January 10, 1985

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Appeal Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	(Steam Generator Repair)
(Three Mile Island Nuclear Station,	)	
Unit No. 1)	)	

AFFIDAVIT OF F. SCOTT GIACOBBE

F. SCOTT GIACOBBE, being duly sworn according to law, deposes and states as follows:

1. I am Manager, Materials Engineering and Failure Analysis for GPU Nuclear Corporation. A statement of my qualifications and experience is attached and incorporated herein by reference.

2. The purpose of my affidavit is to address the allegations of TMIA regarding the possibility of reinitiation of the intergranular stress assisted cracking (IGSAC) which took place on the inner surfaces of the steam generator tubes in 1981. Such reinitiation has not occurred, and neither of the bases cited by TMIA -- temporary increases in the concentrations of sulfates and chlorides in the primary system and recent eddy current indications -- indicate that it has recurred.

3. Attachments 1, 2, and 4 to TMIA's motion to reopen indicate an increase in sulfates in the primary coolant following hot steam generator testing in late 1983, and an increase in sulfates and chlorides following refilling of the primary coolant after the system had been drained. (Attachment 5 refers to draining and refilling the steam generators, a secondary side operation which has no bearing on the IGSAC.) Since we began monitoring the primary coolant water for extremely low levels of contaminants after the tube damage was discovered in 1981, we have found that major changes in the pH of the primary coolant, or draining and refilling the primary side of the steam generators, result in increases in certain chemical impurity concentrations. The increases are both temporary and of very small magnitude, on the order of 0.1 to 0.5 parts per million (ppm). Raising the pH through the addition of ammonium hydroxide can result in changes in sulfur solubility, which permits a temporary increase in the concentration of sulfur in the primary coolant. Draining leaves a film of water on the surface of the tubes, which in turn leaves a residue of impurities on the surfaces when the water dries. When the system is refilled, there is an observed increase in concentrations in the new water as the tube surfaces are washed. This quickly abates as the residues are dissolved and cleanup is initiated. In each case where sulfur concentrations have increased, the reactor coolant is purified immediately, the concentrations are rapidly reduced, and no further contaminant spikes are observed.

4. Thus, levels of sulfur, and for that matter other contaminants, are expected to temporarily increase from time to time for a variety of reasons. As discussed in paragraphs 106 and 108-116 of my February 23, 1984 affidavit, for example, the observed increases in sulfur levels were anticipated. This is why chemistry specification limits are established and why reactor coolant purification systems are part of normal plant systems. These are the methods by which all nuclear power plants control contaminants. Increases in contaminants can result from a variety of sources such as contaminants in chemicals added to the system, impurities from the atmosphere, and dissolution of remaining sulfur from surface oxide films. Irrespective of the cause of contaminant buildup, it was recognized early by GPUN that this would happen and that it would need to be controlled. In addition, because we knew contaminants would be present, we established the long-term corrosion test with contaminants intentionally added to the test solutions to assure ourselves that our specification limits were adequate to prevent IGSAC.

5. The uncertainty as to the reasons for this increase, as expressed in TMIA's attachments, was that Licensee wanted to be certain that there were no unidentified sources of sulfur or chloride contamination and that there were no analytical errors in sulfur measurement. The investigation into these concerns did not uncover any external sources of sulfur contamination other than normal chemical impurities found in chemical

reagents. Some improvements in analytical techniques were made as a result of this investigation.

6. In any event, the temporary spikes in sulfate concentration could not cause reinitiation of the IGSAC. The increases were far too small, and other environmental factors precluded such attack.

7. Similarly, the temporary spikes of sulfate concentration, whether or not due to the addition of ammonium hydroxide which is used to raise the pH of the coolant when the reactor is in wet layup, have no bearing on the concern expressed by staff consultant Dillon, as alleged by TMIA on page 10 of its brief. Dillon's concern was that the peroxide cleaning process, which was completed in August, 1983, would put large quantities of sulfur (5-10 ppm) in solution at that time. His concern had nothing to do with the subsequent control procedures involving the addition of ammonium hydroxide, and he certainly expressed no concern with the magnitude of temporary sulfate concentrations which we have seen. (As I noted at paragraphs 95-97 of my February 23, 1984 affidavit, the peroxide cleaning process generated no more than 0.4 ppm of sulfur compounds, which was not corrosive.)

8. The observations of the small increases in contaminant concentrations have demonstrated that we are able to monitor for minor increases and to control contamination levels through normal cleanup systems when they do occur. They also confirm that the dissolution of residual sulfur compounds

incorporated within the surface oxide films is not a problem, and that, as anticipated, sulfur levels are far below those necessary for the reinitiation of the IGSAC.

9. The recent eddy current indications reported in TMIA's Attachment 6 to its motion are also not indicative that IGSAC has been reinitiated. As described in detail in GPU Nuclear Technical Data Report 638, January 11, 1985 (TDR 638, attached hereto), we have performed an in-depth study to determine the causes of the new indications, with particular emphasis on determining whether they indicate that IGSAC has been reinitiated. The investigation has shown that the degradation is not new, and can best be characterized as intergranular attack (IGA) which occurred in conjunction with the 1981 IGSAC.

10. Our investigation included an analysis of the environmental conditions that the steam generators experienced since the discovery of cracking in 1981. This entailed a review of plant operation and chemistry records and a comparison of the conditions found to existing data on the behavior of Inconel-600 under such conditions. Parameters such as pH of the reactor coolant, contaminant levels, oxygen levels, lithium levels and the water levels in the steam generators were reviewed. The conclusion of this evaluation was that at no time were the steam generators in a condition which would be considered corrosive to the steam generator tubing. <u>See</u> TDR 638, pp. 16-19; <u>see also</u> pp. 33-48.

11. All corrosion testing to date has confirmed our position that, by controlling chemistry, there would be no recurrence of the IGSAC. Analysis of the eddy current indications, recent bubble tests performed, plus visual observations of the tubes via fiberscopic examination down the tube bore provide sufficient evidence to conclude that corrosion of the type previously experienced is not continuing. This evidence in part is made up from the fact that at present there are no leaking tubes, that the current defects have very small circumferential extent, and that visually they appear to be rounded or eliptical, unlike the linear cracks observed before. These defects could be classified as intergranular pit-like defects and as such are much like the IGA island or pits which were observed during the previous failure analysis of the steam generator tubing. <u>See</u> TDR 638, pp. 20-30; <u>see also</u> pp. 6-15.

12. The current indications had previously gone undetected because of their small circumferential size and because with IGA there is very little volume loss (<u>i.e.</u>, loss of metal grains). Because eddy current sensitivity is highly dependent on defect volume, detection of IGA by eddy current is more difficult to detect than is IGSAC. If grains of metal in the IGA area should drop out, however, the volume loss from the defect would be significantly increased and the detectability increased. The thermally induced strains and hydraulic forces during the hot functional testing performed in 1983, subsequent to the record eddy current examinations in 1982, were more than

sufficient to cause grain dropout and grain boundary separation of the previously existing IGA, all of which would increase eddy current detectability. Such grain loss and grain boundary separation from IGA areas have been observed on previously removed tube samples, and is expected to continue for a period of time under the action of thermal or mechanical strains to the tubing which occur during hot functional testing or operation.

13. This recent eddy current inspection, as well as future eddy current examinations, coupled with leak rate monitoring, will continue to assure that such defects are found and that the steam generator tube integrity will be maintained.

F. Scott Giacobbe

F. SCOTT GIACOBBE

Subscribed and sworn to before me this 10th day of January, 1985.

Katherine A. Noonan

NOTARY PUBLIC

My Commission Expires: 3/31/85

Attachment to Affidavit of F. Scott Giacobbe

STATEMENT OF QUALIFICATIONS AND EXPERIENCE

I, F. Scott Giacobbe, am employed by General Public Utilities Nuclear Corporation as Manager, Materials Engineering/Failure Analysis. I have been in this position since July of 1982.

My education includes a Bachelor's Degree in Mechanical Engineering from Villanova University in 1970 and a Master's Degree in Materials Engineering from Drexel University in 1975.

My work experience has provided me many years of direct involvement in the materials evaluation and failure analysis of power plant components; early in my career it also provided a very intense involvement in heat exchanger tubing evaluations.

In 1970, I began my employment with Westinghouse Electric Corporation in their Heat Transfer Division as a Materials Engineer. In this position I worked on the materials selection, corrosion evaluations and failure analysis of heat exchanger components such as feedwater heaters, condensors, radioactive waste evaporators and other secondary side heat exchangers. In particular, I was responsible for assuring that tubing utilized in the Westinghouse heat exchangers was properly specified and manufactured. This function provided me with in-depth knowledge of heat exchanger tubing fabrication practices, corrosion resistant properties and failure mechanisms.

In 1977 I left Westinghouse to join General Public Utilities as a Senior Engineer in their metallurgical laboratory. This position afforded me the opportunity to expand my areas of expertise to include materials selection, corrosion evaluation and failure analysis of other components of both nuclear and fossil power plants, and to gain a broador understanding of power plant operation.

In 1978 I was promoted to supervisor of the metallurgical laboratory. This was a first line supervising position which gave me the responsibility for the daily operation of the laboratory and supervision of the technicians and engineers reporting to me. This position also carried with it a large technical responsibility which kept me heavily involved in the day-to-day materials engineering problems.

My career took on a slight change in direction in 1980 when the company reorganized and formed the Nuclear Corporation. At that time I became Materials and Welding Manager in the Nuclear Assurance Division. With this position I essentially had the same functions as before, with the added responsibility for welding at the nuclear power stations. While in this position I was responsible for the technical and metallurgical aspects of the development of the Nuclear Corporation welding program. During this time I was still supervising all failure analysis activities, including the TMI spent fuel pool pipe cracking incident.

In July 1982, another reorganization took place. At this time my section merged with the materials engineering section in the Technical Functions Division and I took over management of that newly formed section. In this position I now had functional responsibility for the materials configuration control of both GPU nuclear power plants as well as welding engineering and failure analysis. In addition, my section still provided failure analysis services to the fossil companies.

I have been involved in the steam generator tube failure issue from the beginning. I participated directly in the initial decision-making regarding the tube sampling and removal operations and was present to perform the initial visual evaluations of the removed tubing. I personally planned and oversaw the failure analysis activities performed by the outside laboratories. I also developed the corrosion testing programs which GPUN implemented to gain insight and understanding into the failure mechanism and responsible corrodants. It was also my responsibility to coordinate the input from all our technical consultants as well as plant experience and formulate the current failure scenario.

During the steam generator repair, my section also provided materials evaluation and consultation on all aspects of the repair including explosive expansion, flushing, peroxide cleaning, and so forth. My section also developed and implemented the long term corrosion testing program and is evaluating the results as the testing progresses.

Lastly, during the course of the steam generator repairs, I was responsible for making all presentations to the NRC on corrosion testing and failure analysis activities.

Over the years I have kept fully abreast with the state-of-the-art in corrosion technology through my attendance and participation in technical seminars and conferences, and through attending training sessions. I am a member of the Edison Electric Institute Materials, Piping, Welding and Corrosion Task Force, a group of industry representatives who meet to share and develop solutions to corrosion problems in the field of materials and welding in the power industry. In addition, I am a member of the American Society for Metals.

Publications

1. F. S. Giacobbe, "Examination, Evaluation and Repair of Stress Corrosion Cracking in a PWR Borated Water Piping System", NACE Corrosion 81.

2. F. S. Giacobbe, J.D. Jones, R. L. Long, D. G. Slear, "Repairs of TMI-1 OTSG Tube Failures" Plant/Operations Progress AICHE, July 1983, Vol. 2, No. 3.

Nuclear

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January 4, 1985
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Mr. John F. Stolz, Chief
Operating Reactors Branch No. 4
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Stolz:

Three Mile Island Nuclear Station Unit 1 (TMI-1)
Operating License No. DPR-50
Docket No. 50-289
Steam Generator Eddy Current
Test Result Evaluation

In accordance with the Technical Specifications for TMI-1, an eddy current examination of the steam generator tubes was conducted in November and December 1984. An initial report on the resu e examination was contained in LER-84-007, submitted on Decembe .

We have just completed a Technical Data Report (8) entitled "Evaluation of Eddy Current Indications Detected Du ne 1984 Tech. Spec. Inspection." This TDR supplements the information con ined in LER-84-007.

We are continuing our evaluation of the results of the examination and we will provide you any additional information that becomes available.

Sincerely,

R. F. Wilson
Director
Technical Functions

lr/0537e

cc: R. Conte H. Silver
Dr. T. Murley C. McCracken

GPU Nuclear TECHNICAL DATA REPORT	TDR NO. 638	REVISION NO. 0
	BUDGET ACTIVITY NO. 123125	PAGE 1 OF 48
PROJECT: TMI-1 OTSG REPAIRS	DEPARTMENT/SECTION Engineering & Design Materials Engrg/Failure Anal.	
	RELEASE DATE 1/11/85	REVISION DATE -

DOCUMENT TITLE: Evaluation of Eddy Current Indications Detected During the 1984 Tech. Spec. Inspection

ORIGINATOR SIGNATURE	DATE	APPROVAL(S) SIGNATURE	DATE
J. A. Janiszewski J. A. Janiszewski	1/11/85	F. S. Giacobbe	1/11/85
		G. E. Von Nieda G. E. Von Nieda	1/11/85
		N. C. Kazanas N C Kazanas	1/13/85
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		APPROVAL FOR EXTERNAL DISTRIBUTION	**DATE**
		R. F. Wilson R F Wilson	1/14/85

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ABSTRACT:

In order to identify the cause of the eddy current indications detected during the TMI-1 OTSG tube examination beginning in November 1984, Materials Engineering/Failure Analysis performed an in-depth review of the eddy current results and plant operating/chemistry history since the OTSG's were first filled after the kinetic expansion repairs.

Two possible causes for the eddy current indications were evaluated: corrosion, either continuing or newly initiated, and enhanced eddy current detectability of existing intergranular attack (IGA). During unit layup, GPUN layup specifications were followed. Some out of specification periods did occur; however, they were promptly corrected and were not of sufficient magnitude to have caused corrosion. Additional corrosion-preventive conditions were also maintained during layup.

During hot operations, system chemistry conditions were maintained within specifications that industry experience and TMI-1 tube testing have shown are non-corrosive.

The most likely reason for having eddy current indications at this time was enhanced detectability of pre-existing areas of IGA. As a result of thermally induced strains and hydraulic forces during hot functional testing, grains could fall out or grain boundaries could separate for a short distance within pre-existing IGA, resulting in greater local disturbance and a correspondingly larger eddy current signal.

Additional plant data from leak rate observations and the fiberscope examination of a sample of tubes also support the mechanical damage scenario. No leaks have been identified in the tube free span since 1983. In the region of 1984 eddy current indications, patch-like indications suggestive of IGA were seen by the fiberscope examination.

