high-range effluent monitor (RU-142), which had been abandoned in place when the condenser vacuum exhaust was routed to the plant vent. Existing control room alarm and indication capabilities were utilized.

Procedural Upgrades

The current leak rate limits at PVNGS were developed in response to the Unit 2 tube rupture event in March 1993. An administrative maximum shutdown limit was set at 50 gpd, well below the Technical Specification limit of 720 gpd. It should be noted, that review of the available data prior to the tube rupture event, that the new administrative limits would have resulted in an orderly shutdown prior to tube rupture.

The administrative limits, as well as, a leak rate hierarchy are proceduralized in PVNGS Station Manual Procedure 74DP-9ZZ05, Abnormal Occurrence Checklist. The hierarchy includes:

1. Leak Rate < 10 GPD: Monitor and perform accurate leak determinations shiftly. Inform the Control Room of all leak rate calculation results. Additionally, the CVE Monitor is trended shiftly. If an increase of three-fold is observed, Step 2 is entered. Finally, alarm setpoints for RU-141, as well as RU-4 and -5 are evaluated daily.

2. Leak Rate 10-50 GPD: Monitor and perform accurate leak determinations shiftly. Inform the Control Room of all leak rate calculation results. Additionally, if a increase in leak rate by 50% is observed within a 24 hour period or less, or the leak rate is greater than 25 GPD, formation of an evaluation team is required to address continued operation. Additional monitoring of RU-141, RU-4 and RU-5 is also required.

3. Leak Rate > 50 GPD: Following verification of the calculated leak rate by the most readily available method outlined in 74DP-9ZZ05, the Shift Supervisor initiates a plant shutdown, and then informs plant management.

APS believes the enhancements to the leak rate program provide the operators with sufficient information and direction to recognize a leak prior to break, regardless of whether the defect is axial or circumferential. The overall APS program is considered comparative to the program instituted by EdF. The French philosophy of extensive eddy current inspections, preventative plugging and strict leakage limits (≅ 32 GPD) has resulted in 600 reactor years without tube rupture. Based on typical calculational frequencies, six (6) significant leakage events could of occurred within this operational time frame. As stated previously a significant conservatism associated with the PVNGS philosophy, is a position that all detected cracks are removed from service, whereas EdF utilities are permitted to operate with known SCC defects in service.

Finally, as stated in Reference 5, extensive simulator training of operations personnel for tube rupture events and upgrades to the Emergency Operating Procedures also permit faster identification and isolation of the affected steam generator. Improvements in operator response assure that in the unlikely event of a main steam line break with consequential multiple tube ruptures, the resulting offsite doses are maintained less than 10CFR100 guidelines.

VIII. SUMMARY

The analyses and evaluations contained in this report demonstrate that the current operating and outage plans as illustrated on Figure VI-1 permit safe operation of all three Palo Verde Units. APS has applied an aggressive strategic program for correcting and/or managing the corrosion mechanisms associated with the PVNGS steam generators. These actions include:

- Temperature and/or Power Reductions have been implemented in all three PVNGS units to take advantage of the temperature dependence of SCC growth rates. Stress corrosion cracking is a thermally activated process, and the effects of temperature reduction can be quantified for SCC mechanisms in terms of activation energy for an Arrhenius rate equation.

- APS has removed 31 tubes from service, and has conducted extensive NDE and destructive examination in an effort to determine casual effects of corrosion damage, and to provide substantial improvements in field ECT acquisition and interpretation.

- APS has implemented the industry recommended secondary chemistry controls to mitigate the initiation and propagation of secondary side IGA/SCC. The laboratory evidence from tubes removed from Unit 2 during U2M5-1 show a potential favorable change in crack crevice chemistry tending towards neutral conditions. APS has exceeded EPRI action levels for sulfate by requiring reduced power operation or shutdown for sulfate levels as low as 20 ppb.

- APS has incorporated an integrated leakage monitoring program, utilizing equipment and procedure upgrades, to provide plant operators the ability to detect and respond to changes in steam generator primary-to-secondary leakage, and shutdown the unit prior to a significant leak or steam generator tube rupture should unexpected tube degradation exceed expected values. The program is supported by extensive steam generator inspections and conservative plugging criteria.

- APS with support from ABB-CE, Packer Engineering and APTECH has developed state-of-the-art probabilistic models

for assessing operating cycle lengths which maintain the safety margins specified in Regulatory Guide 1.121.

- APS conducted the first domestic full bundle chemical cleaning of a Recirculating Steam Generator (RSG) in Unit 2 during U2M5-1. Unit 3 was subsequently cleaned during U3R4 and Unit 1 is scheduled for cleaning during U1R5. The primary purpose of the chemical cleaning was the removal of ridge deposits from the ARC Region. The laboratory examinations of tubes removed post-chemical cleaning in Unit 2 indicate that the objectives were satisfied.

These actions are all part of a defense in depth approach employed by APS, to provide reasonable assurance that the PVNGS Units can be safely operated until the next scheduled shutdown for further steam generator inspections. This approach incorporates additional analyses which demonstrate that in the unlikely event of a main steam line break with consequential multiple tube ruptures, with the current administrative limits on reactor coolant system dose equivalent iodine, the resulting offsite doses are less than 10CFR100 guidelines. Additionally, APS has conducted updated training of operations personnel for tube rupture events and has developed upgrades to the Emergency Operating Procedures which permit faster identification and isolation of the affected steam generator.

IX. REFERENCES

1. USNRC Letter, *Summary of Meeting Held November 9, 1993, to discuss Unit 1 Steam Generator Eddy Current Test Results*, dated December 29, 1993

2. *Unit 1 Steam Generator Inspection Report - October 1993*, submitted to USNRC by letter, 102-02716-WFC/RAB/JRP dated November 2, 1993

3. *Unit 2 Steam Generator Tube Rupture Analysis Report*, Submitted to USNRC by letter, 102-02569-WFC/JRP dated July 18, 1993

4. *Unit 2 Steam Generator Inspection Report - Midcycle Outage*, submitted to USNRC by letter 102-02852-WFC/RAB/JRP, dated March 8, 1994

5. Letter, *Steam Generator Tube Evaluation*, 102-02585-WFC/TRB/RAB dated July 25, 1993

6. Letter, *Steam Generator Tube Regulatory Guide 1.121 Analysis for Primary Side Circumferential Cracking*, 102-3013-WCS/AKK/JRP dated June 20, 1994

7. USNRC Letter, *Restart of Palo Verde Unit No. 2 and Request for Information Under 10CFR50.54 (f) Regarding Steam Generator Tubes - Units No. 1,2, and 3*, dated August 19, 1993

8. NRC Inspection Report - 50-528, -59, -530, dated June 23, 1994

9. EPRI TR-102134, *PWR Secondary Water Chemistry Guidelines - Revision 3*, May 1993

10. *Evaluation of Iron Corrosion Product States*, EPRI Crevice Chemistry Workshop, Peter Millet, Boston, June 1993

11. EPRI TR-101010, *Correlation of Secondary Side IGA/SCC Degradation of Recirculating Steam Generator Tubing with On-line Addition of Boric Acid*

12. EPRI NP-5558, *Boric Acid Guidelines for Intergranular Corrosion Inhibition*

13. ABB-CE Letter, V-PENG-94-048, *Chemical Cleaning Experiment on PVNGS-2 Steam Generator Tube*, dated May 4, 1994

14. *Unit 3 Steam Generator Inspection Report, U3R4*, July 1994

15. EPRI NP-7493, *Statistical Analysis of Steam Generator Tube Degradation*, September 1991

16. EPRI NP-6865-L, *Steam Generator Tube Integrity - Volume 1*

17 EPRI NP-6864-I, *PWR Steam Generator Tube Repair Limits*

REFERENCES (cont)

18. NUREG/CR 5117, *Steam Generator Tube Integrity Program/Steam Generator Group Project*

19. *Examination of Palo Verde-3 Steam Generator Tubes Removed During the 1994 Outage, Final Report*, V-PENG-TR-004, dated July 1994

20. *Examination of Palo Verde Unit 2 Steam Generator Tubes*, M. Blaszkiewicz and W. A. Myers, Westinghouse, July 1994

21. Z Szklarska-Smialowska, *Factors Influencing IGSCC of Alloy 600 in Primary and Secondary Waters of PWR Steam Generators*

22. ABB-CE Report TR-MCC-272, *Examination of Steam Generator Tubes Removed form Palo Verde Unit 2 in 1993*

23. EPRI Report NP-4223, *Intergranular Attack of Alloy 600: Laboratory Investigations*

24. B.P. Miglin, et al., *The Role of Sulfur in the Corrosion of NSGs*, August 1989

25. EPRI Report TR-103756, *Examination of Crystal River Unit 3 Steam Generator Tube Sections*, April 1994

26. R. Bandy, R. Roberge, and D. van Rooyen, *Intergranular Failures of Alloy 600 in High Temperature Caustic Environments*, NACE, Volume 41, No. 3, March 1985

27. J.P.N. Paine, R.S. Pathania, C.E. Shoemaker, *Effect of Caustic Environment on Intergranular Attack and Stress Corrosion Cracking of Alloy 600*, Environmental Degradation of Materials in Nuclear Power Systems - Water Reactors, 1988

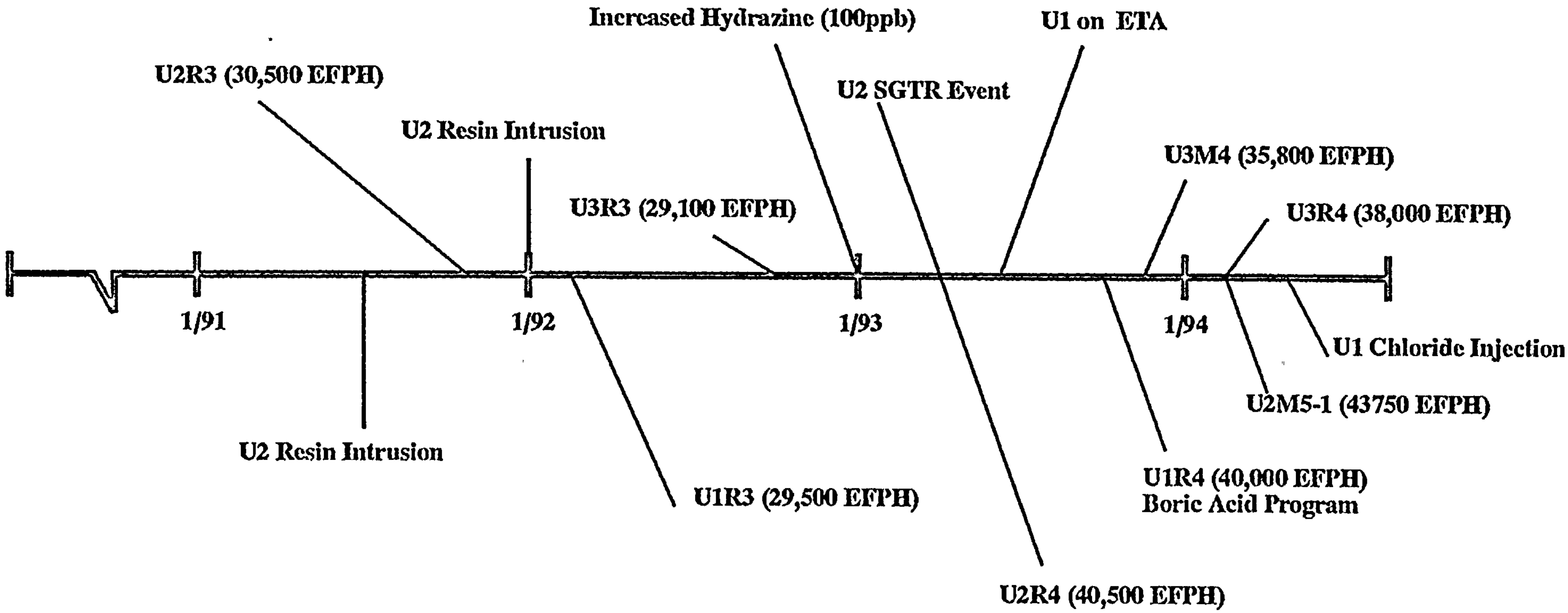
28. P. Combrade, O. Cayla, et al., *About the Role of Surface Films on Alloy 600 Corrosion in High Temperature Deaerated Environments*, Environmental Degradation of Materials in Nuclear Power Systems - Water Reactors, 1988

29. B. Sala, P. Combrade, et al., *Chemistry of Sulfur in High Temperature Water Reduction of Sulfates*, Environmental Degradation of Materials in Nuclear Power Systems - Water Reactors, 1988

30. Letter, *Midcycle Outage Schedule*, 102-03010-WLS/RAB/JRP, dated June 20, 1994

FIGURES

FIGURE III-1 TIMELINE OF INSPECTION AND CHEMISTRY MILESTONES



ECT PROGRAMS

U2R3 -100% Bobbin of SG - 3 ARC Region Defects
U2R4 - 100% Bobbin of SG/100% MRPC of ARC - 157 ARC Region Defects
U2M5-1 - 100% MRPC of ARC - 523 ARC Region Defects

U1R3 (100% SG 1-2, ~40% SG 1-1 Bobbin) - 0 Defects
U1R4 (100% Bobbin 100% MRPC ARC) - 0 Defects

U3R3 (~ 50-80% of Bobbin ARC) - 0 Defects
U3M4 (100% Bobbin ARC, 200 Tube MRPC) - 0 Defects
U3R4 (100% Bobbin ARC, ~ 1900 MRPC Total) - 17 Defects

10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 11
UBEND MRPC

DATE: 05/13/94
TIME: 08: 15: 45

CRITERIA: TUBES TO BE EXAMINED IN GROUP (S) 2, 4, 45, 46, 47, 48, 49, 50, 51, 52, 53

STAYS ▲

PLUGGED	74	X	07H-VS4	125	◆	08H-VS3	58	◆	07H-VS3	142	◆	08H-VS2	660	◆	07H-VS2	1 ◆
			08H-VS1	1372	◆	07H-BW1	8	◆							

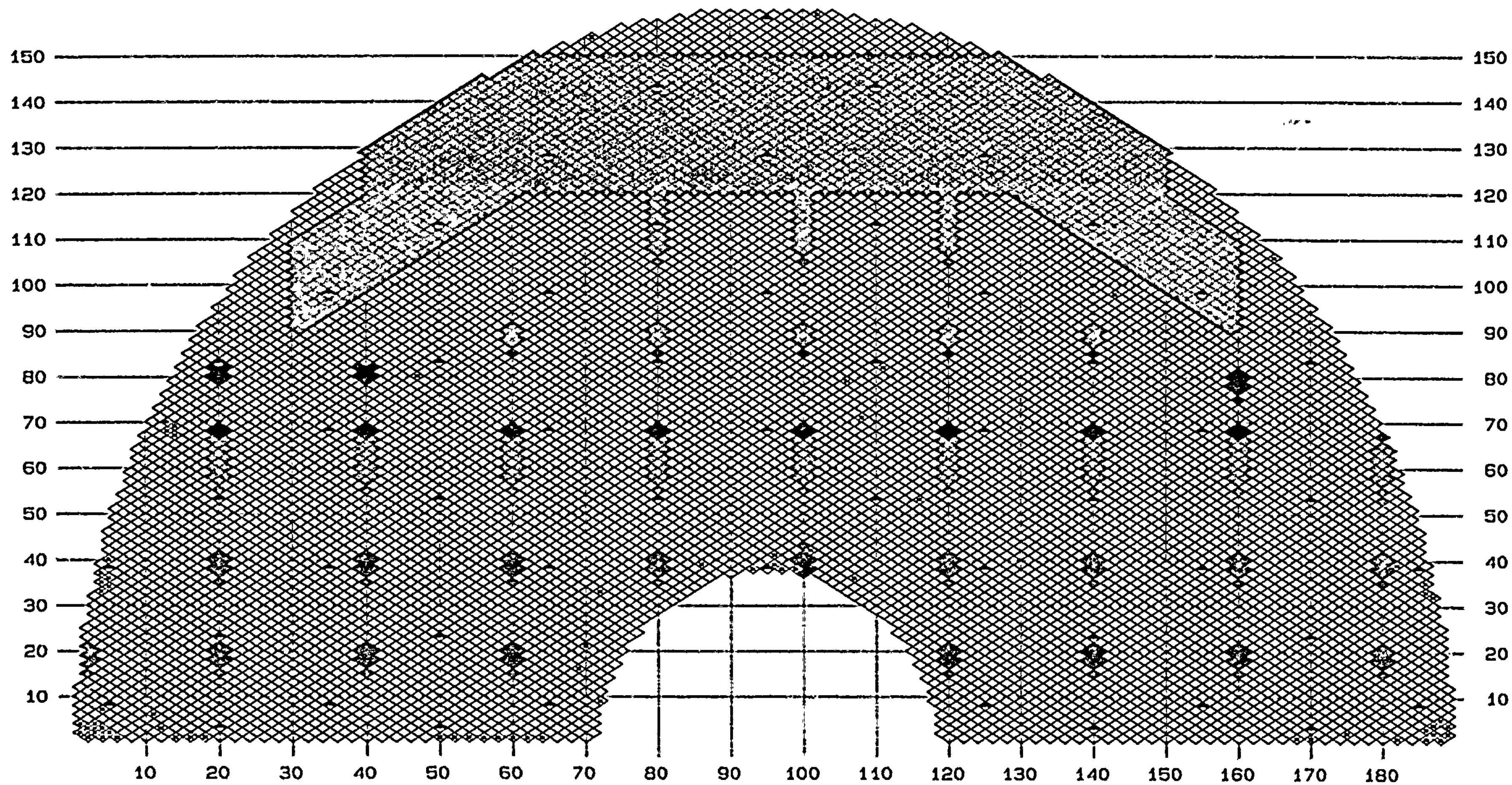


FIGURE III-2 SG 1-1 UPPER BUNDLE MRPC PROGRAM

CONAM NUCLEAR, INC. BW

10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
UBEND MRPC

DATE: 05/13/94
TIME: 08:19:54

CRITERIA: TUBES TO BE EXAMINED IN GROUP(S) 2, 4, 45, 46, 47, 48, 49, 50, 51, 52, 53

STAYS ▲

PLUGGED	67	X	07H-VS5	1	◆	07H-VS4	124	◆	08H-VS3	58	◆	07H-VS3	141	X	08H-VS2	659	◆
			07H-VS2	1	◆	08H-VS1	1367	◆	BW1-VS1	1	X	07H-BW1	8	X	TEH-TSH	1	X

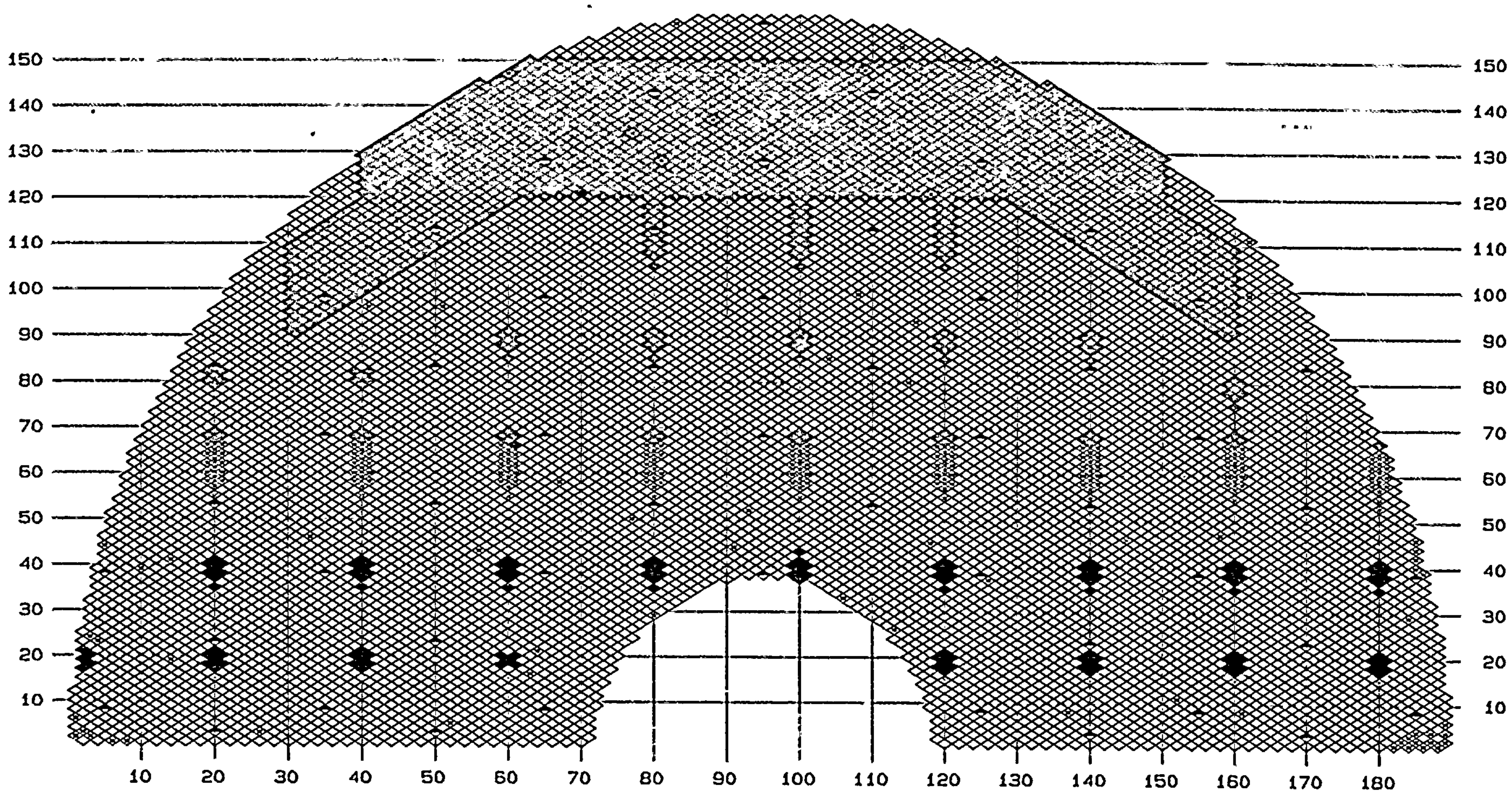


FIGURE III -3 SG 1-2 UPPER BUNDLE MRPC PROGRAM *CONAM NUCLEAR, INC.* BW

04/94, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 31
UBEND RPC

DATE: 08/02/94
TIME: 09:36:16

CRITERIA: TUBES TO BE EXAMINED IN GROUP(S) 12, 13, 14, 15, 81

STAYS ▲

PLUGGED 121 × 08H-VS3 59 ◆ 08H-VS2 73 ◆ 08H-VS1 315 ◆

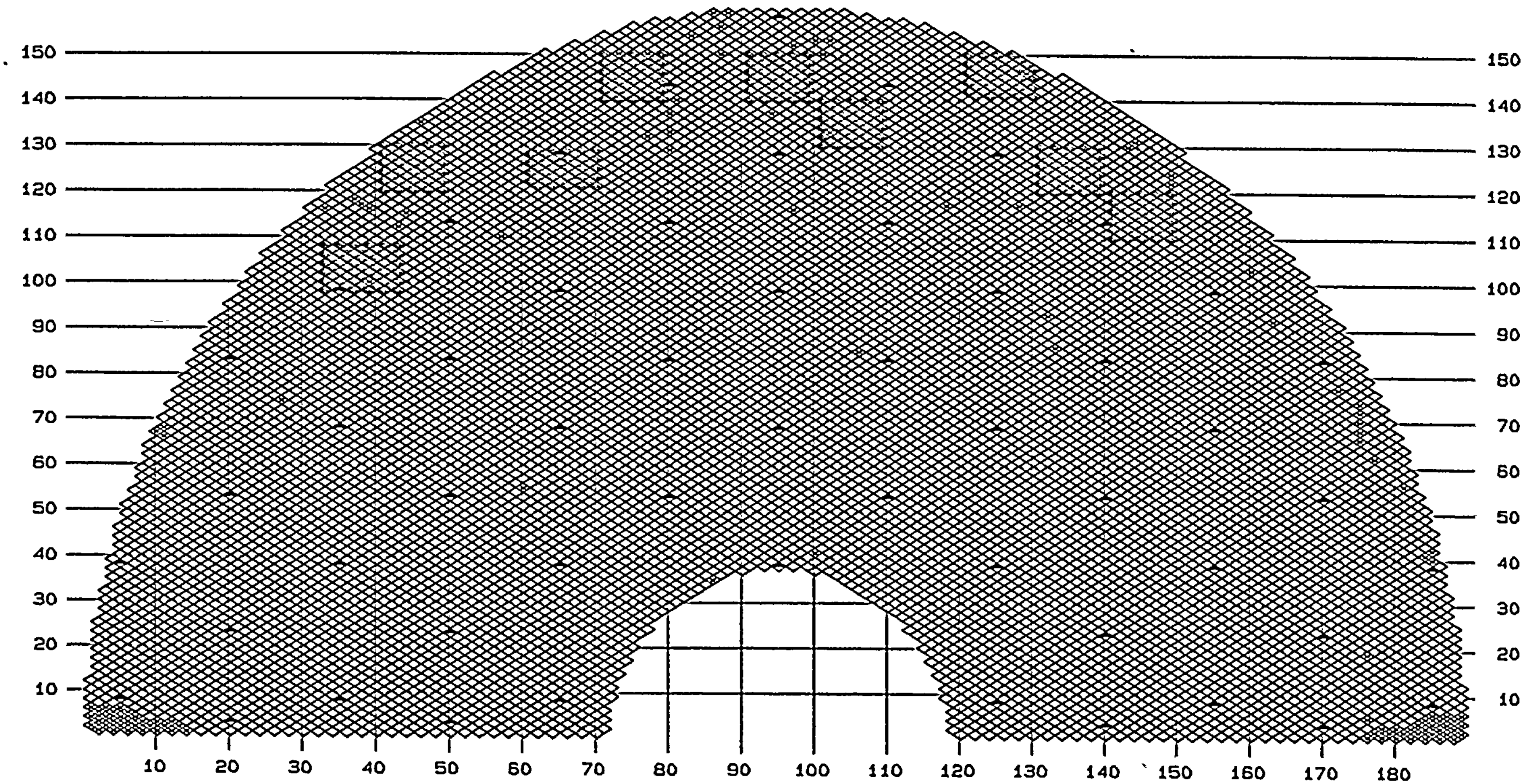


FIGURE III-4 SG 3-1 UPPER BUNDLE MRPC PROGRAM

CONAM NUCLEAR, INC. BW

04/94, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 31
OUTAGE DATA SET : CURRENT
Percent: MAI, SAI

