(7-77)

# LICENSEE EVENT REPORT

UPDATE REPORT
PREVIOUS REPORT DATE 012380

CONTROL BLOCK: (1) (PLEASE PRINT OR TYPE ALL REQUIRED INFORMATION)

| | | |
|---|---|---|
| 01 | Licensee Code (2) | M N P I N 2 |
| 01 | License Number (3) | 0 0 - 0 0 0 0 0 - 0 0 |
| 01 | License Type (4) | 4 1 1 1 1 |
| 01 | CAT (5) | |
| 01 CON'T | Report Source (6) | L |
| 01 | Docket Number (7) | 0 5 0 0 0 3 0 6 |
| 01 | Event Date (8) | 0 1 0 9 8 0 |
| 01 | Report Date (9) | 0 3 0 6 8 0 |

EVENT DESCRIPTION AND PROBABLE CONSEQUENCES (10)

02 During eddy current testing of tubes in Unit 2 steam generators, several
03 indications of tube degradation were seen. See attached details.

| Line | System Code (11) | Cause Code (12) | Cause Subcode (13) | Component Code (14) | Comp. Subcode (15) | Valve Subcode (16) |
|---|---|---|---|---|---|---|
| 09 | C B | E | D | H T E X C H | F | Z |

(17) LER/RO REPORT NUMBER

| Event Year | | Sequential Report No. | | Occurrence Code | Report Type | | Revision No. |
|---|---|---|---|---|---|---|---|
| 8 0 | — | 0 0 3 | / | 0 1 | x | — | 1 |

| Action Taken (18) | Future Action (19) | Effect on Plant (20) | Shutdown Method (21) | Hours (22) | Attachment Submitted (23) | NPRD-4 Form Sub. (24) | Prime Comp. Supplier (25) | Component Manufacturer (26) |
|---|---|---|---|---|---|---|---|---|
| B | X | C | Z | 0 1 4 4 | Y | Y | N | W 1 2 0 |

CAUSE DESCRIPTION AND CORRECTIVE ACTIONS (27)

10 Several tubes were plugged and one tube was removed for further examination. See
11 attached details.

| Line | Facility Status (28) | % Power (29) | Other Status (30) | Method of Discovery (31) | Discovery Description (32) |
|---|---|---|---|---|---|
| 15 | H | 0 0 0 | N/A | B | Eddy current testing |

| Line | Activity Released (33) | Content of Release (34) | Amount of Activity (35) | Location of Release (36) |
|---|---|---|---|---|
| 16 | Z | Z | NA | NA |

PERSONNEL EXPOSURES

| Line | Number (37) | Type (38) | Description (39) |
|---|---|---|---|
| 17 | 0 0 0 | Z | NA |

PERSONNEL INJURIES

| Line | Number (40) | Description (41) |
|---|---|---|
| 18 | 0 0 0 | NA |

LOSS OF OR DAMAGE TO FACILITY (43)

| | Type (42) | Description |
|---|---|---|
| 19 | Z | NA |

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PUBLICITY

| Line | Issued (44) | Description (45) |
|---|---|---|
| 20 | N | NA |

NRC USE ONLY

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GPO 917-926

## Event Description

Eddy current examinations of tubing in both Prairie Island Unit 2 steam generators (S.G. No. 21 and No. 22) were performed (January 7-18, 1980), during the recent refueling outage. In addition to complying with Technical Specification requirements, the examination plan was focused on the peripheral tubes in the inlet side of both steam generators. These examinations of the peripheral tubes were planned to determine if there were any signs of tube damage due to foreign objects.

Westinghouse, along with technical support from Zetec Corporation, was contracted to perform and evaluate the data from the eddy current examinations. These examinations were performed using Westinghouse's new multi-frequency eddy current testing system. This system provided increased analytical capability for determining tube integrity. The four frequencies and their modes that were used for each examination were 400 KHz, 100 KHz and 10 KHz in the differential mode and 100 KHz in the absolute mode.

In addition, Westinghouse was contracted to perform a visual examination, using mirrors and fiber optics, of both steam generators to detect the presence of foreign objects.

During the completion of the eddy current inspection for the inlet side of S.G. No. 21, one tube (row 1 column 1) was detected as having a 66% OD indication approximately 17 inches above the tube sheet. Due to the location of this tube and the indication, and with no other indications detected, foreign object damage was suspected. (This tube damage was later confirmed as being caused by the improper installation of the tube lane blocking device which is a plate assembly used to redirect flow across the tube sheet. See Figure 5.) Thus, the examination plan for the outlet side of S.G. No. 21 was increased to include the entire periphery of the tube bundle.

The results of the tube inspection for the outlet side of S.G. No. 21 revealed signs of tube deterioration in six of the peripheral tubes. These indications were located at either the first or second tube support. The inspection plan of the outlet side was expanded until it was sufficiently demonstrated that this tube deterioration was primarily confined to the tubes at the periphery of the tube bundle at the first and second tube supports.

A similar inspection was performed on S.G. No. 22 and resulted in similar findings. Figures 1, 2, 3 and 4 identify the tubes that were inspected and those tubes that were plugged for the inlet and outlet side of both steam generators. Table I identifies the percentage of tubes that were inspected and Table II provides a tabulation of the number of deteriorated tubes for each steam generator.

Attachment to P-RO-80-3 (con't)

Cause Description

Corrosion; see Appendix A for a preliminary report on examination of the removed tube.

Corrective Actions

a. Tube Plugging

The plugging criterion of the Technical Specification is 50% of tube wall thinning. Additional conservatism was used and all tubes that had areas of wall thinning greater than 43% were plugged. In addition, as a preventive measure, the tubes that are directly in line with the tube lane blocking devices, which are the row 1 column 1 and the row 1 column 94 tubes, were plugged in both steam generators. (This measure was taken even though improvements in design were made to assure proper location and locking of these blocking devices.) Table III identifies all the tubes that were plugged during this outage.

Westinghouse was also contracted to pull one of the degraded tubes and perform the necessary analysis to determine the mechanism for tube wall deterioration. The results of this analytical work substantiated the eddy current results.

b. Chemistry Surveillance

A program of investigation into the secondary chemistry of the unit was started. Sludge lance samples from the Jan. - Feb. '80 outage were sent to NWT, Inc. for analysis. These samples were from both 21 and 22 steam generators. The week of February 3, 1980, a Westinghouse chemistry support group was called in to analyze steam generator water during the unit startup. Analyses were run at discrete points and additional samples gathered for further analysis at Pittsburgh. At the same time NSP chemistry personnel ran heatup analyses and drew concurrent grab samples for shipment to NWT, Inc. Westinghouse left the site on 2/8/80 with the samples.

NSP continued to sample the subsequent cooldown and heatup on 2/9 and 2/10 with onsite analyses and grab samples to be air freighted to NWT, Inc. on 2/11. Then during the power escalation dual samples were drawn at discrete power levels for both Westinghouse and NWT, Inc. and these were air shipped on 2/21. These samples will all be subjected to ion chromatography for anion and cation identification and quantification.

Plant personnel will duplicate the samples drawn on Unit 2 with samples from the Unit 1 startup during the week of 2/25. These samples will be sent to both NWT, Inc. and Westinghouse to be analyzed and compared to the Unit 2 data in an attempt to identify any inconsistencies. NSP is in the process

b. Chemistry Surveillance (con't)

of purchasing an ion chromatography unit that will allow analysis to be done for low level anions and cations on the site. A review of chemistry logs from Unit 2 for the past five years revealed no trends that would warrant any present changes in chemical operating procedures and practices. NSP will continue to work with Westinghouse and NWT, Inc., an EPRI-funded consultant on steam generator chemistry, to identify the species of concern.

c. Condensate Polisher Operation

The condensate polishing system was put into service for the first time during December 1977. Resin bleed-through was suspected with the earliest use of the system because of a slight increase in steam generator cation conductivity during a relatively short time period each time a polisher was put into service. Because of the bleed-through problem it was decided to use the system sparingly until the problem could be corrected. Consequently, the system was operated during startup to eliminate the heavy sediment load from getting to the steam generators and for testing purposes to check out changes in the polisher design. It was also used to test different types of powdered resin performance. Some of the individual polisher runs were quite long while other polisher runs were of very short duration. A total of 32 precoats were applied to Unit #2 polishers and 25 precoats to Unit #1 polishers.

It was determined that the major problems contributing to resin bleed-through were inadequate pre-coat which would allow bleed-through via the unprecoated septum area, reclaim water containing precoat material which is used for back flushing the polisher during the initial filter change operation, and resin collection within low velocity areas in the septums during precoating which moves into the steam generator upon initiation of full flow operation. Also, the use of different brand name resin and different quality resin needed to be investigated to determine which resulted in the lowest bleed-through and yet maintain the ion exchange capacity needed.

The inadequate precoat problem was solved with the assistance of the manufacturer. A small scale vessel was built in April of 1978 and by August 1978 a new baffle system was demonstrated acceptable. The first distribution baffle was installed in 21 polisher November 1978. Additional problems were encountered requiring redesign and testing. This was accomplished and a new design installed in 21 polisher December 1978. A long testing run was initiated using 21 polisher with very good precoating results. However, each new precoat produced a cation conductivity rise in the steam generator when initially placed on the line. The 22 polisher and 23 polisher were modified in August of 79. The 12 and 13 polisher were modified in October of 1979. Number 11 polisher was modified in January of 1980. A series of bleed-through tests were completed on 21 and 22 polisher during August and September of 1979. Results indicated several hundred ppb resin fines within the first 10 minutes, then 1 or 2 ppb (lower limit of detection) after 30 minutes on-line.

c. Condensate Polisher Operation (con't)

Reclaim water used to flush powdered resin material from the polisher was found to contain resin fines. This was due to the inability of the clamshell filter system to adequately clean the water for reuse. The reclaim water system needed a modification to correct the problem. Because the system was not functioning properly all water used for flushing and precoating was taken from the condensate storage tanks.

The problem of resin deposits in the septums results because of the design. During precoating the lower flow velocity allows resin particles to settle within the septum which is on the discharge surface. Upon initiation of full flow the higher velocity washes this resin into the steam generators. Possible solutions such as higher velocity precoating flow and the redesign of the septum are being considered.

Seven different types of powdered resins have been tested on-line. The best results (smallest bleed-through) appears to be with a special pre-washed resin. At least one test with this resin resulted in little or no noticeable increase in steam generator cation conductivity upon initiation of full flow. This resin is selected for use in the event the polishers would be needed for operation.

Our intent is to use the polisher only when necessary until the problems are resolved. The polishers will be used in the event of a very small condenser leak because with the present modifications and changes to our operation the benefit of polisher operation may outweigh the disadvantage of a small amount of resin bleed-through.

Operation of the polisher during plant startup and operation for special testing will be considered on a case-by-case basis until the steam generator thinning problem is resolved.

d. Future Examinations

Future steam generator examinations will be done with a plan similar to what was done on Unit 2 in the 1980 refueling. All tubes with previous indications will be examined, except of course those that were plugged.

e. Summary of NSP-NRC Meeting

Appendix B contains a summary of material presented at the February 12 meeting.

<u>TABLE I</u>

Amount and Extent of Eddy Current Examination for Prairie Island Unit 2
Steam Generator Tubes - January 1980

| STEAM GENERATOR NUMBER & TUBE SIDE | EXAMINATION AMOUNT | EXTENT | TUBE PERCENTAGE |
|---|---|---|---|
| 21 Inlet | 119 | Past 7th Support | 3.5% |
| | 315 | Around U-Bend | 9.0% |
| | 63 | Tight Radius U-Bend | 1.9% |
| 21 Outlet | 429 | Past 3rd Support | 12.7% |
| | 266 | Past 7th Support | 7.9% |
| | 27 | Tight Radius U-Bend | 1.0% |
| 22 Inlet | 80 | Past 1st Support | 2.0% |
| | 105 | Past 7th Support | 3.0% |
| | 318 | Around U-Bend | 9.0% |
| | 89 | Tight Radius U-Bend | 2.6% |
| 22 Outlet | 3 | Past 1st Support | 0.0% |
| | 928 | Past 3rd Support | 27.0% |
| | 212 | Past 7th Support | 6.0% |

## TABLE II

**S.G. No. 21**

| % OF WALL THINNING | NUMBER OF TUBES INLET | OUTLET |
|---|---|---|
| ≥50% | 1 | 1 |
| ≥20%, <50% | 0 | 10 |
| <20% | 0 | 29 |