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Introduction

In accordance with the requirements of Technical Specification 4.19, eddy current testing of the OTSG tubing at TMI-1 was begun in November 1984. Initial testing with the 0.540" high gain standard differential probe method revealed previously unreported indications in the unexpanded portions of the OTSG tubes between the tube sheets.

Two possible causes for the eddy current indications were identified and evaluated; first, whether corrosion of the OTSG tubes caused either new defects or growth of existing defects and second, whether straining of existing defects caused them to become more detectable by eddy current. Since the original 100% baseline inspection of the OTSG tubes in 1982, the tubes have been subjected to mechanical loading during the kinetic expansion and thermal and hydraulic loads during the two hot functional tests.

In order to attempt to determine the cause of these indications, the Materials Engineering/Failure Analysis group reviewed 1) the historical eddy current data and 2) plant operational and chemistry data since the OTSG's were filled after the kinetic expansion repair of the tubes.

Based on the results of this review, the cause of the indications is discussed. Data supporting the conclusion are also included.

Background

As defined by Technical Specification 4.19, GPUN conducted eddy current examinations of both steam generators at TMI Unit 1. Performance of this examination ultimately resulted in 100% of the tubes in A-OTSG and all tubes in the outer 16 tube periphery of the B-OTSG being examined.

The B-OTSG had only a limited number of indications with an indicated through-wall extent greater than 40%. Due to the limited number of B-OTSG indications, statistically-based analysis is not feasible. All these indications, however, are located near the outer periphery of the B-OTSG.

The following generalizations about the EC indications can be drawn from the A-OTSG results:

1. They are primarily located in the upper tube sheet and 16th tube span area.

2. They are concentrated in the outer periphery, but some indications occur across the entire OTSG.

3. Most indications are less than 50% through wall.

4. They generally exhibit voltages in the 0.5-2 v. range.

5 By 8 x 1 absolute eddy current, the number of coils tends to be 2 or less, indicating a small circumferential extent.

Evaluation of Eddy Current Results

Note: This section uses the eddy current data base as of Jan. 3, 1985.

GPUN conducted a qualified full-length, eddy current examination program on all tubes from both generators during July to November 1982. The purpose of this program was to screen out all relevant indications and establish a 6" qualified length in the kinetically expanded zone immediately above the new transition zone which was essentially indication free. It was further established that, although we were using a process that was approximately 175% more sensitive than previously used at TMI in performing eddy current examinations, small defects below the threshold of detection could exist. Reference 1 identifies the maximum size of these small defects which could possibly go undetected.

Prior to the expansion, a 100-tube sample of tubes in each generator was eddy current tested periodically to check for indication changes. These tests were performed on seven occasions over a 7 month period. No growth was observed.

Post-Baseline Growth Studies

In-Process Testing

During and following the kinetic expansion repair, a total of 437 tubes were inspected in both the A and B generators (Ref 2, 3). A total of 15 tubes (3.5%) with indications were found that had not been detected by our ECT inspection program prior to the repair. An evaluation was performed on why these indications were not identified previously (Ref. 3). It was concluded that:

1) The recent indications were not i[illegible] the kinetic expansion process nor was there an[illegible] of ductile propagation of existing indications.

2) The defects were small (threshold) type indications that had been either masked by the high background noise levels in the upper tube regions or were sufficiently tight that sufficient metal removal was not present to permit detection. Kinetic expansion may have altered these areas of IGA to make them more detectable.

Confirmation on the small size of the indications was established by the visual examination using fiber-optics. Some of the indications appeared to be small pits.

Additional confirmation was obtained that kinetic expansion would not cause ductile tearing by using test mock-ups and metallurgical examination (Ref. 2). Small intergranular stress assisted (IGSAC) cracks were examined using eddy current techniques before and after kinetic expansions. Expansion caused the cracks to become non-detectable by .540" S.D. techniques. However, the cracks remained visible to the 8 X 1 absolute technique with essentially no change in signal. These specimen tubes were subsequently removed from the test block and metallurgical examination did not reveal ductile tearing or generation of new indications.

ISI Indications

During OTSG repairs, a subset of tubes (28 in A-OTSG, 56 in B-OTSG) was identified as having eddy current indications that did not require plugging. That is, the indications were less than 40% through wall, not in the lane/lane wedge area, and below the 15th tube support plate. This group of tubes (designated as "ISI" tubes by GPUN) was fully characterized and listed for eddy current inspection in the future as a distinct subset.

The "ISI" tubes were re-examined in April/May 1983. No growth of the existing indications was detected.

As part of the eddy current campaign which started in October 1984, all 84 of the "ISI" tubes have been retested. No growth in the ISI subset was detected. (Growth is identified as a substantial increase in the through wall percentage, combined with an increase in voltage and circumferential extent.)

June 1984 Testing

During June 1984, 67 tubes in B-OTSG and 3 tubes in A-OTSG were eddy current tested. This set of tubes was retested in November 1984 - no new indications were detected for the two retests performed.

100 Tube Sample November 1984

Since discovery of the additional indications in November 1984, a second 100 tube sample with indications has been re-examined at approximate two week intervals. As of December 18, 1984, no growth and no new indications have been detected for the two retests performed.

1984 Technical Specification Required Testing

In November 1984, eddy current testing required by TMI-1 Technical Specification 4.19 was conducted as specified. 3% of the tubes in each generator were initially examined. This examination included tubes randomly selected across the entire generator plus a concentrated examination in the periphery of each generator. The more extensive examination in the periphery was performed because this was the region of highest previous (1981) damage .

As a result of this initial examination, OTSG A was classified as category "C-3" per technical specification and OTSG B was classified as category "C-2". Subsequently the entire A-OTSG was inspected while the B-OTSG inspection was complete after the entire 16-tube periphery, approximately 6500 tubes, had been examined.

The number of indications is much higher in A-OTSG than B-OTSG. In A-OTSG, 2.0% of the tubes (299 out of approximately 14589) have indications greater than 40% through wall, while in B-OTSG, 0.5% (33 out of approximately 6576) have such indications.

Spatial Distribution

The indications with greater than 40% through wall extent are concentrated toward the outer periphery and top of A-OTSG. In the outer periphery, the percentage of tubes with greater than 40% through wall indications is higher than the 2.0% average, while inside the outer support rods the percentage of indications is below 1%. 71% of the indications are located above the 15th tube support plate (TSP).

Characterization of Indications

To understand the nature of the defects [illegible] characterized the indications reported back in the [illegible]-1982 time frame and compared them to the indications discovered today.

The axial and radial locations of indications in A-OTSG are essentially the same in 1984 as in 1982, if one does not consider the 1982 indications in the kinetically expanded region in the 1984 evaluation.

Table 1 characterizes the 1982 and 1984 eddy current signals. The 1984 eddy current indications exhibit a similar type of signal response as the previous test program. Details of the differences in responses are noted below:

1) Reported voltages are essentially the same. This indicates that the 1984 indications present a similar volume for the eddy current probe to detect as the 1982 IGSAC.

2) Both through wall penetration and number of coils is significantly lower in 1984. Thus, the 1984 indications extend a shorter distance both into and around the OTSG tube.

Statistical analysis of the eddy current data reveals that 90% of the observed indications fall between 10% and 50% through wall penetration, and between .020" and .190" long.

Degraded Tubes

Per GPUN procedure, tubes with indications reported between 20 and 40% through wall were not required to be plugged if the tubes were not in the lane or lane wedge and the indication was below the 15th tube support plate. At the completion of the 1982 kinetic expansion repairs, a total of 15 A-OTSG tubes and 51 B-OTSG tubes were classified as "degraded" and were included in the ISI group. As of January 4, 1985, 347 additional A-OTSG tubes and 98 additional B-OTSG tubes are classed as degraded.

Table 1

Comparison of 1982 and 1984 Eddy Current Data

a) Reported Voltage - % of indications reported

	A-OTSG		B-OTSG	
Voltage	1982	1984	1982	1984
< 1	34	40	24	27
1	44	35	30	21
2	16	20	25	29
3	4	4	10	12
> 3	2	1	11	11

b) Reported through wall penetration - % of indications

	A-OTSG		B-OTSG	
% T.W.	1982	1984	1982	1984
< 20	< 1	< 1	12	
20-40	3	61	28	75
40-60	21	25	24	18
60-80	17	10	15	5
> 80	59	4	21	2

c) Number of coils on 8 x 1 examination - %

	A-OTSG		B-OTSG	
Coils	1982	1984	1982	1984
1	20	90	18	80
2	26	10	24	20
3	16	< 1	15	< 1
> 3	38	< 1	43	< 1

NOTE: 1982 data includes inspection of original tube roll transition area. The 1984 data does not include inspection from the top of tube sheet to the bottom of the kinetically expanded region.

Chemistry Specifications

Corrosion Experience with Inconel 600

Three types of primary-side initiated attack have been identified in Inconel 600. In recirculating steam generators using mill-annealed tubes that have not been stress-relieved after U-bending, stress corrosion cracking (SCC) has initiated from the primary side in the highly stressed bend areas. Also in mill-annealed tubes in recirculating steam generators, SCC has been found to initiate from the primary side at highly stressed transition areas in the lower tubesheet. Laboratory studies have shown that the stress relieved Inconel tubing used in OTSG's is significantly more resistant to SCC than the mill annealed type.

The other primary side attack of Inconel 600 that has occurred in steam generators is the intergranular stress assisted cracking (IGSAC) caused by reduced sulfur species on sensitized OTSG tubing. This is the mechanism which caused the TMI-1 OTSG leakage in 1981. This mechanism requires sensitized tubing, low temperatures, oxygen, and significant levels of reduced sulfur species.

Corrosion Test Results

As part of the overall program to evaluate the most recent eddy current testing results, we have reviewed the results of corrosion tests performed as part of the original failure analysis and OTSG requalification programs. These data provided a partial basis upon which we could evaluate the layup and test conditions to which the steam generators had been subjected.

Long Term Corrosion Test (LTCT)

The primary purpose of the long term corrosion tests was to verify that the proposed operating chemistry specifications are satisfactory to prevent corrosive attack of the OTSG tubes. To this end, chemistry conditions for the testing were established at the maximum allowable values consistent with the upgraded TMI-1 operating specification (Ref. 4). The LTCT was conducted using actual TMI-1 tubing. Temperatures, tube loads, and heatup and cooldown rates were representative of actual plant operating conditions.

In addition, as the LTCT was actually performed, specific factors which parallel actual plant layup conditions were experienced. The tubes were held in a cold, aerated condition for several days after the completion of each operating cycle. Aeration was done after cooldown. Before heatups, or while waiting for other autoclaves in the test program to be ready for operation, the test loops were operated in a cold, deaerated, circulating mode. Because eddy current examinations were done after each test cycle, the tubes had to be removed from the autoclaves and drained. Thus, drained aerated layup conditions were also included.

Table 2 summarizes LTCT operational times in each mode. All loops spent significant time under drained, cold deaerated, and aerated conditions.

Review of the chemistry history of the LTCT's revealed that the conditions were comparable to the plant's experience. The LTCT specification (Ref 5) for sulfate and chlorides was 0.100 ppm + .050 ppm. Actual analysis results (Ref. 6, 7, 8) revealed that the concentrations of these species were maintained at or slightly above the .150 ppm upper limit. The actual values measured in these tests bound any of the contaminant "spikes" reported in the Chemistry and Operational History Review.

C-ring tube samples from archive tubing (tubing never installed in the TMI-1 OTSG's, which was included as a control sample) showed no evidence of cracking, pitting or general corrosion.

Some intergranular attack (IGA) was noted on 4 C-rings made from a single TMI-1 OTSG tube; this IGA was evaluated to be pre-existing damage associated with the 1981 IGSAC incident. Of a total of 38 C-rings evaluated, 31 had no visible defects, 3 showed very shallow cracks when strained severely, and 4 had IGA as described above.

Five full tube samples were metallographically examined after the LTCT. In addition to previously reported defects, four samples exhibited scattered, shallow cracking or IGA which was not detectable by eddy current testing. This IGA was consistent in size and shape with IGA that had been seen during the failure analysis (Ref. 9). Therefore, the observed IGA on these four tubes was judged to have been present at the start of the LTCT.

One tube sample had severe IGSAC and IGA which had progressed during the term of the LTCT and had been detected by eddy current. The tube sample which showed flaw growth during the LTCT was exposed in the test loop in which the sulfur species was thiosulfate, at a concentration of 0.100 ppm $\pm$ 0.050 ppm (as sulfate). Therefore, the only tube sample exhibiting flaw growth during the LTCT was exposed to intentionally added, reduced corrosive sulfur species.

The four C-ring samples showing IGA and the full tube sample showing flaw growth were removed from the same OTSG tube. This tube was recorded as having multiple eddy current indications when inspected in the OTSG. The IGA seen in the post-test examination is therefore consistent with an original tube sample which had multiple defects and, presumably, associated IGA.

Results of metallographic examination of the LTCT samples (Ref. 8) confirmed that in the absence of intentionally added aggressive sulfur species, normal operations would not cause corrosion of TMI-1 OTSG tubing.

Short Term Test Results

Several sets of tests were previously run on Inconel 600 tubing to establish corrosion resistance under various conditions representative of TMI-1 service. Those results which apply to the period of this review are summarized below:

1) Screening work on actual TMI-1 removed tubes and archive tubes (Ref. 10) identified that at oxidizing potentials, 1 ppm of thiosulfate was required to cause IGSAC. Sulfate levels as high as 10 ppm did not cause IGSAC.

2) Simulation of hot functional testing and cooldown (Ref. 11) utilizing thiosulfate contamination and actual operating temperatures and times revealed that 1 ppm of thiosulfate caused IGSAC.

These short term tests thus confirmed that in the absence of thiosulfate contamination, no short term attack of OTSG tubes is expected.

Bulk vs. Surface Effects

The above corrosion tests were performed using actual TMI-1 OTSG tubing. The surface film condition was therefore representative of that in the plant. Chemistry control in both corrosion testing and actual operation is done by the measurement and control of species of interest in the bulk fluid.

Since both surface conditions and chemistry control were identical between the laboratory tests and plant operations, the results of the corrosion tests can be directly applied to the plant environment, and, conversely, plant bulk chemistry data can be used to evaluate the propensity for corrosion.

TMI-1 Chemistry Guidelines

Hot Operations

After sulfur was identified as the causative agent of the 1981 IGSAC, hot operational guidelines (Ref. 4) were reviewed to ensure that adequate corrosion protection was maintained. As a result of this review, two changes were made to provide increased margins against corrosive attack.

First, a requirement was added that primary system sulfate be maintained below 0.100 ppm. Sulfate at this level does not cause corrosive attack of Inconel 600 in primary coolant, and maintaining sulfate below this level provided assurance that intermediate sulfur species could not exist at harmful concentrations.

