

**Duke Power Company
McGuire Nuclear Station
Unit 2 Steam Leak
August 31, 1993**



September 5, 1993

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EXECUTIVE SUMMARY

On August 31, 1993, with Unit 2 in mode 3 at full temperature and pressure, an attempt was made to stop a small secondary system steam leak inside containment. The leak was from a 1 inch pipe cap downstream of an assumed closed manual Kerotest valve, 2CF-130. During the course of the repair effort, the pipe cap came off and resulted in an unisolable leak from steam generator 2A. The resultant increase in containment pressure and temperature caused the ice condenser inlet doors to open. The unit was cooled down to terminate the leakage.

In response to this event, a McGuire Project Management Team, under the leadership of the Station Manager, was formed to coordinate and conduct investigations, manage recovery plans and implement corrective actions. Additionally, a Significant Event Investigation Team (SEIT) investigation, Mechanical Maintenance HPES investigation and a LER investigation were begun. The NRC also dispatched an Augmented Inspection Team (AIT).

The Project Team concentrated on reviewing identified root causes and specifying corrective actions. Response to the event was assessed and corrective actions were identified to correct event response problems. The Project Team interfaced with other investigative teams to clarify, consolidate and bring closure to all concerns. The Project Team maintained a running list of all identified issues and made assignments to investigate and resolve each one. As each item was resolved, it was documented and all appropriate short and long term corrective actions were developed and assigned to responsible individuals with required completion dates. All concerns were grouped into five general categories: maintenance execution, post maintenance testing, work control, control of plant during cooldown and other corrective actions.

The primary cause of this event was that 2CF-130 was improperly assembled during corrective maintenance performed during 2EOC-8. The spring guide was installed backwards on the valve disc assembly. This caused the valve disc to be held off the seat and made it impossible for this valve to block flow. This improper assembly was not identified by post maintenance checks or testing, but was discovered upon disassembly of the valve.

The direct cause of the steam leak, and subsequent ice condenser lower inlet door opening, was the ejection of the pipe cap from the pipe nipple downstream of 2CF-130 while the cap was being loosened as part of a vendor leak repair procedure. The cap came off prematurely due to inadequate thread engagement.

During the plant cooldown, an inadvertent change in modes from 4 to 3 while the ice condenser lower inlet doors were inoperable occurred. The primary cause of this was failure to recognize the proximity of the reactor coolant temperature to the mode 3 limits and inadequate communications by the reactor operator.

A comprehensive review and investigation of the original work execution, post maintenance testing, subsequent planning for leak repair, response of the plant during the event and damage to the plant during the event were conducted and short and long term corrective actions identified. This report documents the recovery plans and corrective actions executed and planned.

TEAM CHARTER

Date: 9/1/93

Project Title: Unit 2 Steam Leak in Containment

Start Date: 8/31/93

Expected Completion Date: 9/7/93

Sponsor/Team Leader: Ted McMeekin / Mac Geddie

Team Members:

Ronnie White	Gary Gilbert
Bruce Travis	Tom Curtis
Bruce Hamilton	Jack Boyle
Robert Sharpe	

Purpose and Scope:

Coordinate/conduct investigations, manage recovery plans and implement corrective actions associated with the 8/31/93 steam leak in containment event on McGuire unit 2.

Project Background:

Repair efforts to correct leakage from a pipe cap at valve 2CF130 (secondary side tube sheet drain) resulted in the pipe cap blowing off and dumping steam into lower containment. Ice condenser doors opened and some capacity of the ice condenser was used.

The unit was cooled down and depressurized to Mode 5 to facilitate repairs and recovery from the event. A SEIT was initiated to investigate the event due to the obvious significance. Mechanical Maintenance initiated an investigative effort and LER investigation was begun.

Deliverables:

Management attention and focus to assure root causes are understood. An assessment of our response to the event and identification of corrective actions to correct root cause and event response problems. Interface with investigative teams to clarify, document and bring closure to all concerns generated by this project team and all other investigation teams.

Actions are clearly categorized and agreed upon as:

- (1) Short Term (needed for unit startup), or
- (2) Long Term (clear responsibility assigned and target completion dates).

Measurable Success Indicators:

Short term actions are completed to support unit return to service by 9/13/93.

McGuire management, the SEIT and the NRC are satisfied with investigative and corrective actions. NRC concurs with actions taken to proceed with unit startup.