**S.G. No. 22**

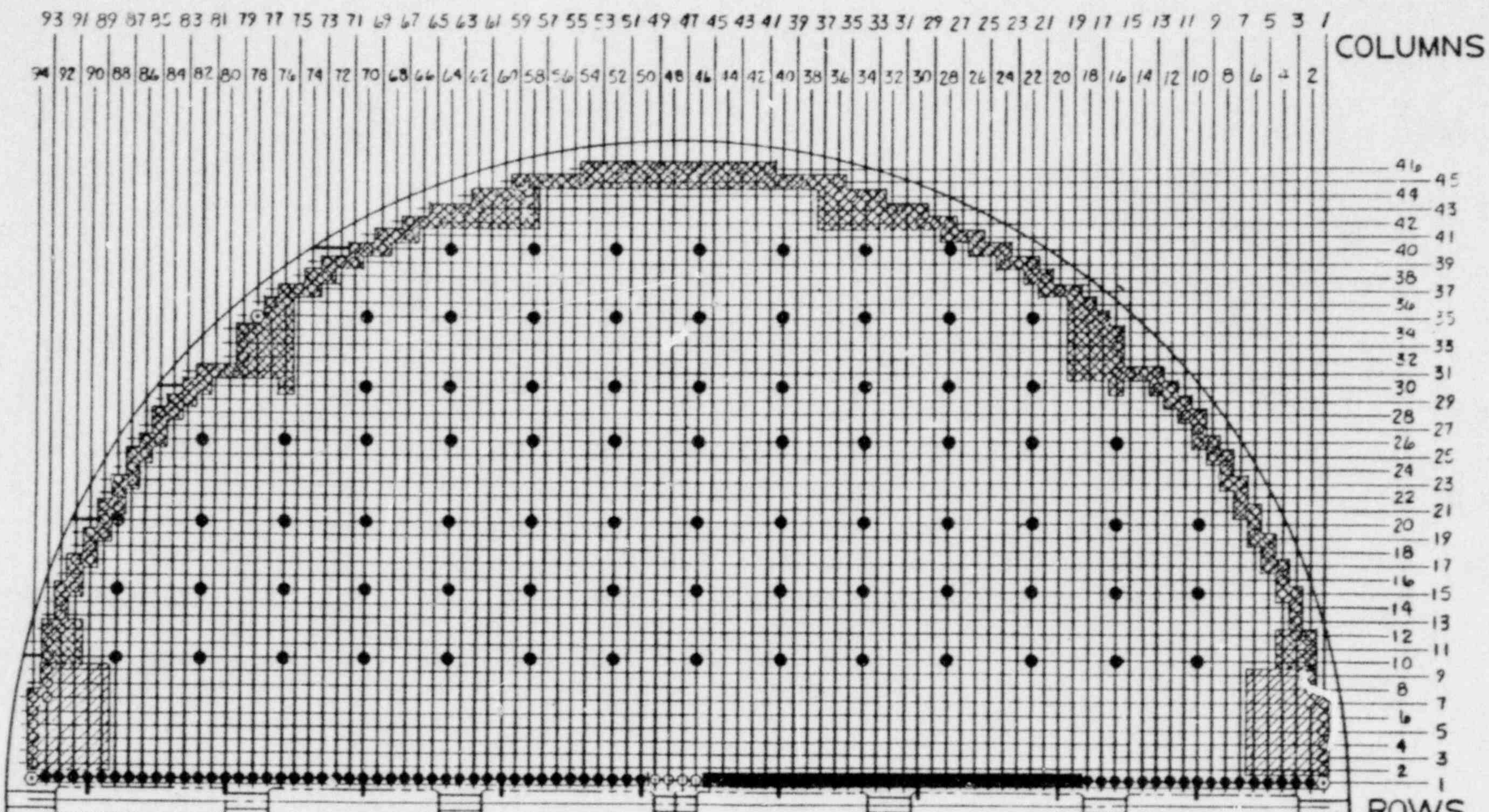
| % OF WALL THINNING | NUMBER OF TUBES INLET | OUTLET |
|---|---|---|
| ≥50% | 0 | 4 |
| ≥20%, <50% | 0 | 39 |
| <20% | 0 | 53 |

TABLE III

Steam Generator Tubes Plugged During Prairie Island Unit 2 January 1980 Refueling Outage.

| STEAM GENERATOR NUMBER | TUBE NUMBER ROW | COL. | PERCENTAGE OF WALL THINNING | REMARKS |
|---|---|---|---|---|
| S.G. No. 21 | 1 | 1 | 66% | |
| | 1 | 94 | --- | Preventive |
| | 35 | 78 | 72% | |
| S.G. No. 22 | 1 | 1 | --- | Preventive |
| | 1 | 94 | --- | Preventive |
| | 34 | 79 | 43% | Pulled |
| | 34 | 18 | 48% | |
| | 42 | 34 | 54% | |
| | 43 | 37 | 47% | |
| | 44 | 37 | 47% | |
| | 45 | 37 | 51% | |
| | 44 | 41 | 49% | |
| | 46 | 48 | 48% | |
| | 38 | 74 | 49% | |
| | 34 | 76 | 56% | |
| | 33 | 78 | 70% | |
| | 35 | 78 | 46% | |
| | 33 | 79 | 46% | |

SERIES 51




←MANWAY

NOZZLE→

Prairie Island Nuclear Generating Plant Unit II
STEAM GENERATOR NO. 21 "INLET"
Multi-frequency Examinations:
▨ or ■ tubes inspected through 7th Support
▩ or ● tubes inspected through U-Bends
⊙ tubes plugged

Figure 1

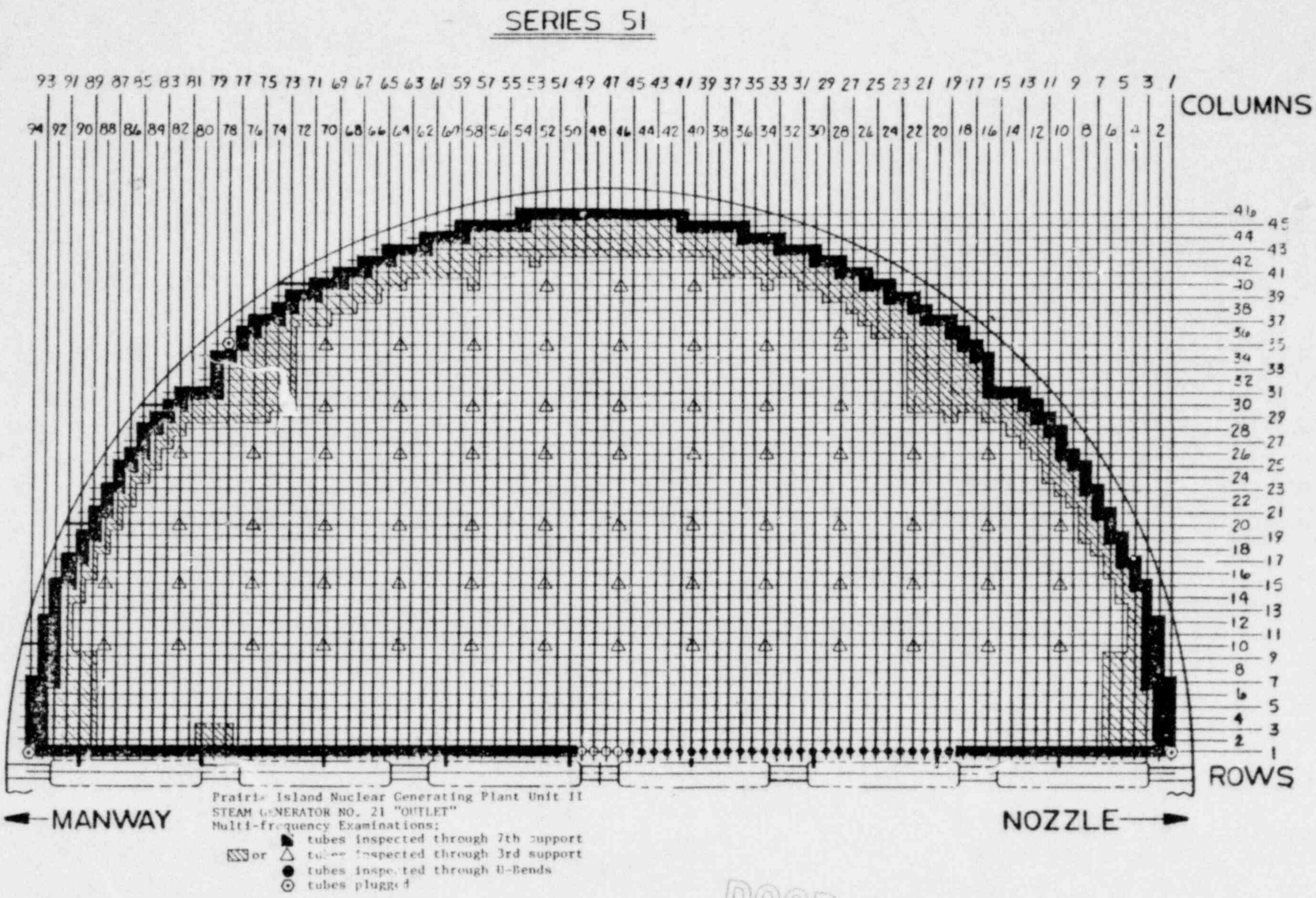
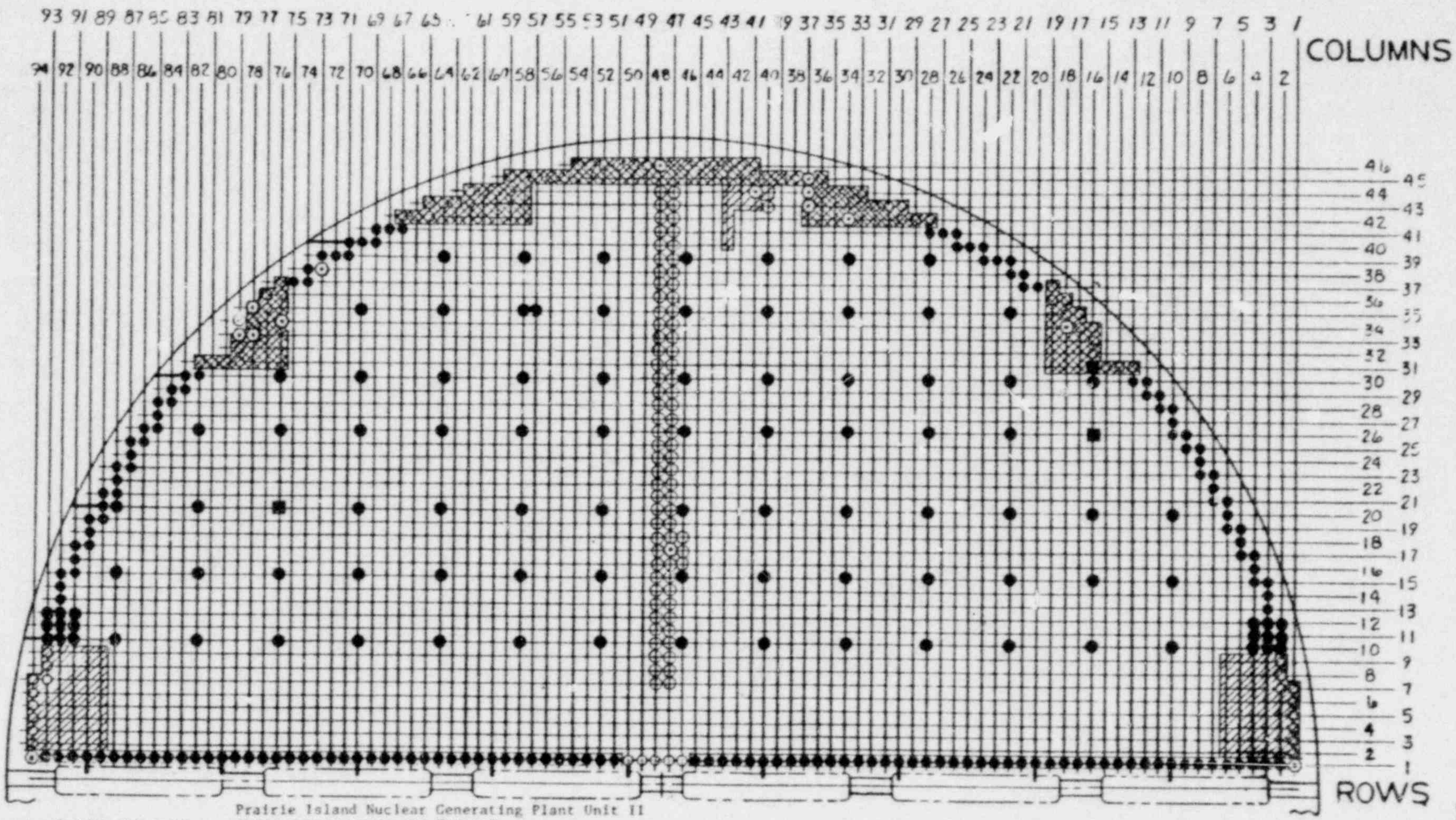

SERIES 51
COLUMNS
ROWS
MANWAY
NOZZLE
Prairie Island Nuclear Generating Plant Unit II
STEAM GENERATOR NO. 21 "OUTLET"
Multi-frequency Examinations:
tubes inspected through 7th support
or tubes inspected through 3rd support
tubes inspected through U-Bends
tubes plugged