DATE: 08/02/94
TIME: 09:26:38

STAYS ▲

PLUGGED 121 × MAI 0 ◆ SAI 2 ◆

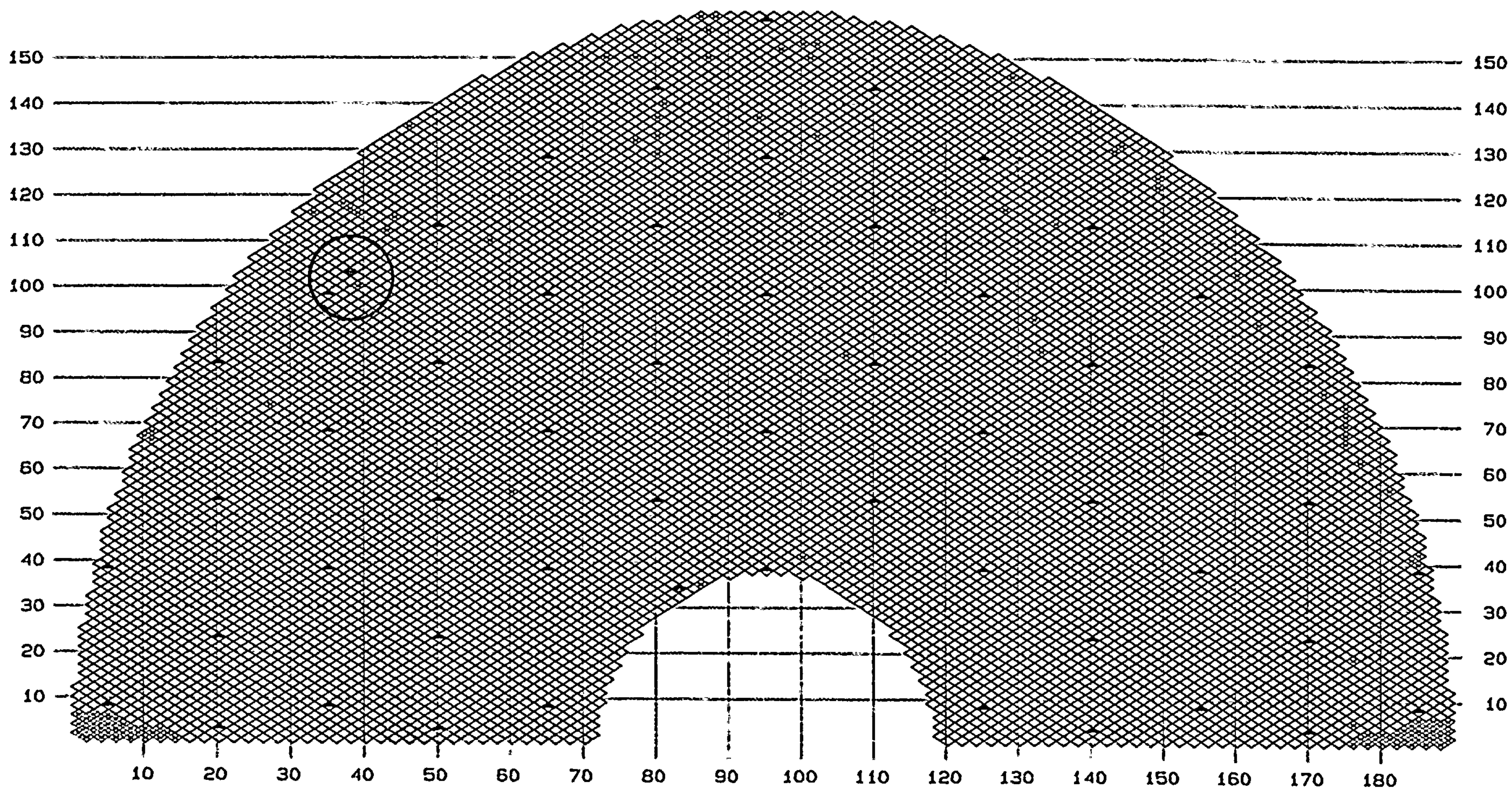


FIGURE III-5 SG 3-1 ARC REGION DEFECT - U3R4

CONAM NUCLEAR, INC. BW

04/94, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 32 | DATE: 08/02/94
UBEND | TIME: 09:49:27

CRITERIA: TUBES TO BE EXAMINED IN GROUP(S) 2,5,6,7,8,55,61,65,66,69,70,71 | STAYS ▲

PLUGGED 113 × 08H-VS5 45 ◆ 08H-VS3 1093 ◆ 07H-VS3 1 ◆ 08H-VS2 63 ◆ 08H-VS1 316 ◆

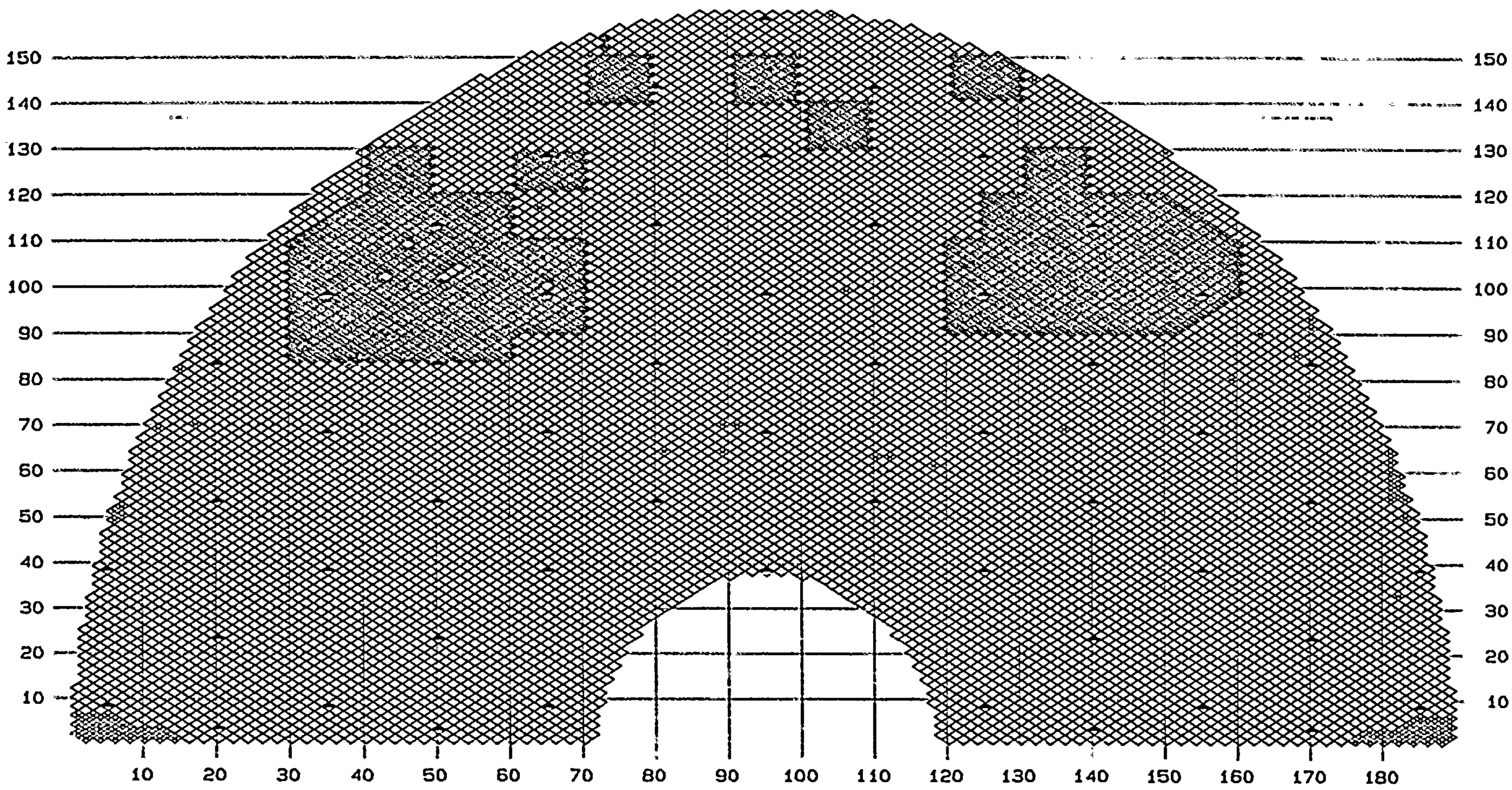


FIGURE III-6 SG 3-2 UPPER BUNDLE MRPC PROGRAM

CONAM NUCLEAR, INC. BW

04/94, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 32
OUTAGE DATA SET : CURRENT
Percent: MAI, SAI

DATE: 08/02/94
TIME: 09:43:49

STAYS ▲

PLUGGED 113 × MAI 0 ◆ SAI 18 ◆

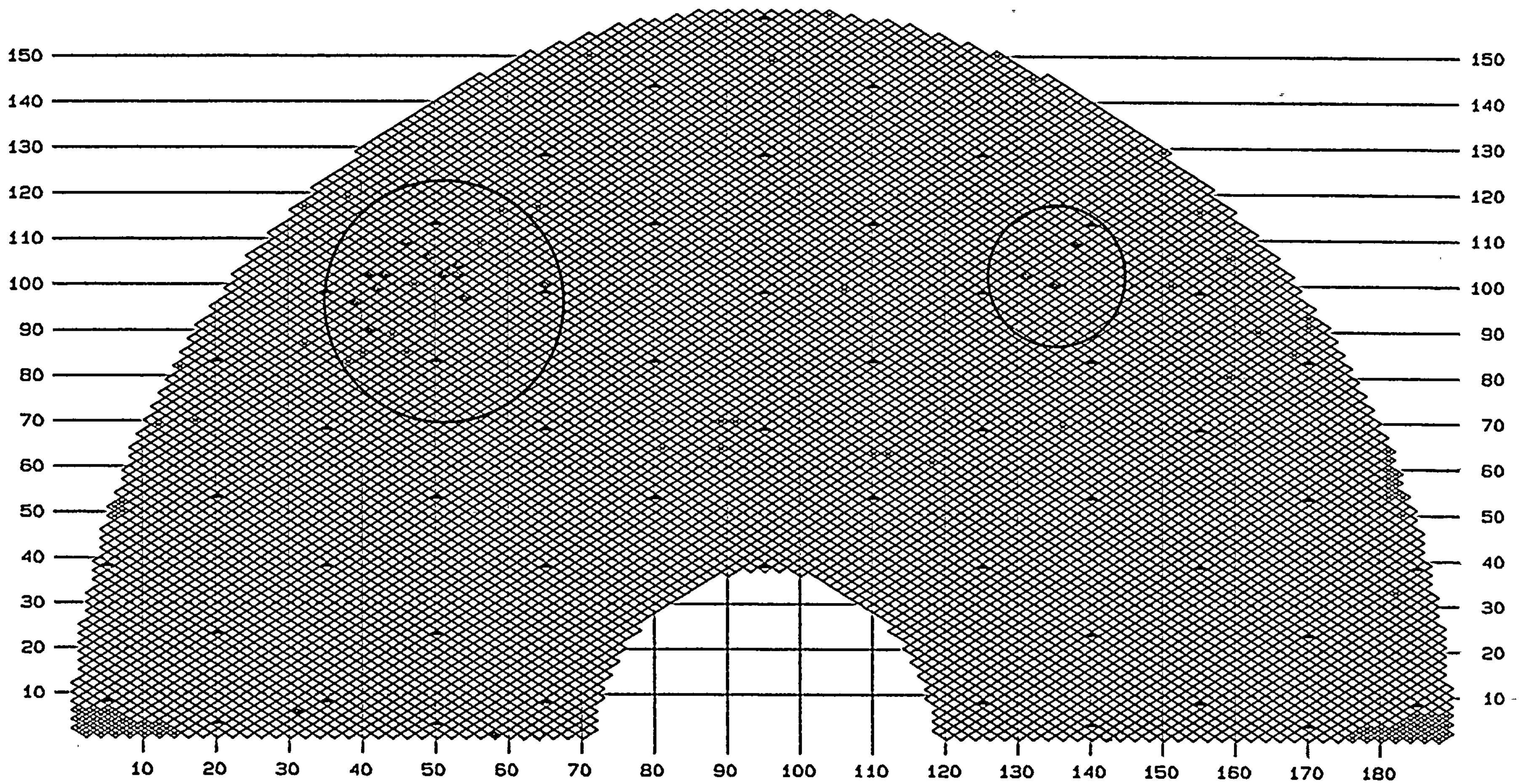


FIGURE III-7 SG 3-2 ARC REGION DEFECTS - U3R4

CONAM NUCLEAR, INC. BW

10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Indication Location: TSH 0.00 to TSH +10.00 AND Percent: SLG

DATE: 12/16/93
TIME: 11:15:27

STAYS ▲

PLUGGED 67 ◆ 0.0 in - 1.0 in 698 ◆ 1.1 in - 1.5 in 610 ◆ 1.6 in - 2.0 in 292 ◆ 2.1 in - 2.5 in 26 ◆ > 2.5 in 1 ◆

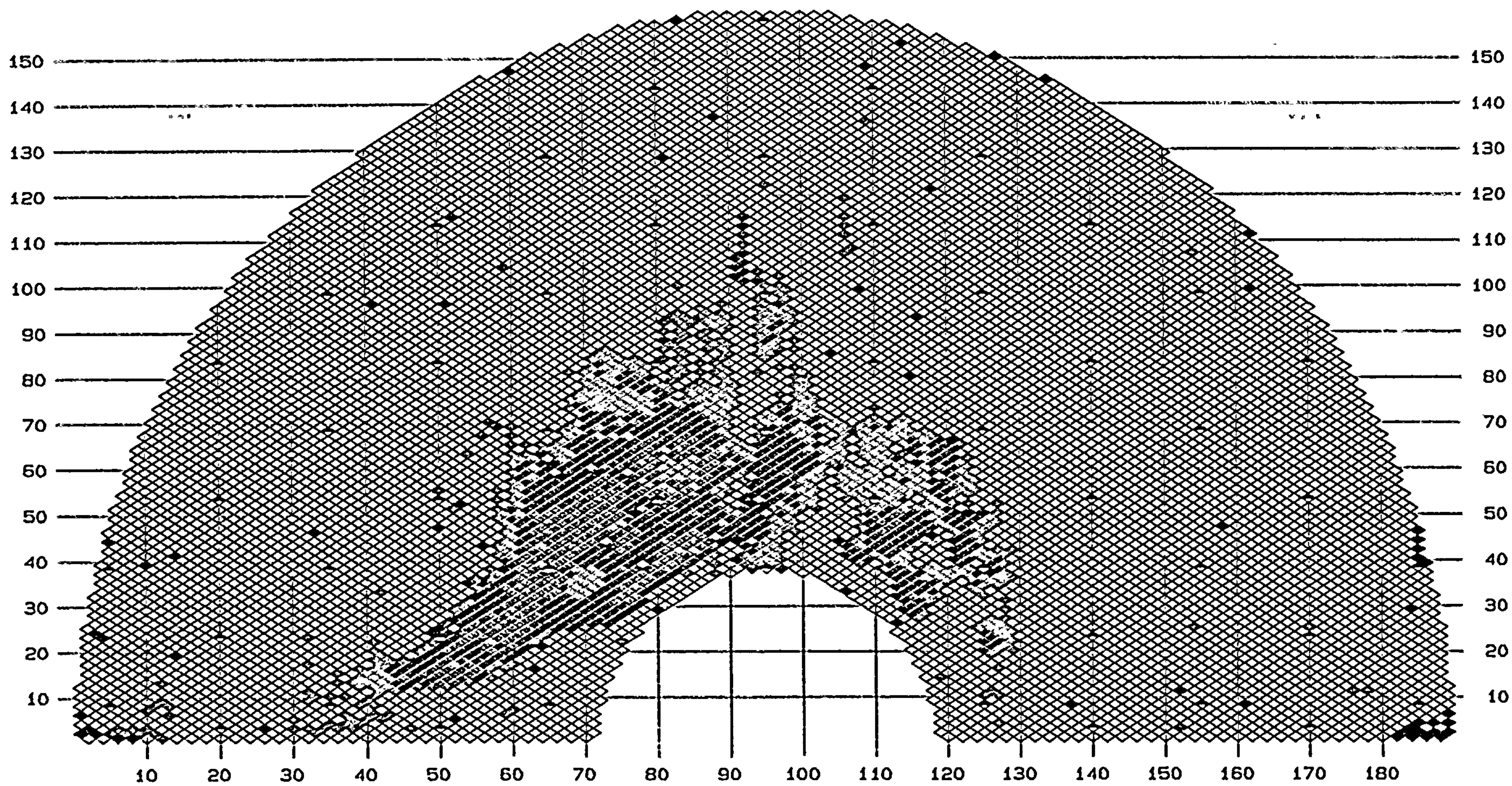


FIGURE III-8 SG 1-2 SLUDGE PROFILE MAP - U1R4

CONAM NUCLEAR, INC. BW

10/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 1

STEAM GENERATOR: 12
OUTAGE DATA SET : CURRENT
Percent: MCI, SCI

DATE: 10/26/93
TIME: 15:21:07

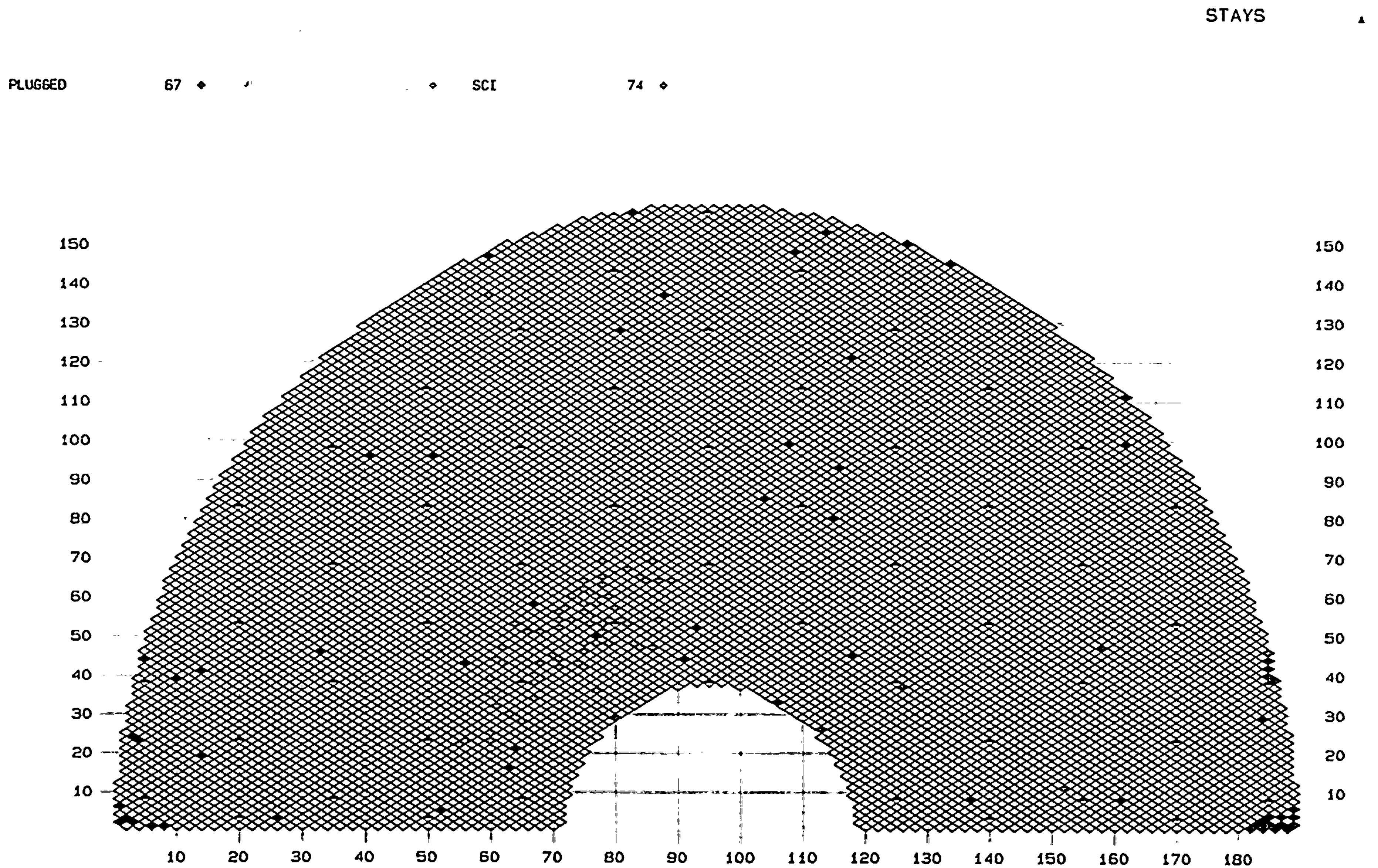


FIGURE III-9 SG 1-2 CIRCUMFERENTIAL DEFECTS - U1R4

CONAM NUCLEAR, INC. BW

04/93, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 22
OUTAGE DATA SET : CURRENT
Indication Location: TSH 0.00 to TSH +10.00 AND Percent: SLG

DATE: 08/02/94
TIME: 10:47:51

STAYS ▲

PLUGGED 195 × 0.0 in - 1.0 in 823 ◆ 1.1 in - 2.0 in 14 ◆ 2.1 in - 3.0 in 2 ◆ 3.1 in - 4.0 in 0 ◆ > 4.0 in 0 ◆

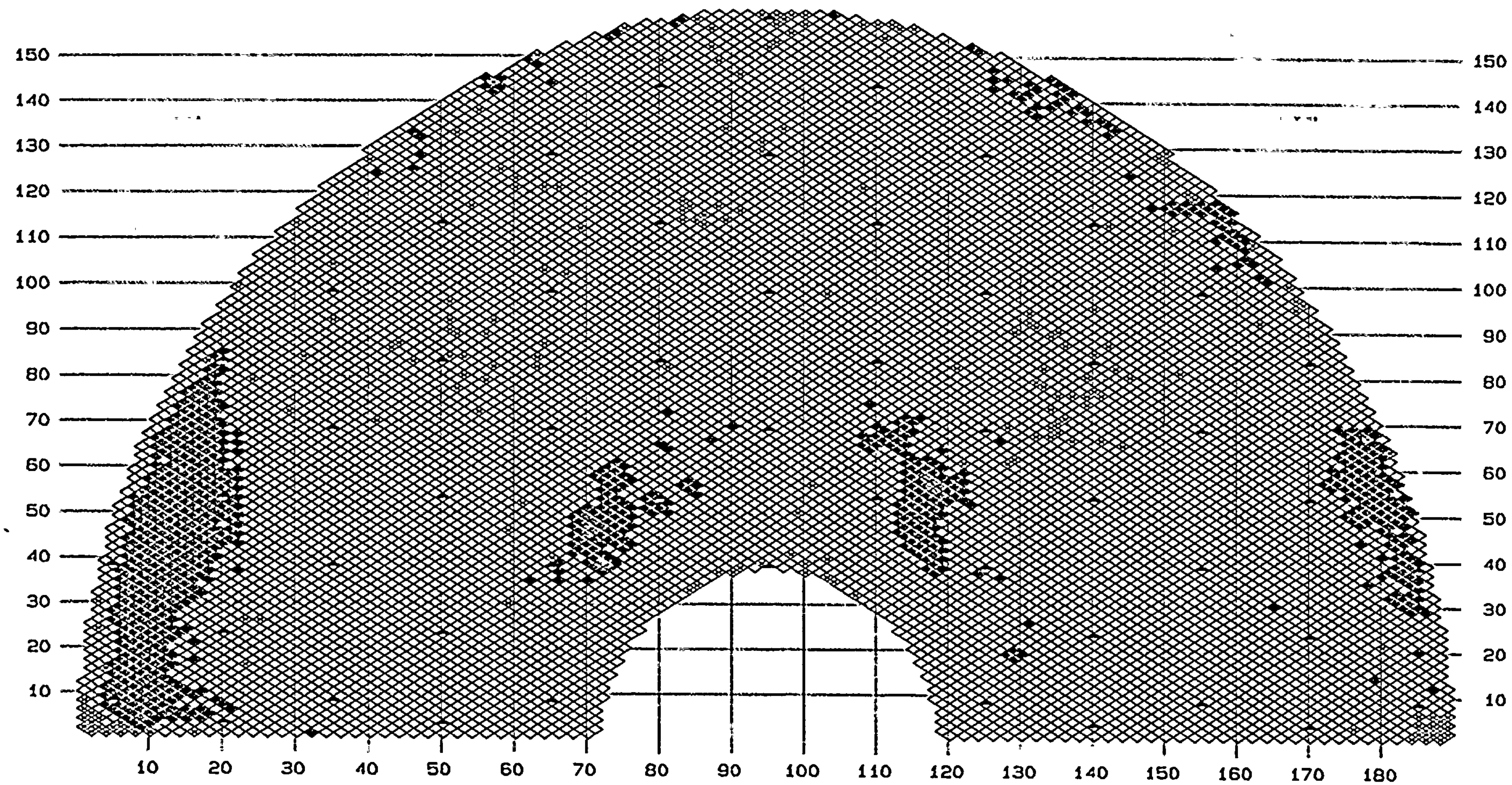


FIGURE III-10 SG 2-2 SLUDGE PROFILE MAP - U2R4

CONAM NUCLEAR, INC. BW

01/94, ARIZONA PUBLIC SERVICE, PALO VERDE, UNIT 2

STEAM GENERATOR: 22
OUTAGE DATA SET : CURRENT
Percent: MCI, SCI

DATE: 08/02/94
TIME: 10:32:33

STAYS ▲

PLUGGED 371 × MCI 0 ◆ SCI 4 ◆

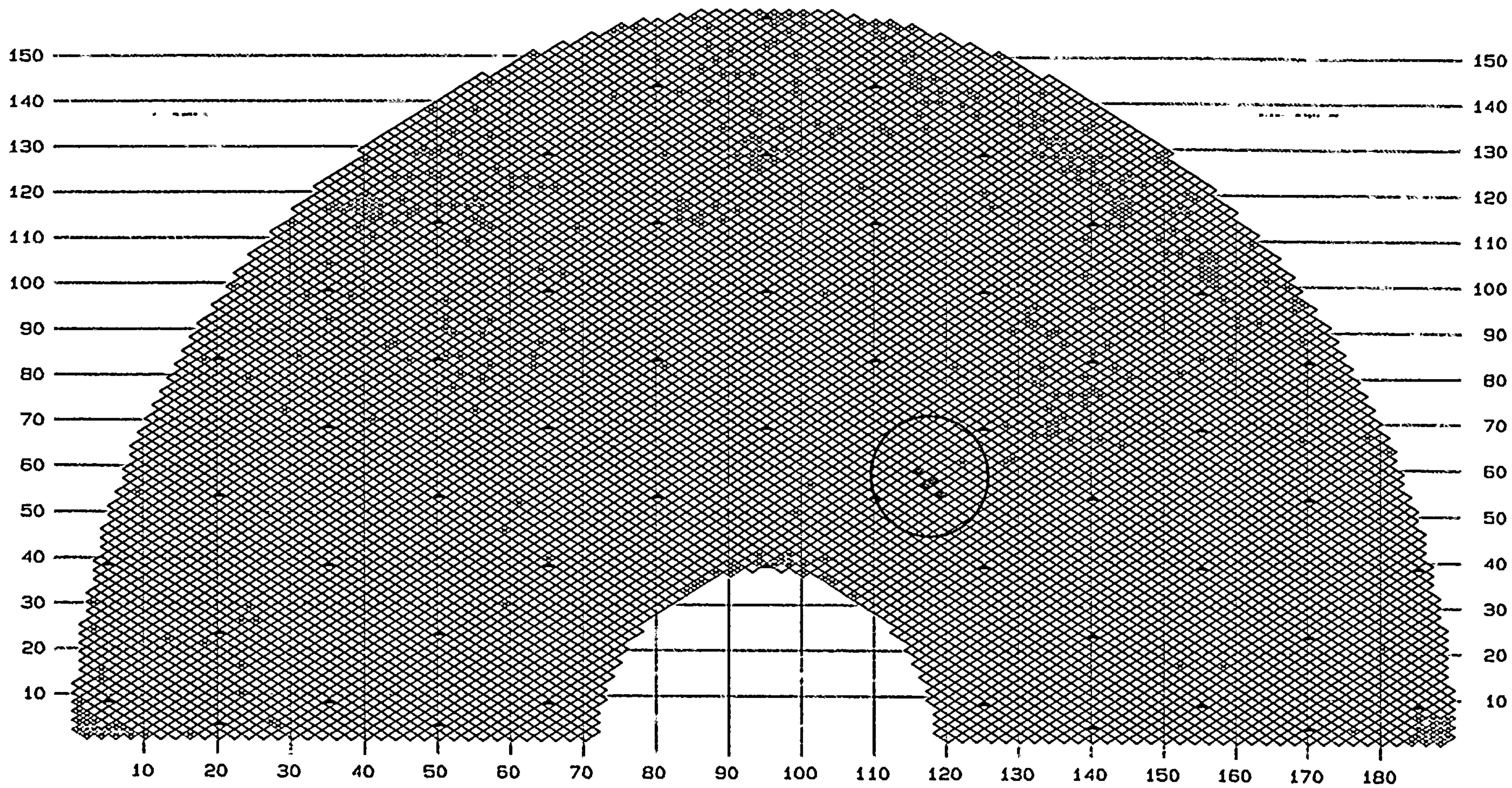


FIGURE III-11 SG 2-2 CIRCUMFERENTIAL CRACKS - U2M5-1

CONAM NUCLEAR, INC. BW

10/92, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 32
OUTAGE DATA SET : CURRENT
Indication Location: TSH 0.00 to TSH +10.00 AND Percent: SLG