Second, the lower limit on lithium concentration was increased to 1.0 ppm, to take advantages of lithium's inhibiting effect on sulfur-induced IGSAC in Inconel 600 (Ref. 12).

The net result of these changes is to ensure that total sulfur species concentrations are a factor of 10 below the level at which corrosive attack might occur. At the same time, the minimum Li/S ratio will be 30 (or Li/SO4 of 10), which is a factor of 3 over the recommended (Ref. 12) ratio of 10 for inhibition of IGSAC initiation.

Layup

For cold layup conditions, guidelines have been established to maintain as many protective conditions as feasible. The individual protective conditions that are feasible for the TMI-1 RCS are:

1) Elevated pH - during layup, pH has been elevated, using ammonia, to at least 7.2. The normal pH without ammonia is 5.6 - 6.5.

2) Control of contaminants - The primary water contaminants of concern are chlorides and sulfates. Chlorides have traditionally been limited to less than 0.100 ppm during operation; we have maintained this level as a general guideline during layup. The sulfate level of less than 0.100 ppm used during hot operation also applies to layup.

3) Control of oxygen level - When the system is filled and able to be pressurized, the oxygen level is to be maintained below 0.1 ppm. For cases where the primary system is open and oxygen cannot be excluded, air saturated conditions are specified as this is more protective than some intermediate oxygen level.

4) Control of OTSG level - One of [illegible]ributing factors to the 1981 IGSAC incident was [illegible]ence of a water line on the primary side of the [illegible]. For layup of the OTSG's, wherever possible, no static waterline shall be allowed to exist in the OTSG tubes. Either the water level should be above the upper tubesheet or the OTSG primary side should be fully drained.

5) Inventory Turnover - Periodic replenishing of the OTSG contents will assure that local buildup of contaminants will not occur. Layup guidelines have included provisions for periodically turning over the water inventory on the OTSG primary side to meet this objective.

TABLE 2

Summary of Operations for Long Term Corrosion Tests

	Operating Days				
		Cold Circulating		Drained	
Loop	Hot	Deaerated	Aerated	Layup (Note 1)	Comments
1	348	52	28	132	
2	308	69	27	157	Thiosulfate loop
3	241	42	23	58	
4	242	40	22	61	

Notes

1. Does not include drained layup between completion of operational cycles and start of metallographic examination.

Chemistry and Operating History Review

Data Base

The chemistry and operating history data were obtained from two sources. First, the on-site Plant Analysis group reviewed operational records to identify plant conditions during this time period (Ref. 13). Then, we retrieved the primary plant chemistry parameters of interest from the GPUN computerized chemistry data base.

The major plant activities that occurred between May 1983 and October 1984 are listed in Table 3. Within each of these periods, we identified different plant conditions of RCS level, temperature, pressure, circulation, and pH. Then, we reviewed the chemistry data for each time period.

Chemistry data selected to be of interest with respect to corrosion were pH, oxygen, lithium, sulfate and chloride. As an additional check on the effectiveness of chemistry controls, we calculated the lithium to sulfur ratio for each operating period. In cases where simultaneous analyses for lithium and sulfate exist, we calculated the Li/S ratio for each data point.

The data from the operational and chemistry investigations are plotted as a function of time in Appendix A.

Results of Operational/Chemistry Review

During both hot shutdown and cold layur [illegible]ditions, TMI-1 has maintained conditions within chemistry guid[illegible] about 95% of the time. For short time periods, some deviati[illegible] [illegible]ccurred which are discussed in the balance of this section.

Chloride and Sulfate

There have been short time periods where chlorides and/or sulfates have exceeded specified limits. In all instances chemistry data reflect that corrective actions were appropriately and promptly taken to return the concentrations of these species to specified levels. Collectively, these out-of-specification periods can best be described as normal chemistry "spikes".

Oxygen

In preparation for both the September 1983 and May 1984 hot functional tests, it was necessary for the RCS to be taken from a layup to an operating mode. During this transition, oxygen levels were higher than desired for optimum protection, but other factors made it very unlikely that corrosion occurred. First, chloride and sulfate concentrations were controlled to acceptably low levels. Second, the lithium level was maintained such that the minimum lithium to sulfur ratio was 66; the recommended minimum value for protection against IGSAC is 10 (Ref. 12). Chemistry control during these periods is summarized in Table 4.

Other Operational Considerations

During the Integrated Leak Rate Test (ILRT) in April 1984, the primary side water level was maintained at about the 12th tube support plate for 8 days. This condition was both preceded and followed by drained layup with elevated pH, aerated water. Both sulfate and chloride levels remained within specification. Therefore, no OTSG tube corrosion was expected.

In August 1983 and May 1984 oxygenated water was injected into deoxygenated RCS during HPI testing. Most of these tests were conducted prior to the high temperature portion of the hot functional tests, and the oxygen introduced would have been consumed by hydrazine and/or hydrogen added for that purpose. One test was conducted on May 26, 1984, at the end of HFT and may be postulated to have injected 5000-6000 gallons of oxygen-saturated water. During this time period, however, the lithium to sulfur ratio was greater than 30 which was more than adequate to inhibit corrosion during this test.

TABLE 3

Major Plant Evolutions, 5/83 to 10/24

Event	Duration
Fill & Bubble Test	June 1983
Peroxide Clean	July 1983
Hot Functional Test	Aug - Oct 1983
Circulating Wet Layup	Oct - Nov 1983
DH-V1 Repair	Nov 1983
Circulating Wet Layup	Nov 1983 - Jan 1984
RC-P1B Repair	Feb - April 1984
Integrated Leak Rate Test	April 1984
Hot Functional Test	May 1984
Non-Circulating Wet Layup	May - June 1984
Tube Plug Rerolling and Bubble Testing	Oct 1984

TABLE 4

Chemistry Summary Before Hot Functional Testing

Period	Days	Oxygen, ppm	Li, ppm	SO_4, ppm	Cl ppm	Li/S Ratio
8/83	29	0.3	.82-1.96	.047-.079	.05-.156	66-123
5/84	19	.075-2.2	1.06-2.17	.02-.047	.05-.110	127-240

In-Plant Observations

Leak Testing

Since completion of the kinetic expansion repairs, several leak tests have been performed to measure primary-to-secondary leakrates and identify individual leaking tubes. These tests are summarized in Table 5.

No pattern of tube leakage can be seen. After the cooldown tests included in hot functional testing some increase in leakage was seen. Further investigation showed that this leakage was the result of leaks through a small number of tubes. These leaks were located in the expanded region within the upper tube sheet and were repaired by mechanically rolling a portion of the expanded area.

Of greatest significance is that since 1983 no tube which is in service has had a leak in an unexpanded portion of the tube. All leaks have either been due to bypass leaks in the expanded area or leaking plugs.

Fiberscope Inspection of Selected Tubes

A fiberscope inspection was performed (Ref. 14) of six A-OTSG tubes which exhibited typical eddy current indications. During the inspection features were observed on 4 out of 6 tubes at the same elevation as the eddy current indications.

The visual features were "patchlike" rounded areas having an outer ring which was darker than the general tube surface and slightly reflective components in the interior. The patches were between 0.020 and 0.060" in diameter.

The patches appeared similar to surface features seen during the initial tube failure analysis. These earlier defects were found to be associated with partial through wall intergranular attack.

TABLE 5

Leak Tests in OTSG's Since 5/01/83

Month/Year	Test Type	Reason For Test	Results	Repairs
May 1983	Drip	Test of Kinetic Expansion	2 Leaking Tubes, 8 Leaking Rolled Plugs 10 Leaking Explosive Plugs	Plugs Installed/Rerolled
June 1983	Bubble/Drip	Final Test of Kinetic Expansion	Small Number of Slightly Leaking Tubes and Plugs in A OTSG - 1 Leaking welded plug	Repaired welded plug
Sept 1983	Kr-85 Tracer	Establish Baseline Leak Rate	Baseline Leak Rate 1 gph	None Required
May 1984	Kr-85 Tracer	Measure Baseline Leak Rate	Slight Increase in Leak Rate	None Required
June 1984	Bubble/Drip	Identify Leaking Tube(s)	4-5 Leaking Tubes in B-OTSG	Plug 3 tubes w/welded plugs
			6 Rolled Plugs Missing	Reroll all W plugs Replugged tubes.
Oct. 1984	Bubble/Drip	Test Rolled Repairs	Small Number of Leaking Tubes, one welded plug	Roll 8 Tubes Reweld Plug

Note: No leaks seen in final October 1984 Bubble Test, after tube rolling.

Discussion

General

Removal of sodium thiosulfate from the TMI-1 site and tighter operational chemistry controls implemented since 1981 have made it highly unlikely that the conditions to cause sulfur-induced IGSAC could be recreated. The steam generator layup guidelines are specifically designed to protect the steam generators from additional corrosion and are more stringent than B&W's generic recommendations, particularly in the areas of contaminant control and the use of elevated pH during cold layup. Industry experience on B&W PWR's also does not reveal any other primary-side initiated attack mechanisms on Inconel OTSG tubing.

TMI-1 compliance with operating and layup specifications has been excellent. Transient out-of-specification conditions, which were identified during plant operation, have been infrequent and corrected promptly by the plant operators. Plant conditions have always been bounded by those which were evaluated during corrosion testing and found to be satisfactory.

The only period of possible vulnerability to corrosion would have existed during the time when the OTSG's were drained for the kinetic expansion repair. During this period sulfur would have remained in the oxide film on the tube surfaces as peroxide cleaning had not yet been performed. During this time, however, eddy current testing done on the 100 tube surveillance sample did not reveal any growth of existing indications or any new indications. Thus, while the oxide film may have contained sulfur during this time, there is no evidence that corrosion continued.

Previously detected IGA, both ir[illegible]ure analysis (Ref. 9) and long term corrosion test (Ref. 8), ha[illegible]een in the form of hemispherical pits penetrating approxi[illegible] through wall. A pit of this shape and penetration would appear a[illegible]e on the surface of diameter of approximately 0.035". Areas of th[illegible] circumferential extent would not be predicted to be detectable by the .540 S.D. eddy current technique (Ref. 2).

Under mechanical loadings induced by kinetic expansion or cooldown, these areas could become more detectable by eddy current through several mechanisms:

1) creation of a linear grain boundary separation within the IGA islands as was seen in the LTCT (Ref. 8), or

2) disconnected grains dropping out and leaving pits.

Two additional pieces of data from Ref. 16 lend support to the mechanical scenario. First, peripheral tubes consistently see higher loads than core tubes. Therefore, in the periphery, the highest stresses would also act on this IGA. Second, the A-OTSG cooled down more quickly than the B unit. The peak load during the most rapid cooldown (Ref. 16) was 200 lb, or higher (12%), in the A-OTSG than in B-OTSG. Figure 1 is a representation of how the A-OTSG would have had significantly more tubes carrying loads high enough to cause IGA to become more detectable.

A previous study (Ref. 15) on crack opening displacement of archive tubes with approximately .5" long through-wall cracks found that loads between 1500 and 2000 lbs. would induce permanent displacements in the vicinity of the cracks. Loads less than this would induce only elastic displacements with a load of 1000 lbs. producing an elastic displacement of approximately .002". Although tubes with cracks of this size are no longer in-service with the steam generators, this study does point out that one can expect local straining in the vicinity of smaller defects, but that it would be of proportionately lesser magnitude.

During the 1983 HFT, the most rapid cooldown was calculated to have induced loads in the tubing of between 1600 and 1700 lbs. (Ref. 16). It is such loads acting on the regions of IGA which we believe leads to grain dropping or grain boundary separation.

Visual observations made during the fiberscope examination of selected OTSG tubes support the cause of the present eddy current indications being mechanical damage to existing IGA. At locations where eddy current indications existed, we frequently saw rounded, darkened areas of a size consistent with IGA detected in the original failure analysis.

<u>Detectability of Indications by Eddy Current</u>

It should be noted that the primary defects of concern for OTSG tube integrity (i.e. tube rupture) are circumferential cracks. The production of 0.540" standard differential eddy current technique is optimized and qualified for this type of defect. However, it can also be used for detecting different defect geometries as discussed below.

The 1984 tube ID indications as detected by eddy current and as seen during the fiberscope inspection had significantly different characteristics than the IGSAC responsible for the 1981 tube leakage. The 1981 IGSAC consisted of tight, circumferential cracks that penetrated completely through the wall. The 1984 observed IGA is more rounded and does not completely penetrate the tube wall.

The different geometry will have a direct effect on detectability. The current .540" S.D. eddy current technique was optimized for the IGSAC geometry; therefore, a different geometry will have a different detectability. The balance of this section of this report will discuss changes in sensitivity due to changes in indication geometry.

Figure 2 (Figure 2 from Reference 2) shows the measured sensitivity of the .540" S.D. technique in the range of short circumferentially oriented defects. The shaded region in Fig. 2 identifies the area in which 90% of the 1984 indications fall. It can be seen that the eddy current calls span the 0.3 volt detectability limit. Thus only slight changes in indication geometry could cause a particular indication to become detectable.

In Figure 3a and 3b, we have taken the eddy current data and visual observations from the fiberscope inspection (shown in Table 6) and indicated where the indications would be in relationship to the calibration curves. The tubes for fibrescope inspection were chosen to be representative of the types of indications being found in 1984. All of the below-UTS indications (Figure 3b) are close to the 0.3 v detectability limits; the within-UTS indications (Figure 3a) do not fall into the detectable range. Therefore, it is reasonable that before mechanical loading these indications may not have been detectable. Mechanical loading, as discussed in the previous section, can alter IGA geometry.

Because the calibration was done on a length vs. through-wall basis using EDM notches of a constant axial width of about 0.004", IGA geometry could produce a different signal. Patch-type indications of the same length would have a larger axial extent, and therefore a larger volume, and could be expected to give a higher voltage signal. The S.D. response would also be enhanced by increased axial extent, even at constant defect volume, since the differential coils are wound in the circumferential direction and are more sensitive to the axial extent of defects.

The large increase in the number of degraded tubes in A-OTSG and B-OTSG is also consistent with the scer[illegible] of pre-existing IGA becoming more detectable. IGA islands of 20-4[illegible]h wall extent would be expected to have a length of about .0[illegible]ches; this is below the 300 mV sensitivity for free-span detec[illegible]e 2). The additional disturbances of mechanical, thermal, and [illegible] loading could easily disturb these islands enough to now make th[illegible]e detectable.