Figure 2

## SERIES 51

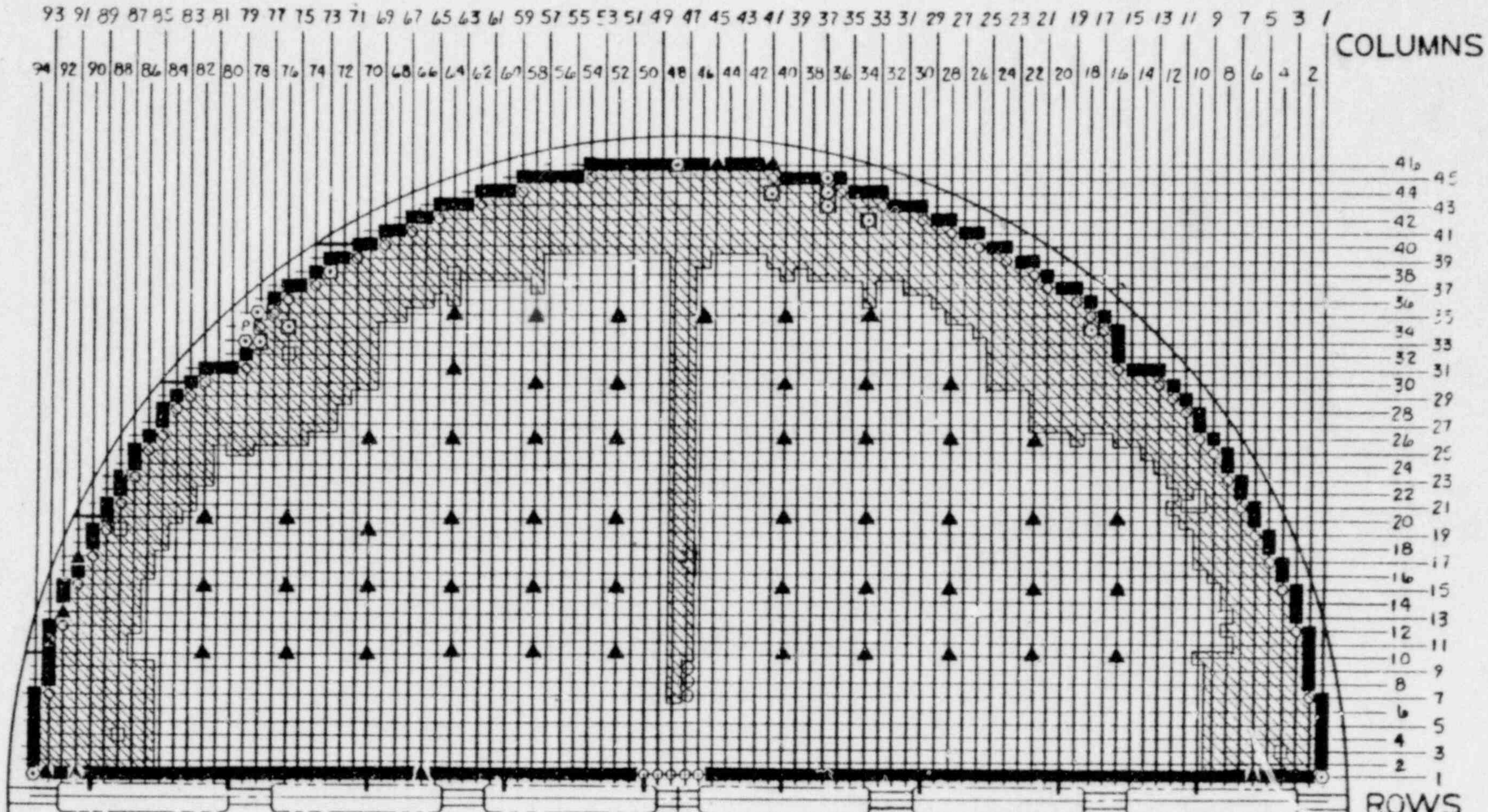



Prairie Island Nuclear Generating Plant Unit II
STEAM GENERATOR NO. 22 "INLET"
Multi-frequency Examinations:

- ▨ or ■ tubes inspected through 7th Support
- ▩ or ● tubes inspected through U-Bend
- ○ tubes inspected through 1st Support
- ⊙ tubes plugged
- x Incomplete Inspection

Figure 3

## SERIES 51




← MANWAY

NOZZLE →

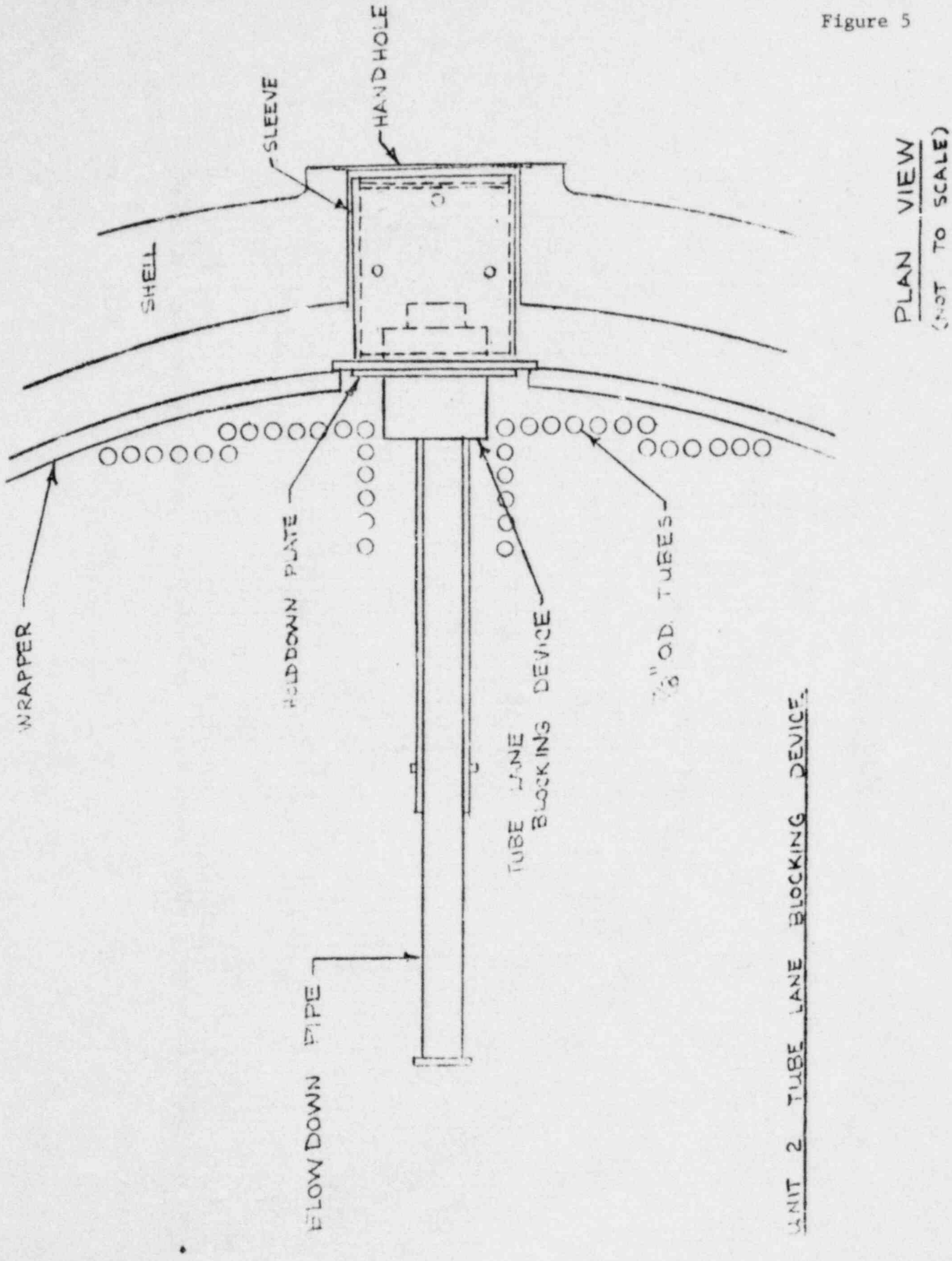
Prairie Island Nuclear Generating Plant Unit II
STEAM GENERATOR No. 22 "OUTLET"
Multi-frequency Examinations:

- ■ Tubes Inspected through 7th Support
- [hatched] or ▲ Tubes Inspected through 3rd Support
- ○ Tubes Inspected through 1st Support
- ⊙ Tubes Plugged
- x Incomplete Inspection
- P Pulled

POOR ORIGINAL

Figure 4

Figure 5



HAND HOLE
SLEEVE
SHELL
WRAPPER
HOLDDOWN PLATE
TUBE LANE BLOCKING DEVICE
7/8" O.D. TUBES
BLOW DOWN PIPE
PLAN VIEW
(NOT TO SCALE)
UNIT 2 TUBE LANE BLOCKING DEVICE

APPENDIX A

EXAMINATION OF REMOVED TUBE

Recent eddy current examinations of Prairie Island Unit 2 steam generator tubes revealed indications in a number of tubes. The indications ranged from less than 20% of wall thickness to one at approximately 75%, with the majority in the less than 20% category. The indications were interpreted as some form of OD wall loss, located in the center of the support plate intersection.

To determine the actual cause of the indication, a representative tube, R34C79 of S/G 22 was removed on Jan. 27, 1980 and sent to the Westinghouse Forest Hills site for detailed examination. The purpose of this document is to briefly report the initial findings of this examination and to discuss the preliminary conclusions.

NON-DESTRUCTIVE EXAMINATION OF TUBE R34C79

All tube section containing support plate intersection were photographed at 4 rotations (0°, 90°, 180°, 270°). Only the first and second intersections exhibited wall loss, the next four intersections had slight discolorations and possibly local deposits and the seventh exhibited shallow circumferential striations.

All support zones were radiographed using the double wall technique. The first support zone exhibited ~0.010" maximum wall reduction while the second support zone had approximately 0.020" - 0.025" wall loss. The 3rd, 4th, 5th, 6th and 7th showed no detectable wall loss. Standards shot with each exposure revealed that 1 mil of wall reduction could be detected.

Eddy current testing using multi-frequencies gave results similar to those obtained by radiography. The first support showed about a 0.010" wall reduction while the second support revealed 0.025" wall reduction. The remaining support zones gave no wall loss indications.

Detailed profilometry of the OD at the affected first and second intersections generally supported the other findings; the maixmum OD reduction agreed with the X-ray and E/C estimates of wall loss.

Destructive Examination (performed at Westinghouse R & D Center)

Tube support zones 1 and 2 were removed and split longitudinally so that wall measurements could be made using a pointed micrometer. These measurements are shown in attached Figure 1. The deepest penetration found in support zone #1 is about 0.007" of wall loss and about 0.020" lost from support zone #2. The nominal wall thickness is 0.050".

Examination of the tube surface was accomplished using the Scanning Electron Microscope (S.E.M.) and deposits analyzed on the Energy Dispersive X-Ray Analyzer (E.D.A.X.). These results show the surface deposits to be the typical boiler water specie. Some spot analyses within the disturbed zone show high sulfur peaks. Other microanalytical tools will be used to further explore these deposits.

Several metallographic samples have been prepared from the 1st and 2nd support plate areas. Representative photographs are seen in Figures 2 and 3. Figure 2 is a half ring sample taken near the area of deepest attack on support zone #2. Figure 3 shows representative areas in the etched condition. No intergranular attack and no cold working of the surface is seen in the damaged area.

Knoop microhardness traverses were done on samples from both the first and second support zones. Figures 2 and 4 give the results for support #2. It can be seen that hardnesses near the surface of the damaged zone (Figure 2) are less than that outside the damaged zone (Figure 4). The higher readings in the unaffected region are normal and are due to surface work hardening imparted by the final belt polishing operation of the tubing during manufacture. Figure 5 gives similar results obtained on support zone #1.

Conversion of a Vickers 100g hardness reading to Rockwell B shows this tubing to be about 89.2 $R_B$ which is normal for a mill annealed tubing product.

The lack of evidence of surface cold work, adduced both from the micro-hardness traverses and the metallography, essentially eliminate wear and vibration as the primary cause of the degradation. The most likely cause is corrosion, caused by the local concentration of an as yet undetermined contaminant in the crevices formed between the tubes and the tube support plate holes.

Additional metallography is underway at several other intersections and more detailed examinations are planned but it is unlikely that the initial conclusion will be affected. The major effort will be the micro-analyses of the affected surfaces to identify the contaminants involved. Sulfur bearing compounds are suspect, because of the reported instances of resin carryover from the Powdex polisher and the EDAX indication of sulfur on the affected surface.

Conclusions of the Tube Examination Findings

The preliminary conclusions are as follows:

1. Since wear/vibration are apparently not involved, no mechanical revisions to the steam generators are suggested.

2. There is no known safety issue. The eddy current in-service inspection plan, however, will have to be revised in regard to Reg. Guide 1.83.

3. The identification and source of the contaminants must be determined and appropriate operational procedures taken to (1) reduce the contaminant inventory and (2) to prevent further ingress.

A brief discussion of each of the above items follow.

Mechanical Revisions

The effect of the original mechanical modifications (which were made on Prarie Island Unit 2 prior to start-up) on both tube wear and corrosion can be summarized as follows:

Specific Modifications

1. Downcomer Resistance Plate Removal
   A. Fretting/Wear - The velocity at the bundle inlet is increased from about 5 to 9 ft/sec. This would increase the potential for fretting or wear between the tube and the support.
   B. Corrosion - The circulation ratio is increased from 2.4 to 5.2, thereby increasing the support plate pressure drop and the flow between the tube and the support, which is beneficial. Nevertheless, the periphery of the bundle likely has a lower velocity region, so that the local circulation flow may not have been increased significantly.
2. 80-20 Feedwater Flow Split at the Feedring
   A. Fretting/Wear - Minimal effect because the flow split does not affect the velocity at the tube bundle inlet.
   B. Corrosion - The 80/20 flow split reduces the thermal siphoning of flow from the cold leg to the hot leg. Since more of the recirculating flow remains in the cold leg, this is expected to produce a small increase in the circulation pattern in the peripheral cold leg region. However, the reduction in mixing between the feed and recirculating flows in the cold leg causes the bulk cold leg concentration of dissolved chemicals to increase from .8 to .9 of the recirculation flow concentration. Consequently, the net effect is likely to be small.
3. Tube Lane Blockage and Blowdown Redirection
   A. Fretting/Wear - The crossflow velocities at the bundle entrance are increased slightly.
   B. Corrosion - The increased velocities should promote a small increase in flow at the bundle periphery.

It is concluded that higher velocities in the bundle do increase the potential for wear, but have either no effect or are slightly beneficial with regard to corrosion. Since the evidence does not support a wear phenomenon, no change in the modifications made to the steam generators are recommended.