DATE: 12/16/93
TIME: 21:22:58

STAYS ▲

PLUGGED 94 ◆ 0.0 in - 1.0 in 202 ◆ 1.1 in - 2.0 in 56 ◆ 2.1 in - 3.0 in 0 ◆ 3.1 in - 4.0 in 0 ◆ > 4.0 in 0 ✕

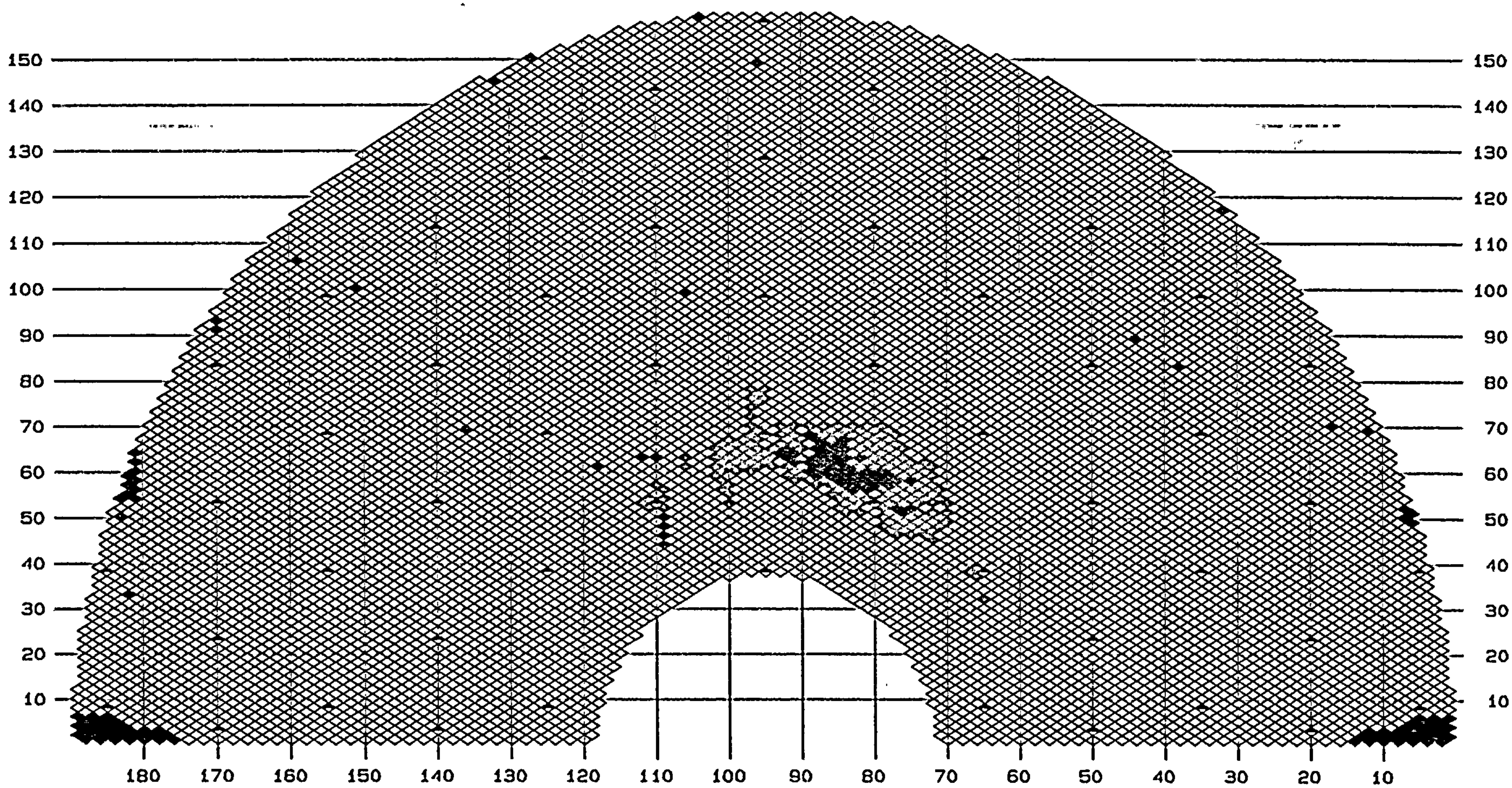


FIGURE III-12 SG 3-2 SLUDGE PROFILE MAP - U3R3

CONAM NUCLEAR, INC. BW

12/93, ARIZONA PUBLIC SERVICE CO., PALO VERDE, UNIT 3

STEAM GENERATOR: 32
OUTAGE DATA SET : CURRENT
Percent: MCI, SCI

DATE: 08/02/94
TIME: 10:21:14

STAYS ▲

PLUGGED 94 ✕ MCI 1 ◆ SCI 3 ◆

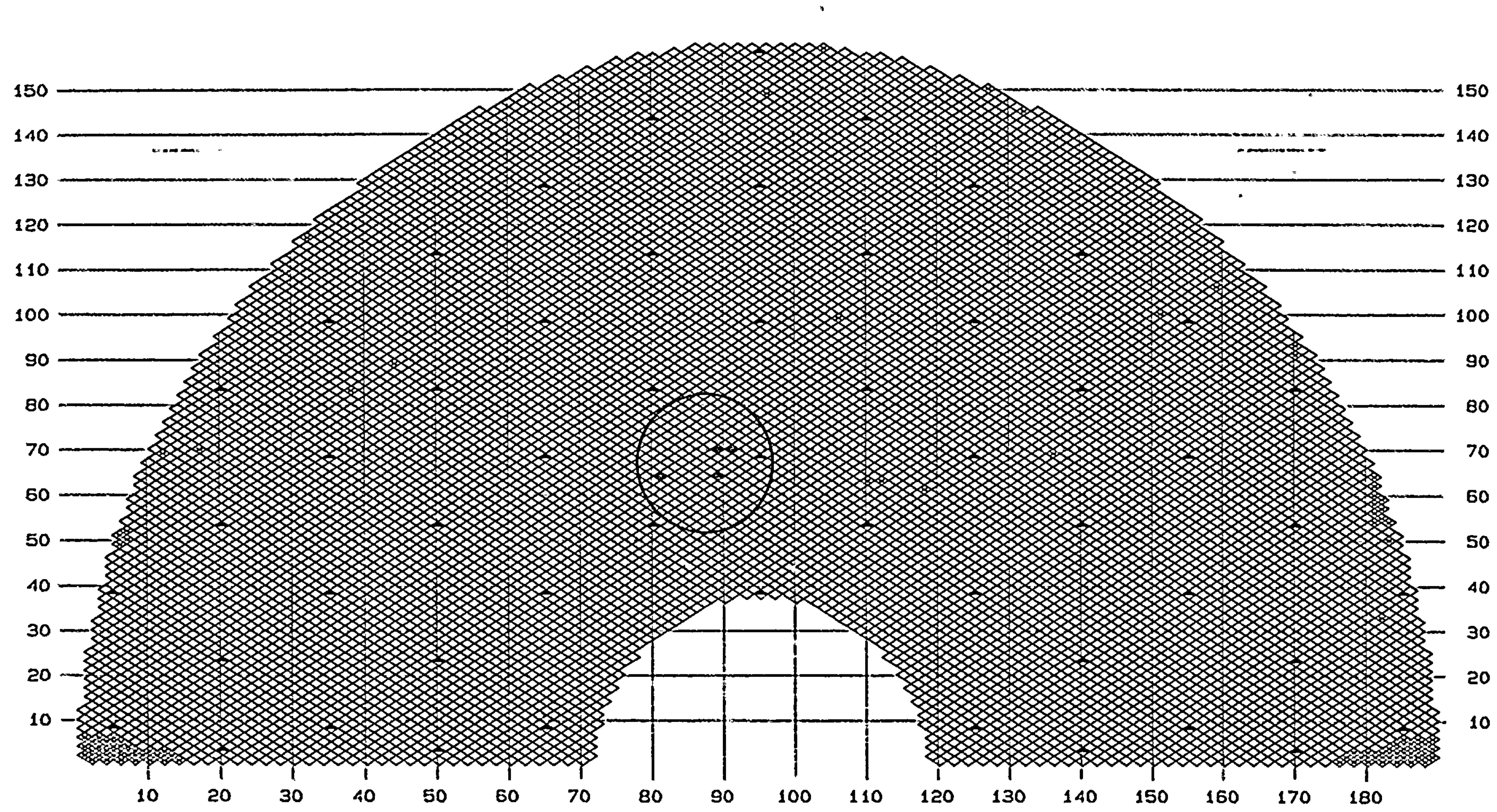


FIGURE III-13 SG 3-2 CIRCUMFERENTIAL DEFECTS - U3M4

CONAM NUCLEAR, INC. BW

FIGURE III-14

SCC Growth Rate vs. pH

Mill Annealed Alloy 600 at 316°C
Stress at About Yield or
Stress Intensity About 10 ksi root inch

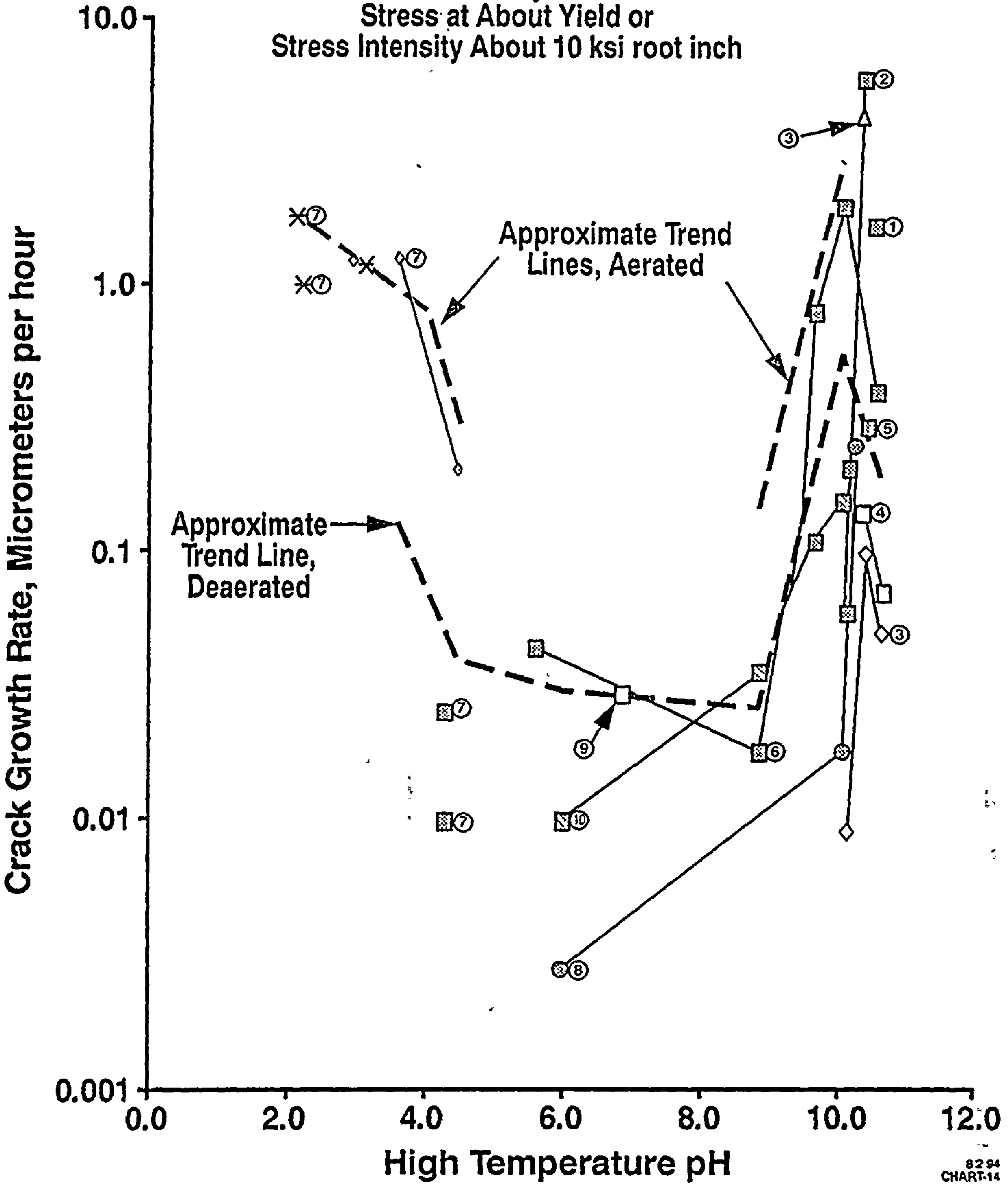
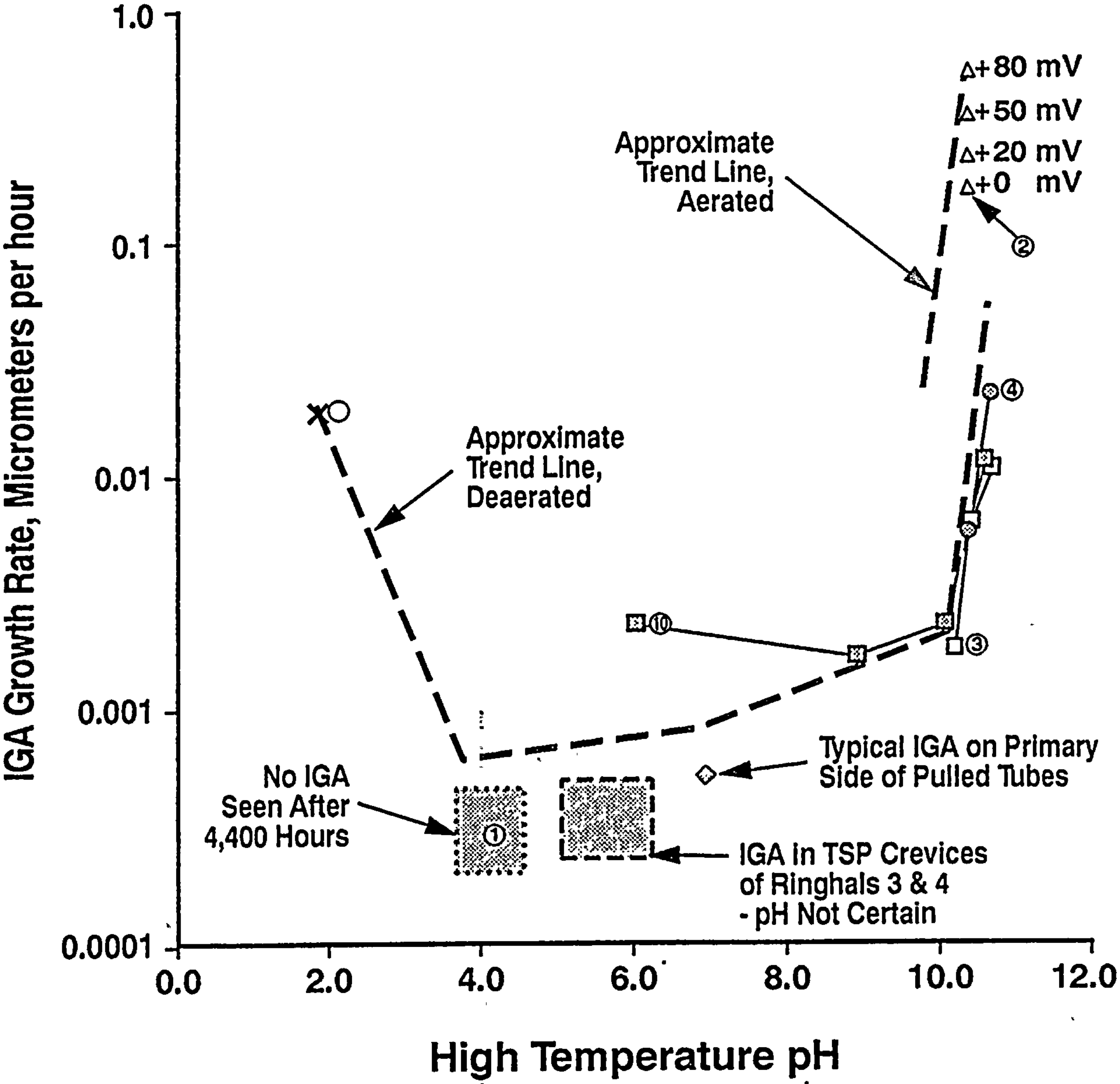


FIGURE III-15

IGA Growth Rate vs. pH

Mill Annealed Alloy 600
316°C, Low Stress

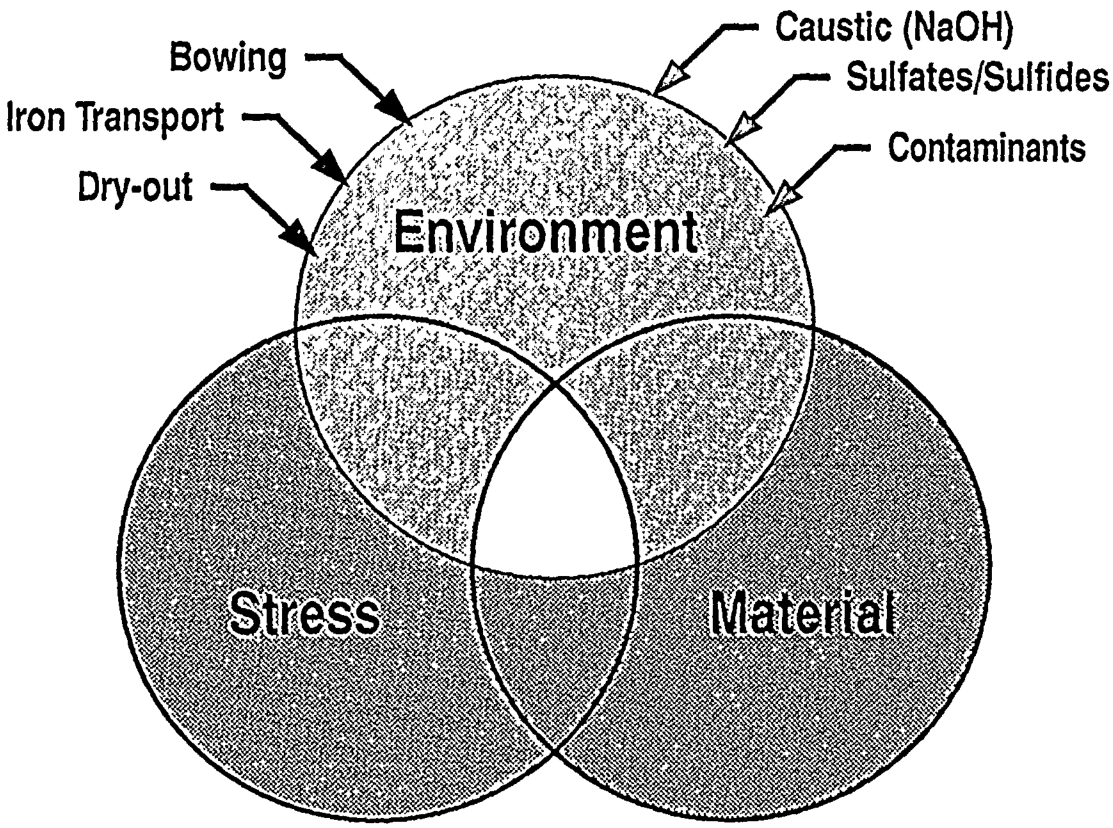


7/21/94
CHART-15

FIGURE III-16

Upper Bundle Stress Corrosion Cracking

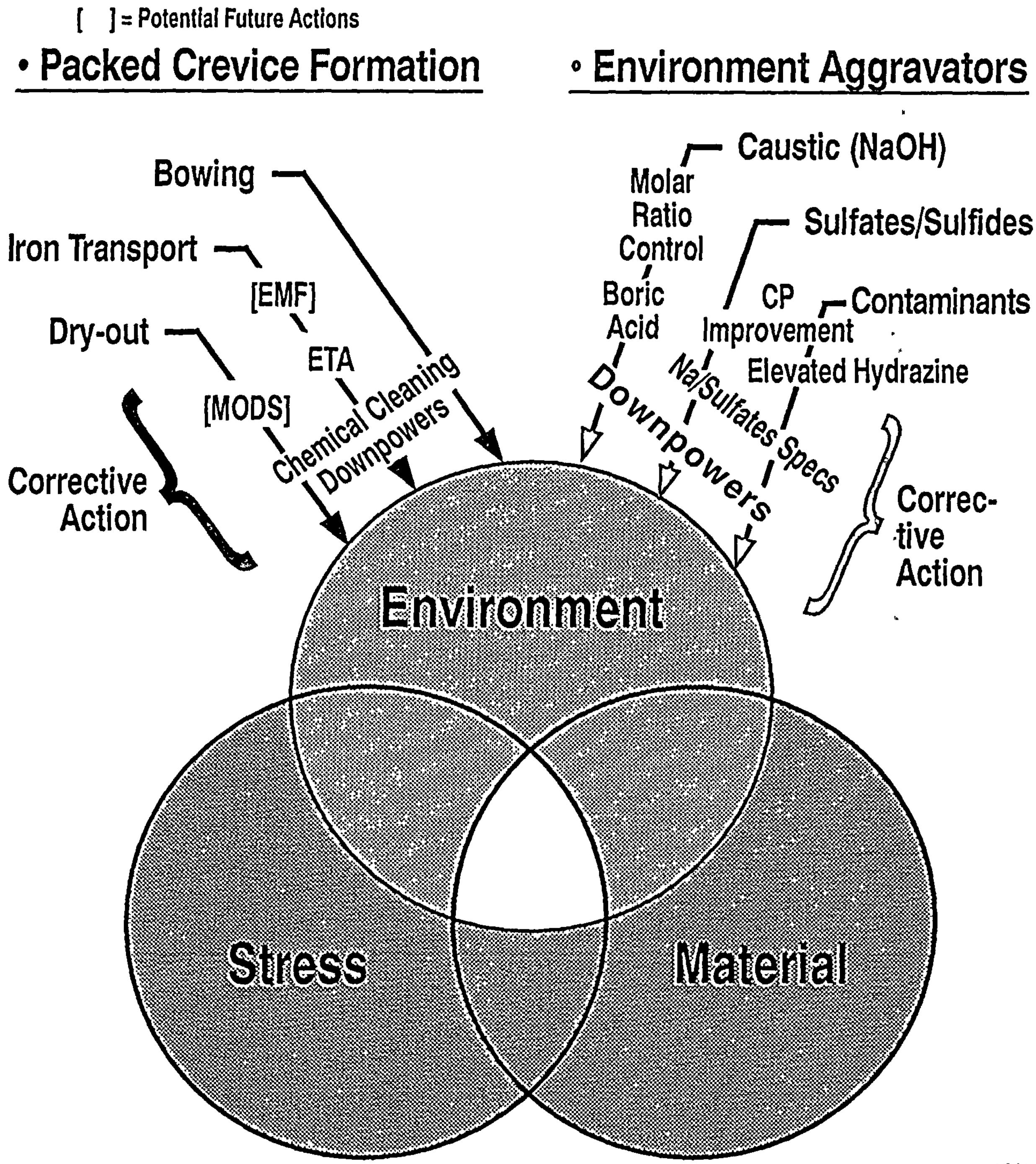
• Packed Crevice Formation • Environment Aggravators