Table 6 - Comparison of Preliminary Eddy Current Data and Fiberscope Results

			EC Results				
			.540 S.D.		8 X 1		
Row	Tube	Elevation	% T.W.	Volts	Volts	Coils	Visual Observations
89	124	US+5.4	98	1.6	1.6	2	
		US+4					Rounded indications - possible IGA
		US+5.8					Axial alignment of 3 rounded indications
76	119	US+2.4	97	2.1	0.8	2	
		US+5.5					Small dark spot when scanning w/90° head
66	129	15+27.6	70	2.8	1.3	2	
		15+24.5					Rounded indications - possible IGA
61	123	15+21.8	67	2.3	1.1	2	
		15+26					Small dark spot - no detail visible
		15+24.7	45	1.7	0.5	1	
57	128	US-2.6	92	1.3	0.3	1-2	
		US-1.5					Axially oriented rounded indications
60	126	15-14.2/15-6.5	37/42	1/1.0	NDD		Small single rounded indication

Figure 1 - TMI-1 OTSG Testing 3rd Cooldown (10-2-83)

Tube Load Distribution as a Function of Tube Location at the Peak Applied Load for "A" and "B" OTSGs

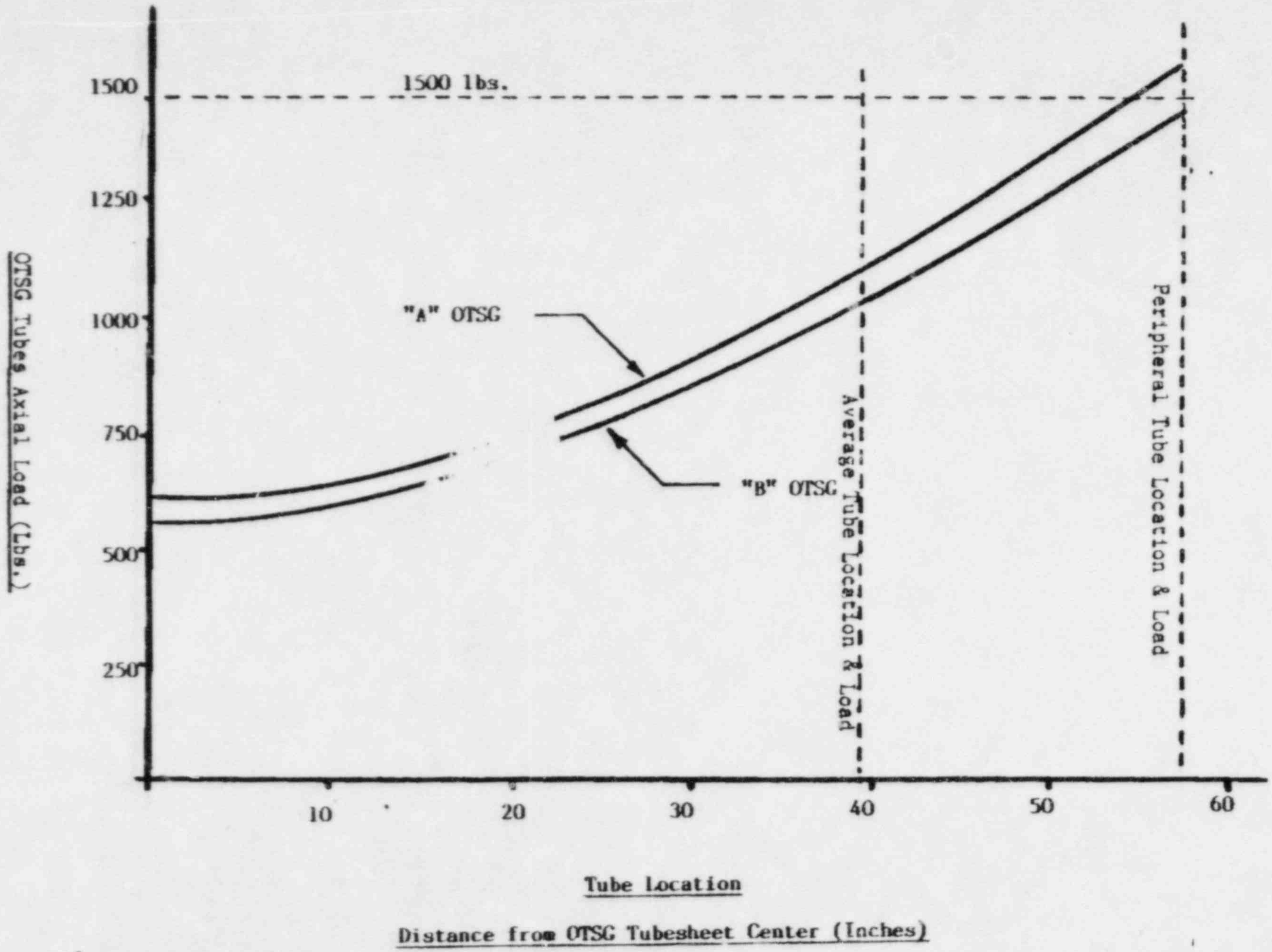


Figure 2 - 1984 Eddy Current Date

Compared to Detectaability Limits

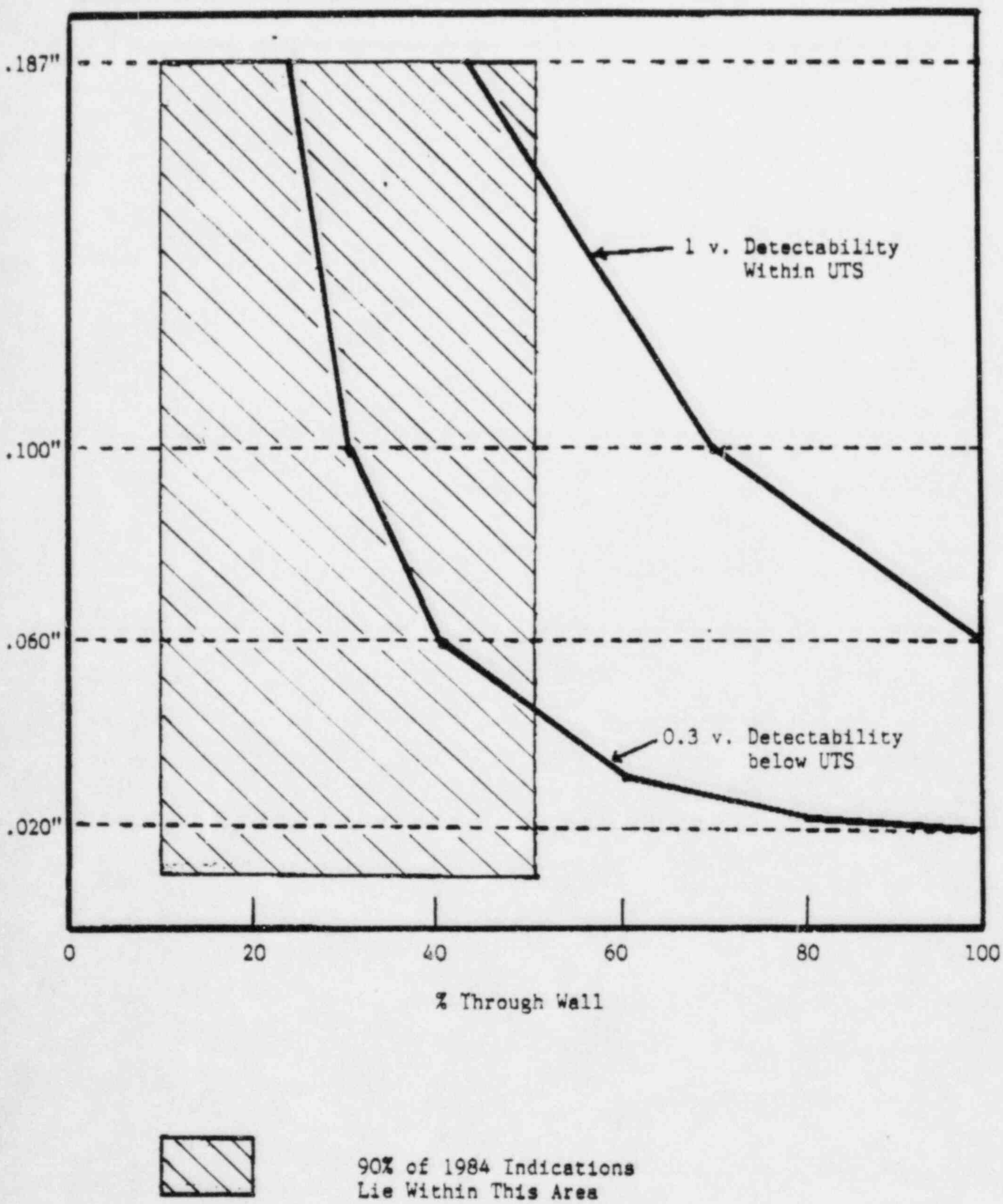
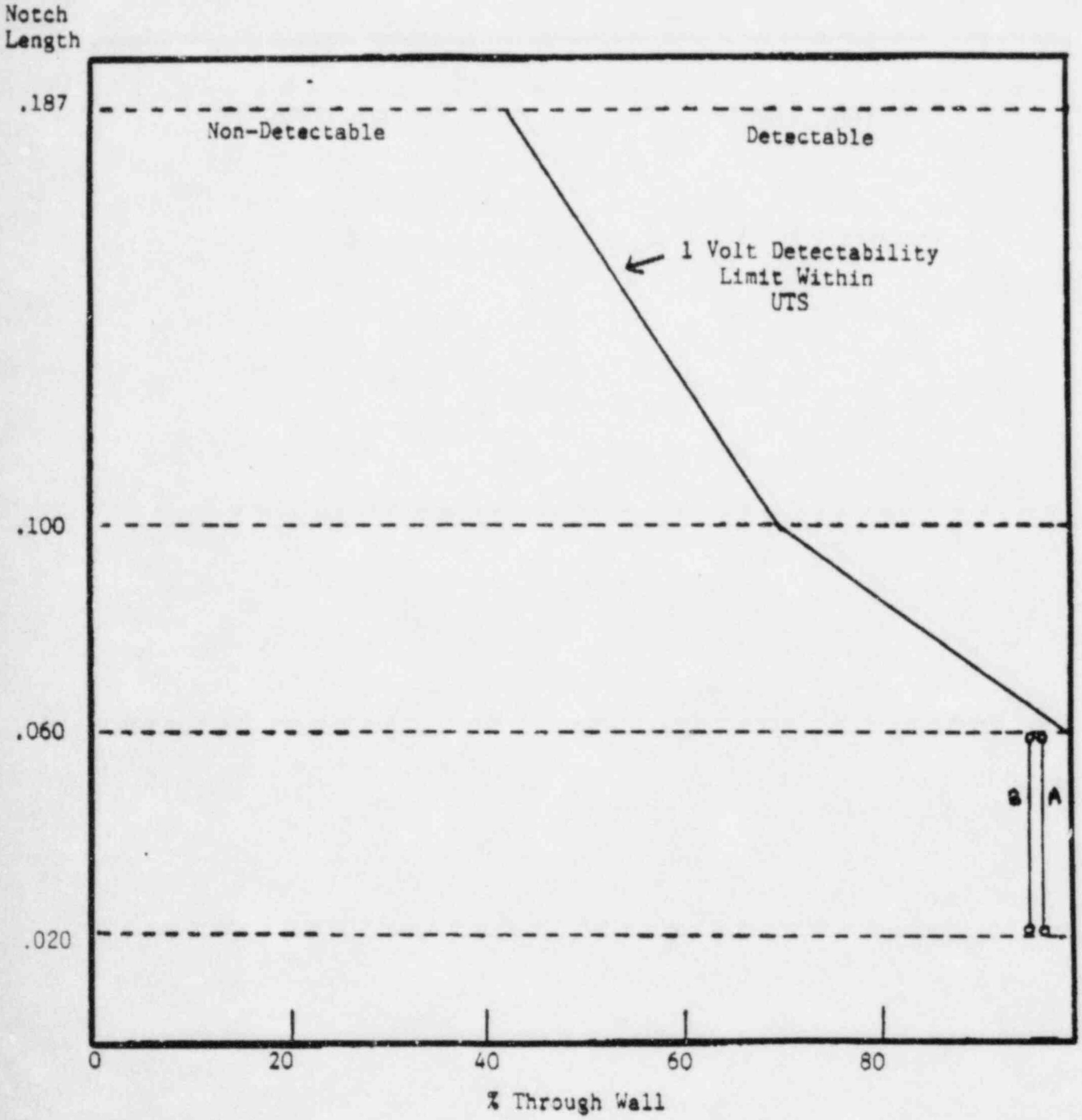


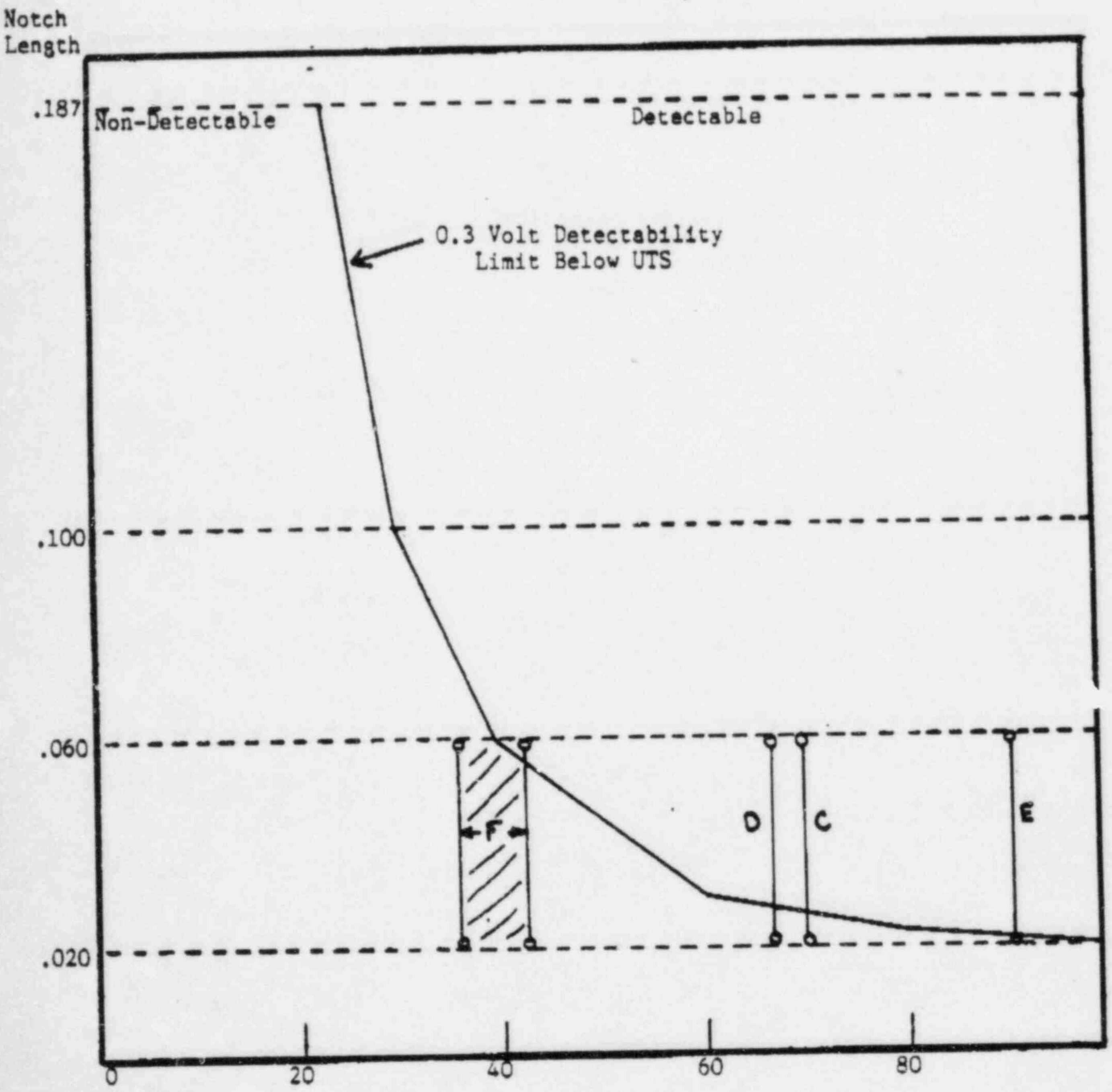
Figure 3a - Within - Tubesheet Fiberscope Indications Compared to Detectability Limit



Tube Identification

A	A-89-124
B	A-76-119

Figure 3b - Below - Tubesheet Fiberscope Indications Compared to Detectability Limit



TDR

Tube Identification

C A-66-129
D A-61-123
E A-57-128
F A-60-126

Conclusions

1. The TMI-1 layup guidelines are adequate to prevent any identified mechanisms for primary side initiated corro ion of Inconel 600 OTSG tubes.