Contaminant Identification and Control

It is recommended that a test program be immediately implemented, prior to Unit 2 power operation, to identify the chemical species in the secondary side bulk water and to sample subsequently during power ramp, power operation and shutdown so as to characterize chemical hideout and return.

Safety Issue

The safety position for steam generator tube degradation is that the tube will leak a detectable amount of primary fluid before the defect reaches a critical flaw size. This is known as the tube leak before break hypothesis. The issue with the tube degradation at Prairie Island is whether this form of degradation follows the previous patterns. The examination of the Prairie Island tube indicates that a corrosive environment has affected the tubes. The examined tube had two areas where the corrosion was the most severe. These areas are at the first and second support plate locations, with the second support plate area having the most pronounced corrosion. The second support plate area has a truncated penetration. It is postulated that if the corrosion were to continue, the more affected area would precede the lesser affected surrounding area and form a pin hole type leak in the tube wall.

The first support area does not appear to have a truncated penetration. This area appears to be in the early stages and may progress to a truncated position. The characteristic of a tube that has a hole type defect is that as the hole and the leak rate increase, the tube's burst strength also decreases. However, the leak rate increases at a faster rate than the tube's burst pressure decreases. This form of steam generator tube degradation will cause a tube to leak before break and does not pose a safety issue for continued operation.

The other safety objective is to prevent any steam generator tube from degrading to the point where a leak will occur. The time required for a leak to occur is a function of the corrosion rate. The investigation of the degraded tube leads to a hypothesis that the corrosion may be a result of the intrusion of resins from the condensate polishers which have been used sporadically since December, 1977. It is postulated that this form of corrosion took place during the two years of condensate polisher availability. This information allows a rate of corrosion to be estimated. Each area of degradation establishes its individual rate of corrosion dependent upon the unique steam generator conditions in that area. The remaining affected tubes in service have ECT indications that are less than 45% of tube wall thickness. If we assume a maximum corrosion of 45% over 24 months, than the anticipated maximum corrosion rate is approximately 1.8% per month. The minimum tube wall required for faulted plant conditions is 0.013 inches from a nominal thickness of 0.050 inches. Thus a minimum remaining wall of 26% thickness is needed to sustain plant faulted conditions. This difference between the minimum required tube wall thickness and the remaining tube wall thickness in a tube with a 45% ECT indication is the amount of tube wall which may be lost via the corrosion mechanism. This amount of tube wall is 0.0145" or 29% of the tube wall. Therefore, the postulated corrosion rate of approximately 1.8% per month should permit an estimated operating time of approximately 15 months without violating the plant faulted condition minimum tube wall.

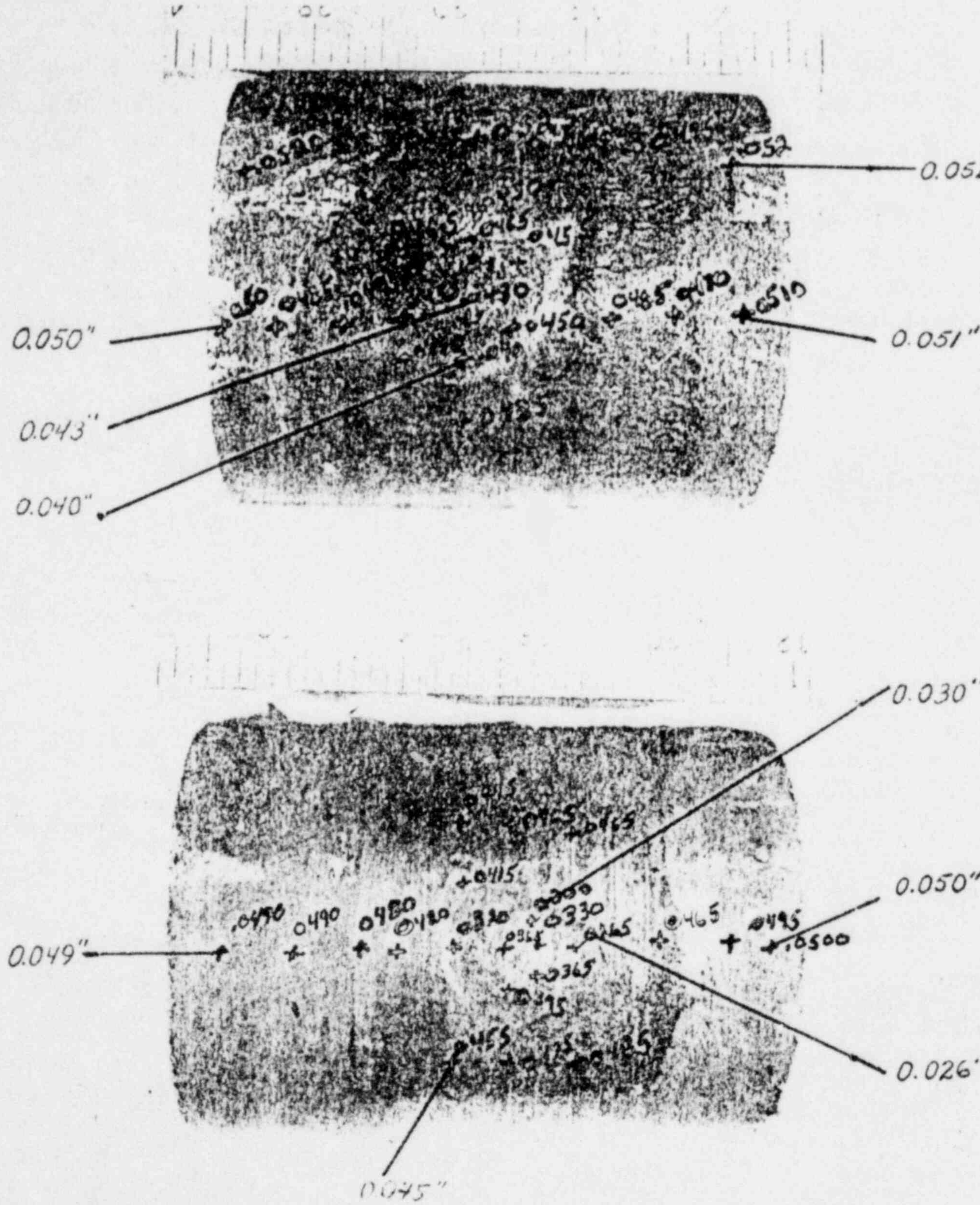





FIGURE 1: Painted micrometer measurements showing amount of wall remaining for support zones 1 and 2. The design wall thickness is 0.050".

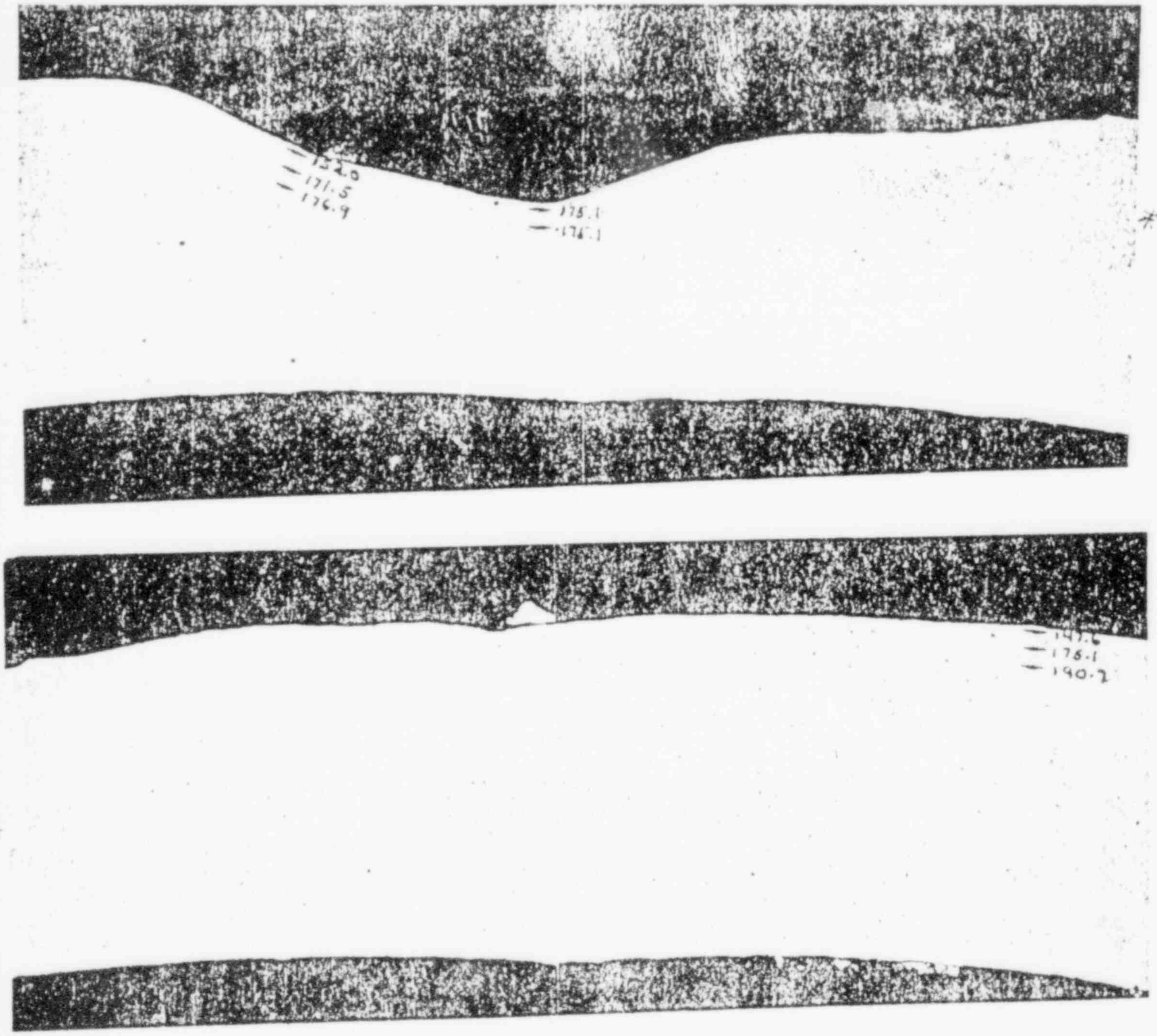





FIGURE 2: Polished 1/2 ring from support zone 2 near the area of deepest attack.
* designated matching surfaces