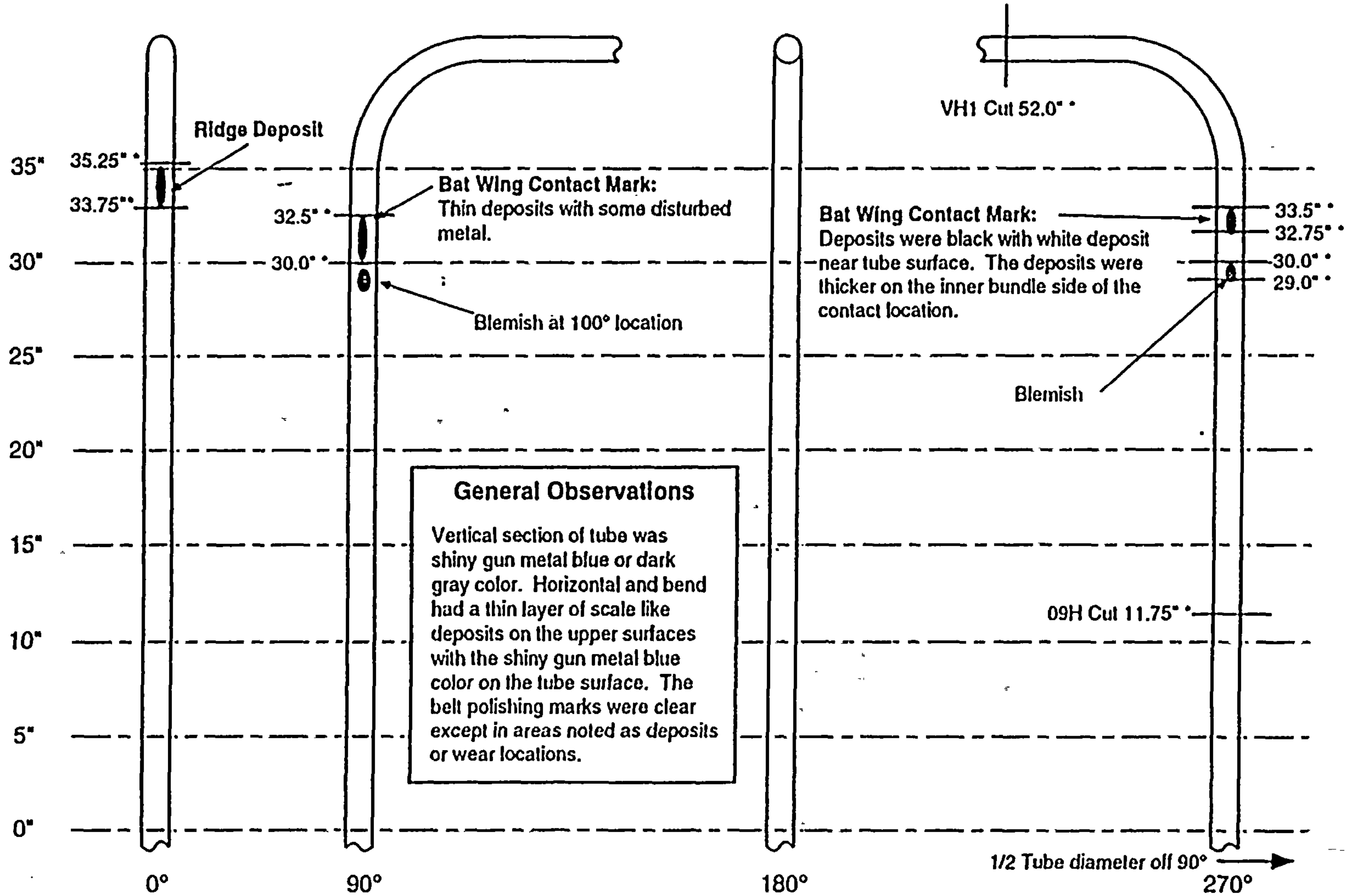
6 2 94
CHART-16

FIGURE III-17

Crevice Corrosion Corrective Action



Tube 133-134 (A)



* ABB Laboratory Reference

Figure IV-2. Summary of initial Visual Observations of Tube A

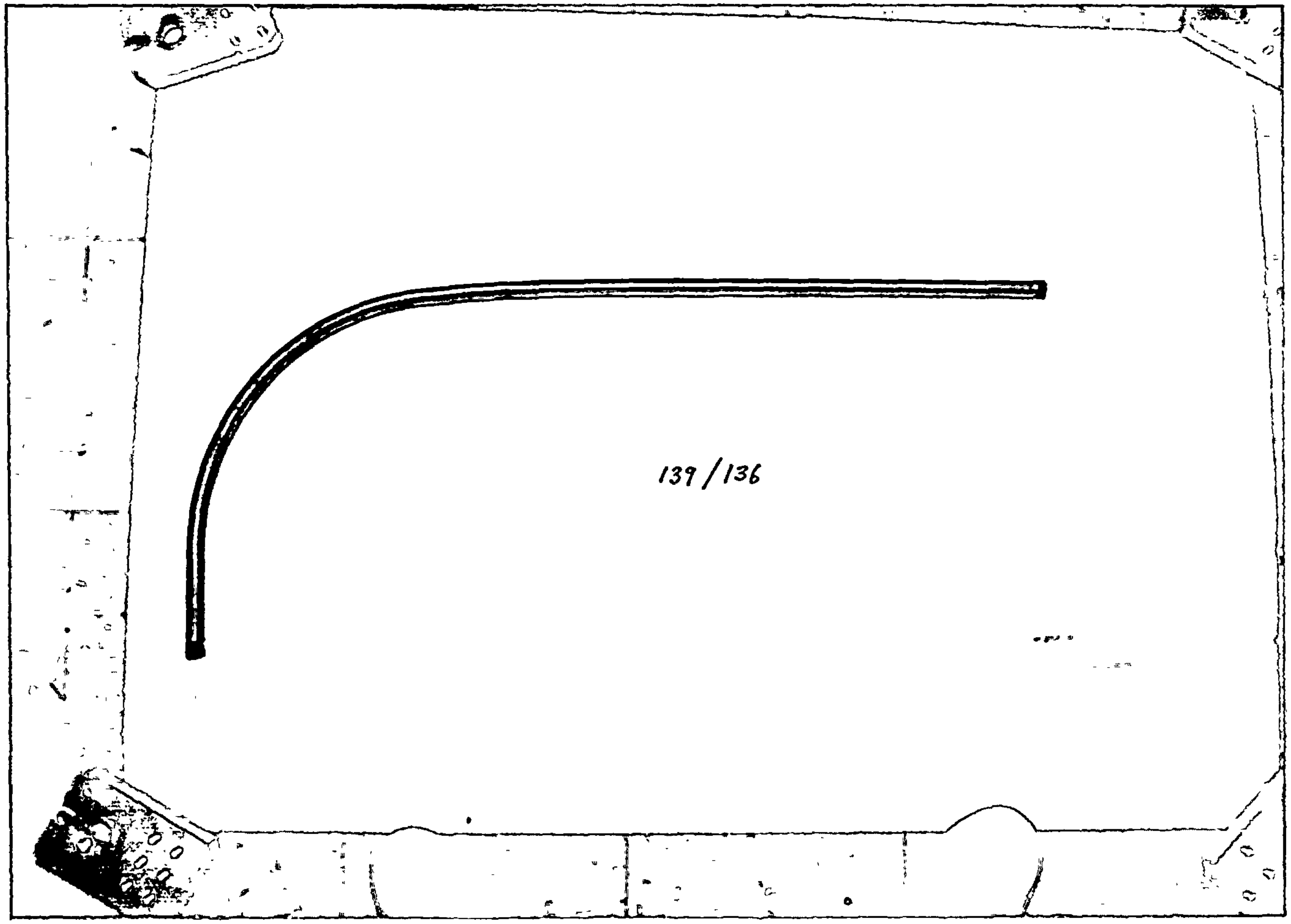
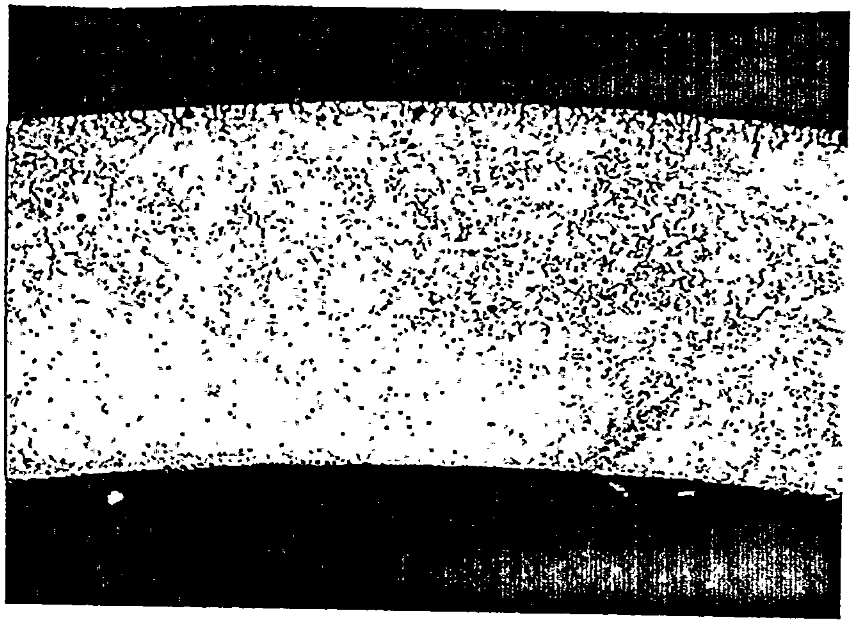
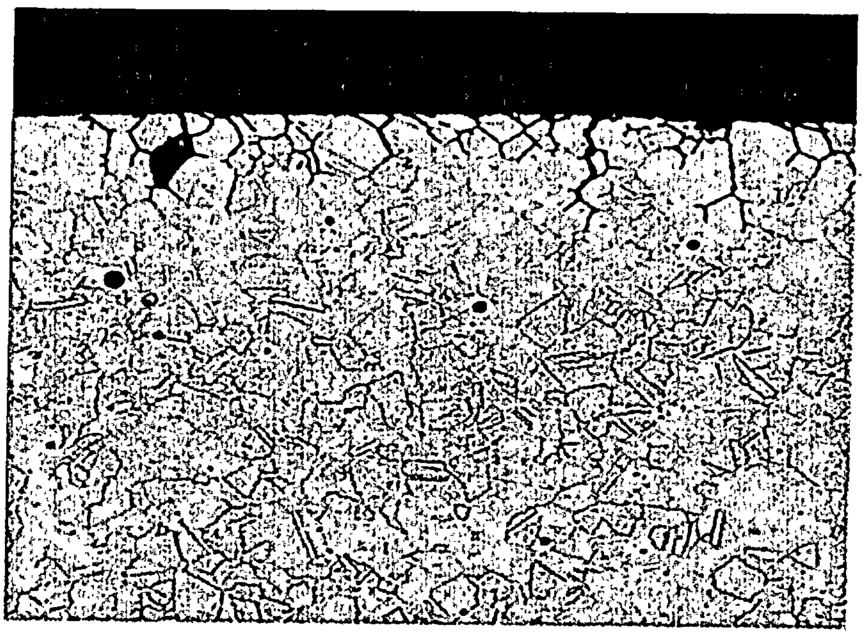


Figure IV-3. Photograph of Tube R139L136 (M) Showing the Extent of Bowing



50X



200X

Figure IV-4. Shallow IGA at the 30° Orientation of Tube R134L135 (D) in the Area of a Field Eddy Current Indication. (Glyceregia Etch)

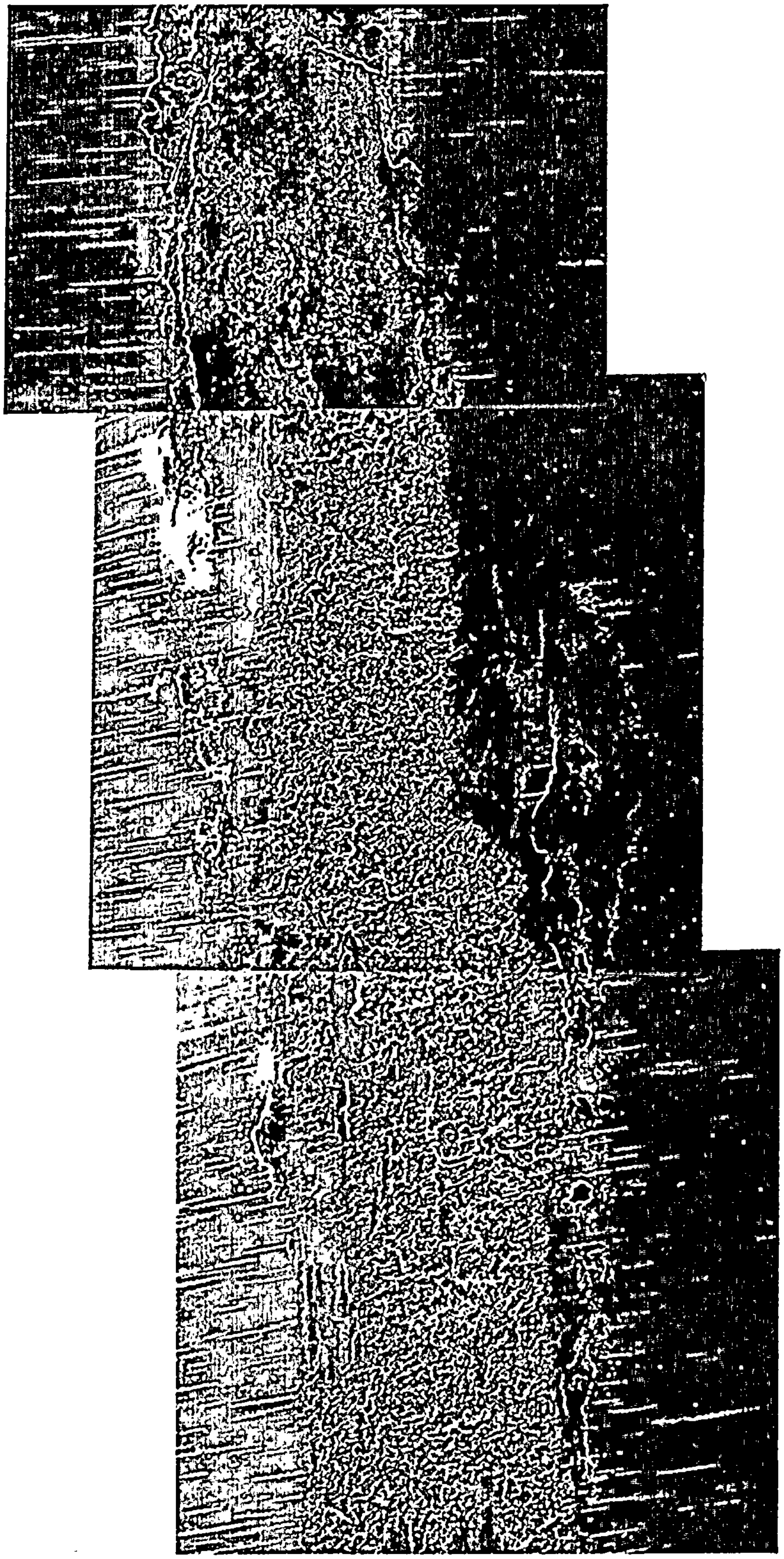


Figure IV-5. Low Magnification Micrograph of Wear Scar on Tube R139L136 Zero-Degree Extrados Location

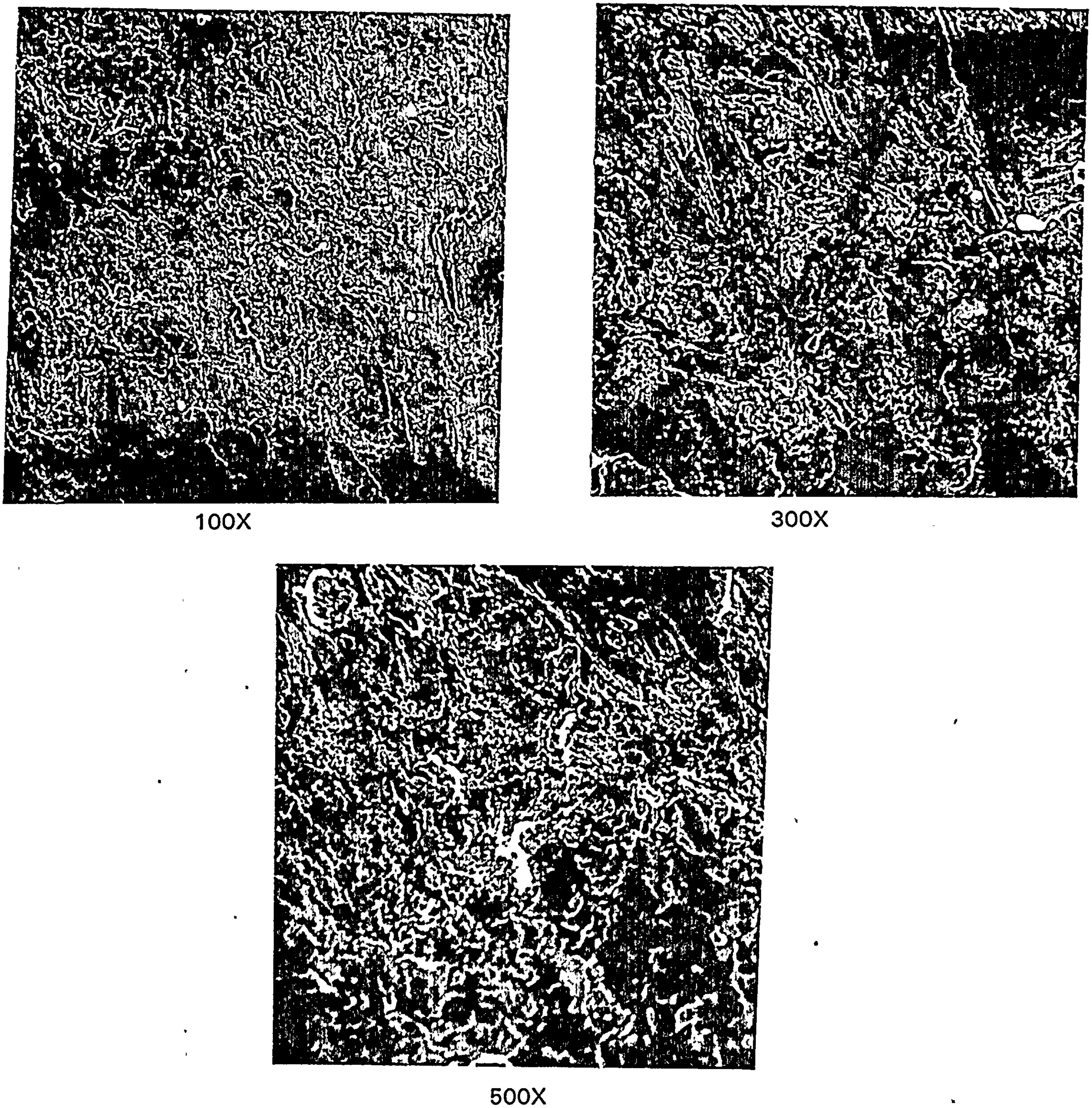


Figure IV-6. Higher Magnification Micrographs of Wear Scar on Tube R139L136 Zero-Degree Extrados Location

MRPC PROBABILITY OF DETECTION VERSUS AXIAL CRACK DEPTH

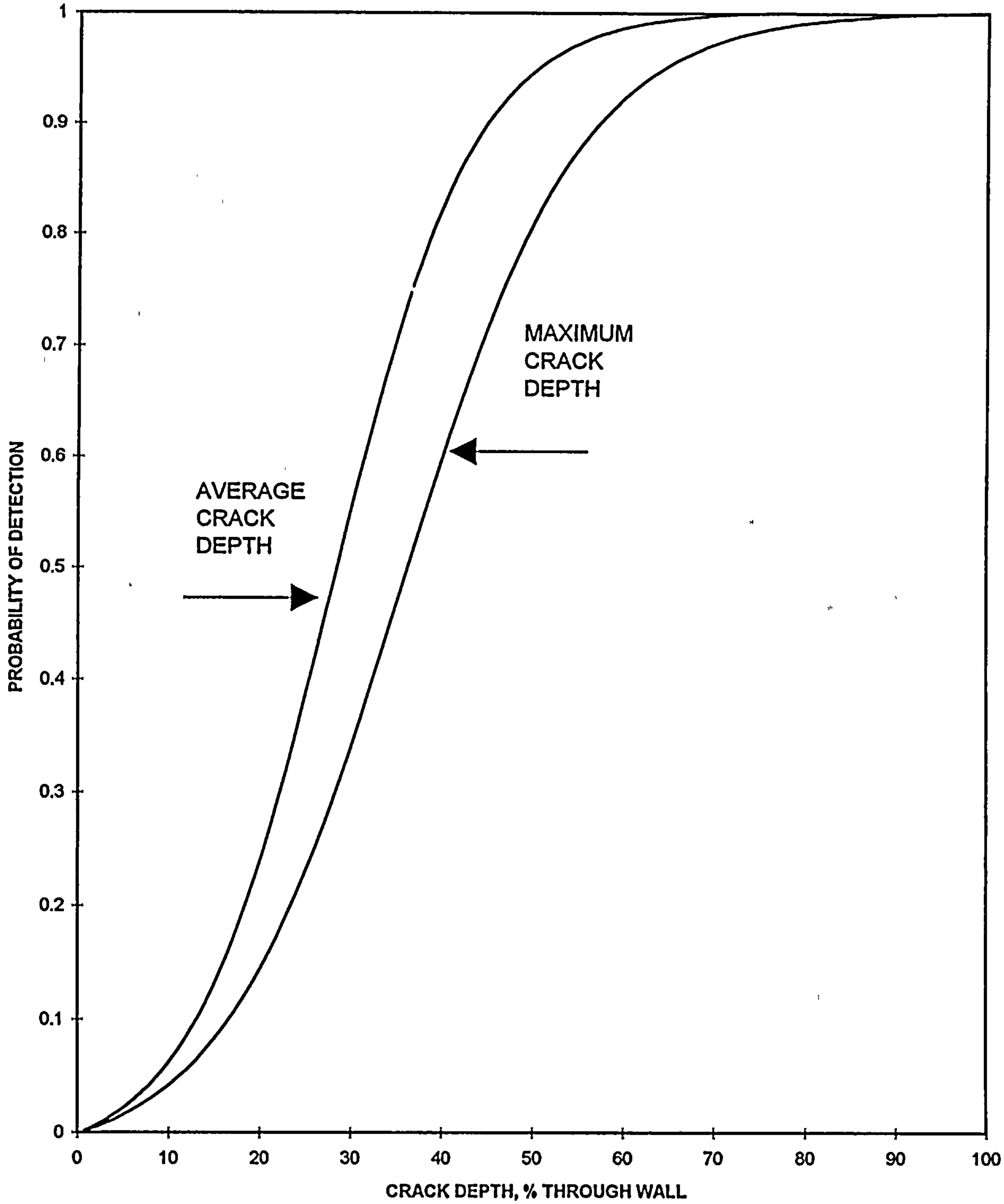


FIGURE V-1

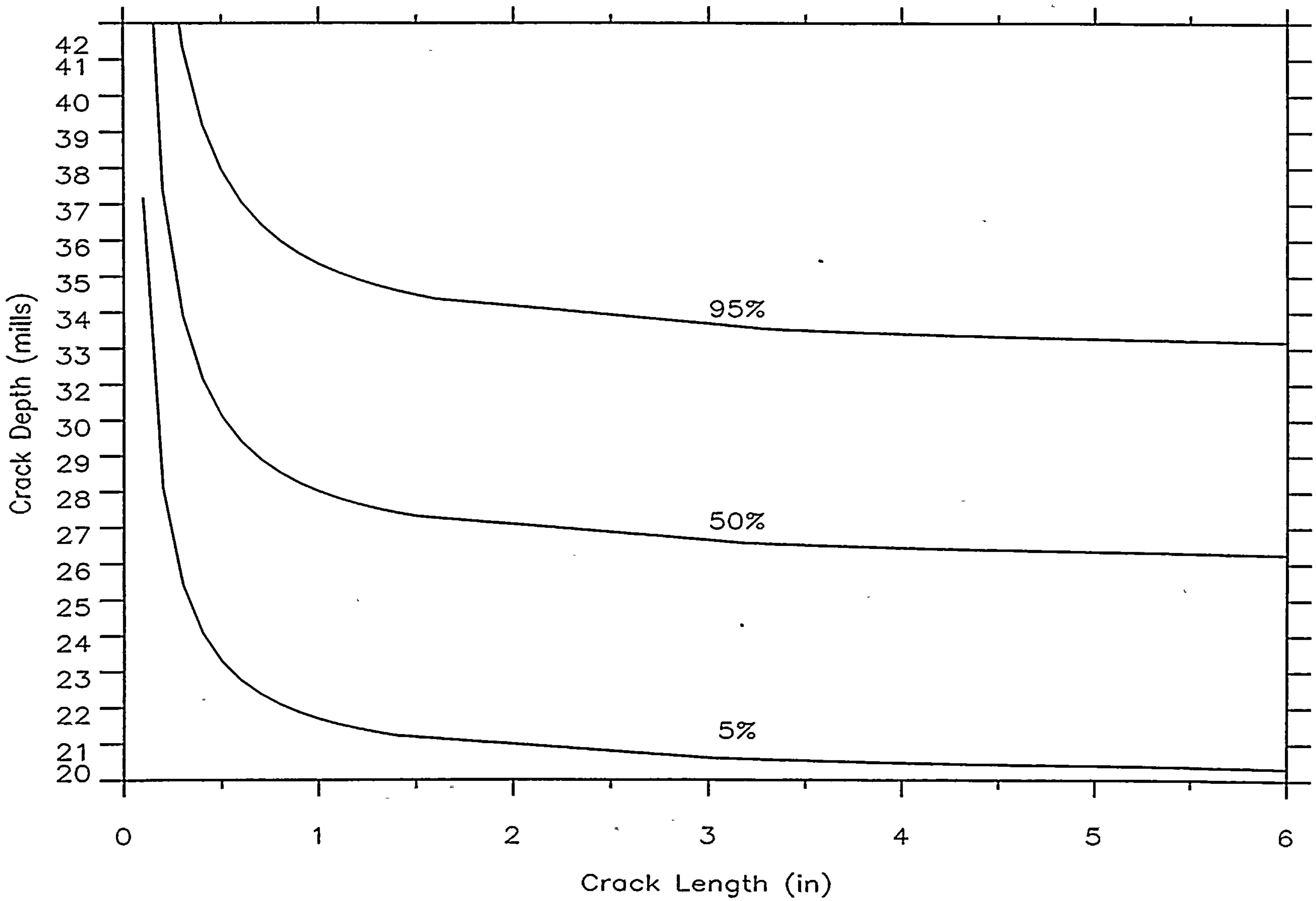


Figure V-2: RG 1.121 - 90% Confidence Interval for Critical Combinations of Crack Length and Depth