2. The TMI-1 layup guidelines have been adhered to since completion of the kinetic expansion repair. Minor deviations have been corrected promptly.

3. Vulnerability to corrosion may have existed during the period when the OTSG's were drained for repair prior to peroxide cleaning. However, eddy current data and the absence of OTSG leakage during this time period do not show evidence of corrosion of OTSG tubes.

4. Results of both GPUN-sponsored and industry corrosion test programs confirm that corrosion would not be expected during TMI-1 operations since May 1983.

5. Results of eddy current tests since 1982 do not indicate any trends of indication growth of pre-existing indications.

6. Leak rate testing and OTSG bubble testing do not indicate any increases in leakage or new leaks in the tube free span.

7. The eddy current data and visual observations are consistent with a mechanism where previously existing areas of intergranular attack are made more detectable by mechanical loading during kinetic expansion and thermal and hydraulic loading d ing cooldown from HFT.

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APPENDIX A

TMI-1 CHEMISTRY DATA

MAY 1, 1983 to OCTOBER 26, 1984

Contents

Table A1

CHEMISTRY GUIDELINES APPLIED TO TMI-1

5/1/83 to 10/26/84

Operating Mode	Wet Layup	Drained Layup	Hot Shutdown (Hot Functional Testing)	Peroxide Cleaning
OTSG Primary Level	Full	Drained	Full	Full
Maximum Chloride, ppm	0.1	0.1	0.1	0.2
Maximum Sulfate, ppm	0.1	0.1	0.1	Note 2
Maximum Oxygen, ppm	0.1	N/A	0.1	Note 2
pH	greater than 7.2	4.6-8.5	4.6-8.5	8.0-8.5
Li,ppm	1.0-2.0	1.0-2.0	1.0-2.0	1.8-2.5
Minimum Li/S ratio		10	10	N/A

Notes:
1. Limits are for bulk RCS - no water in OTSG's at this time.