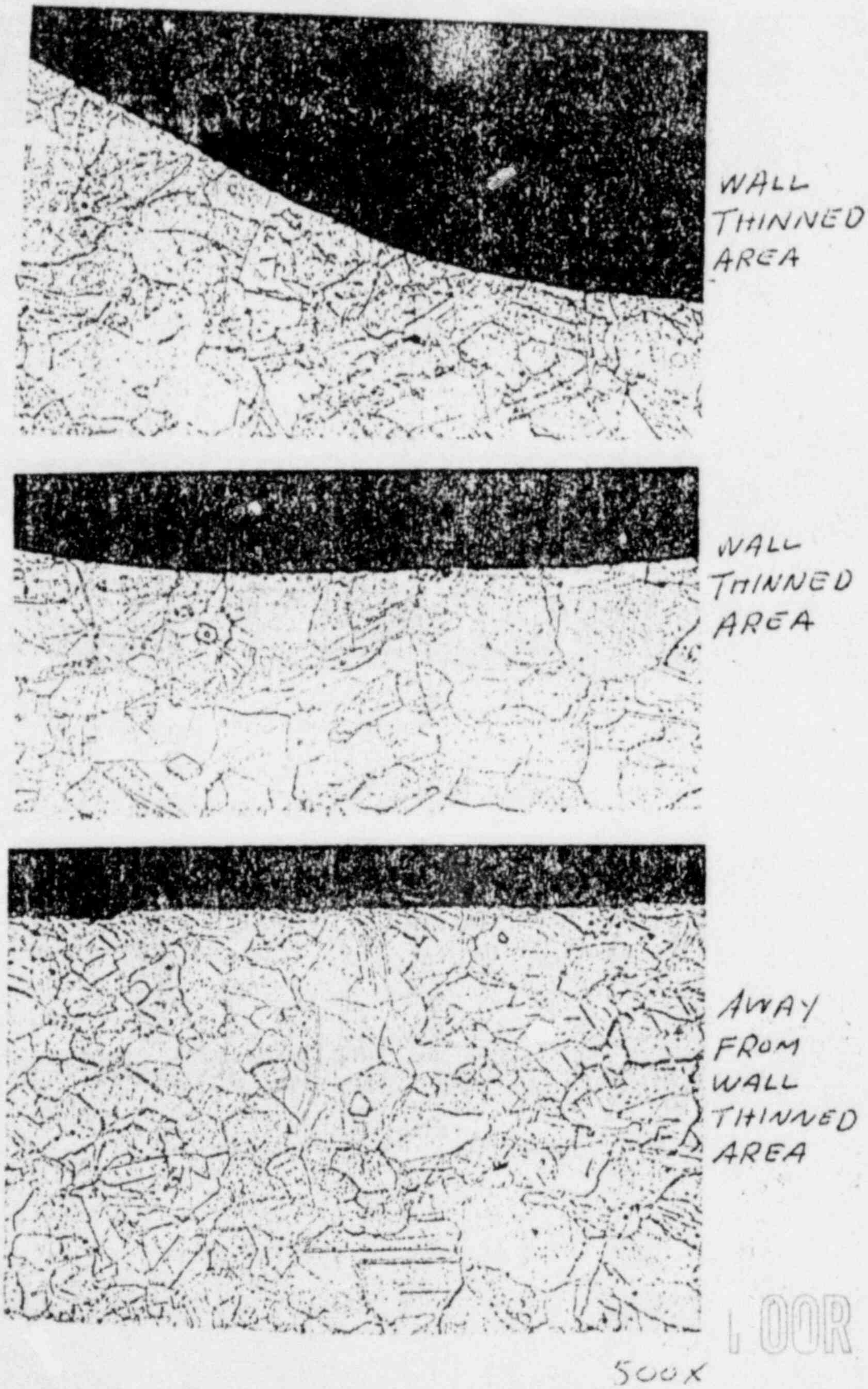
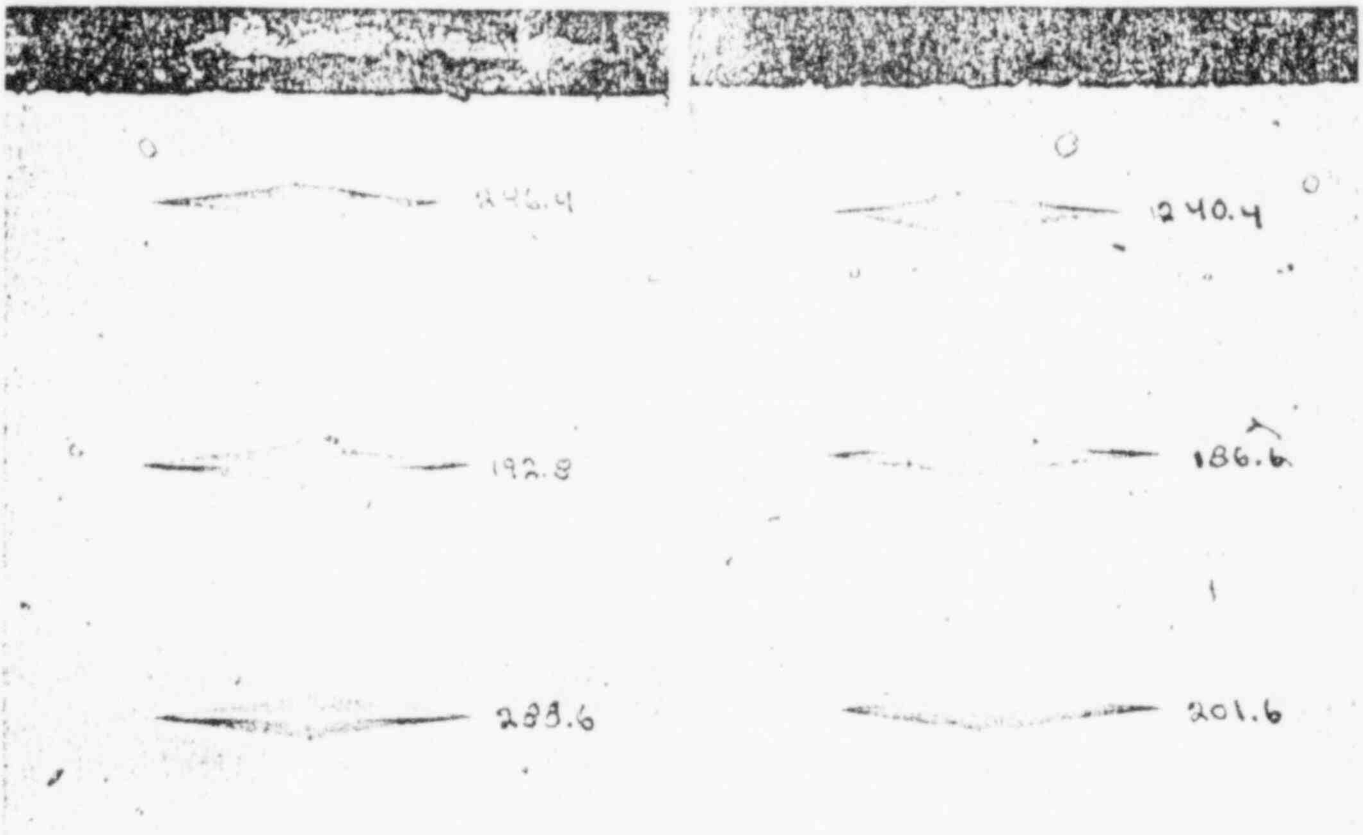
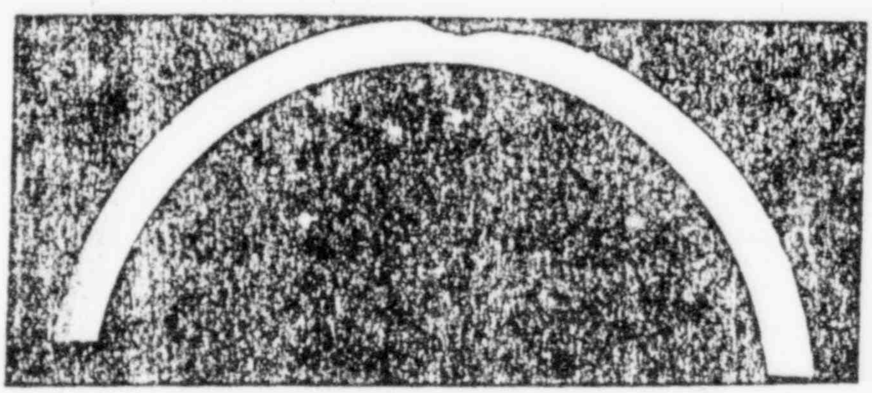





FIGURE 3: Polished and etched 1/2 ring from support zone 2 as shown in previous figure.




500X



5X



FIGURE 4: Microhardness reading taken in the unetched region of the sample prepared from the second support zone. These numbers can be compared to those in Figure 2 taken in the damaged area.

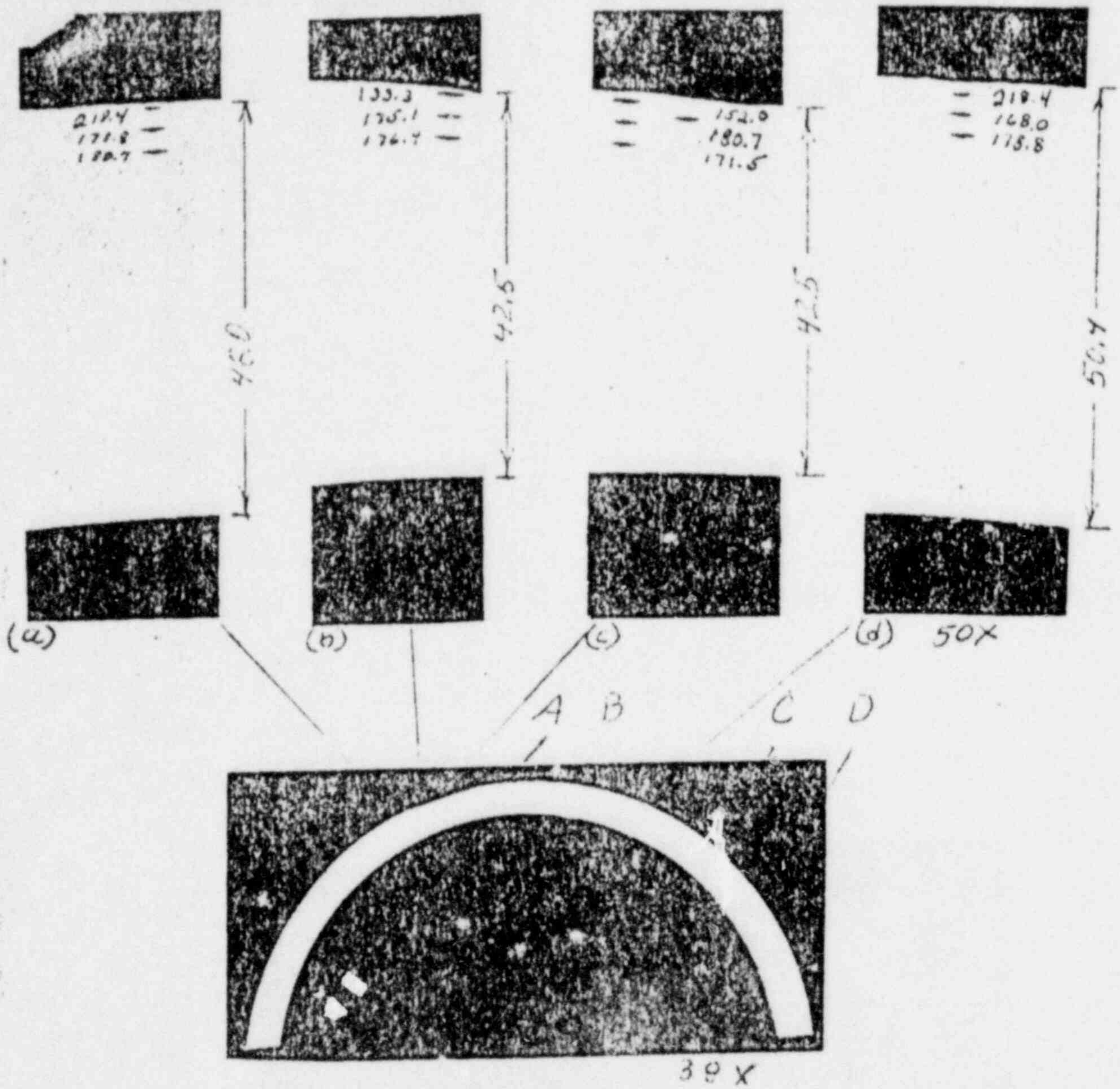
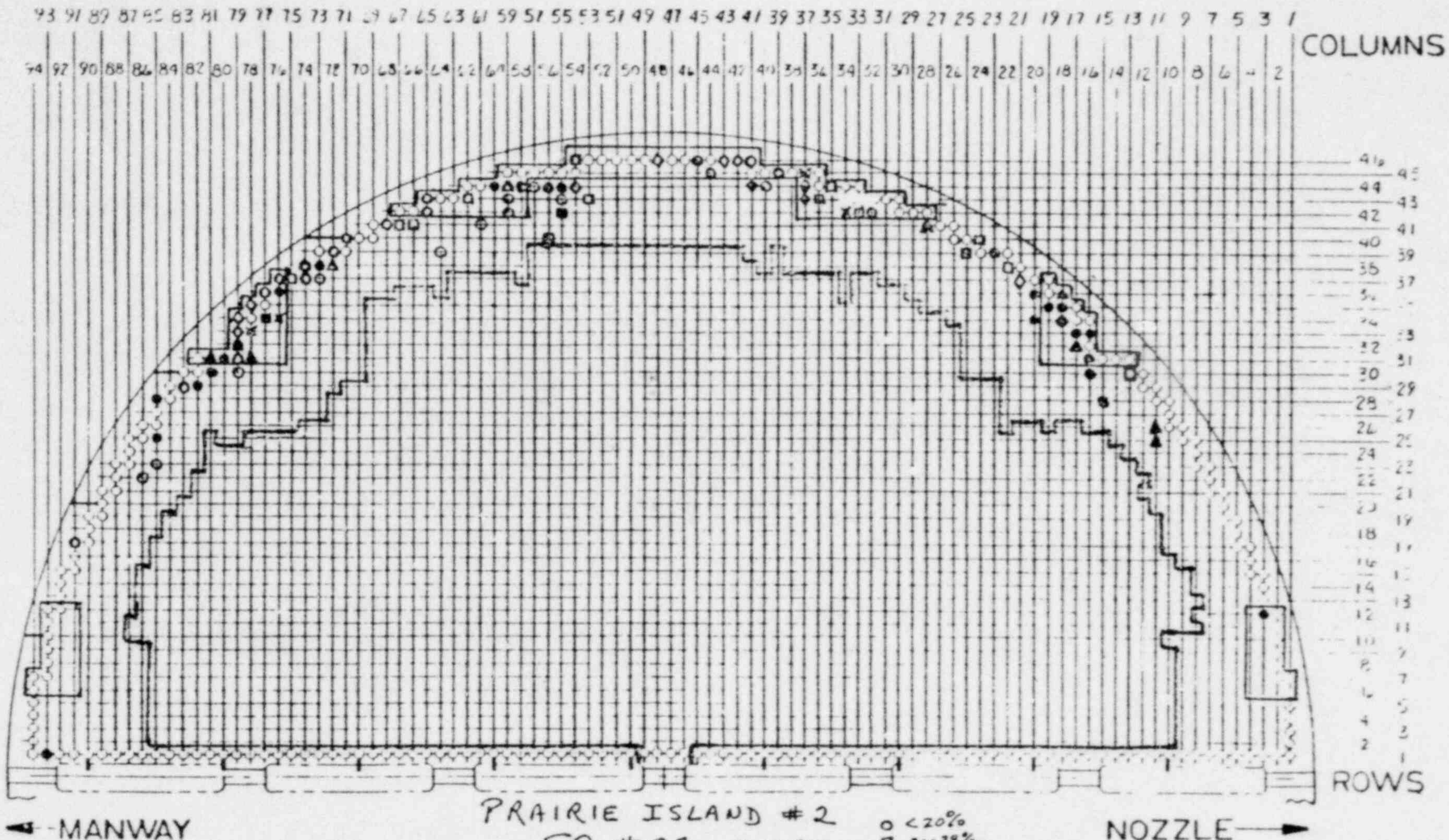





FIGURE 5: Knoop microhardness readings and wall thickness measurements in mils taken on a half ring sample prepared from support zone 1.