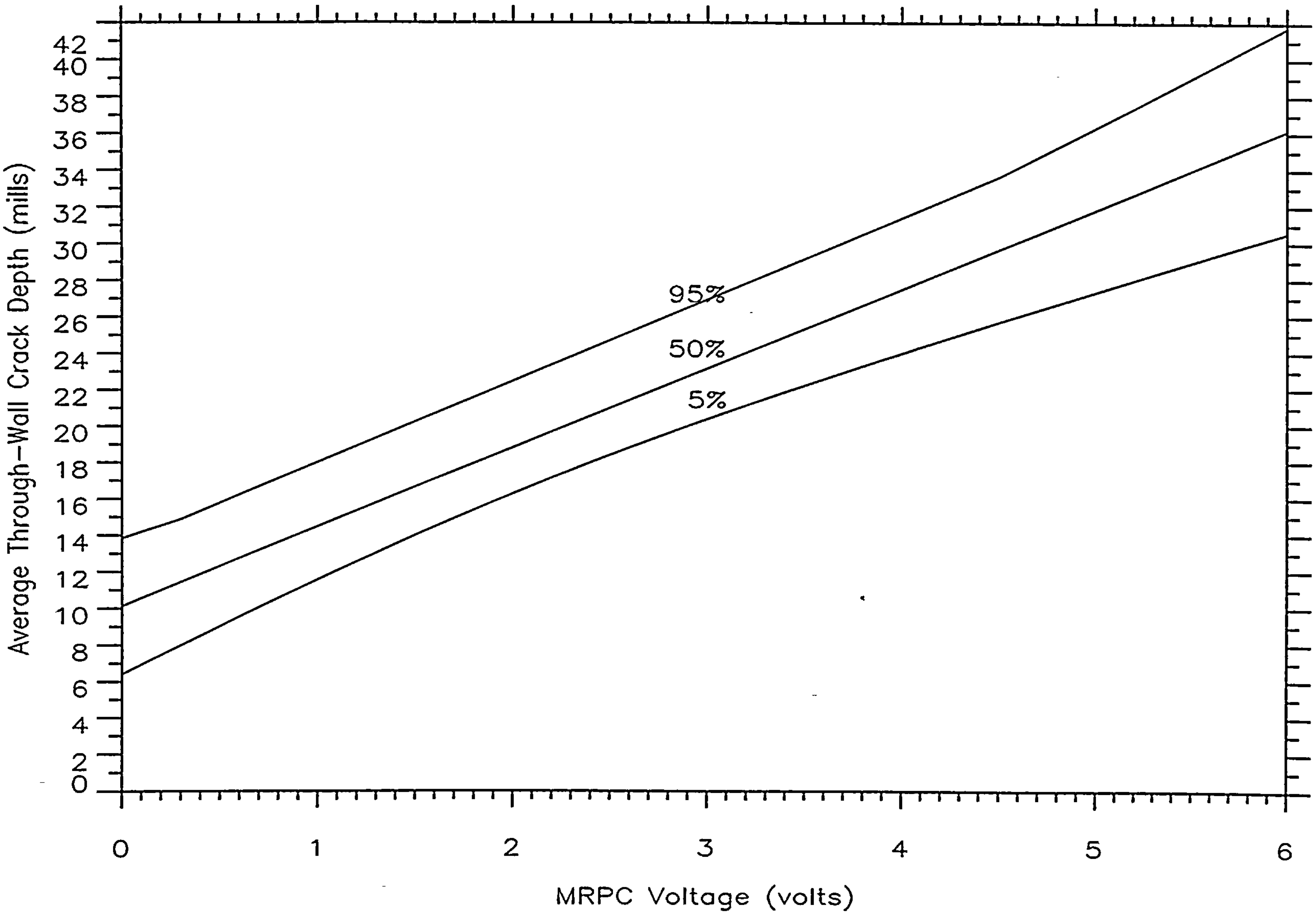
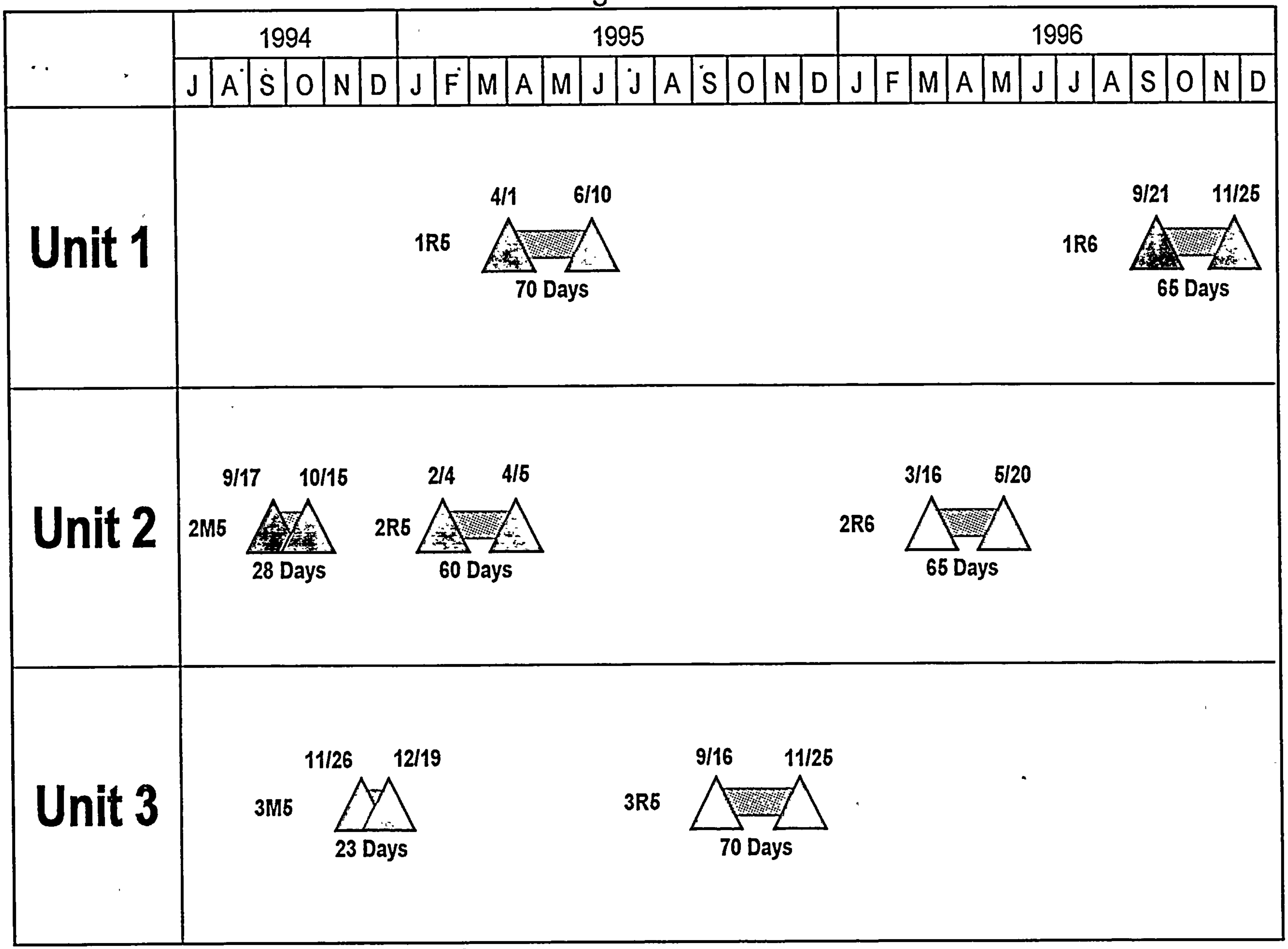


Figure V-3: 90% Confidence Interval for True Mean Value of Crack Average Depth vs. MRPC Voltage

PVNGS 1994-1996 PLANNED OUTAGES

Figure VI-1



APPENDIX A

PALO VERDE UNIT-1 STEAM GENERATOR TUBE REGULATORY ANALYSIS FOR AXIAL CRACKING

Submitted by:

PACKER
ENGINEERING INC.

J.A. BEGLEY
S.D. BROWN
B.W. WOODMAN

August 1994

Report No. B51549-R1-Rev. 1
Prepared for:

ARIZONA PUBLIC SERVICE COMPANY

PALO VERDE UNIT-1
STEAM GENERATOR TUBE
REGULATORY ANALYSIS
FOR
AXIAL CRACKING

Table of Contents

PACKER
ENGINEERING INC.

REGULATORY ANALYSIS FOR AXIAL CRACKING PALO VERDE UNIT-1 STEAM GENERATOR TUBE

1.0 INTRODUCTION

This report describes an analysis of the issue of upper bundle axial ODSCC as it applies to steam generator tubing in Unit 1 at the Palo Verde Nuclear Generating Station. Based on past inspection results for Units 2 and 3 at Palo Verde, the detection of secondary side stress corrosion cracks in the upper bundle region of Unit 1 may occur at some future date. The following sections provide a description and analysis of the probability of axial ODSCC in Unit 1 leading to the exceedance of Regulatory Guide 1.121 structural limits. The probability of structural limit exceedances is estimated as function of run time using a conservative approach. The chosen approach models the historical development of cracks, crack growth, detection of cracks and subsequent removal from service and the initiation and growth of new cracks during a given cycle of operation. Past performance of all Palo Verde Units as well as the historical performance of other steam generators was considered in the development of cracking statistics for application to Unit 1. Data in the literature and Unit 2 pulled tube examination results were used to construct probability of detection curves for the detection of axial IGSCC/IGA using an MRPC eddy current probe. Crack growth rates were estimated from Unit 2 eddy current inspection data combined with pulled tube examination results and data in the literature. Modeling efforts are continuing and input data is under refinement. Improved estimates of the probability of structural limit exceedance will be incorporated in successive report drafts.

[illegible] [illegible] [illegible]

2.0 BACKGROUND

Cracking of steam generator tubing in the upper bundle regions of steam generators at PVNGS was first detected in 1991 in Unit 2 during the U2R3 outage.[1] A 100% eddy current inspection of the upper bundle using a bobbin coil probe revealed a single axial indication and two other indications which were later classified as axial, crack-like indications. In the U2R4 outage, following a tube rupture event, eddy current inspection of a total of 8000 tubes using an MRPC probe revealed a total of 122 axial indications, with 104 in SG 22 and 18 in SG 21.[2]

Examination of tubes pulled from Unit 2 then showed the degradation to be a combination of intergranular stress corrosion cracking and intergranular attack on the outer diameter of the tubing.[2] IGSCC/IGA was observed in the vicinity of upper bundle eggcrate and batwing supports and also in apparently free span locations. Cracking at apparent free span locations was associated with long narrow ridge deposits. Occasionally these deposits bridged neighboring tubes. Bridging/ridge deposits, apparently encouraged by diminished tube separation, are considered to act as crevice sites, capable of concentrating aggressive chemical species. Upper bundle IGSCC/IGA was also found to be confined to an arc region of high mass flow and high quality where film boiling and dryout was indicated. These conditions favored deposit formation and concentration of chemical species. A root cause analysis attributed the IGSCC/IGA degradation to caustic/alkaline environments in eggcrate, batwing and tube to tube crevices and similar conditions under bridging/ridge deposits. Sulfur species, OD tube scratches, and less than favorable Alloy 600 metallurgical structures were found to be exacerbating factors.

Axial indications have also been found in steam generator tubes in Unit 3. After 4 cycles of operation, an MRPC inspection of a total of 1975 tubes revealed 17 axial indications. When normalized to the same inspection sample size as the Unit 2 inspection during the U2R4 outage, a total of 55 axial indications would have been expected. At comparable points in their operating histories, taking into account the learning curve for MRPC inspection procedures, Unit 3 has experienced about 25% of the extent of upper bundle IGSCC/IGA as Unit 2.

[illegible] [illegible] [illegible]

A mid cycle MRPC inspection of Unit 2 after about 4.5 cycles of operation, U2M5, revealed additional axial indications.[3] However, of the 86 axial indications detected prior to chemical cleaning, all but 1 were determined to have been present at the end of the previous cycle. At this point, chemical cleaning was conducted. A combination of increased analyst experience and training, equipment improvements relative to the U2R4 outage and removal of deposits by chemical cleaning then led to the detection of a total of 330 axial indications. These confounding variables complicate the analysis of the rate of appearance of new indications. However, analysis of eddy current data in terms of crack growth rates points to the effectiveness of temperature and power reductions and elevated hydrazine levels in mitigating IGSCC/IGA degradation rates. Preliminary analysis of pulled tube data (crack face oxide compositions) also points to a lessening of aggressive chemical conditions in the last half cycle of operation.

No axial indications have been observed in Unit 1 after 4 operating cycles.[1] MRPC inspections of a total of 5038 tubes in the upper bundle arc region did not reveal a single axial indication. In terms of the onset of upper bundle IGSCC/IGA, Unit 1 clearly is superior to Unit 2. The quantitative implications of the inspection results for Unit 1 are utilized in Section 3. As discussed in a previous report, Unit 1 has a consistently better record of molar ratio control compared to Units 2 and 3, with an obvious implication of less aggressive crevice chemistries. Although the three units have a similar history of sulfate levels, only Unit 2 experienced a resin intrusion. In terms of the expected behavior of Unit 1 for the present cycle, boric acid treatment of the secondary side was initiated at the beginning of the cycle and elevated hydrazine levels were instituted two months into the operating cycle. Both of these factors are expected to mitigate the development of aggressive crevice chemistries. While Unit 2 pulled tube metallurgical studies indicated less than favorable metallurgical structures relative to caustic IGSCC, there is an indication that steam generator tubing in Unit 1 may be more resistant to caustic IGSCC/IGA. Five percent of the tubes in Unit 2 exhibit flow strengths higher than the highest strength tube in Unit 1. In summary, there are chemical and possible metallurgical factors which are consistent with the superior upper bundle corrosion degradation performance of Unit 1.

[illegible] [illegible] [illegible]

[illegible]

3.0 PROBABILITY OF DETECTION OF AXIAL CRACKS

Determining the probability of detection of axial IGSCC/IGA degradation is a key feature of both deterministic and probabilistic evaluations of acceptable run times based on meeting Regulatory Guide structural limits. For deterministic evaluations, a start of cycle crack depth must be assumed. In probabilistic evaluations, probability of detection curves can be used in a number of different approaches to estimate the populations of cracks in service as a function of run time. At the present time, upper bundle eddy current inspections at PVNGS are carried out using MRPC probes. Hence, the probability of an MRPC probe detecting axial IGSCC/IGA as a function of degradation depth is of interest.

Both industry wide data and Palo Verde pulled tube data is available to construct an MRPC probability of detection curve for axial IGSCC/IGA degradation. Obviously, the industry wide database is larger than the database specific to Palo Verde. A comparison of the number of data points is illustrated in figure 3.1. Using the industry data of Figure 3.1, a sigmoidal curve fit was obtained. This POD curve is plotted in Figure 3.2. Note that the crack depth is the maximum depth of cracking determined by destructive examination. A bar graph plot, comparable to the industry data of Figure 3.2, is shown in Figure 3.3 using data from the first Palo Verde Unit 2 tube exam. This plot, dealing with maximum crack depth, is being updated. At present, it is clear that the Palo Verde pulled tube data and MRPC inspection results are consistent with the industry database.

In the evaluation of structural limits, the crack depth parameter of interest is the average crack depth rather than the maximum crack depth. Through wall cracks of significant length will meet burst strength requirements. Maximum crack depth may be an issue relative to leakage, but, in terms of strength requirements, average crack depth is the parameter of concern. Figure 3.4 is a plot of maximum crack depth versus average crack depth for Palo Verde Unit 2 pulled tubes which have been burst tested. The significance of the burst test is that it reveals the crack length over which the average depth should be computed. The burst test reveals the structurally significant portion of the crack profile. It should be noted that if a complete crack profile is available, a technique has been developed to compute the structurally significant crack length and associated average depth.

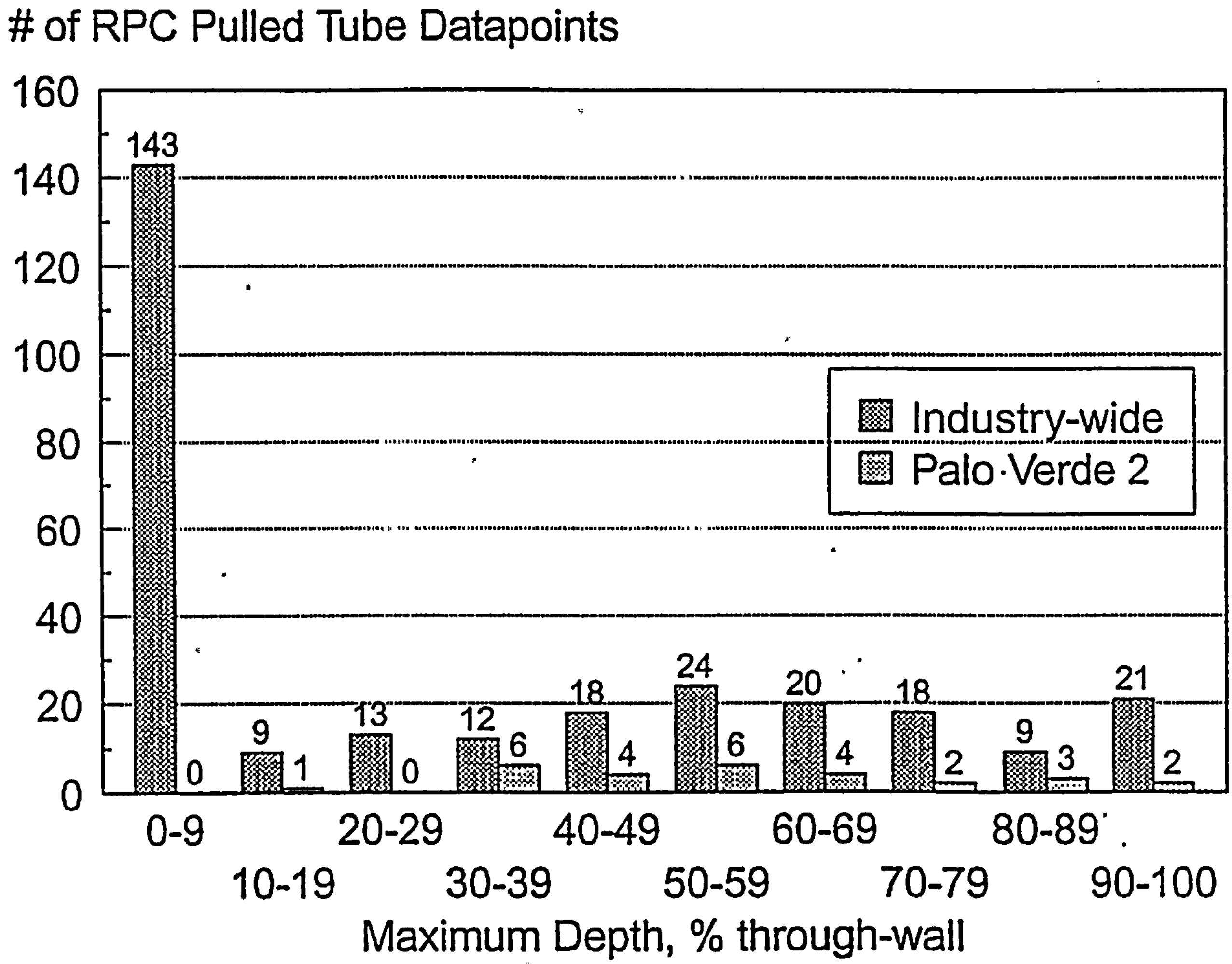


Figure 3.1 **Distribution of Pulled Tubes with Axial SCC With Respect to Crack Depth (% Through Wall.)**

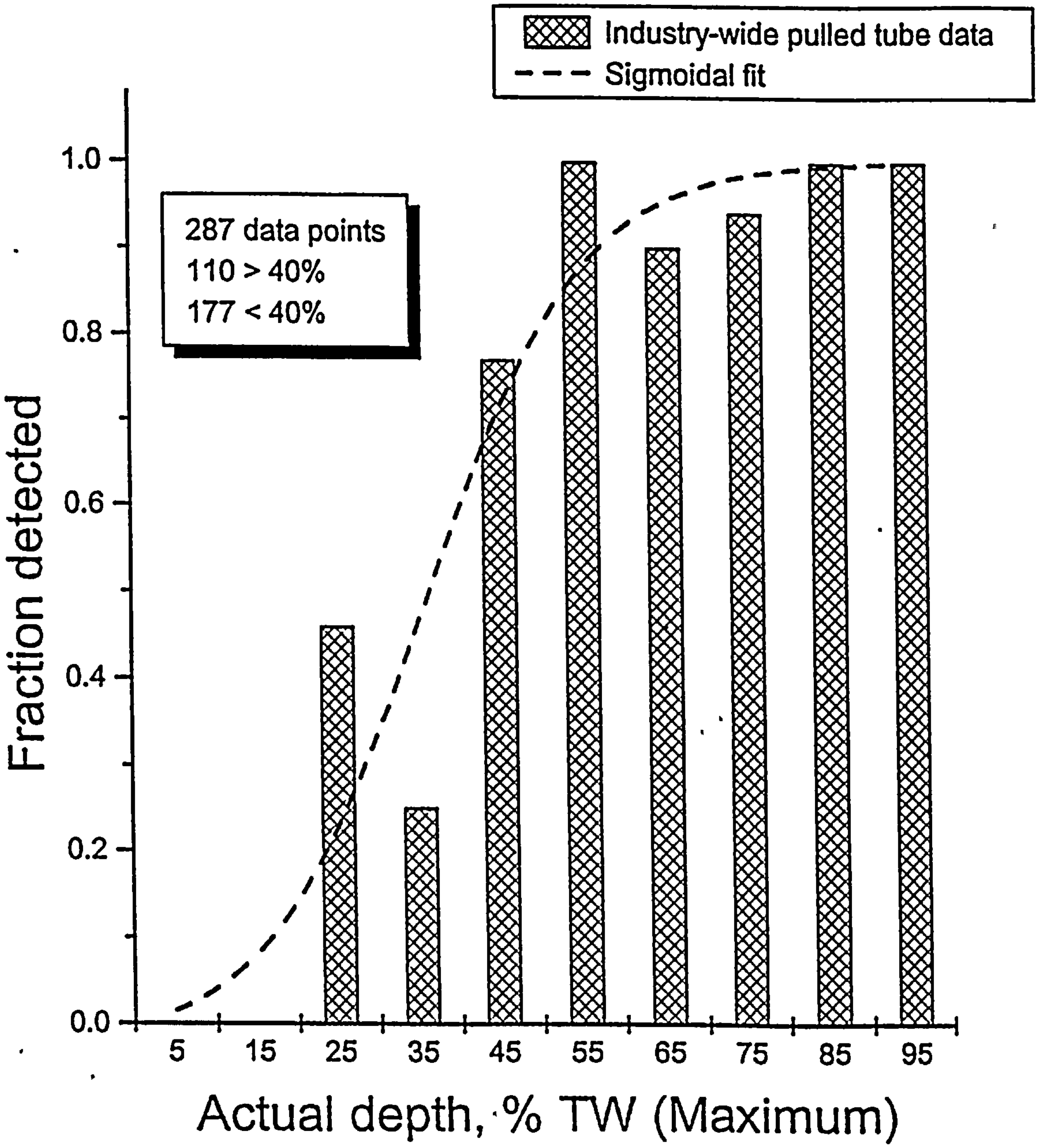


Figure 3.2 MRPC Probability of Detection Estimates for Axial SCC, Industry-wide Pulled Tube Database

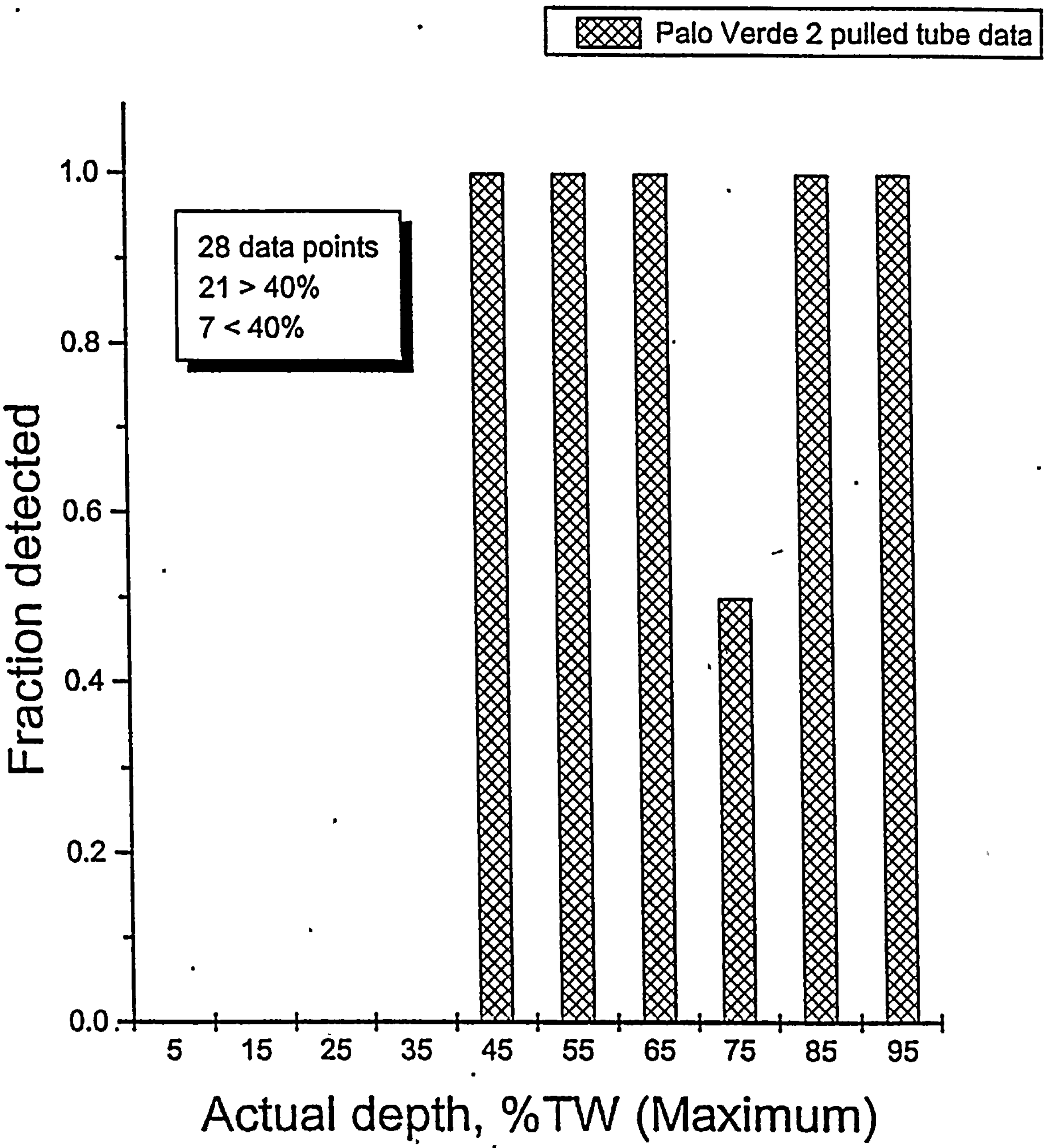


Figure 3.3 MRPC Probability of Detection Estimates for Axial SCC, Palo Verde Pulled Tube Database.