2. Sulfate and oxygen were monitored but no limit was applied.

CHEMISTRY DATA
FILL AND BUBBLE TEST PERIOD
May – July 1983

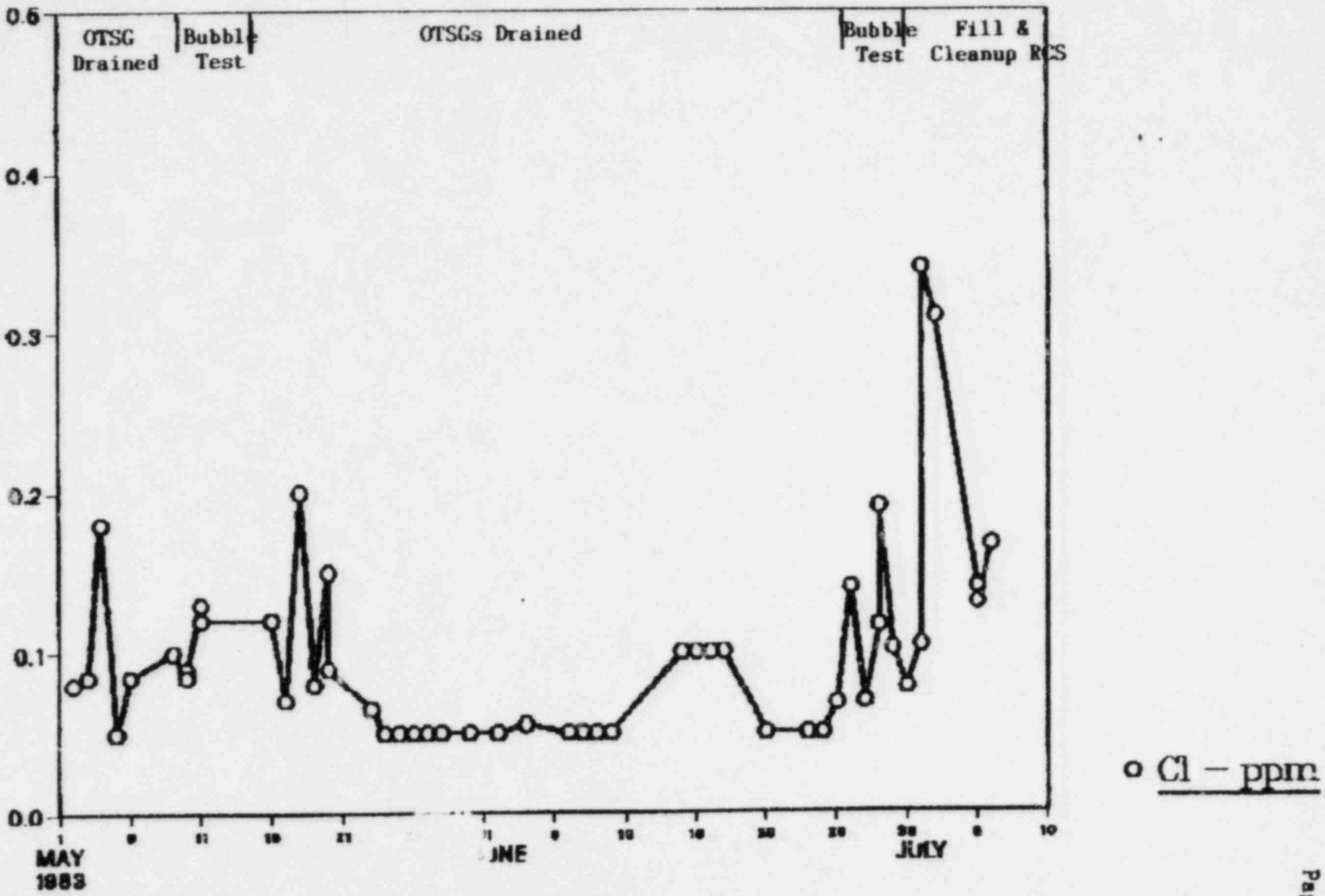

Figure A1-1a

CHEMISTRY DATA
FILL AND BUBBLE TEST PERIOD
May – July 1983

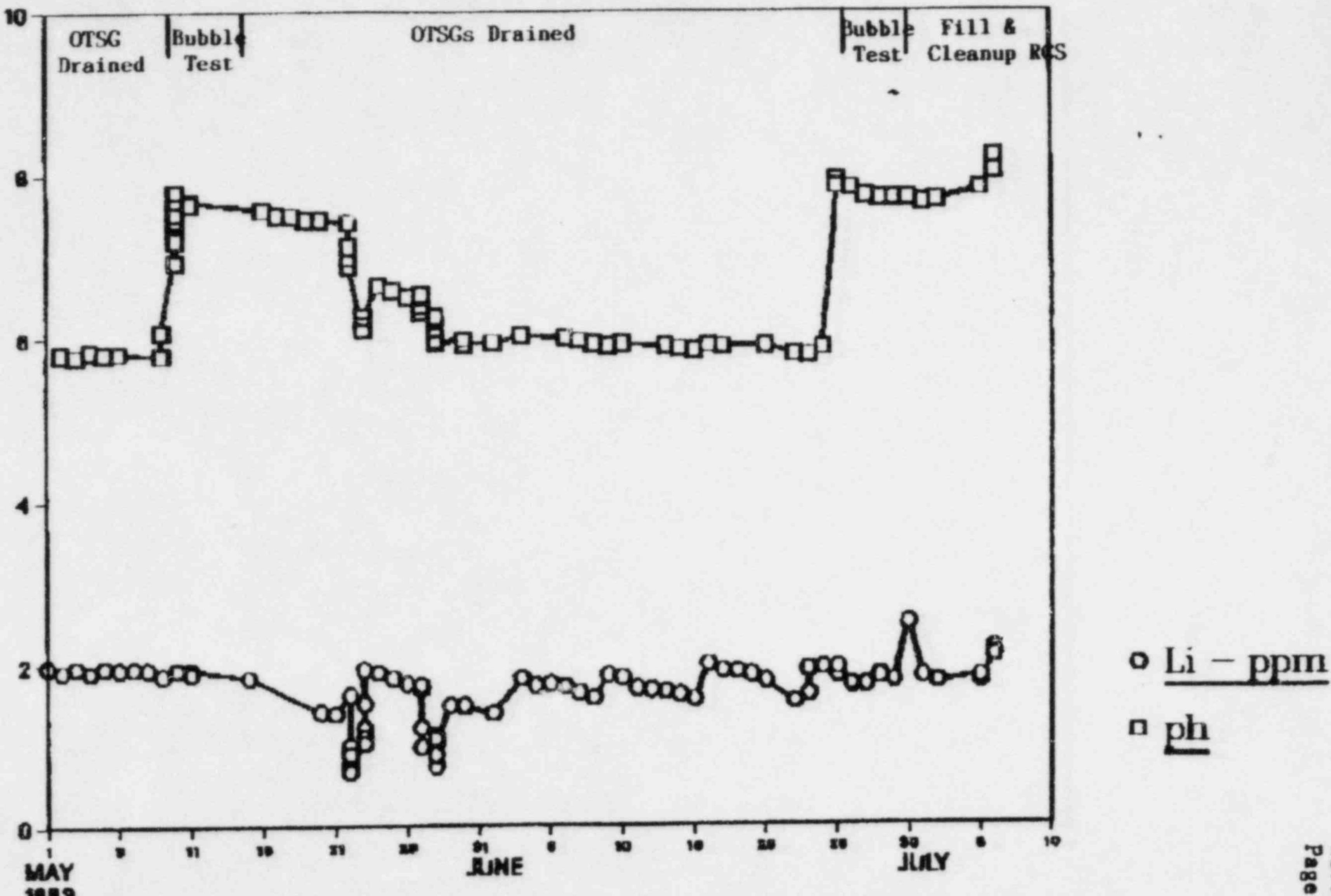

Figure A1-1b

CHEMISTRY DATA
PEROXIDE CLEANING AND PREPARATIONS FOR HFT
July - August 1983

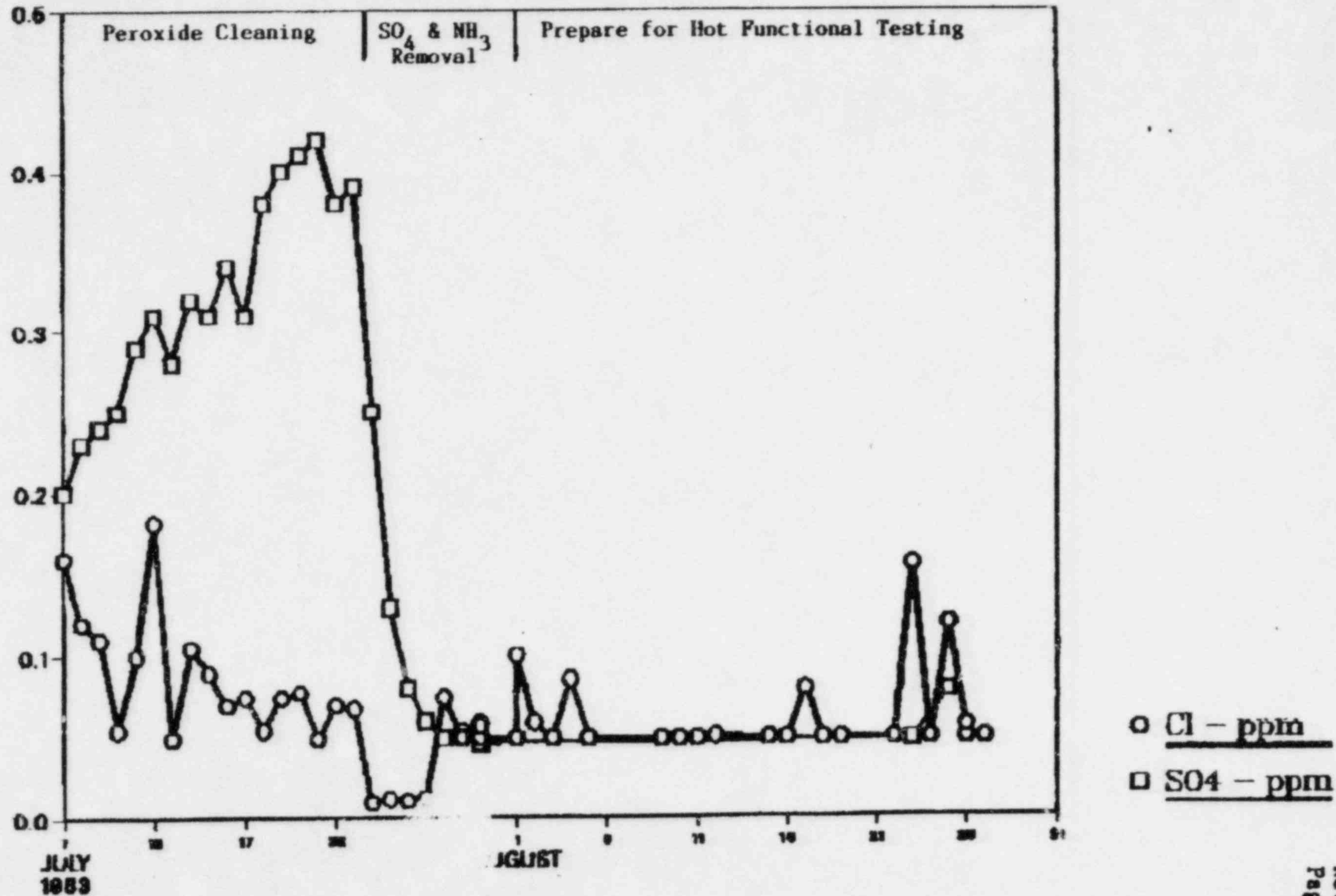

Figure A1-2a

CHEMISTRY DATA
PEROXIDE CLEANING AND PREPARATIONS FOR HFT
July - August 1983

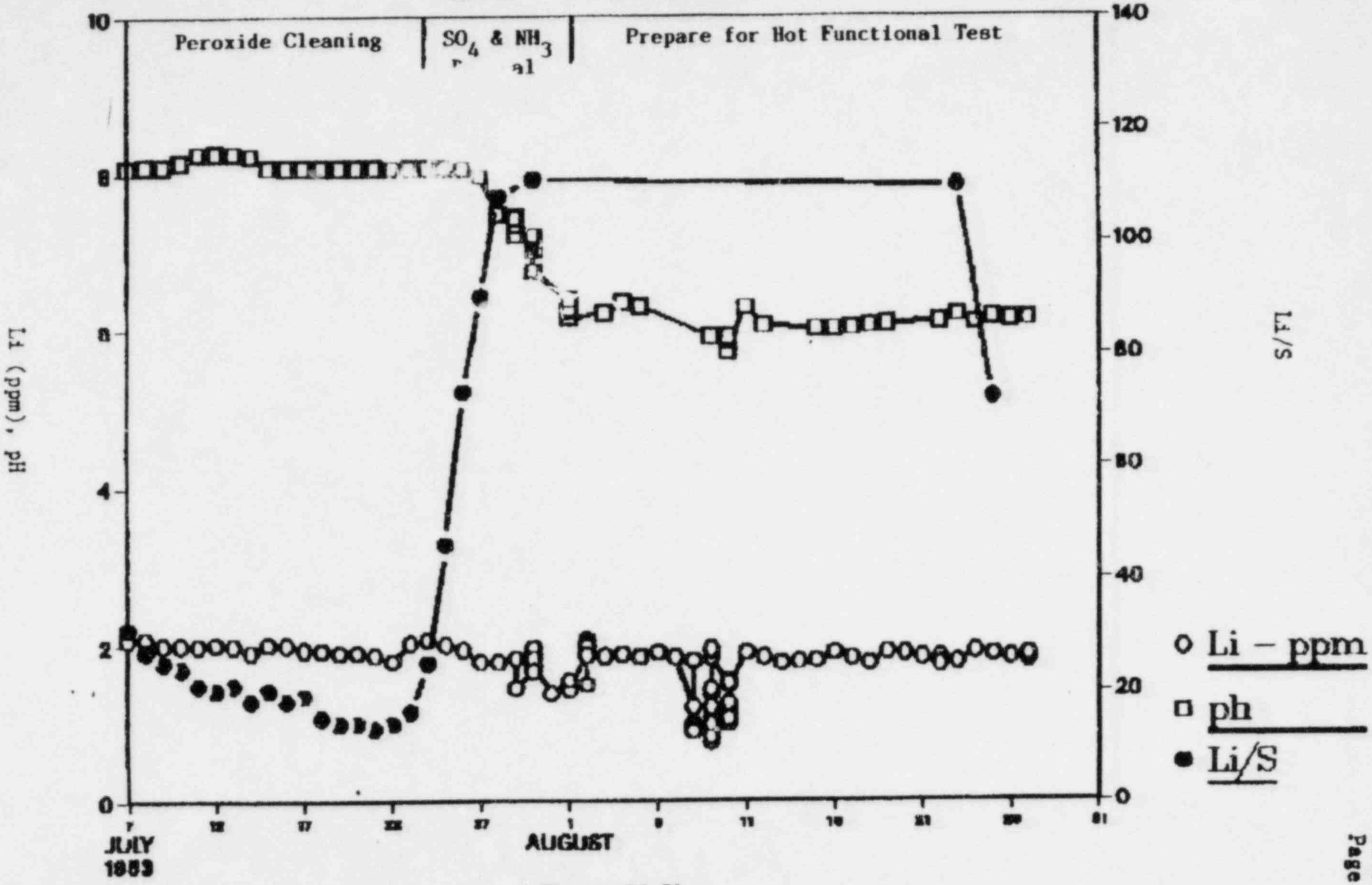

Figure A1-2b

CHEMISTRY DATA
HOT FUNCTIONAL TESTING AND WET LAYUP
August - November 1983

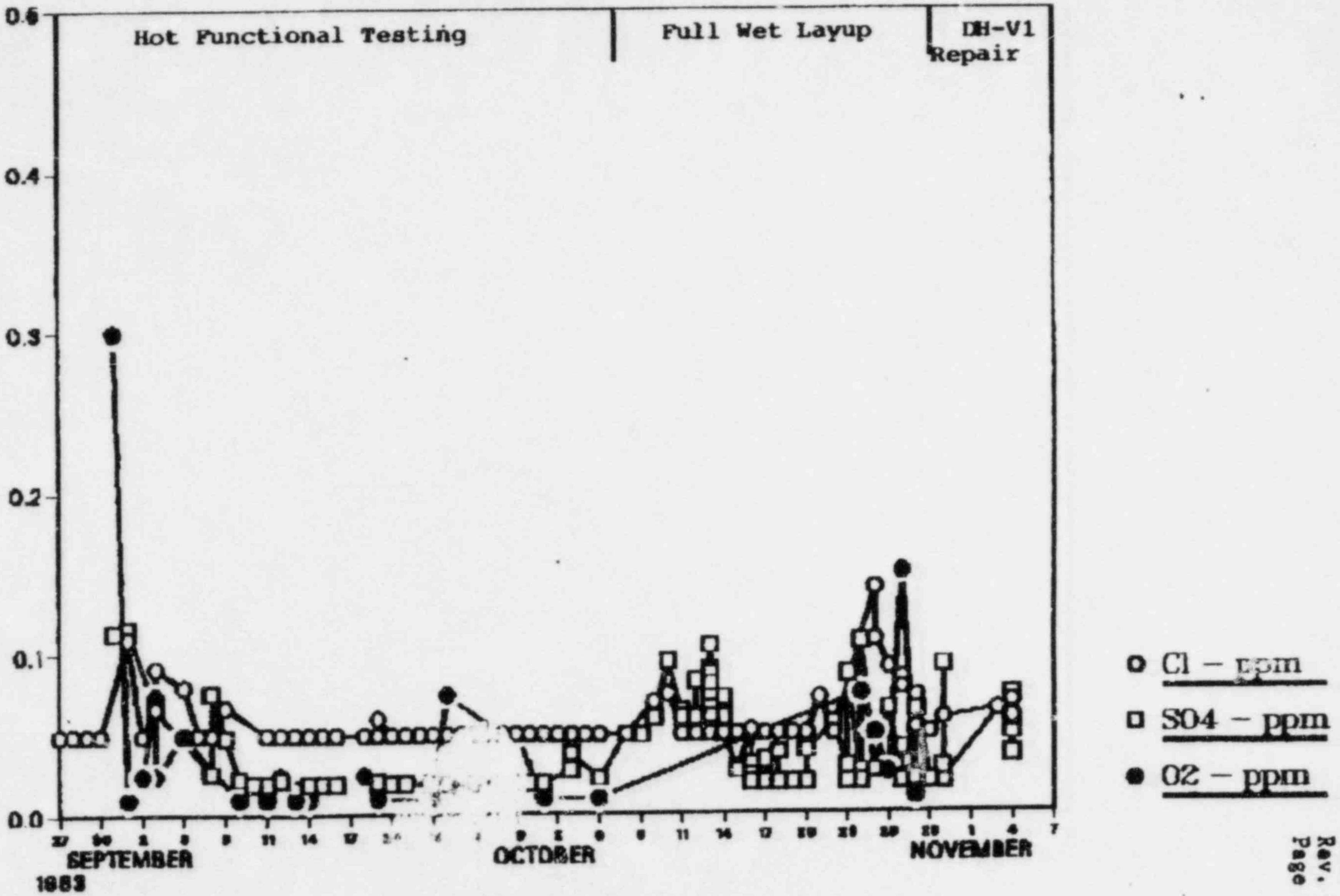

Figure A1-3a

CHEMISTRY DATA
HOT FUNCTIONAL TESTING AND WET LAYUP
August - November 1983

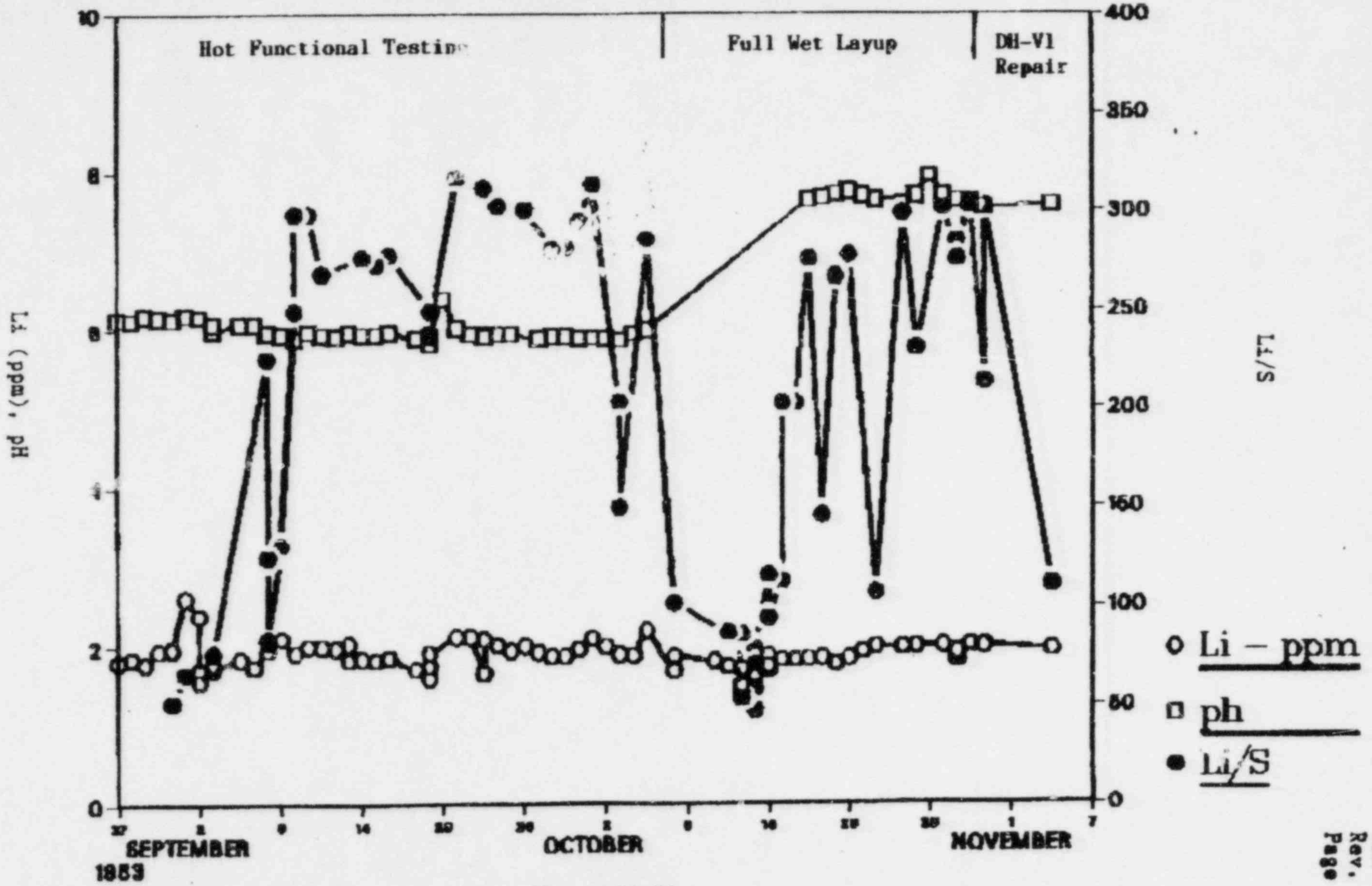

Figure A1-3b

CHEMISTRY DATA
FULL WET LAYUP
November – December 1983