# SERIES 51

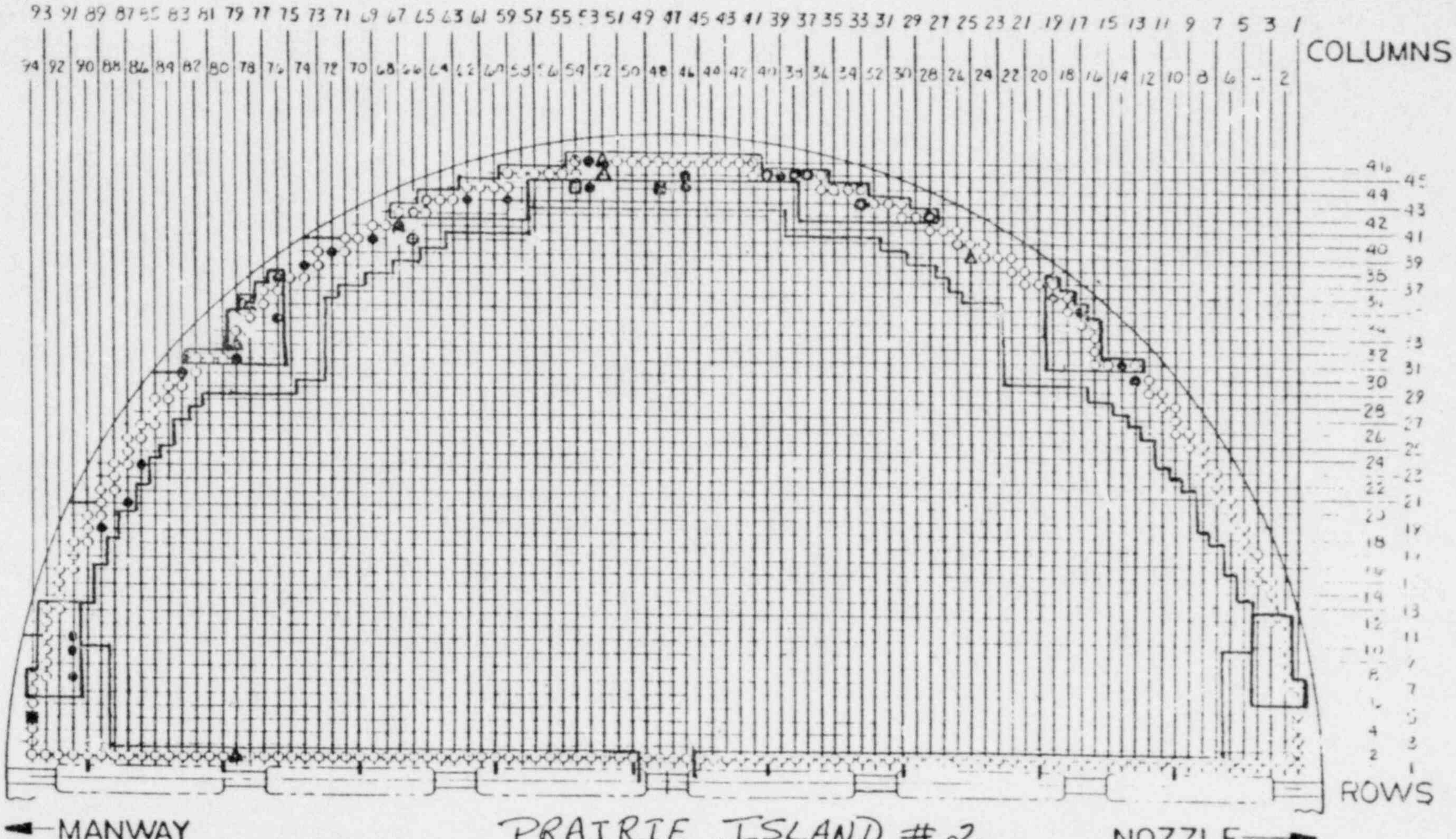



PRAIRIE ISLAND #2
SG #22 OUTLET
1/80

○ < 20%
□ 20-29%
△ 30-39%
◇ 40-49%
× > 50%

Open #2 TSP
Dark #1 TSP

# SERIES 51




PRAIRIE ISLAND #2
SG 21 OUTLET
1/80

○ <20%
□ 20-29%
△ 30-39%
◇ 40-49%
× >50%

Open #2 TSP
Dark #1 TSP

APPENDIX B - material presented at

NORTHERN STATES POWER COMPANY - NRC MEETING

FEBRUARY 12, 1980

Westinghouse Forest Hills Site

INTRODUCTION: NSP

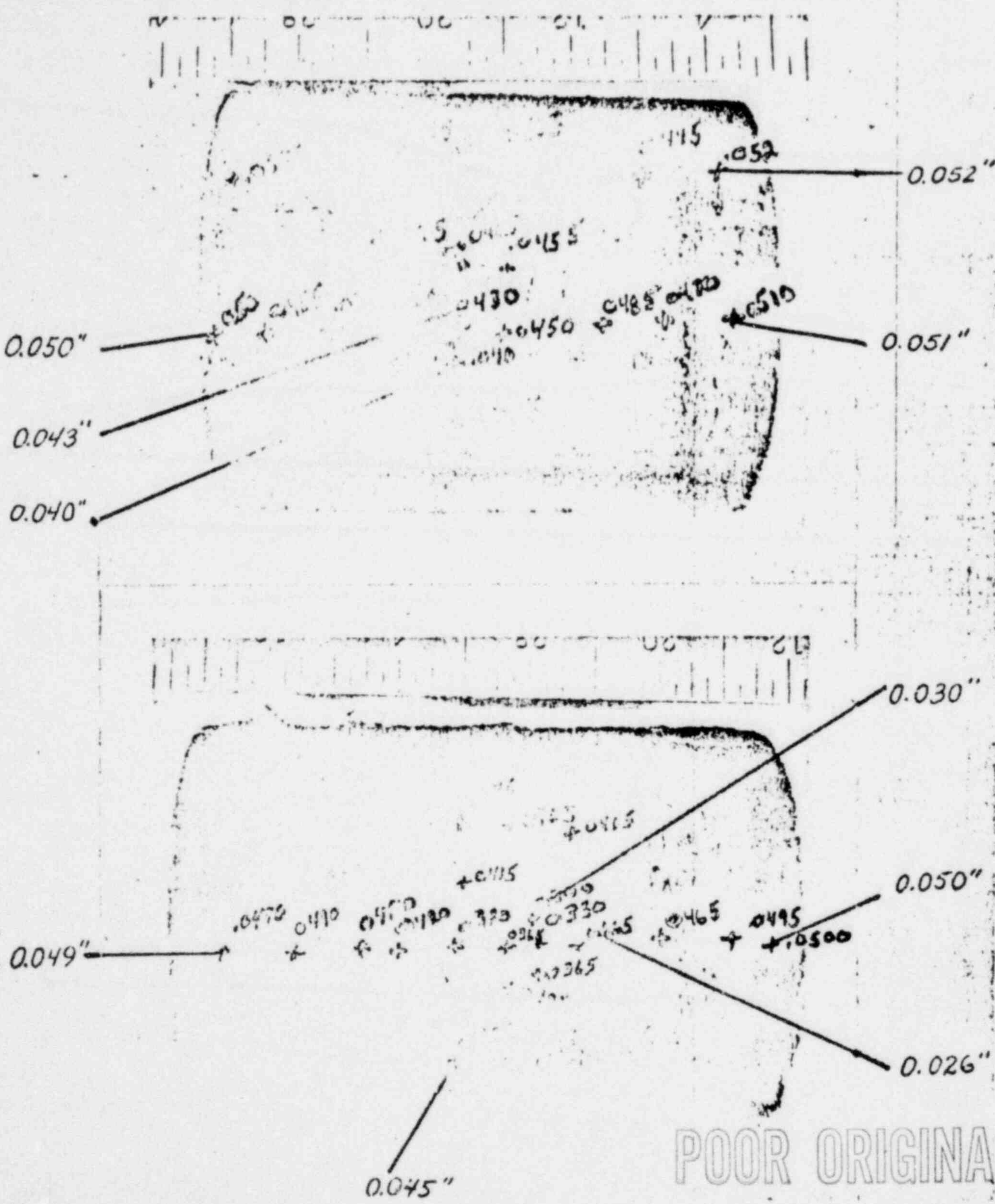
| | | |
|---|---|---|
| I. | Tube Wear Caused by Blocking Device and Corrective Action. | E. Watzl |
| II | Cold-leg, Peripheral Tube Findings | |
| | a. Review In-Plant Inspection Findings | D. D. Malinowski |
| | b. Tube Pull & Lab Examination | R. G. Aspden |
| | c. Summary | A. W. Klein |
| | - Cause | |
| | - Rate | |
| | d. Safety Considerations | C. W. Hirst |
| | e. Future Actions | NSP/Westinghouse |
| | - Chemistry Surveillance | |
| | - Inspection Plans | |

Attendance 2/12/...

| | |
|---|---|
| M. [illegible] | NRC |
| B. D. Liaw | NRC |
| C. W. Hirst | WNTD |
| P. J. Krumpos | NSP |
| G. H. Niels | NSP |
| E. Watzl | NSP |
| [illegible] Kelly | [illegible] |
| J Strosnider | NRC |
| F. L. [illegible] | NRC |
| R. G. Aspden | (W) R+D |
| W. [illegible] Utley | W-NCD |
| Dan Malinowski | (W) NTD |
| W. D. Fletcher | W NTD |
| A. W. Klein | W NTD |
| C. W. Rowland | W NSD |
| [illegible] | (W) NTD |
| A. Baum | (W) NTD |
| T. Timmons | W NTD |
| A J Baum | W NTD |
| E P Morgan | W NTD |
| F. Almeter | NRC |
| J. Weeks | BNL |

POOR ORIGINAL

2/12/80






Prairie Island Tube R34C79 COLD LEG

FIGURE 1: Painted micrometer measurements showing amount of wall remaining for support zones 1 and 2. The design wall thickness is 0.050".

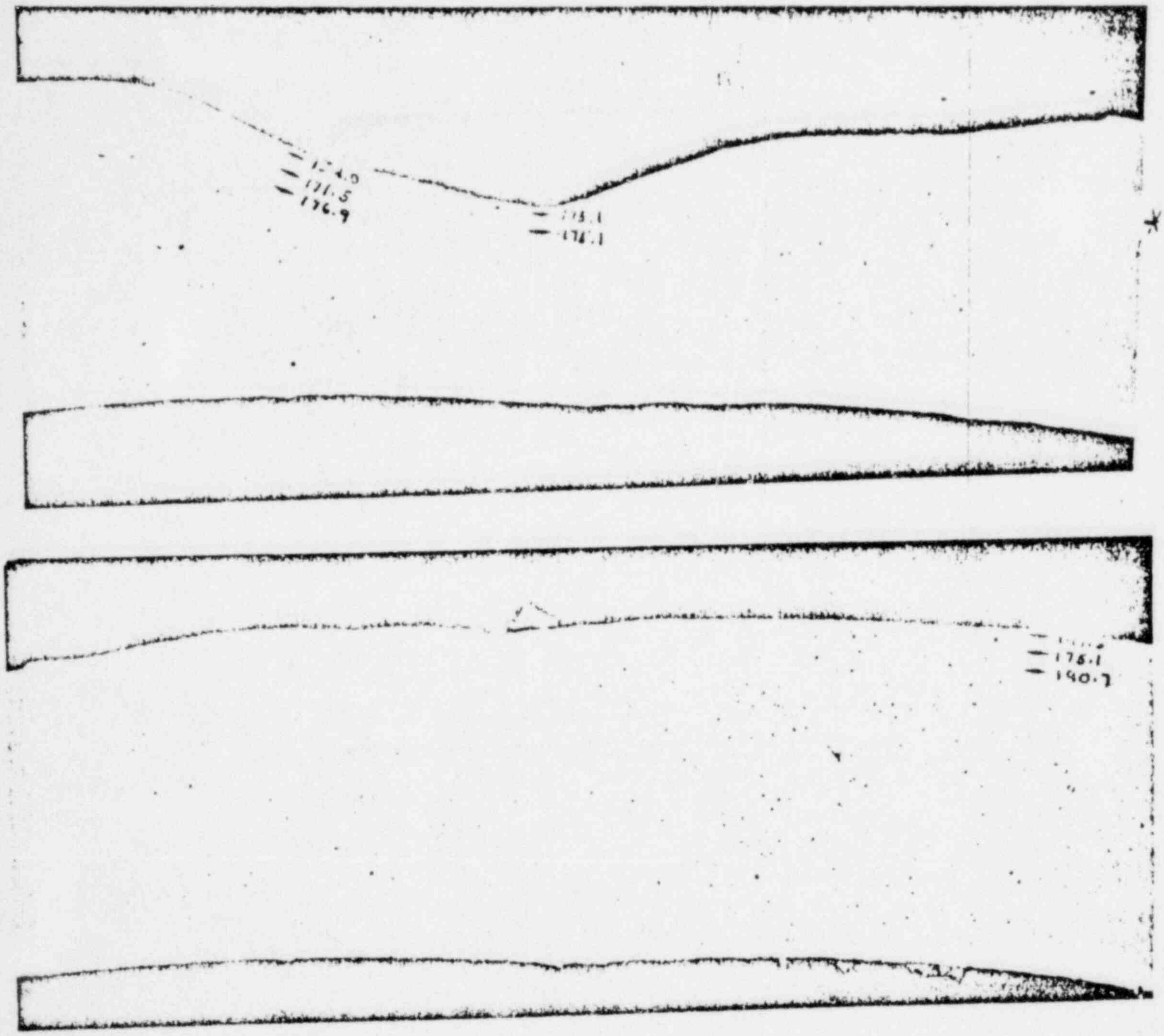





FIGURE 2: Polished 1/2 ring from support zone 2 near the area of deepest attack.
* designated matching surfaces