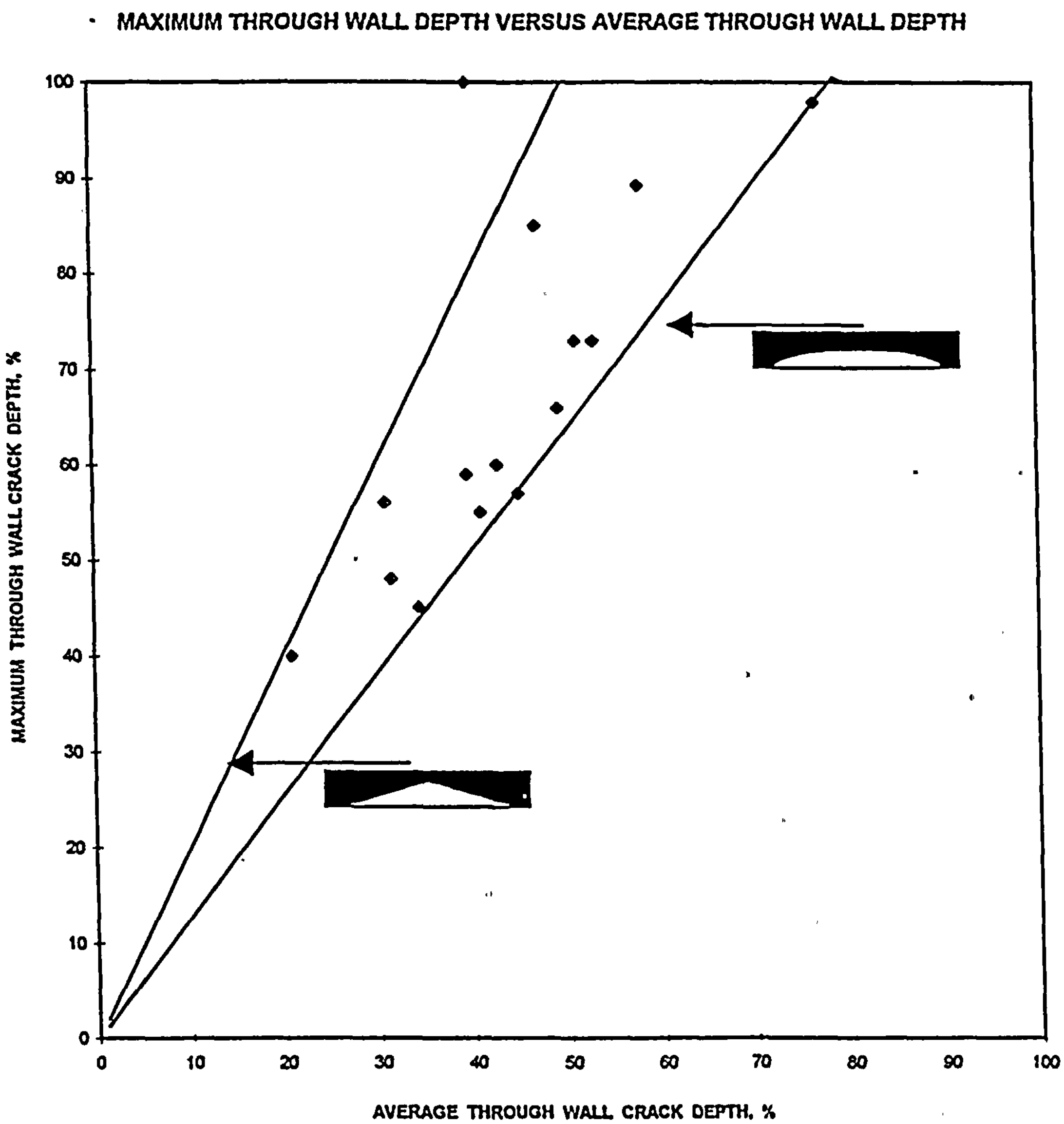


Figure 3.4 Maximum Through Wall Depth Versus Average Through Wall Depth, Palo Verde Unit 2 Pulled Tubes.

Two geometric shapes essentially bound the data of Figure 3.4. A likely candidate to bound the lower ratio of average crack depth to maximum crack depth is a triangle. A ratio of average to maximum depth greater than 0.5 would require a figure with concave sides, which is mechanistically improbable. An average to maximum depth ratio of 1 requires a rectangle. Since a square cornered profile is again mechanistically improbable, a more likely bounding figure is a semi-ellipse. In this case, the average to maximum depth ratio is Π/4. This figure is an excellent bound to actual observations. Using a conservative ratio of average to maximum crack depth of Π/4, the maximum depth POD curve of figure 3.2 can be converted to an average depth POD curve. Both average and maximum depth POD curves based on industry wide data are shown in Figure 3.5. A preliminary average depth POD curve is shown in Figure 3.6 using only measured depths from Palo Verde pulled tubes. Data from both Unit 2 tube exams is included. The Palo Verde and industry database POD curves based on average depth compare very well. If more data had been available at larger crack depths for the Palo Verde tubes, the two POD curves would be expected to be virtually coincident.

4.0 CHARACTERIZATION OF CRACK GROWTH RATES

The initial large scale, upper bundle, MRPC eddy current inspection at PVNGS was conducted in Unit 2 after 4 cycles of operation.[2] A total of 122 axial MRPC indications were found. Additional MRPC axial indications were found during the first mid-cycle inspection, U2M5, after 4.5 months of operation.[3] Of the indications found prior to chemical cleaning, all but one exhibited the presence of precursor signals upon review of the U2R4 inspection data. With the knowledge gained from U2R4 pulled tube examinations and improved eddy current analysis procedures, these precursor signals are now considered flaw indications and MRPC voltages can be assigned. Evaluation of crack profiles from pulled tubes from the both the U2R4 and U2M5 outages has led to an empirical correlation of average crack depth with maximum (vertical) MRPC voltage. Comparison of beginning of cycle and mid cycle MRPC voltages can be used to estimate crack growth rates.

There are two data sets of voltage pairs available for analysis. One data set is composed of voltages measured with a 0.080 inch diameter MRPC coil and the other refers to voltage pairs obtained with a 0.115 inch diameter coil MRPC probe. In many cases voltage pairs are available for the same tube with both size MRPC coils. Correlations of MRPC voltage with average crack depth have been developed for both 0.080 inch and 0.115 inch diameter MRPC coils. The data for

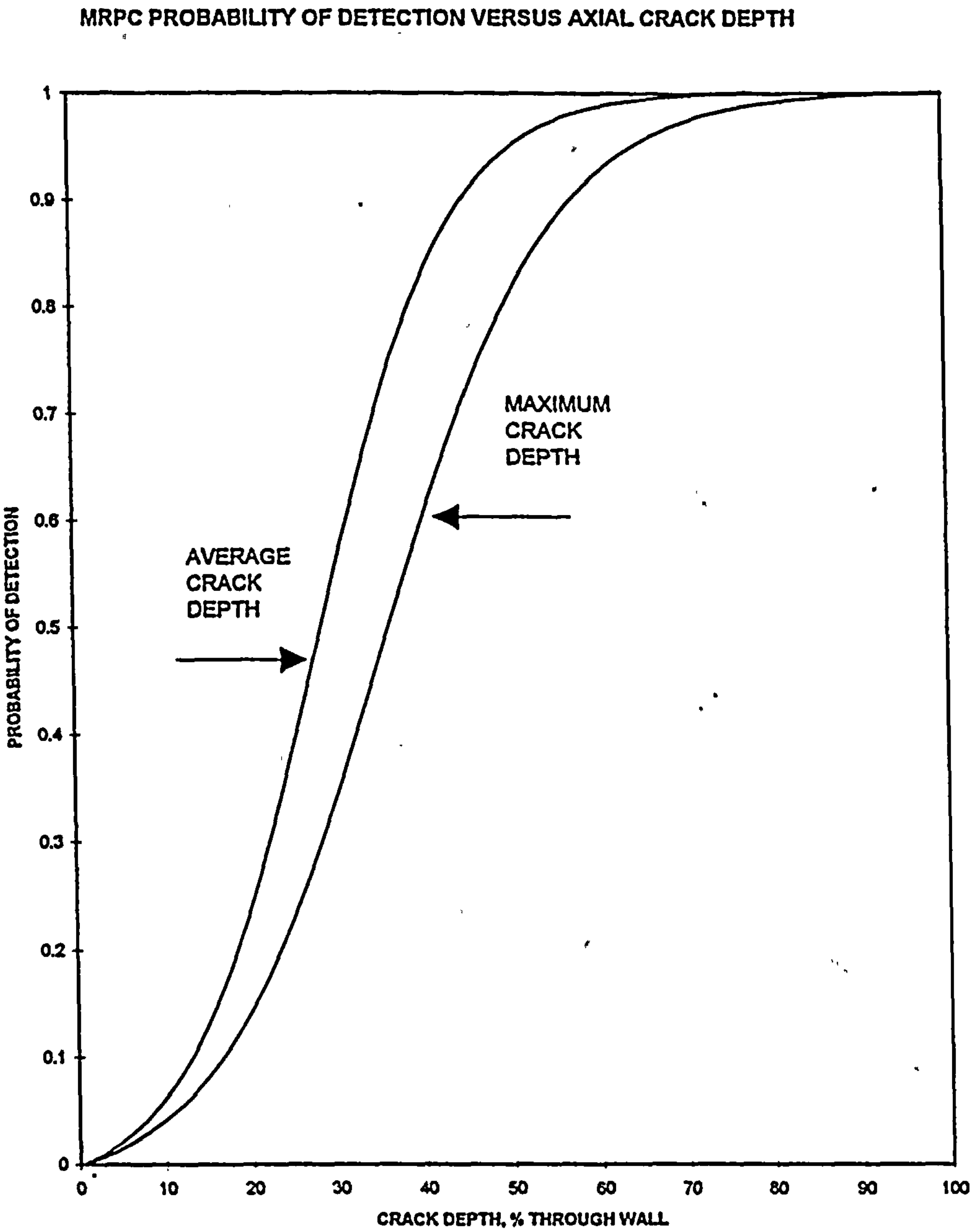


Figure 3.5 MRPC Probabilty of Detection Versus Axial Crack Depth.

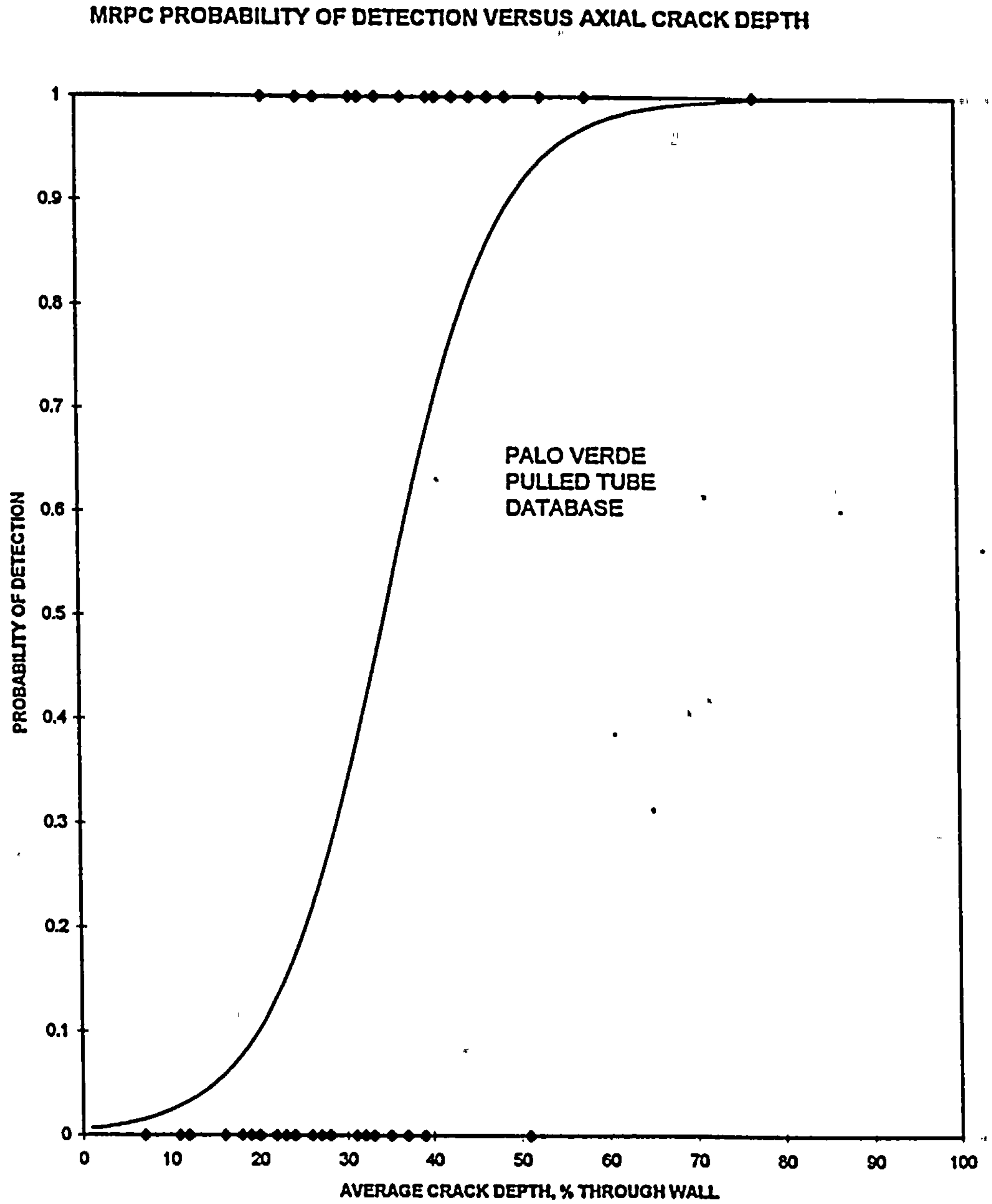


Figure 3.6 MRPC Probability ot Detection of Axial IGSCC/IGA Degradation Versus Average Degradation Depth, Palo Verde Pulled Tube Database

the 0.080 inch diameter coil covers a broader range of crack depths and this correlation is considered more reliable. Voltage data using 0.115 inch and 0.080 inch coils have been obtained on a set of tubes and a conversion function has been developed to convert voltage measurements from one size coil to another using a best fit linear relationship. The average crack depth - MRPC calibration curve is shown in Figure 4.1 for the 0.080 inch diameter coil. The circled points refer to results converted from the larger size coil. Figure 4.2 shows a replot of this data in terms of voltage relative to a 0.115 inch coil.

Figures 4.3 and 4.4 illustrate a comparison of MRPC voltages at the beginning of cycle 5 for Unit 2 and again after 4.5 months of operation. There is a consistent increase in voltage levels from one inspection to the next. This is true for both sizes of MRPC coils. Some voltage changes are negative, but, in general, the scatter in voltage measurements does not obscure the fact of increased voltage levels after operation for 4.5 months. Additional analysis shows that the increase in voltage is not correlated with the beginning of cycle voltage.

The substantial scatter in crack depth at a given voltage is large. Hence for any given voltage pair, the possible range in crack depths is large. Fortunately the large number of data points and data sets for two sizes of MRPC coils makes it reasonable to estimate most likely crack growth rates and then examine the range of these values. At a given beginning of cycle voltage, the most likely crack depth is on the best fit line. One choice for the end of cycle crack depth is simply the best fit straight line value at the indicated voltage. On this basis a decrease in crack depth would be indicated for some voltage pairs. While scatter in voltage measurements is expected, negative crack growth is not sensible. The crack depth at the mid cycle inspection is selected on the following basis; a decrease in crack depth is not allowed and the selected crack depth is either on the best fit line or midway between the beginning of cycle depth and the upper range of the scatterband at the mid cycle voltage. The upper scatterband is selected as a line with the same slope as the best fit line which bounds all data. The crack growth rate is obtained from the difference in beginning of cycle and mid-cycle crack depths divided by the run time of 4.5 months.

With the above calculational procedure, crack growth rates were obtained from a total of 155 voltage pairs. The number of voltage pairs available from the two MRPC coil sizes are about equal. Statistical analysis showed that the crack growth rate populations obtained from large and small coil MRPC inspections were not significantly different and could be considered as part of the same population.

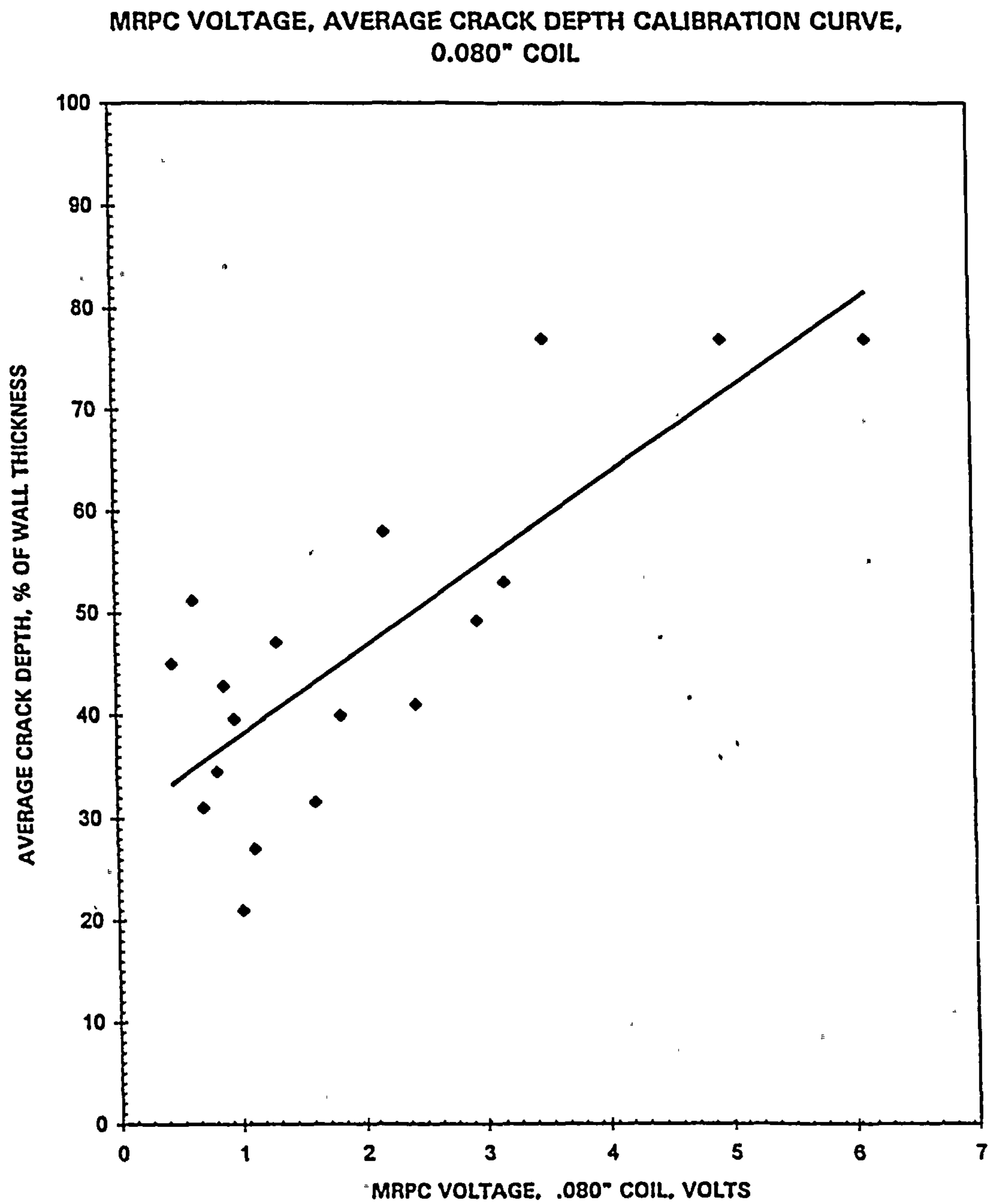


Figure 4.1 Average Crack Depths Versus MRPC Voltage, 0.080" Diameter Coil.

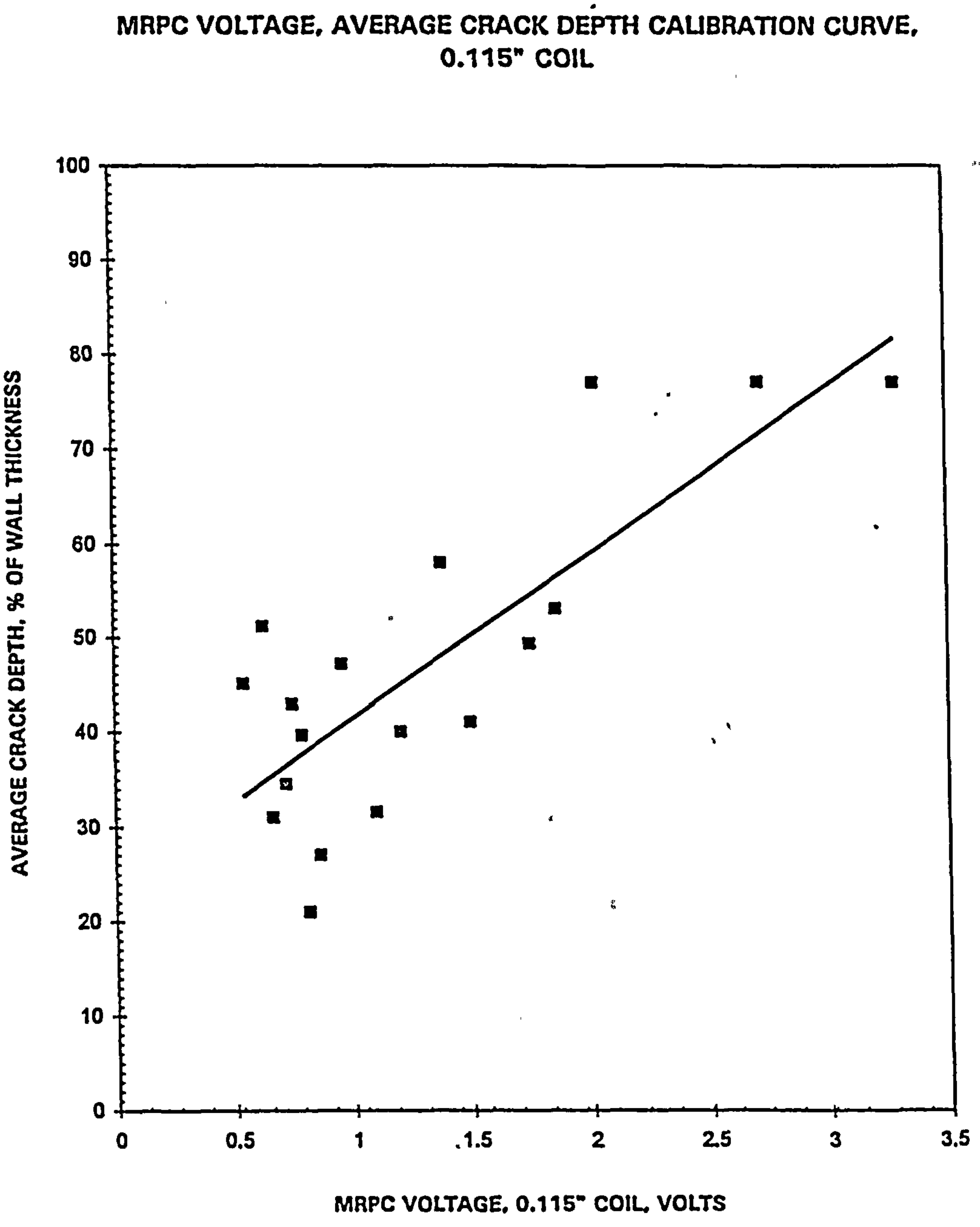


Figure 4.2 Average Crack Depths Versus MRPC Voltage, 0.115" Diameter Coil.