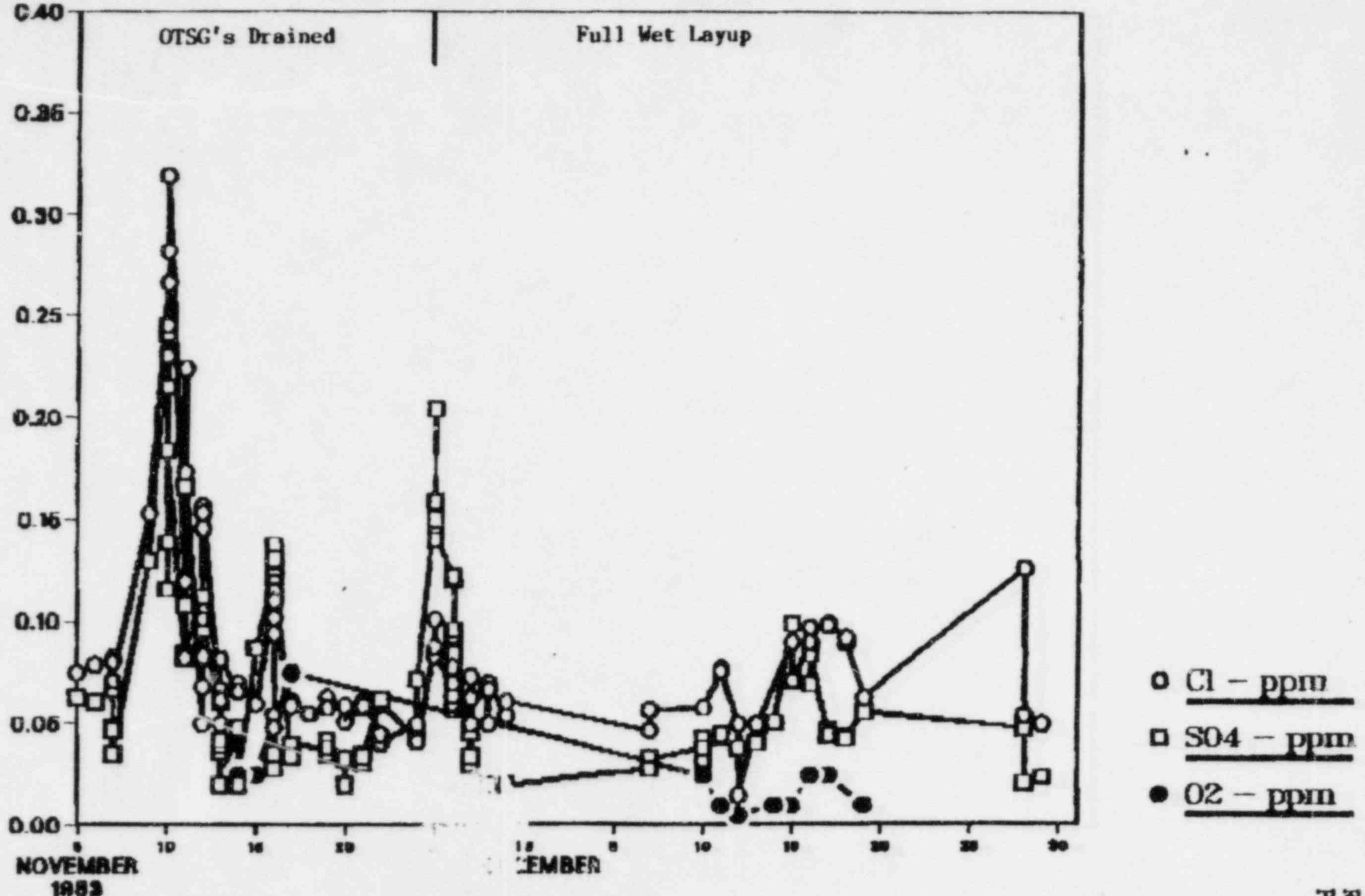

Figure A1-4a

CHEMISTRY DATA
FULL WET LAYUP
November - December 1983

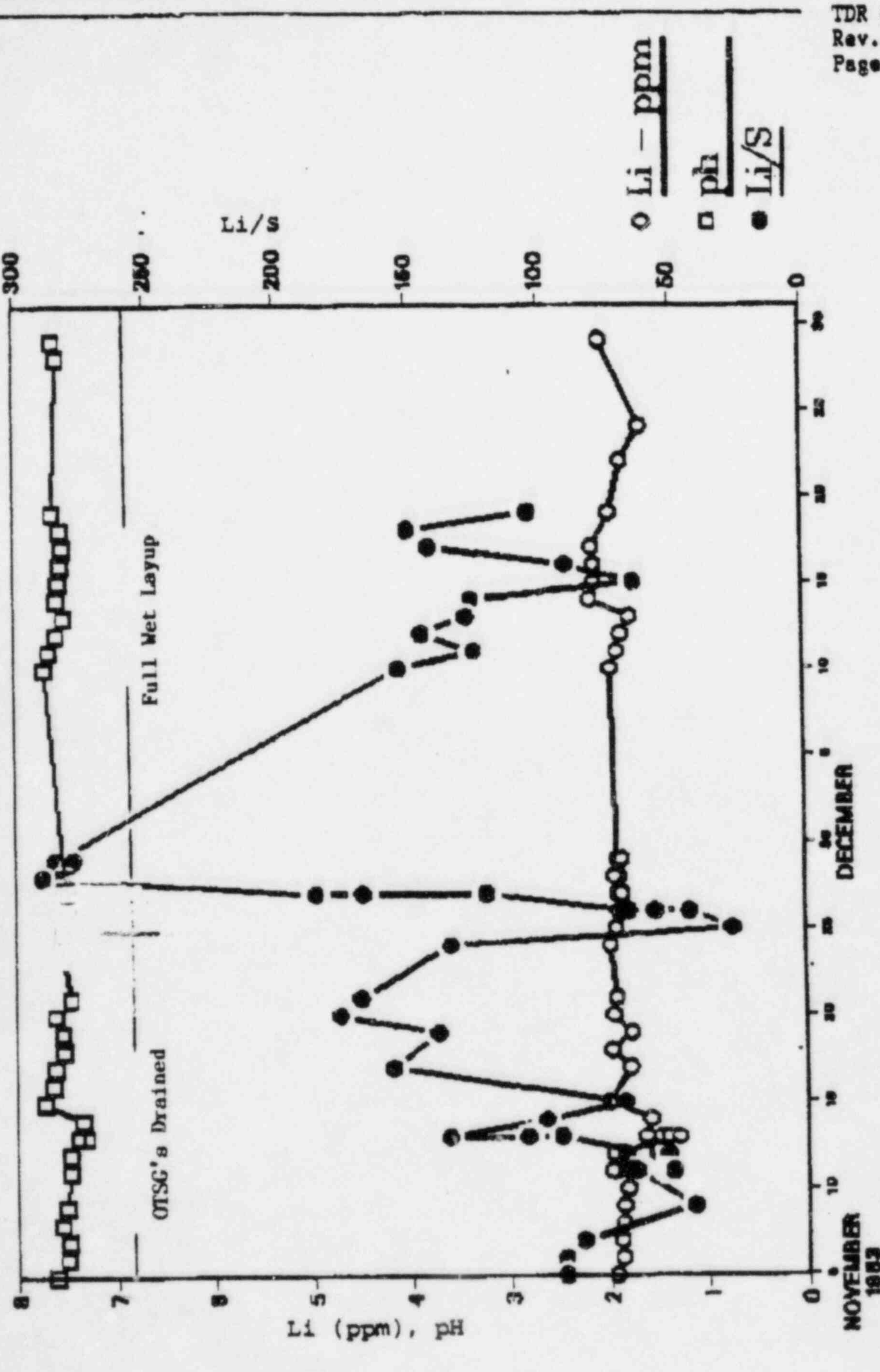

Figure A1-4b

CHEMISTRY DATA
FULL WET LAYUP AND RC-P1B TESTING
January - April 1984

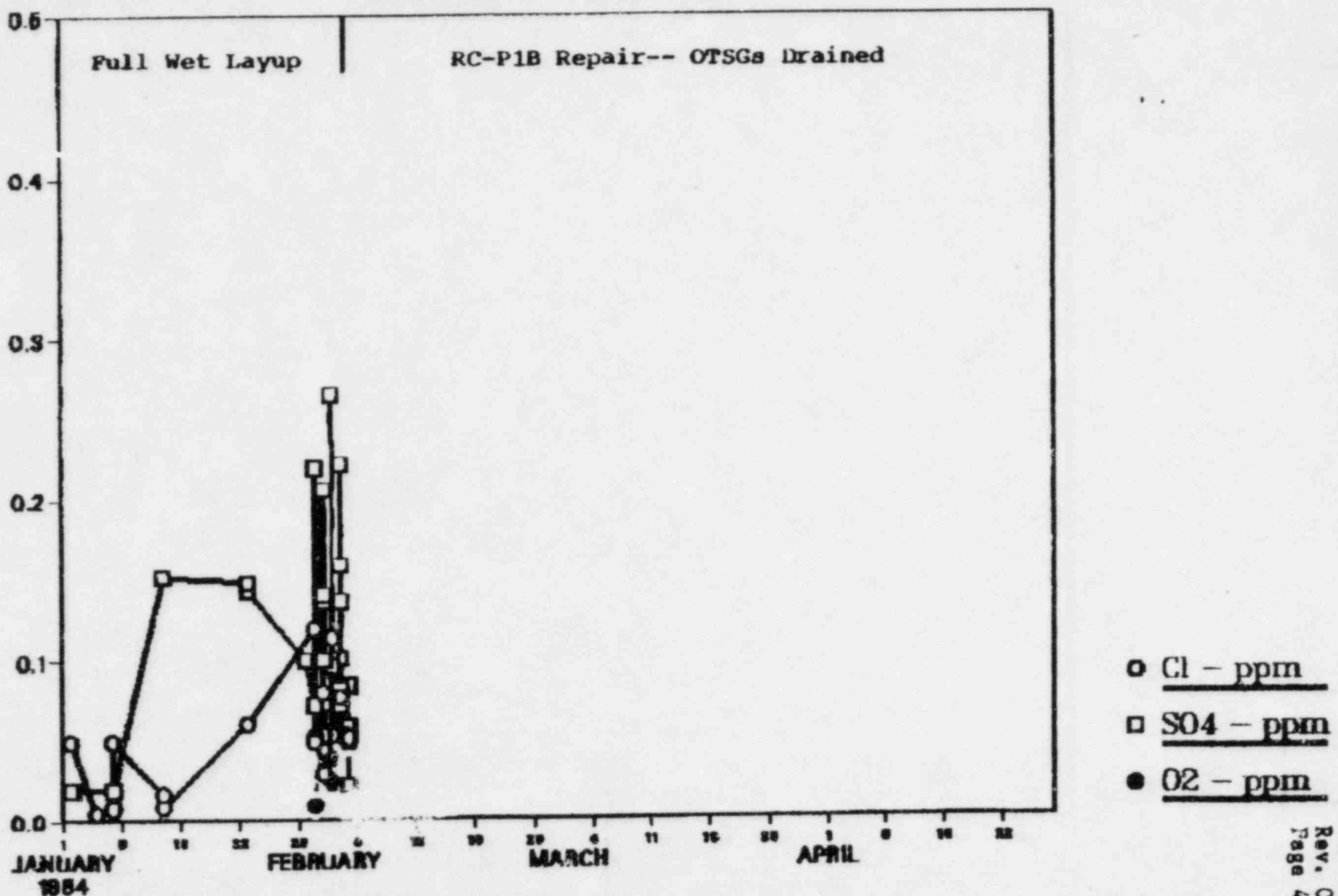

Figure A1-5a

CHEMISTRY DATA
FULL WET LAYUP AND RC-P1B REPAIR
Janu--- - April 1984

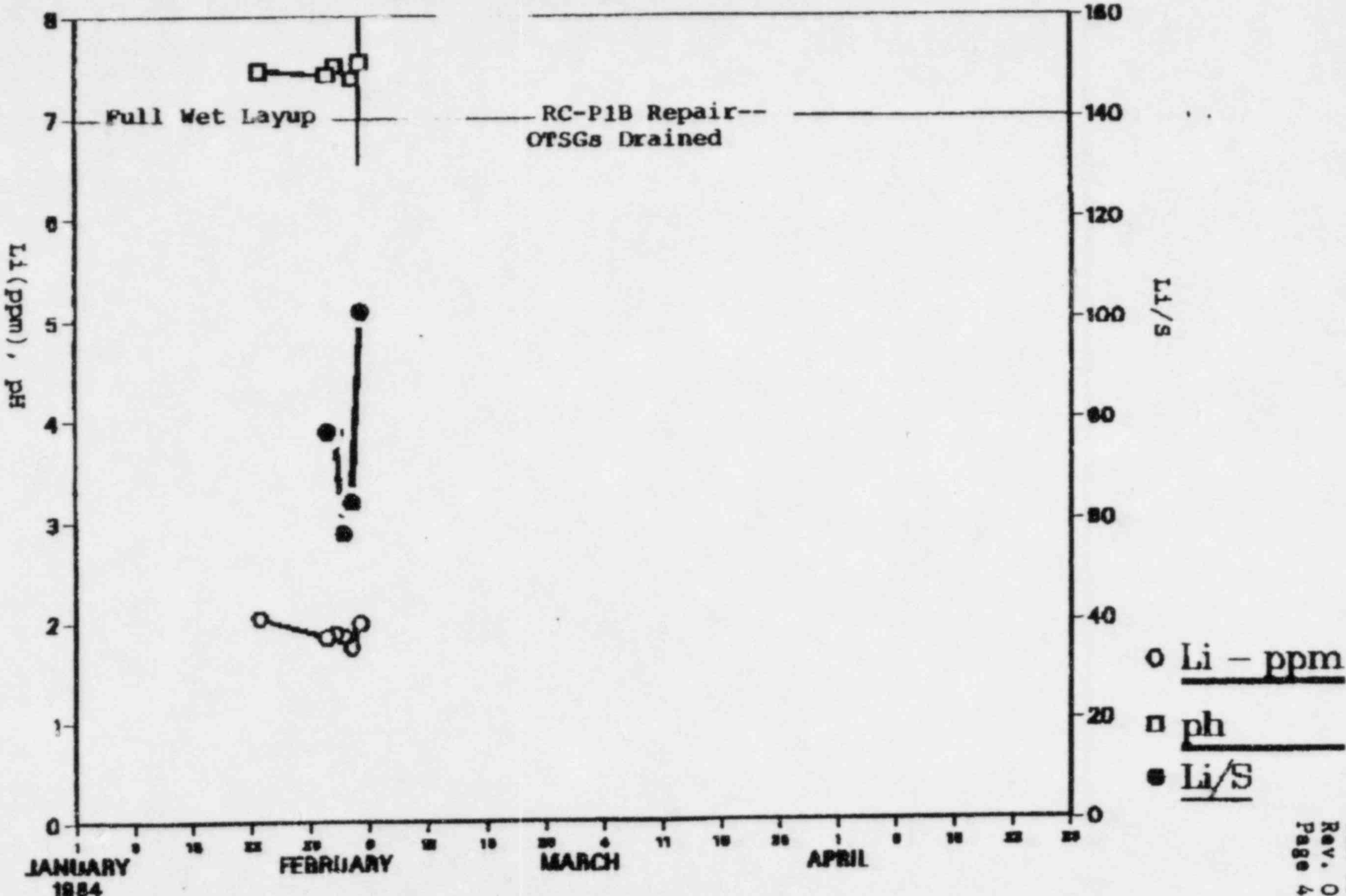

Figure A1-5b

CHEMISTRY DATA
HOT FUNCTIONAL TESTING AND WET LAYUP
April – June 1984

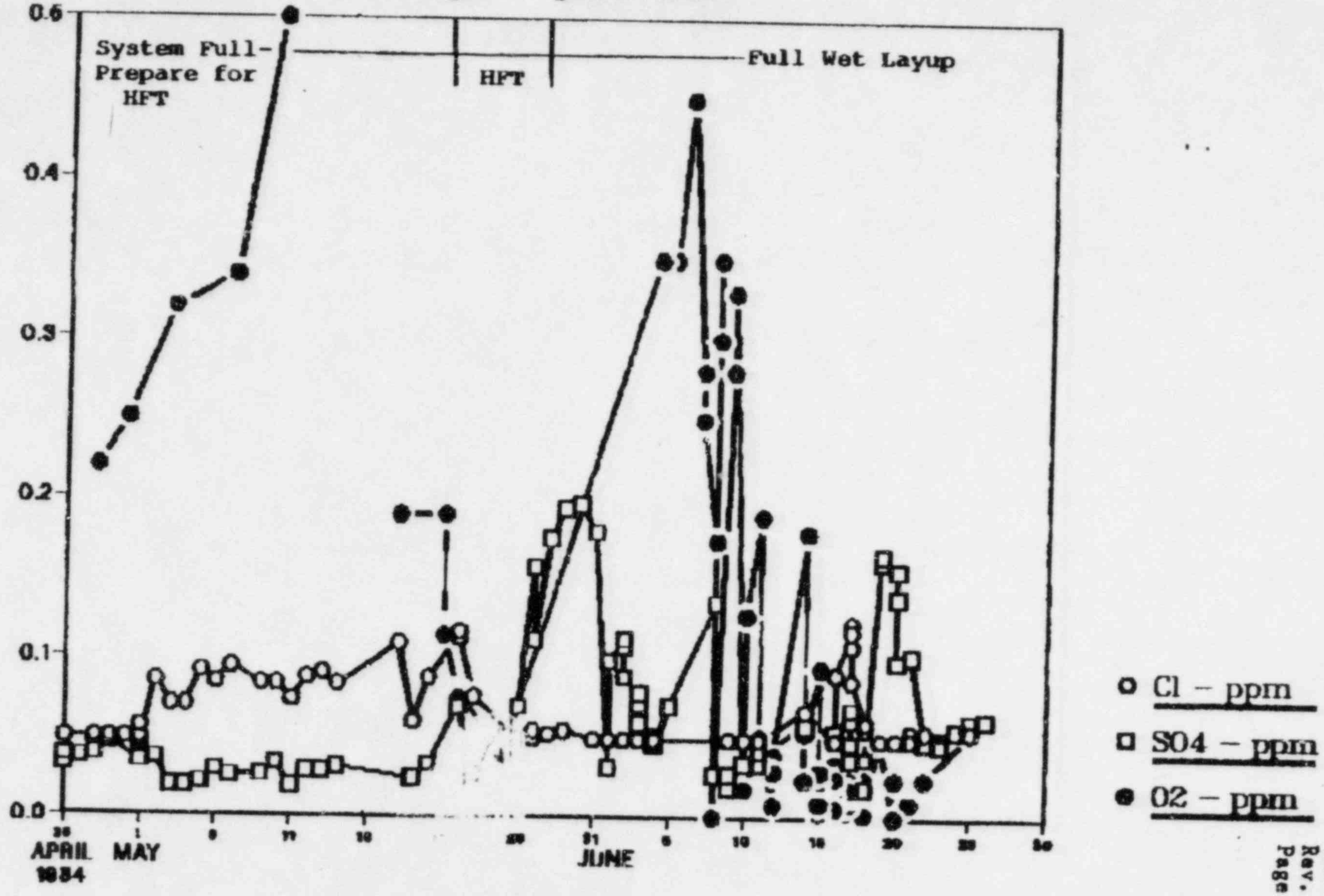

Figure A1-6a

CHEMISTRY DATA
HOT FUNCTIONAL TESTING AND WET LAYUP
- June 1984

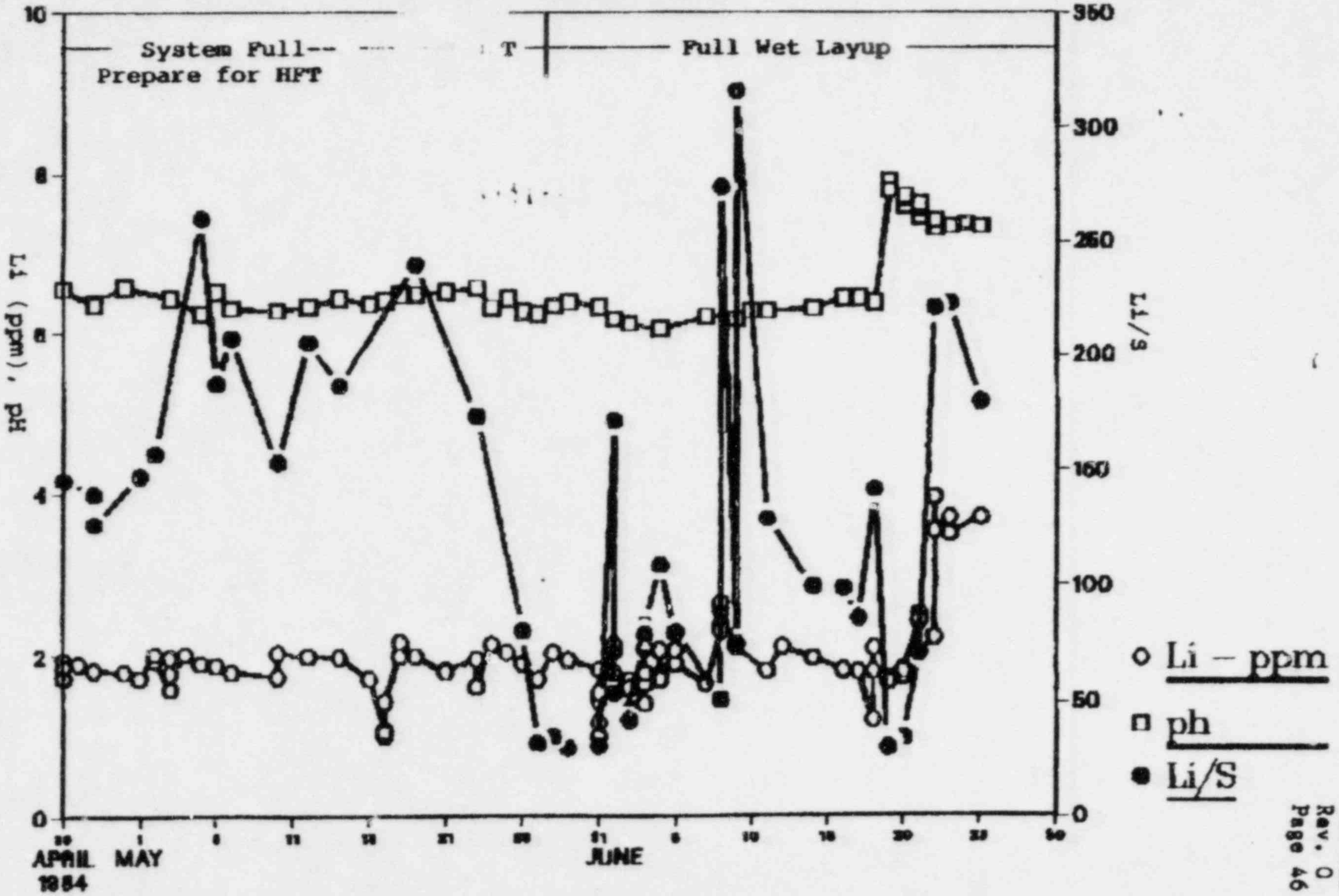

Figure A1-6b

CHEMISTRY DATA
PLUG REROLLING AND BUBBLE TESTING
June – October 1984

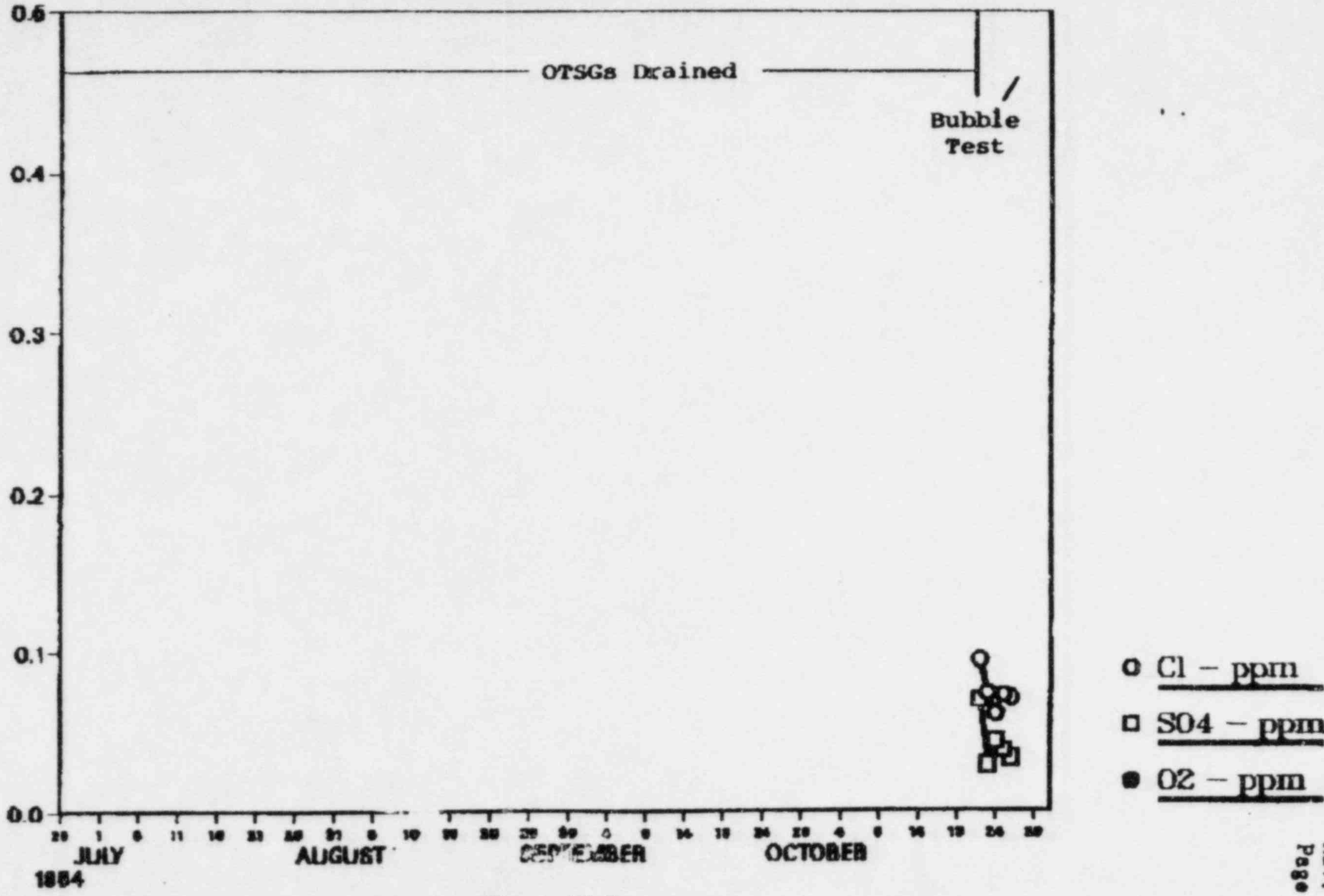

Figure A1-7a

CHEMISTRY DATA
PLUG REROLLING AND BUBBLE TESTING
July - October 1984

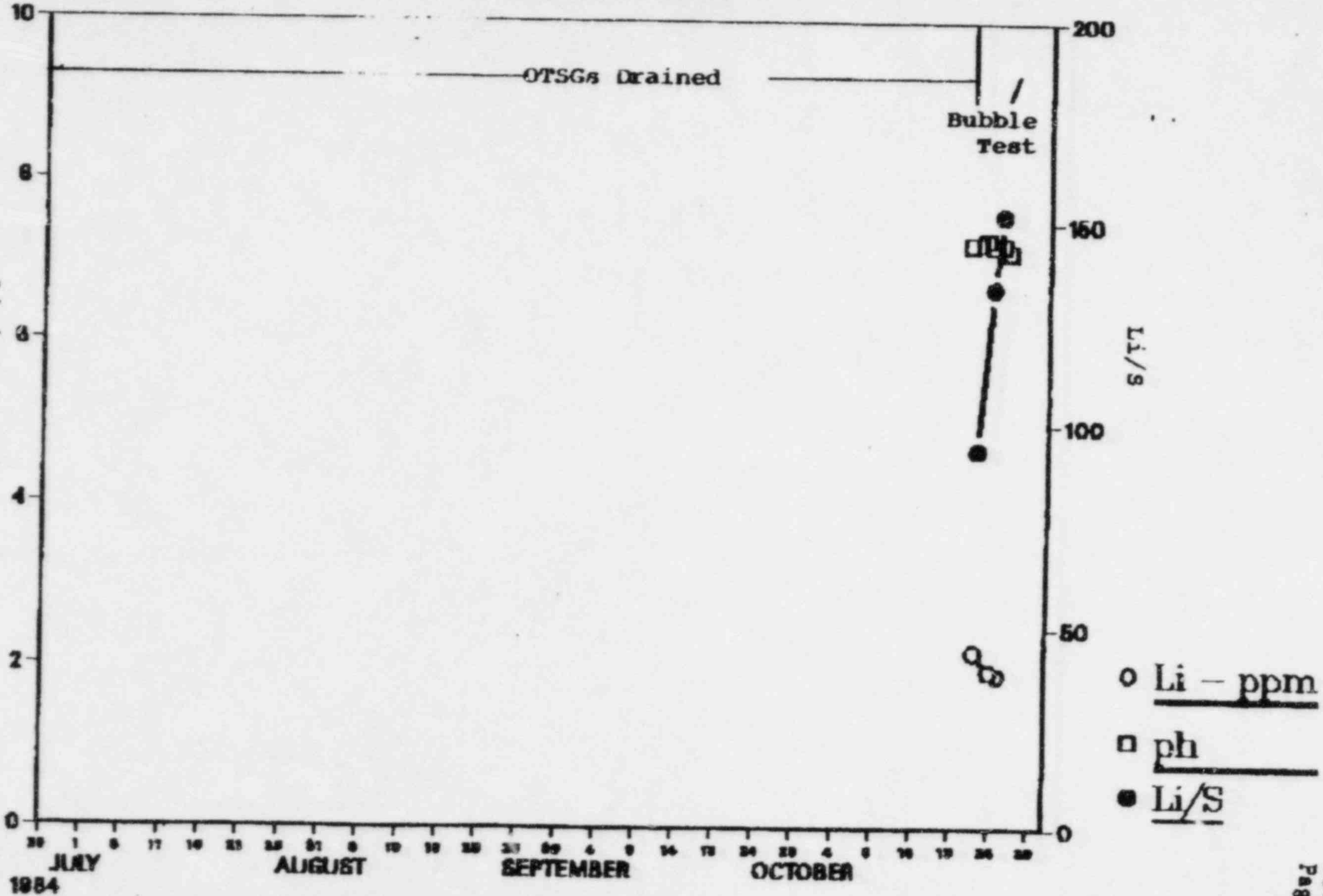

Figure A1-7b

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Appeal Board

In the Matter of	)	
	)	
METROPOLITAN EDISON COMPANY, ET AL.	)	Docket No. 50-289-OLA
	)	(Steam Generator Repair)
(Three Mile Island Nuclear	)	
Station, Unit No. 1)	)	

CERTIFICATE OF SERVICE

This is to certify that copies of the foregoing Licensee's Brief in Opposition to Appeal of TMIA From Initial Decision and Licensee's Answer to TMIA's Motion to Reopen the Record were served by deposit in the United States Mail, First Class, postage prepaid, this 14th day of January, 1985, to all those on the attached Service List.

Evans Huber

EVANS HUBER

DATED: January 14, 1985

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Appeal Board

In the Matter of	)	
	)	
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Unit No. 1)	)	

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