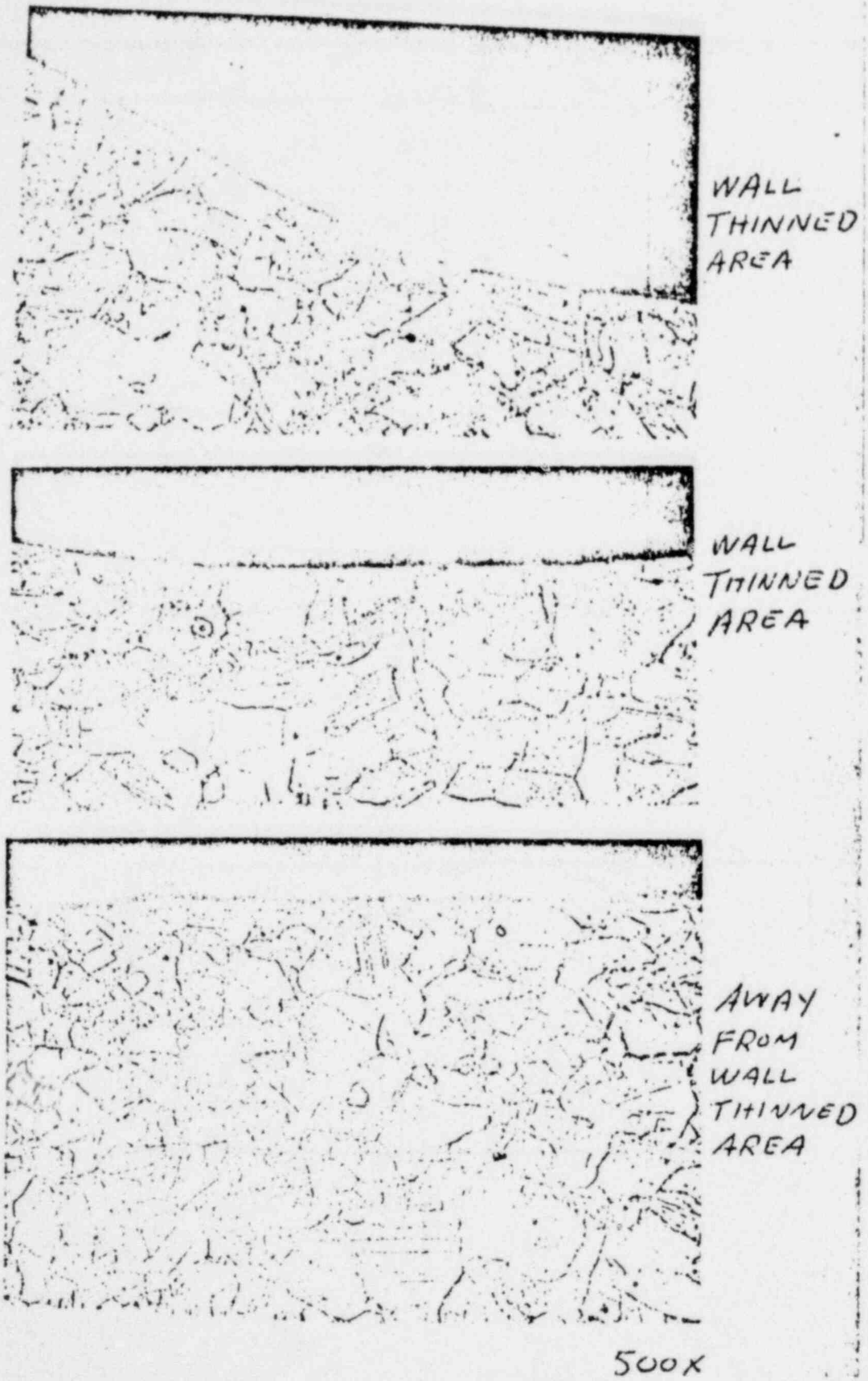



FIGURE 3: Polished and etched 1/2 ring from support zone 2 as shown in previous figure.

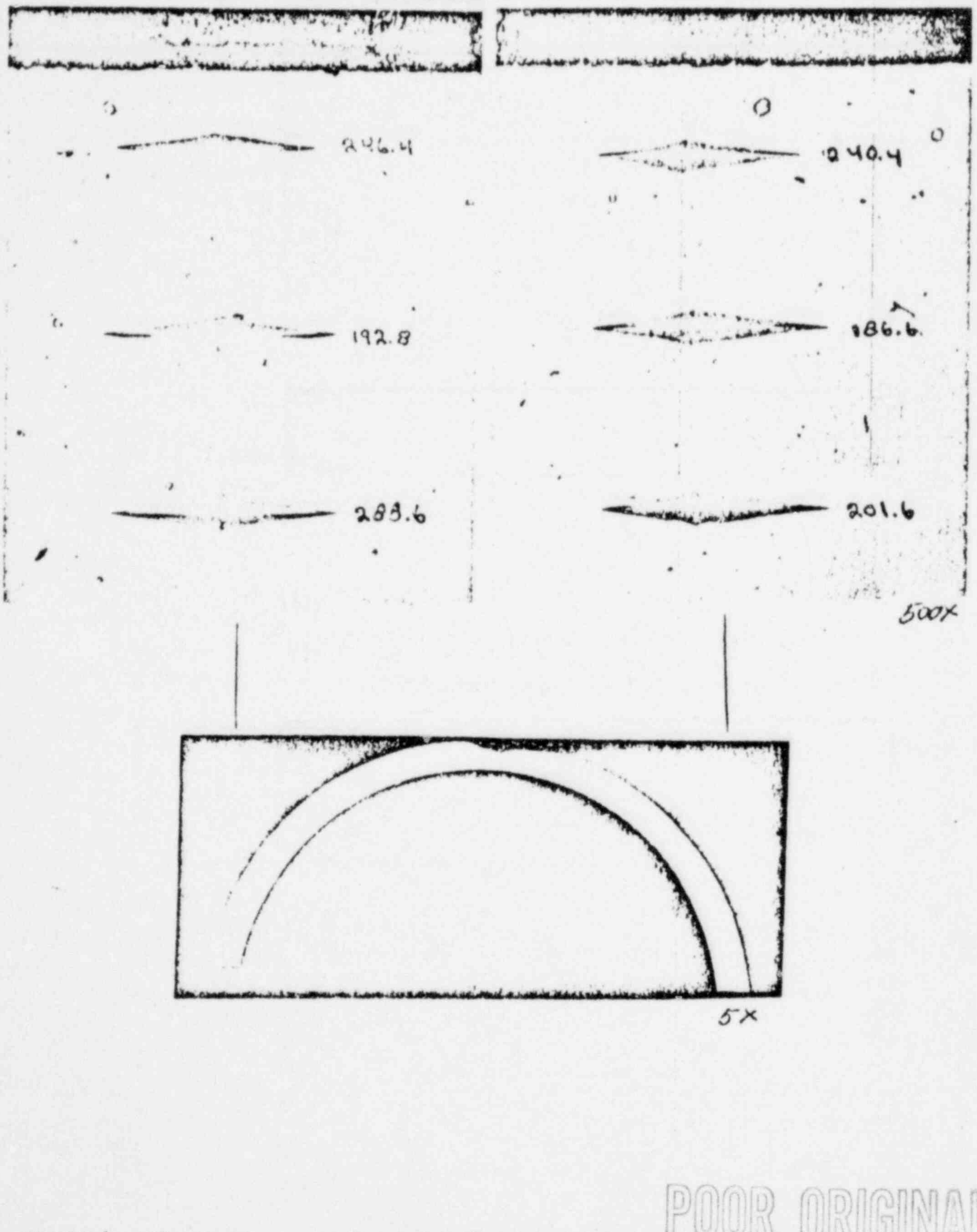





FIGURE 4: Microhardness reading taken in the unetched region of the sample prepared from the second support zone. These numbers can be compared to those in Figure 2 taken in the damaged area.

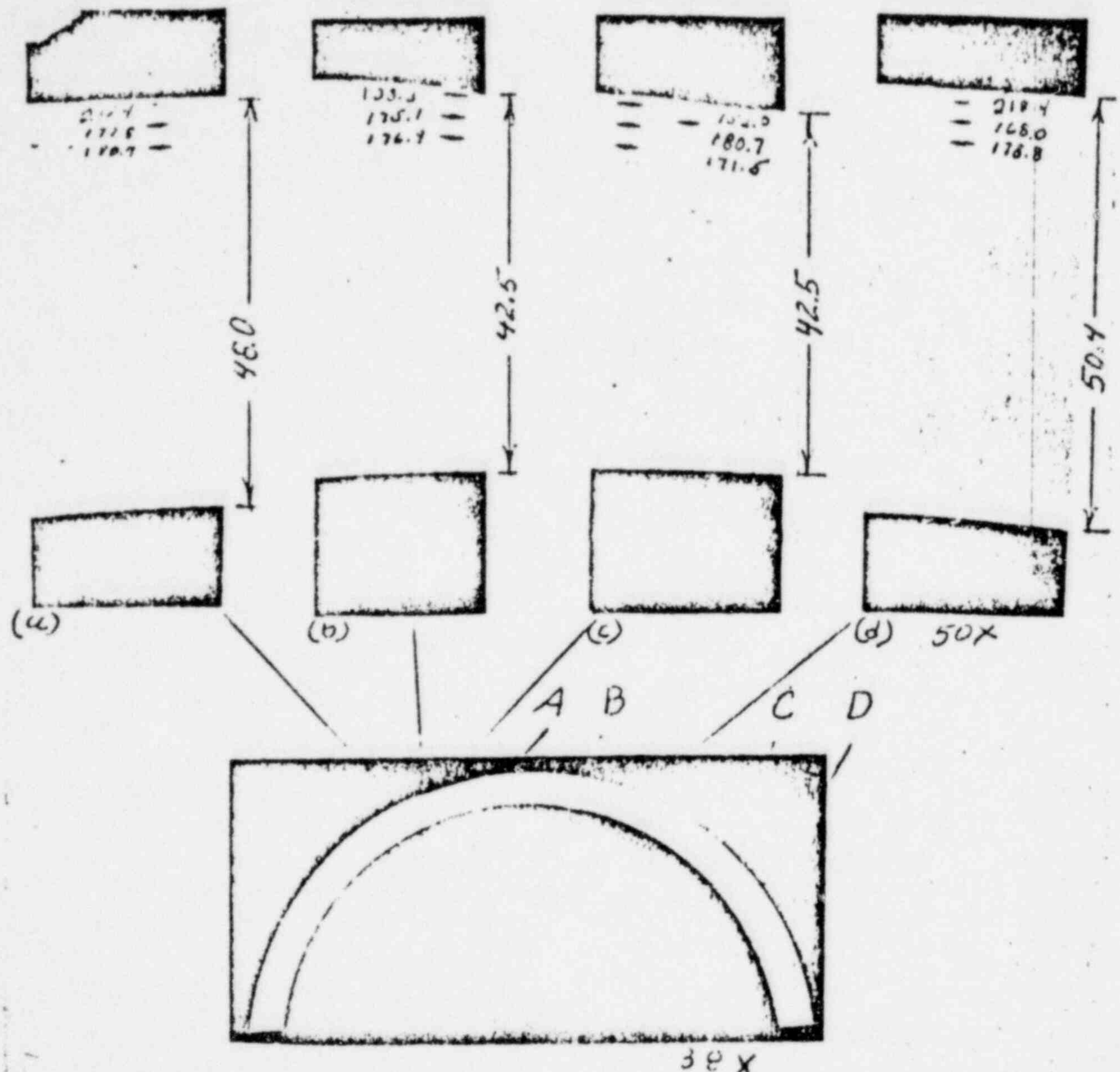



FIGURE 5: Knoop microhardness readings and wall thickness measurements in mils taken on a half ring sample prepared from support zone 1.