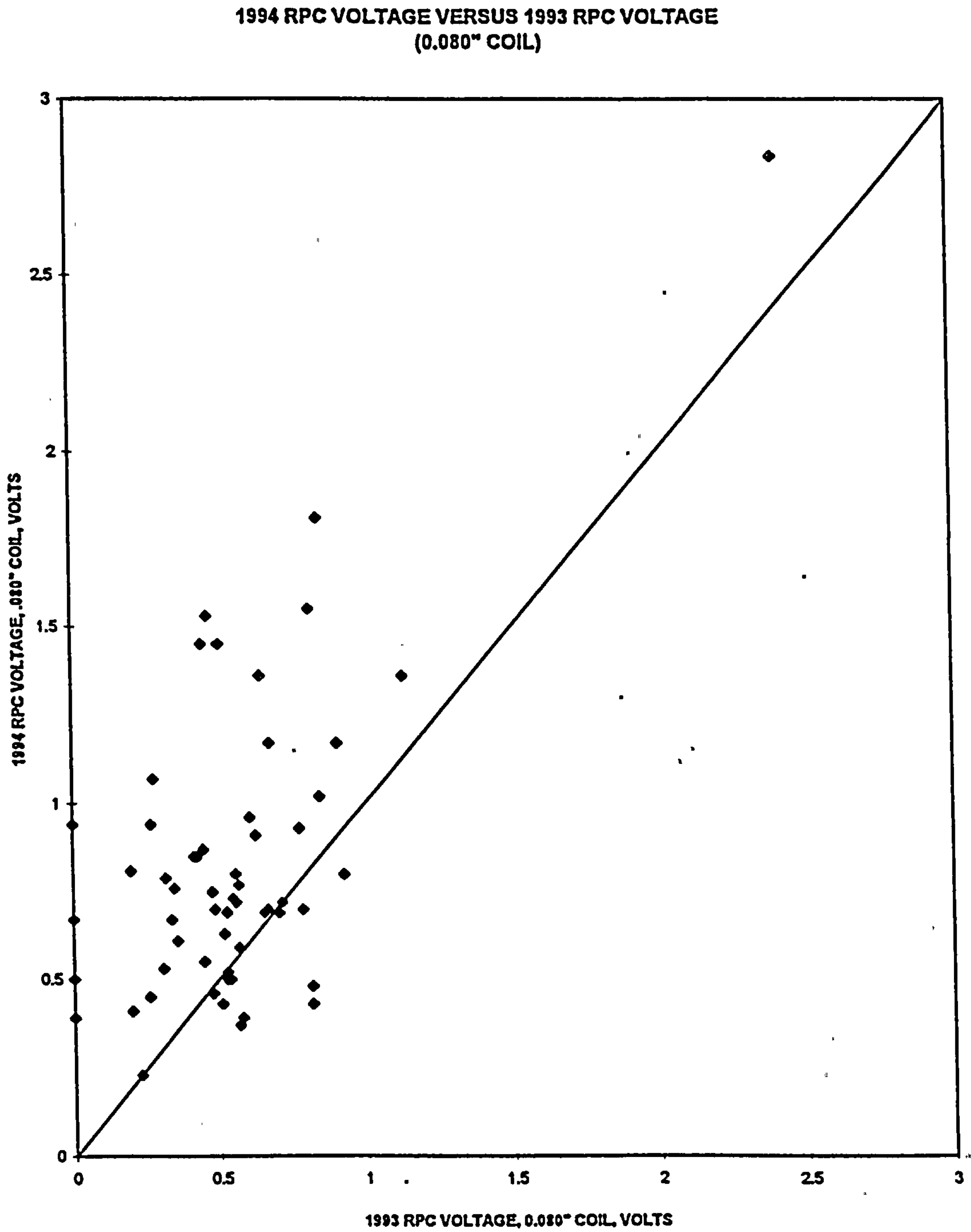


Figure 4.3 MRPC Voltage of Indications at U2M5 Versus MRPC Voltage of Same Indications at U2R4, 0.080" Diameter Coil.

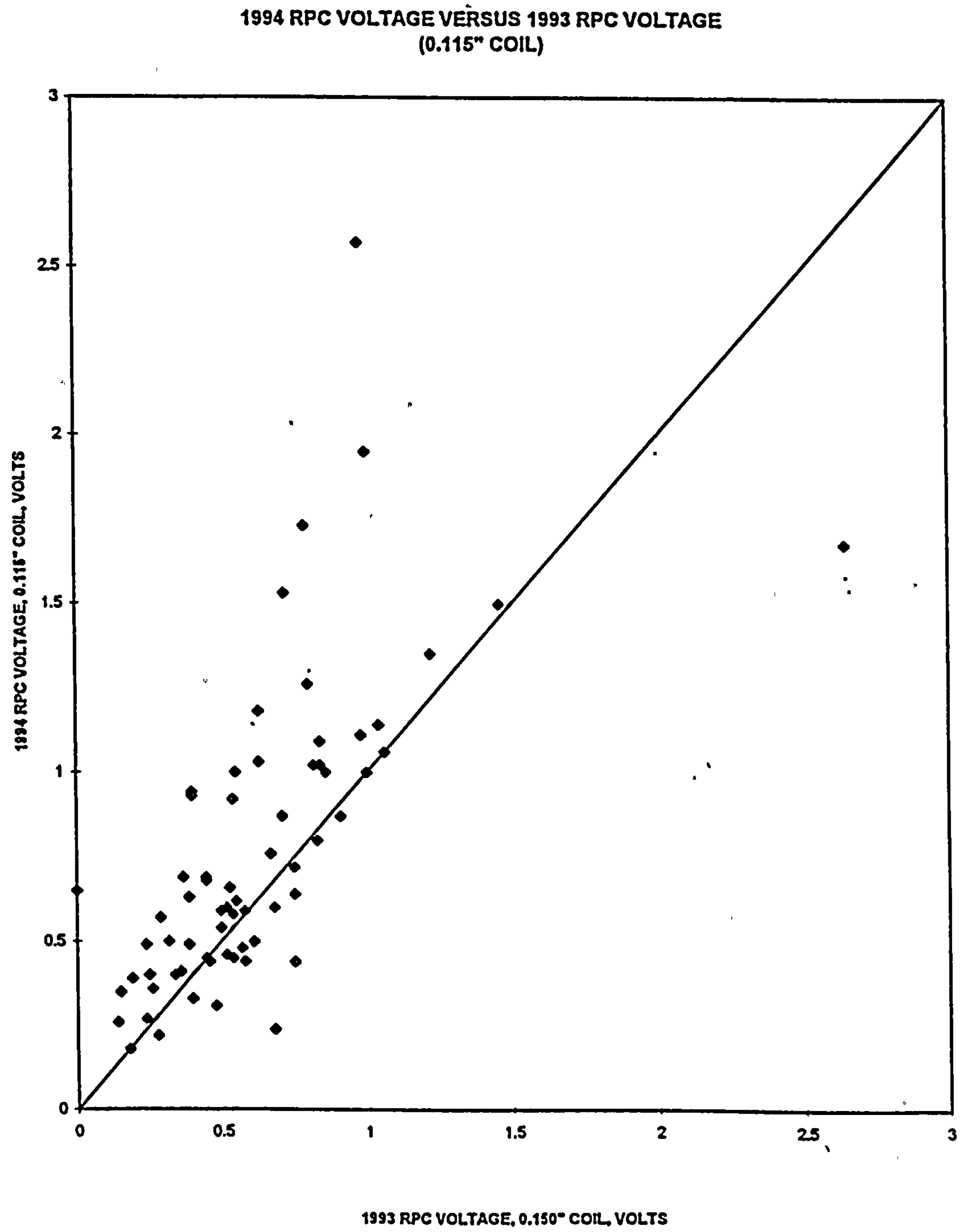


Figure 4.4 MRPC Voltages of Indications at U2M5 Versus MRPC Voltage of Same Indications at U2R4, 0.115" Diameter Coil.

[illegible]

A lognormal probability distribution function fitted to these crack growth rates is shown in Figure 4.5. The most likely crack growth rate is about 28% through wall per effective full power year. This is about 1mil per month. The bar graph representation shows the upper range of estimated crack growth rates to be about 45% through wall per effective full power year, or about 1.6 mils/month. These crack growth rates are somewhat slower than those estimated from bobbin coil eddy current data collected during the U2R4 outage. Several other approaches to estimating crack growth rates from MRPC data are under development. Crack growth rates will be updated as alternative approaches are completed.

As discussed in previous reports,[2-3] estimated crack growth rates are a reasonable fit to data in the literature.[4-14] Data for IGSCC and IGA degradation rates in caustic environments are shown in Figures 4.6 through 4.8. A significant IGA component was noted in the examination of the first tubes pulled form Unit 2. Fractographic and metallographic examination of tubes pulled during the Unit 2 mid cycle outage indicate a somewhat enhanced IGA nature with a morphology that has been termed cellular corrosion or cellular IGA. Since propagation rates for IGA are approximately an order of magnitude slower that IGSCC rates in caustic environments, tube examination results support the use of crack growth rates at least on the low side of the IGSCC scatterband, if not lower.

The above discussions basically refer to observations of IGSCC/IGA degradation rates relative to Unit 2. Given the excellent upper bundle performance of Unit 1, it is conservative to apply these crack growth rates to Unit 1 structural integrity evaluations in a straightforward manner. As discussed in the next section, crack growth rates were increased to account for higher temperature operation for part of the Unit 1 cycle. Better molar ratio control, the absence of resin intrusions, boric acid addition and high hydrazine levels in Unit 1 point to the conservative nature of crack growth assumptions applied in the Unit 1 analysis.

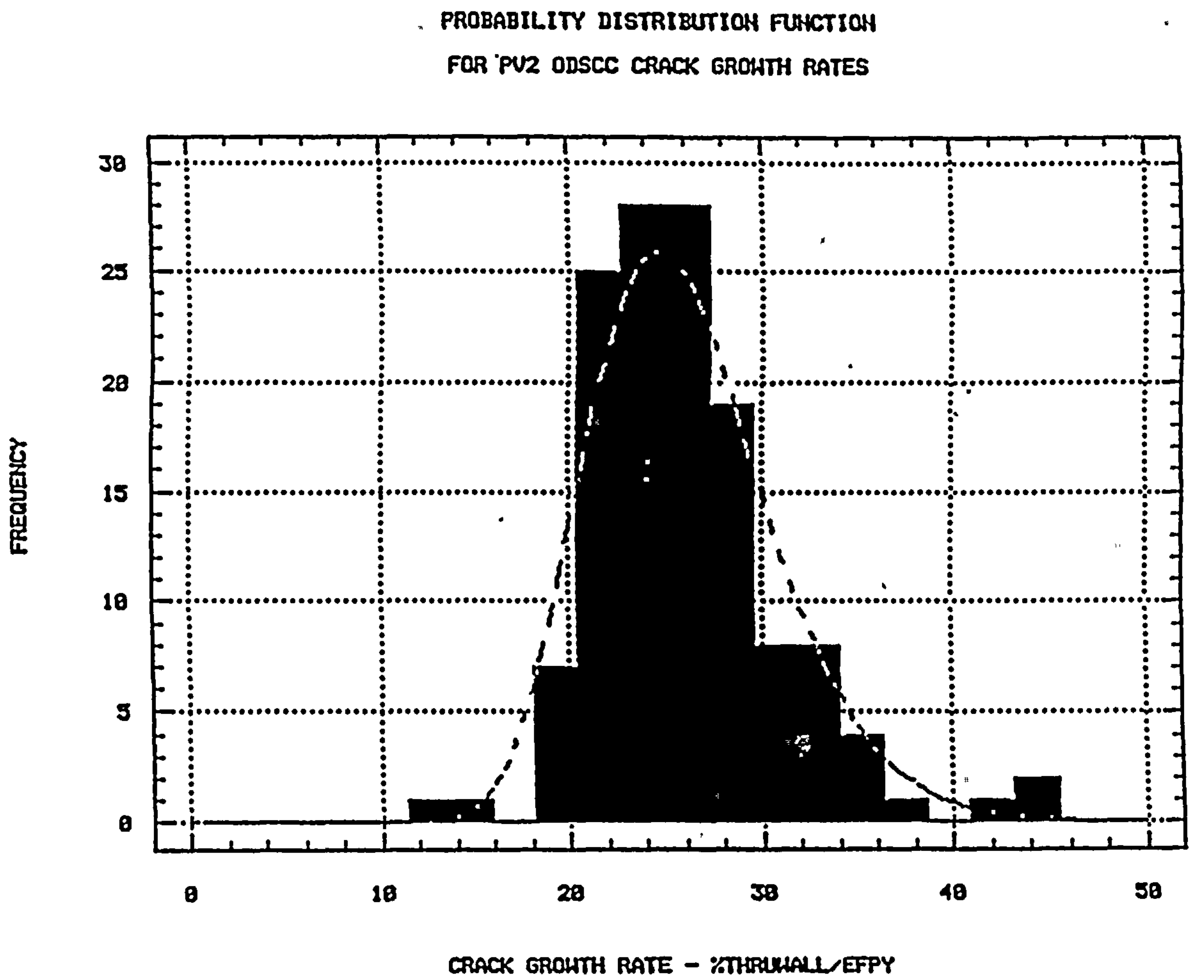


Figure 4.5 Distribution of Crack Growth Rates Calculated From MRPC Voltages.

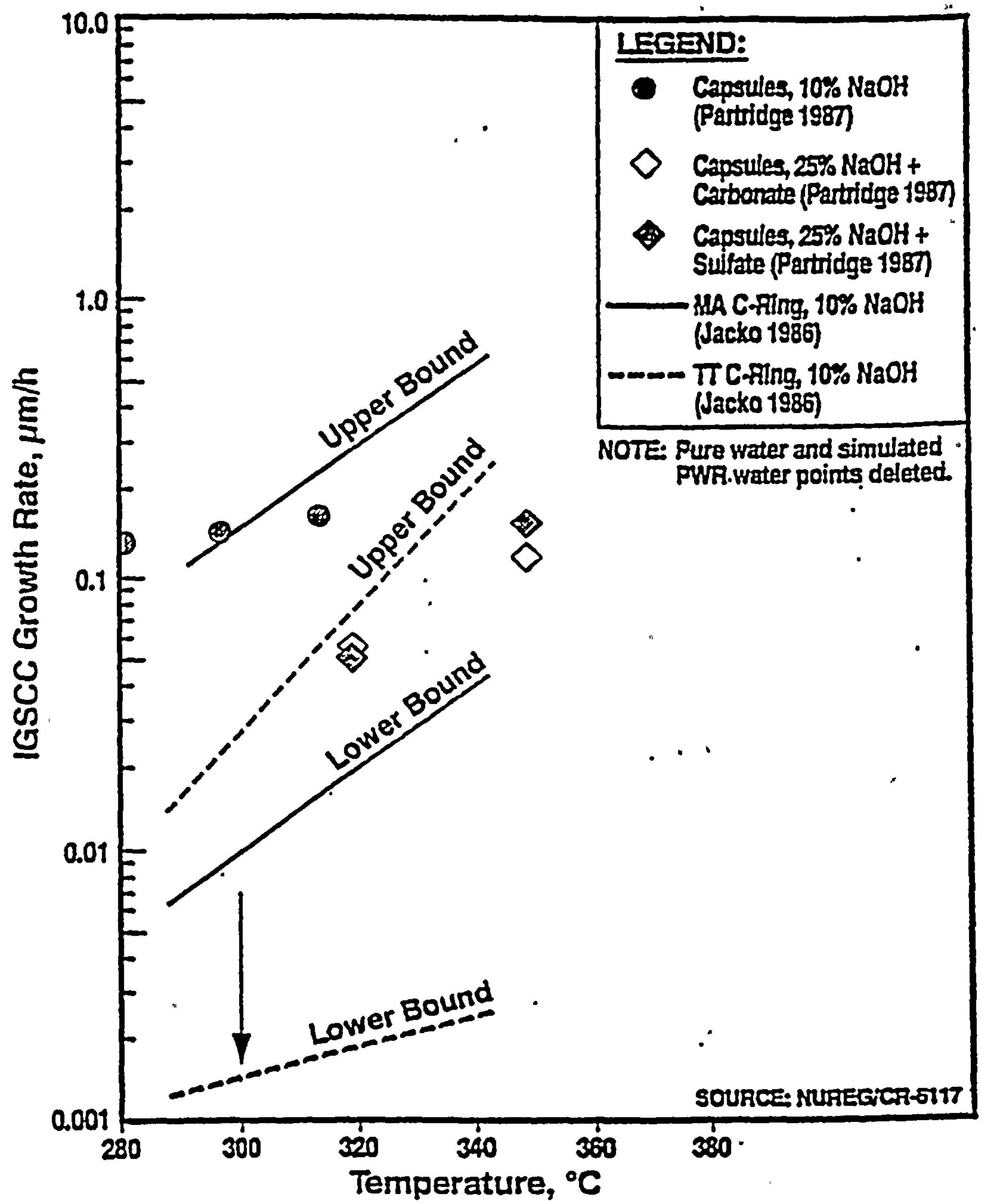


Figure 4.6 Growth Rates of Intergranular Stress Corrosion Cracks in Alloy 600 Versus Temperature Concentrated Caustic Solutions.

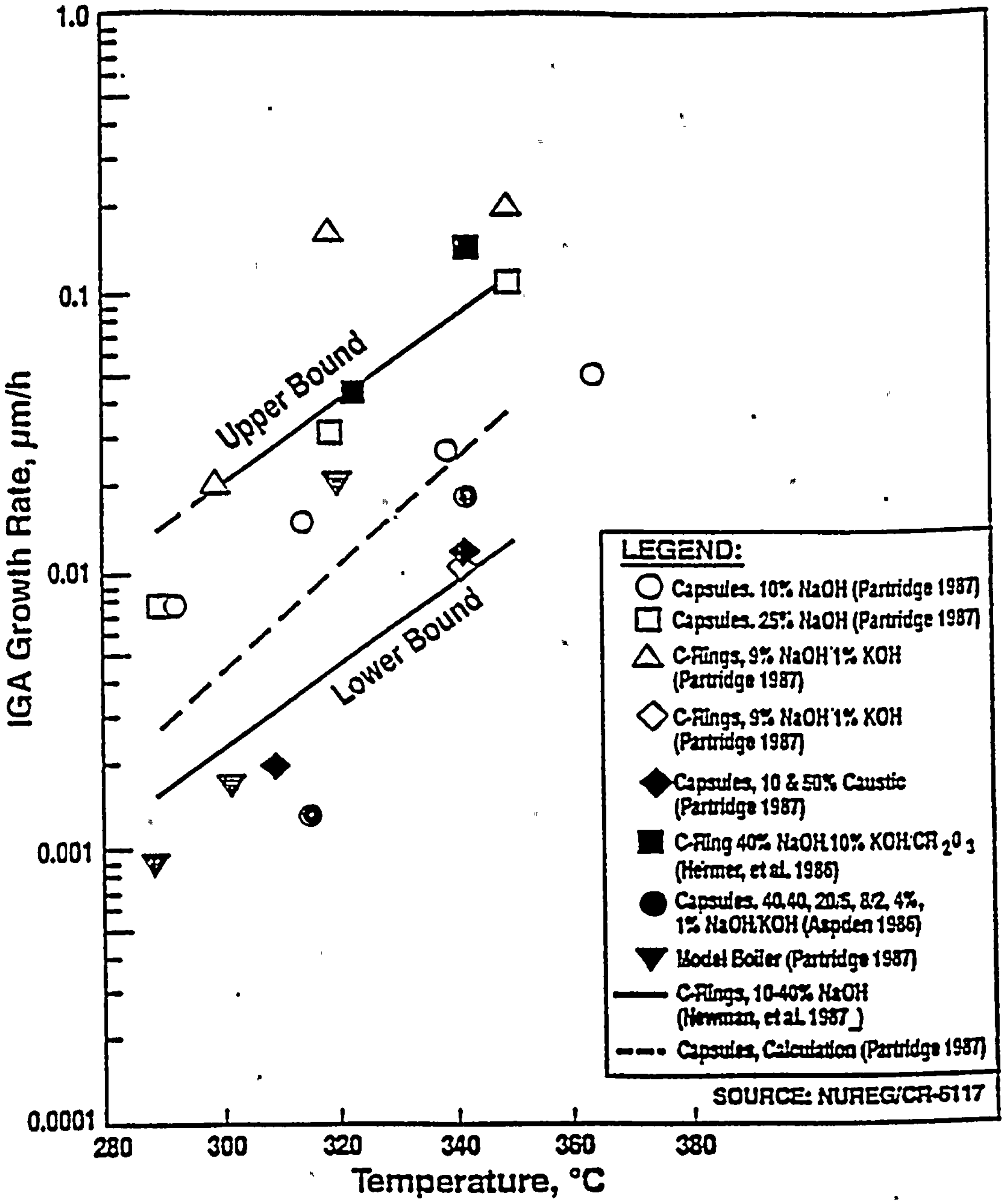


Figure 4.7 Growth Rates of Intergranular Attack In Alloy 600 Versus Temperature, Concentrated Caustic Solutions.

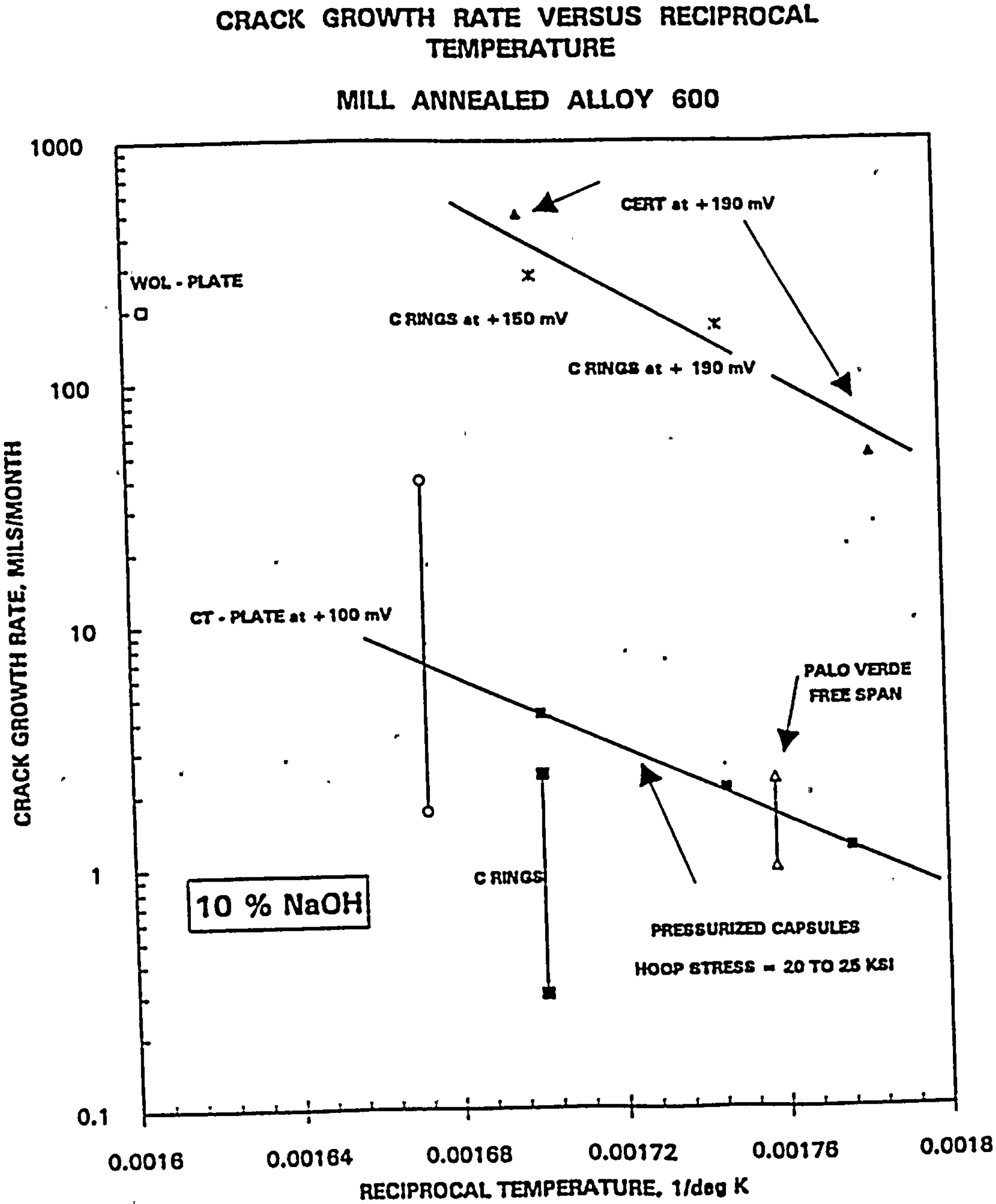


Figure 4.8 Growth Rates of Stress Corrosion Cracks Versus Reciprocal Temperature, Alloy 600 Tested in 10% NaOH.

5.0 PROBABILISTIC ANALYSIS

5.1 DESCRIPTION OF PROBABILISTIC MODEL

The probabilistic model developed for the Unit 1 upper bundle ODSCC RG 1.121 analysis is similar to one developed for circumferential cracking at the tubesheet[15] and is designed to reflect four basic processes:

- Upper bundle axial crack initiation
- Crack growth
- MRPC inspection
- Removal/repair of degraded tubes

Each of these processes, with the possible exception of repair, has large components of associated uncertainty. This characteristic requires the implementation of a fully probabilistic overall model in order to realistically assess the permissible operating/inspection periods for the Palo Verde Unit 1 generator. Enhancements to the probabilistic modeling include incorporation of material property distributional effects and flaw length distributional effects obtained form Unit 2 mid-cycle outage data analysis. In addition, an improved probability of detection function (POD) was incorporated into the model.

5.1.1 Crack Initiation and Growth Models

The crack initiation process is simulated by the well known Weibull time-to-failure function given by:

$$P(t) = e^{-(T/B)^{N}}$$

where: P (t) = proportion of tubes experiencing cracking by time T

N = shape parameter
B = scale parameter

The parameters for the Weibull distribution have physical significance. The scale parameter (B) is the exposure time at which approximately 63% of the population at risk is expected to have failed. The shape parameter (N) has significance in terms of hazard rate as shown in Figure 5.1. For $N<1$, the hazard rate is decreasing such as is typical of electronic components during the "burn-in" period. For $N=1$, the hazard rate is constant and the Weibull model becomes equivalent to an Exponential model. For $N>1$, the hazard rate increases with exposure time, a situation typical of most corrosion phenomena. The range of interest for steam generator tube modeling appears to be:

$$1<N<6$$

Gorman[16] has provided an extensive catalog of Weibull parameter estimates based on worldwide operating plant data. This of course represents data from cracks which have progressed well beyond initiation into the detectable regime. It can be experimentally shown, however, that this represents only a time delay function for reasonable crack growth rate distributions which can be easily accommodated by a minor adjustment to the scale parameter (B).