2/12/85

# SAFETY EVALUATION

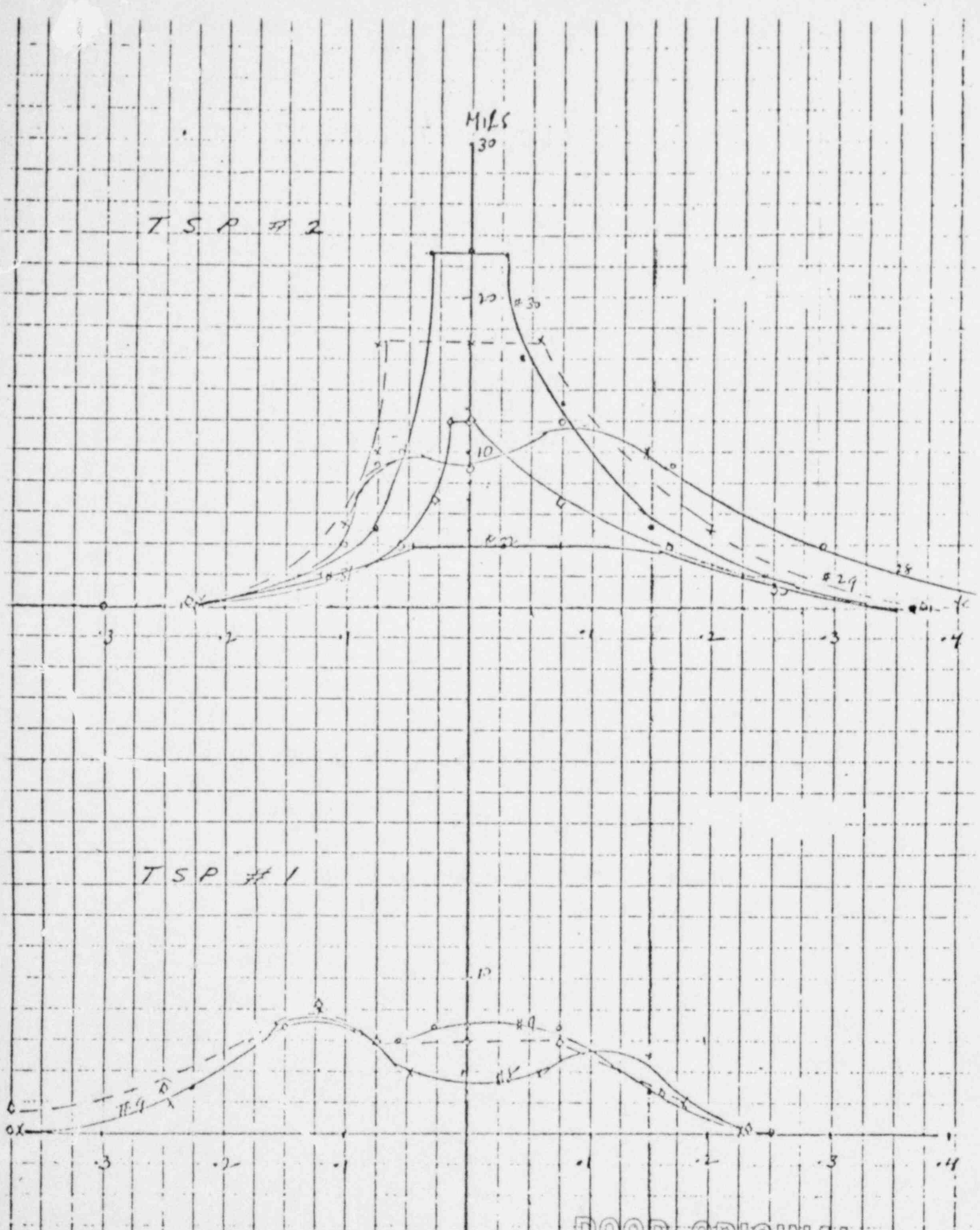
- Leakage and Critical Area
- Tube Integrity
- Corrosion Rate
- Operating Interval
- Conclusion

# LEAKAGE AND CRITICAL AREA

- DEFINITION OF LEAK
  - NORMAL SHUTDOWN PROCEDURES
  - NO SAFEGUARDS ACTUATION
  - NOMINAL LEAK FLOW AREA
    - 3/8 INCH DIAMETER HOLE
    - FLOW AREA = .110 SQ. IN.
  - NOMINAL LEAK FLOW
    - 125 GPM

- PROFILE OF CORRODED AREAS ON PRAIRIE ISLAND 2 R34 C79
  - TSP #2 AREA .060 x .1875 = .011 SQ. IN.
  - TSP #1 AREA .24 x .1875 = .045 SQ. IN.

- LEAK RATE VS. BURST PRESSURE

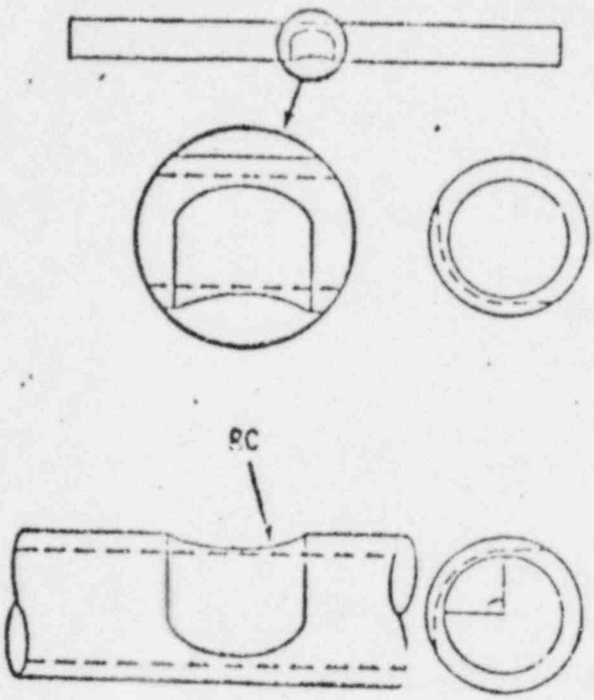

MILS
30
TSP #2
20
#30
10
#29
28
.3
.2
.1
.1
.2
.3
.4
TSP #1
10
.3
.2
.1
.1
.2
.3
.4

# TUBE INTEGRITY

- TUBE WALL REQUIRED
  - NORMAL .008
  - FAULTED .013
- TUBE BURST DATA
  - CORROSION PROFILES
  - TUBE BURST TESTS

# GEOMETRY OF

# ELLIPTICAL WASTAGE SPECIMEN



# BURST PRESSURES FOR THREE HEATS OF 0.875 IN. X 0.050 IN. SPECIMENS

| DEFECT TYPE | HEAT B, 50 KSI YIELD | HEAT E, 44 KSI YIELD | HEAT F, 41 KSI YIELD |
|---|---|---|---|
| UNDEFECTED | 9260 | 9460 | 9180 |
| | 9275 | 9665 | 9450 |
| | 9440 | 9500 | 9240 |
| ELLIPTICAL WASTAGE | | | |
| 55 - 60% | 5550 | 5635 | 5465 |
| $R_C$ = 12" | 5635 | 5280 | 5700 |
| LENGTH = 1 ½" | | | |
| 85 - 90% | 2950 | | |
| $R_C$ = 6" | 2970 | | |

REF: NUREG/CR-0277, JULY 1978

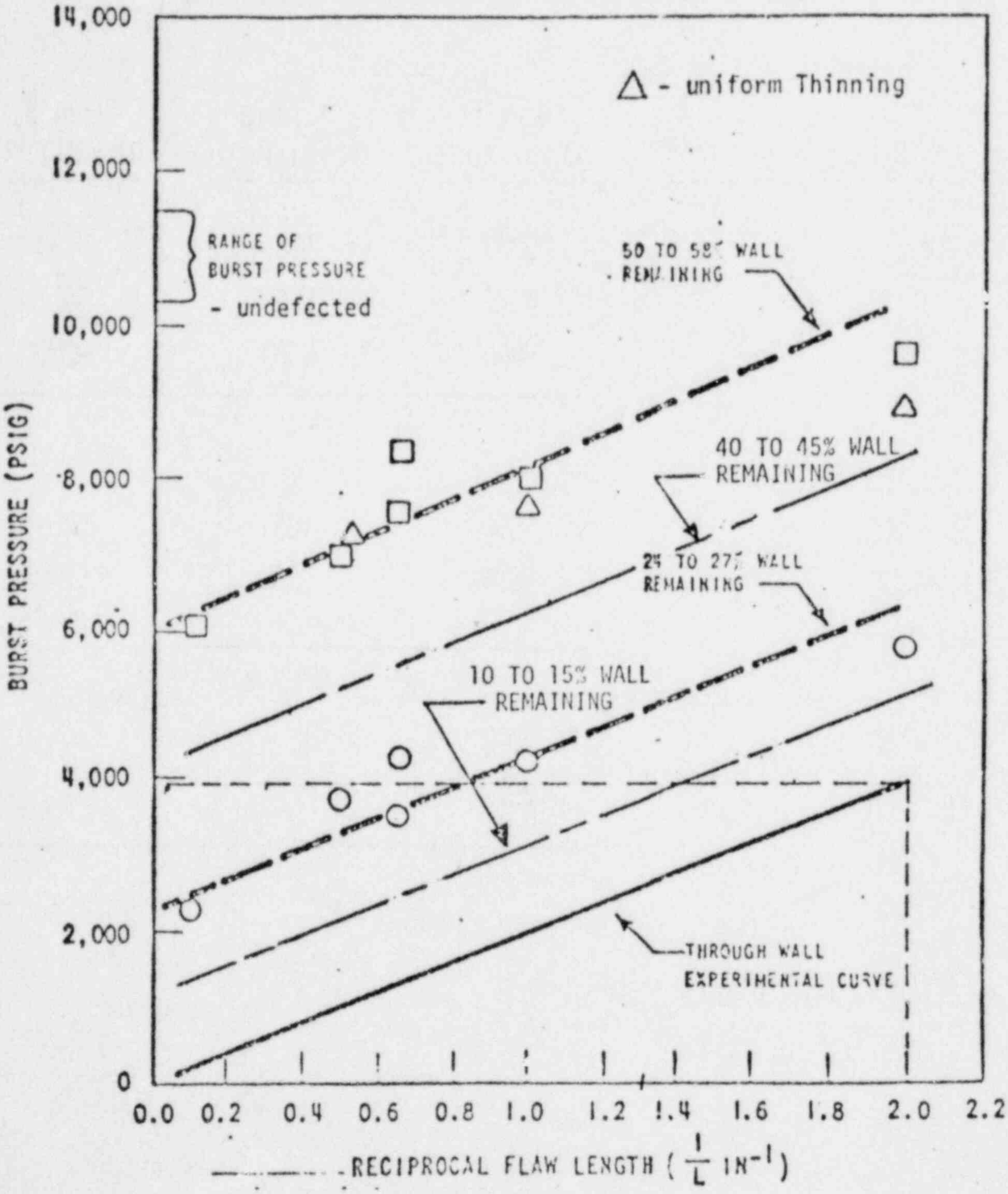



Figure 5. Room Temperature Burst Pressure of 7/8" Tubes with Machined Flats (Ref. WCAP-8429)

POOR ORIGINAL

# CORROSION RATE

- Corrodent Source
  - Resin Intrusion
  - Condensate Polishers

- Tube Exposure to Corrodent
  - Polisher Availability 12/77
  - 24 Months Operation

- Tube Corrosion Rate
  - Individual Location Corrosion Rate
  - Largest ECT Indication in Service is 45%
  - Calculated Corrosion Rate of 1.8% / Month

# OPERATING INTERVAL

- Required Minimum Tube Wall
  - 13 Mils = 26%
- Large.. ECT Indication in Service
  - 45% = 55% Remaining Wall
- Corrosion Rate 1.8% Per Month
- Permissible Operating Interval for Minimum Tube Wall

$$\frac{\text{Remaining Wall - Required Wall}}{\text{Corrosion Rate}} = \text{16 Months of Operation}$$

# CONCLUSIONS

- ADEQUATE BURST PRESSURE IS MAINTAINED

- CORROSION RATE 1.8% PER MONTH

- OPERATING INTERVAL 16 MONTHS

Current NRC
2/12/80

SURVEY
OF
WESTINGHOUSE OPERATING PLANTS
COLD LEG STEAM GENERATOR EC DATA

- Plants reporting TSP elevation tube wastage:

| | | |
|---|---|---|
| MIHAMA #2 | 1/75 | 5 tubes |
| TAKAHAMA #1 | 12/75 | 8 tubes |
| GINNA | 2/79 (3/75) | 2 tubes |
| PRAIRIE ISLAND #2 | 1/80 | 61 ~~91~~ tubes |
| ROBINSON #2 | 11/75 | 3 tubes |

- Tube pulls at Mihama #2 and Takahama #1 indicated $PO_4$ wastage

- Findings at Robinson #2 and Ginna were following periods of $PO_4$ usage and during first examinations of the Cold Leg areas where the indications existed.

  - $PO_4$ wastage is the probable cause since no new indications have been found since that time

- No other plants have reported Cold Leg wastage in the absence of $PO_4$ history

Given to NRC
2/12/80

# PRAIRIE ISLAND #2
# STEAM GENERATOR INSPECTIONS
# JANUARY, 1980

| | SG #21 | SG #22 |
|---|---|---|
| • INLET | | |
| • Tubes Inspected | | |
| • thru U-bend (720 mil probe) | 345 | 345 |
| • thru U-bend (540 mil probe) | 63 | 90 |
| • thru #7 Support Plate | 92 | 92 |
| • thru #1 Support Plate | | 75 |
| • Indications Reported | 1 | 0 |
| • OUTLET | | |
| • Tubes Inspected | | |
| • thru U-bend (540 mil probe) | 27 | 0 |
| • thru #3 Support Plate | 466 | 934 |
| • thru #7 Support Plate | 257 | 213 |
| • Indications Reported | | |
| • ≥ 20% Eddy Current Indications | 30 | 37 |
| • < 20% Eddy Current Indications | 30 | 54 |

# SUMMARY OF METALLURGICAL EXAMINATION

| Obs. \ TSP | #1 | #2 | #4 | #6 | #7 |
|---|---|---|---|---|---|
| WALL REDUCTION | | | | | |
| LVDT | 9 mils | 22 mils | None | | None |
| X-ray | Thinning | Thinning | | | |
| Micrometer | 10 mils | 20 mils | | | |
| Metallography | 7.5 mils | 25 mils | | None | None |

OD suface at wall thinned location of TSP Nos. 1 and 2.

1. No intergranular attack was present.
2. No evidence for increased cold work at surface; based on metallography and microhardness readings.
3. Areas were [illegible] of gross deposits, frequently contain swirls, and have pits nearby.
4. Deposits in and near wall thinned area contain Na, P, Al, Si, Ca, S, Cl, K, Ti, Mg, Ni, Cr, Fe.

## CONCLUSIONS FROM TUBE EXAMINATION

1. The primary cause of the wall loss at the first and second tube support plate indications is corrosion from an as yet unidentified corrodent.

2. Wear and/or fretting is eliminated as a significant causative agent.

3. Resin carryover from the Powdex polisher is possibly one source of contamination.