For Palo Verde Unit 1 which has experienced no upper bundle axial cracking as of the most recent inspection, Weibull parameters were developed from Unit 2 behavior. The shape parameter used in the analysis has a relatively conservative value of 5.5 typical of IGA/IGSCC phenomena in HTMA tubing. The scale parameter was developed on the basis of null inspection results for the R4 inspection outage. The value of the scale parameter ultimately chosen is in fact the lowest (most conservative) value for which the Weibull model would predict a zero incidence of axial cracks at reasonable probability (5%).

The crack growth model discussed in Section 4 was incorporated into the simulation in log-normal form (Figure 4.5). Since the data was obtained from the most recent Unit 2 inspection results, adjustments were made to the growth rate to compensate for temperature differences (611°F vs. 605°F). It should be noted that the average through wall crack propagation rate based on Unit 2 data was significantly less adverse in the extremes than those observed in circumferential cracking at the tube sheet.

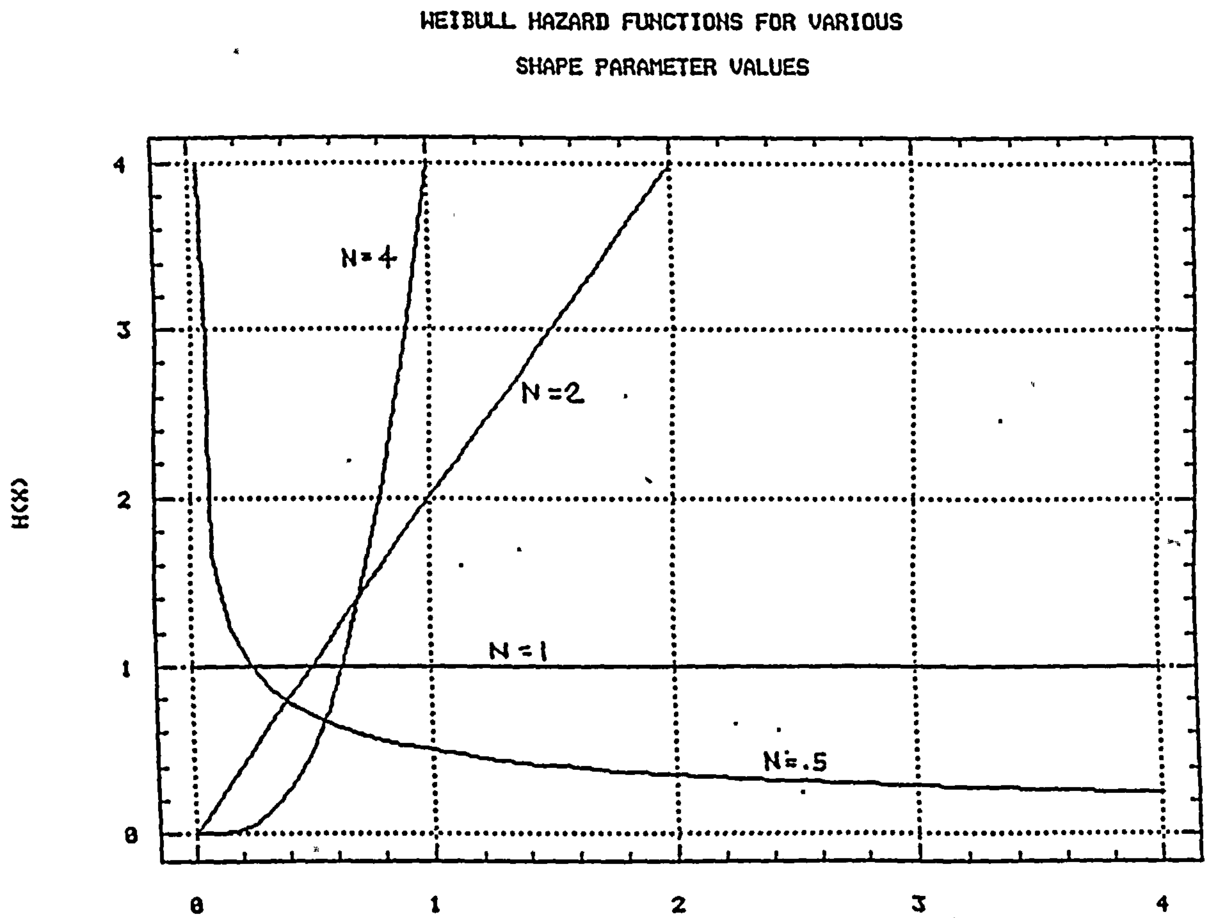


Figure 5.1 Weibull Hazard Functions for Various Shape Parameter Values.

[illegible]

5.1.2 Inspection/Repair Model

The inspection/repair process for circumferential cracking is completely dependent on the capabilities of the inspection methodology, in this case MRPC. Simulation of the inspection/repair process requires the probabilistic implementation of a probability of detection function (POD). For this purpose a new POD function discussed in Section 3 was included in the simulation. Implementation of the inspection process is straightforward. At a given inspection time, each of a group of active cracks is subjected to a probability of detection function. Corresponding to each crack is a POD based on the function. A uniformly distributed random number is chosen to decide if a given crack is detected. If the crack is detected it is removed from further service or subsequent inspection.

5.1.3 Material Property and Crack Length Effects

The most significant differences between the axial and circumferential cracking simulations involve the inclusion of material and crack length effects. The material property effects are included by obtaining randomized flow stress values specific to Unit 1 tubing. The crack length effects are included by sampling from Unit 2 measurements (Figure 5.2). In both cases, the probabilistic effects are reflected as distributional terms in the implementation of Regulatory Guide Limits for axial cracks.

5.1.4 Simulation of Overall Process

The computer simulation of the overall process is shown conceptually in Figure 5.3 and consists of steps reflecting the four basic processes discussed in Section 4.1. The initial sequence involves the computation of crack population size, crack initiation times, and crack growth rates for given Monte-Carlo trial. The population size (NMAX) is determined from the Weibull initiation model and the final inspection time for a given case. The crack initiation times (TI_i) for a given sample are determined from a randomized selection using the Weibull initiation model.

[illegible]

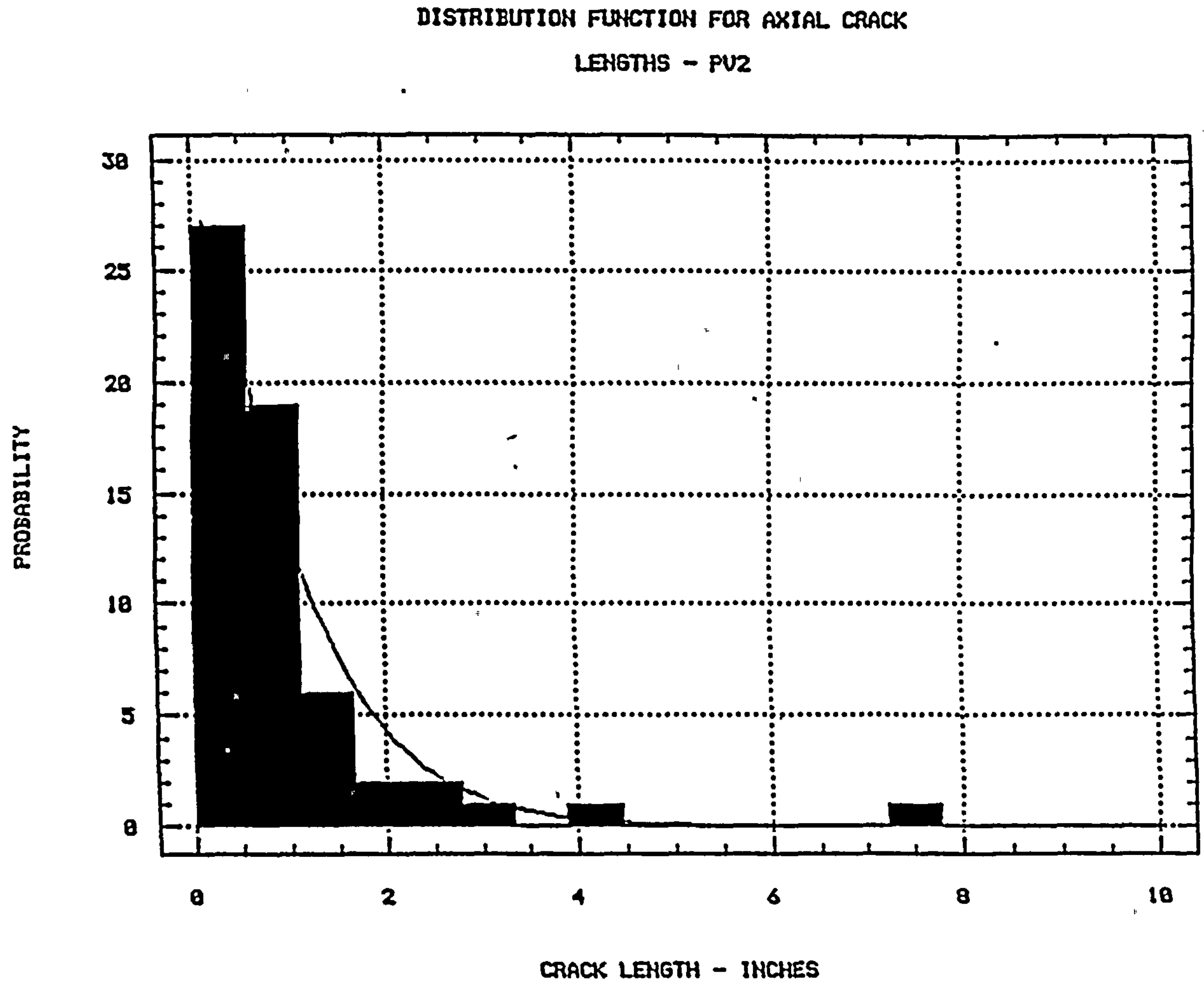


Figure 5.2 Distribution Function for Axial Cracks Based on Unit 2 MRPC Data.

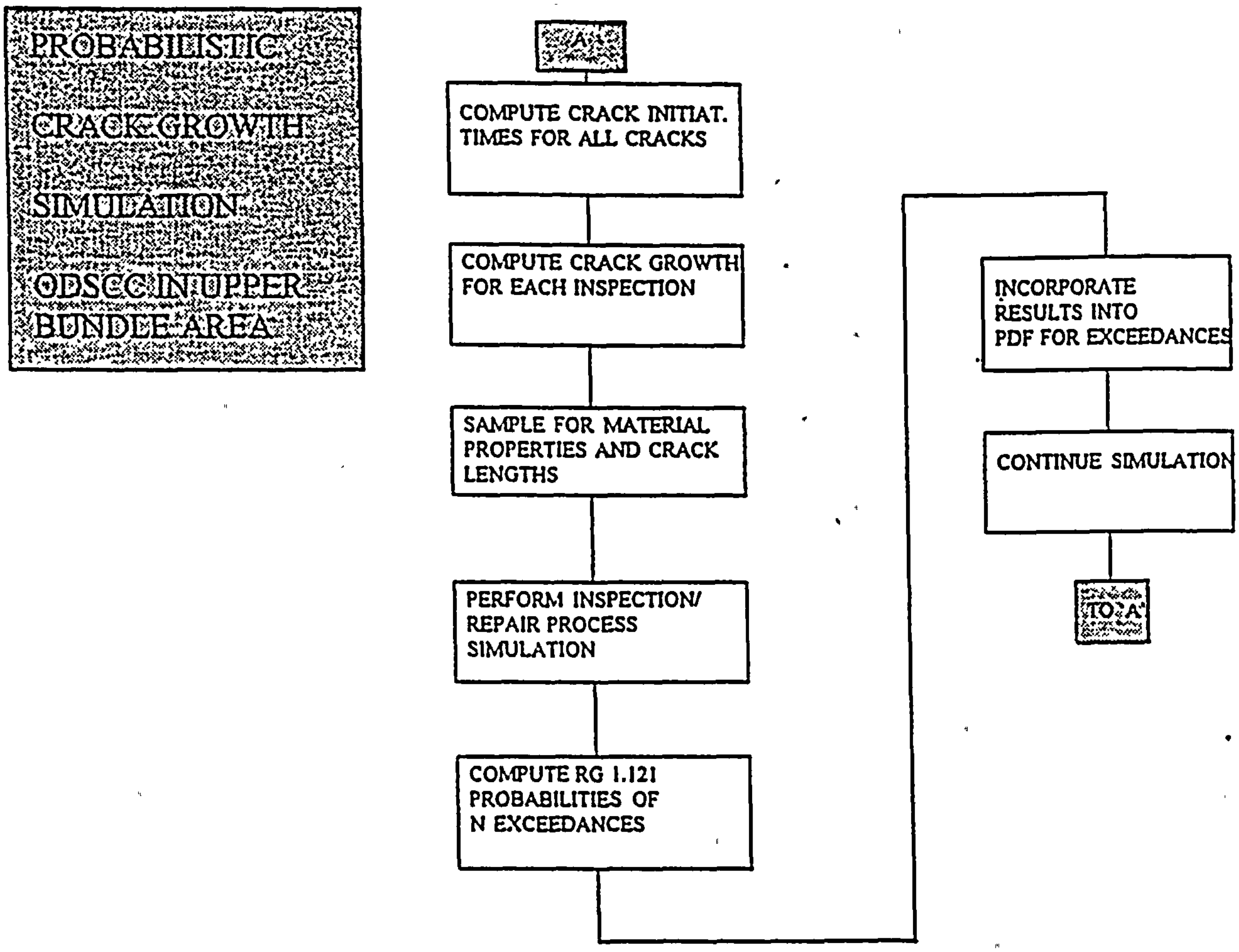


Figure 5.3 Flowchart for Computer Simulation of Crack Initiation, Crowth, Detection, Removal/Repair and Structural Limit Check.

Log-normal random deviates are used to obtain crack growth rates (V_i) for each crack and are assumed to be constant throughout the propagation process.

The second sequence computes a matrix of crack sizes (D_{ij}) for each inspection time (T_j) in the simulation process:

$$D_{ij} = V_i (T_j - TI_i) \qquad (4)$$

$$D_{ij} = 0 \text{ if: } TI_i > T_j \qquad (5)$$

i.e. crack has not initiated prior to inspection

i = crack identity index
j = inspection time index

The third sequence is the simulation of the inspection/repair process. The process proceeds in time sequence beginning with the first inspection time ($T_{j=1}$). Each crack is subjected to a pseudo-inspection in which the POD function is used in conjunction with a uniform random number to determine if a given crack is detected. An identification matrix (I_{ij}) is used to track the status of crack detection and repair (removal from service):

$I_{ij} = 0$ for undetected cracks
$I_{ij} = 1$ for newly detected cracks
$I_{ij} = 2$ for repaired cracks
($I_{ij} = 2$ if $I_{ij-1} = 1$)

The final sequence in the simulation is the examination of newly detected cracks ($I_{ij} = 1$) to determine the number of exceedances of RG 1.121 criteria. This is performed by examining crack depths (D_{ij}) for each inspection period. For the Palo Verde Unit 1 cases, criteria reflecting variations in tube material properties and crack lengths were used.

The above sequences, taken in total, represent one outcome or Monte-Carlo trial. The overall process is repeated 1000 times to develop distribution functions for the number of RG 1.121 exceedances for each inspection interval.

[illegible] [illegible] [illegible]

5.2 OPERATING CYCLE LENGTH EVALUATION

The Palo Verde Unit 1 operating cycle length evaluation consists of a simulator case run for Unit 1 operating conditions of 611°F for periods varying from 200 day operation to 425 day operation. Specific newly implemented model capabilities included :

- Improved POD function for axial cracks
- Unit 1 specific tube material property distribution
- Axial crack length distribution (from Unit 2 MRPC inspections)

All cases were run with a POD function which permitted detection of no cracks with average depths less than 5% through wall and permitted detection of all cracks with average depths greater than 75% through wall. For the purposes of crack initiation, a temperature correction was performed using an activation energy of 50 Kcal/mole. For crack propagation an activation energy of 30 Kcal/mole was used. The crack initiation Weibull functions are shown in Figure 5.4. The output for the case set is included in the Appendix A tables. The probabilities of various numbers of tubes exceeding RG 1.121 limits are given for several run lengths and three future outages.

The allowable operating cycle length can be obtained from the case set results using a probabilistic acceptance criterion. For each case set the following example acceptance criterion was applied:

- There must be a 90% probability that one or fewer tubes will be expected to violate RG1.121 limits for axial cracks during the current operating period.

The results of the case included in Appendix A show an accepted operating period of 425 days for Palo Verde Unit 1 based on the above criterion. These results are specific to axial cracking in the upper bundle area.

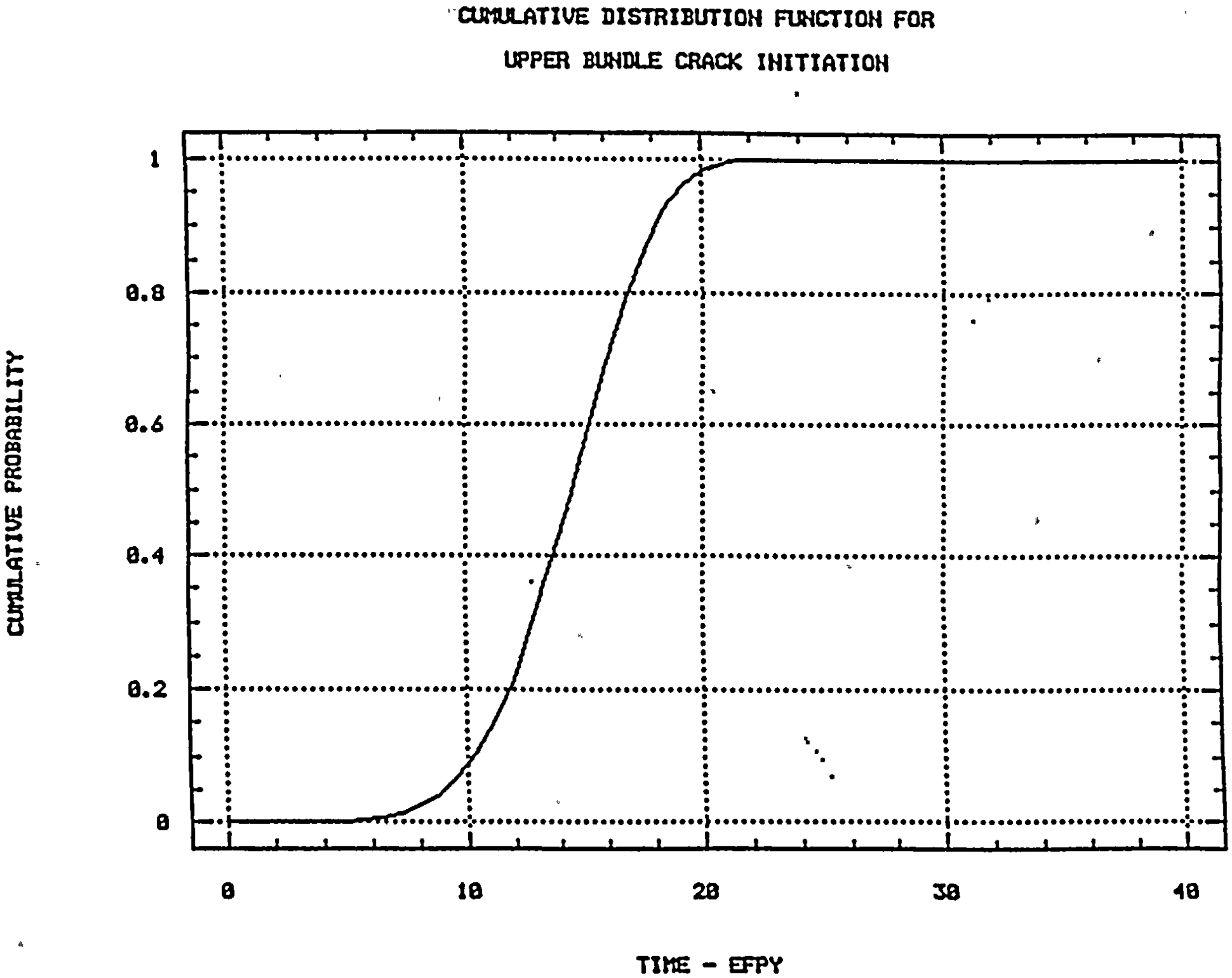


Figure 5.4 Cumulative Distribution Function for Upper Bundle Axial IGSCC/IGA Initiation.

[illegible]

6.0 SUMMARY AND CONCLUSIONS

An analysis was conducted of the probability of upper bundle, axial IGSCC/IGA leading to the exceedance of Regulatory Guide 1.121 structural limits for Unit 1 at the Palo Verde Nuclear Generating Station. Although there have been no NDE indications of the presence of upper bundle IGSCC/IGA in Unit 1 after 4 operating cycles, the detection of upper bundle corrosion degradation of tubing in Units 1 and 3 does raise the possibility of similar corrosion degradation in Unit 1 at some later date.

A fully probabilistic model was constructed to reflect the basic ongoing processes of crack initiation, crack growth, periodic MRPC inspection, and removal/repair of degraded tubes. The past performance of all steam generators at PVNGS together with the industry wide, historical performance of steam generators with Alloy 600 tubing was considered in the development of conservative cracking statistics for application to Unit 1. An updated MRPC probability of detection curve is part of the present model as are revised crack growth rates and fully probabilistic treatments of tube material properties and axial degradation lengths.

The probability of structural limit exceedances caused by upper bundle IGSCC/IGA was calculated as a function of run time for the current Unit 1 cycle of operation. Past history and changes in operating conditions are included. Projections for additional operating cycles are also included. With the chosen probabilistic approach and selected cracking statistics, a reasonable, prudent acceptance criteria is that there must be a 90% or better probability that only one or fewer tubes will be calculated to violate RG 1.121 limits for operating period of interest. On this basis, a run time of 425 days is acceptable for the current Unit 1 operating cycle

7.0 REFERENCES

1. Palo Verde Nuclear Generating Station, Units 1 and 3 Return to 100% Power Report, June, 1994

2. Palo Verde Nuclear Generating Station, Unit 2 Steam Generator Tube Rupture Analysis Report, July, 1993

3. Palo Verde Nuclear Generating Station, Unit 2 Steam Generator Inspection Report, Mid-Cycle Outage, March, 1994

4. Crum, J. R., "Stress Corrosion Cracking Testing of Inconel Alloys 600 and 690 Under High Temperature Caustic Conditions, Corrosion, Vol. 42, No. 6, June, 1986.

5. Bandy, R., Roberge, R., and van Rooyen, D., "Intergranular Failures of Alloy 600 in High Temperature Caustic Environments", Corrosion, Vol. 41, No. 3, March, 1985.

6. Konda, N., Toyama, K., Yamanaka, K., and Tokimasa, K., "Environmental Effects on the Crack Growth Properties of Alloy 600", International Journal of Pressure Vessels and Piping, Vol. 52, 1992.

7. Berge, Ph., and Donati, J. R., "Materials Requirements for Pressurized Water Reactor Steam Generator Tubing", Nuclear Technology, Vol. 55, October, 1981.

8. Airey, G. P., "Effect of Processing Variables on the Caustic Stress Corrosion Resistance of Inconel Alloy 600", Corrosion, Vol. 36, No. 1, January, 1980.

9. Pathania, R. S., and Chitty, J. A., "Stress Corrosion Cracking of Steam Generator Tube Materials in Sodium Hydroxide Solutions", Corrosion, Vol. 34, No. 11, November, 1978.

10. Pathania, R. S., "Caustic Cracking of Steam Generator Tube Materials", Corrosion, Vol. 34, No. 5, May, 1978.

11. Pesall, N., Airey, G. P., and Lingenfelter, B. P., "The Influence of Thermal Treatment on the SCC Behavior of Inconel Alloy 600 at Controlled Potentials in 10% Caustic Soda Solutions at 315° C", Corrosion, Vol. 35, No. 3, March, 1979.

12. Crum, J. R., "Effect of Composition and Heat Treatment on Stress Corroison Cracking of Alloy 600 Steam Generator Tubes in Sodium Hydroxide", Corrosion, Vo. 38, No. 1, January, 1982.

13. Cels, J. R., "Caustic Stress Corrosion Cracking Studies at 288° C (550° F) Using the Straining Electrode Technique - Comparison of Alloy 600, Allo6 800, and Type 304 Stainless Steel", Corrosion, Vol. 36, No. 4, 1978.

14. Kurtz, R. J., Clark, R. A., Bradley, E. R., Bowen, W. M., Doctor, P. G., Ferris, R. H., and Simonen, F. A., "Steam Generator Tube Integrity Program/Steam Generator Group Project" Final Project Summary Report, PNL-6446, NUREG/CR- 5117.

15. Hall, J., Woodman, B. W., Maurer, R. S., Radspinner, M., "Palo Verde-1 Steam Generator Tube Regulatory Guide Analysis for Primary Side Circumferential Cracking, ABB Combustion Engineering Nuclear Operations, V-PENG-TR-003, Rev. 1, May, 1994.

16. Gorman, J. A., Staehle, R. S., and Stavropoulos, K. D., "Statistical Analysis of Steam Generator Tube Degradation", EPRI Final Report, Project S405-9, EPRI NP-7493, September, 1991.

APPENDIX A
PALO VERDE UNIT ONE
SIMULATION OF UPPER BUNDLE CRACKING

TABLE A.1

PROBABILITY OF REGULATORY GUIDE 1.121 EXCEEDANCE

RUN TIME = 200 DAYS

Number of Tubes	Outage 0	Outage 1	Outage 2	Outage 3
0	0.8990	0.9890	0.9850	0.9850
1	0.9940	1.0000	0.9980	1.0000
2	1.0000	1.0000	1.0000	1.0000
3	1.0000	1.0000	1.0000	1.0000

RUN TIME = 350 DAYS

Number of Tubes	Outage 0	Outage 1	Outage 2	Outage 3
0	0.8800	0.8960	0.8230	0.7670
1	0.9930	0.9930	0.9890	0.9770
2	1.0000	1.0000	0.9990	0.9990
3	1.0000	1.0000	1.0000	1.0000

RUN TIME = 425 DAYS

Number of Tubes	Outage 0	Outage 1	Outage 2	Outage 3
0	0.8880	0.7940	0.6840	0.5290
1	0.9950	0.9670	0.9420	0.8490
2	0.9990	0.9960	0.9920	0.9710
3	1.0000	1.0000	1.0000	0.9980