Progress Updates:

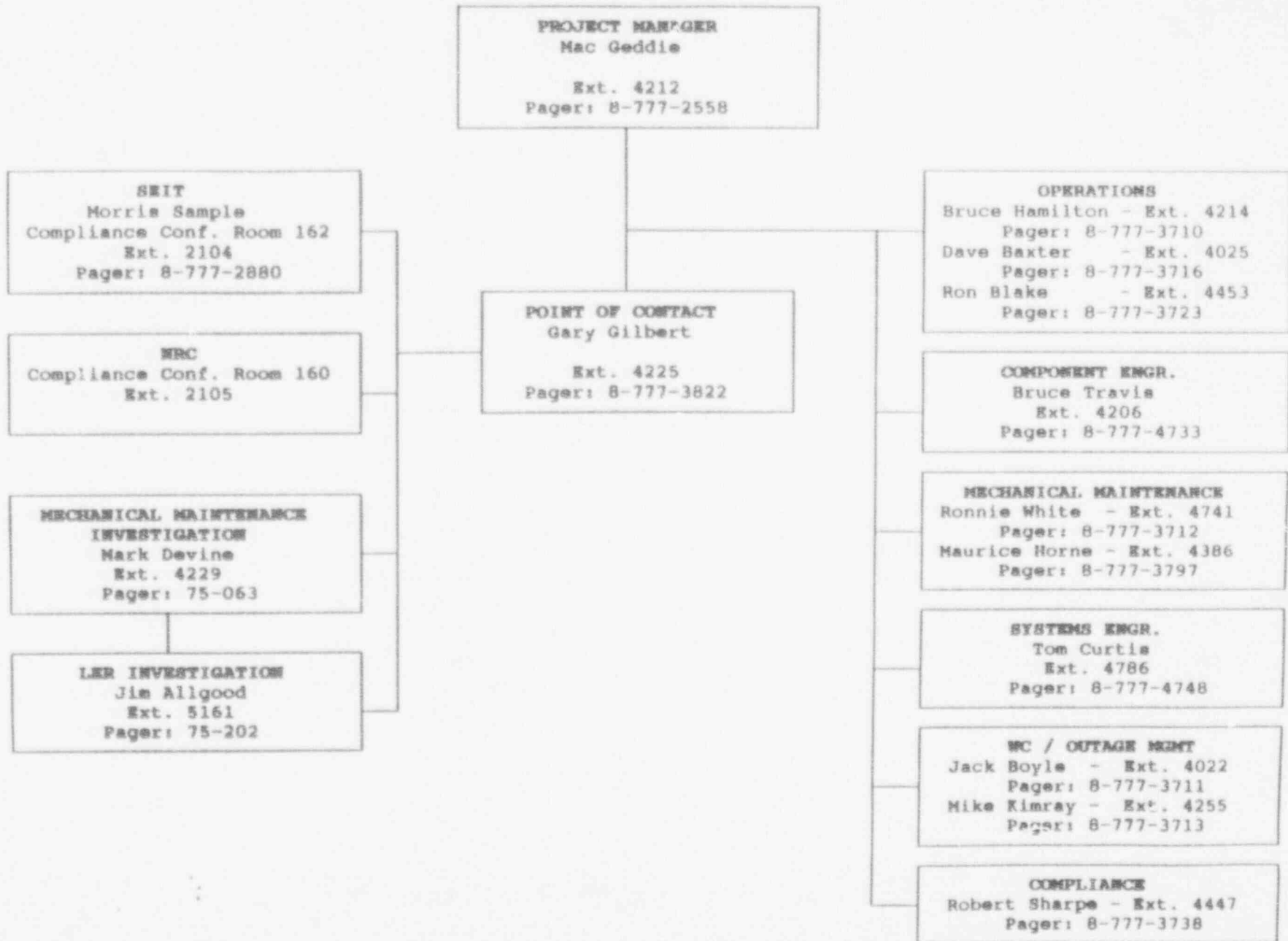
The team will initially meet twice a day to review concerns, action responsibility and status. SEIT and NRC interface will take place during these meetings to bring closure to issues.

Project Goal:

Identify all correct actions that need to take place, complete these actions to our satisfaction and NRC's satisfaction to support an on-line date of 9/13/93.

Key Results:

NW UNIT 2
INCIDENT INVESTIGATION AND UNIT RECOVERY



08/30/93	AM	Operations Staff A originated WR 93029766 to repair pipe cap on 2CF-130. He included the information about the pipe threads being damaged; however, he placed some of the information in the title instead of the problem statement.
08/30/93	AM	Planner A originated and planned WO 93063230 to repair the leak identified on WR 93029766; however, the information about the damaged threads was not documented on the WO.
08/30/93	AM	Mechanical Maintenance Technician D performed Functional Verification of valve 2CF-130 per WO 93012110. This involved visual inspection for leaks following repair. The inspection revealed leakage around the pipe cap.
08/31/93	0030	Vendor Technician A attempted to repair leak of pipe cap downstream of valve 2CF-130 per WO 93063230, MP/0/A/7650/077, On-Line Leak Sealing Initial Injection, Temporary Modification, and vendor procedure.
08/31/93	0030	Control Room annunciator 2AD-9 A-5 "Ice Condenser Lower Inlet Doors Open" alarm
08/31/93	0035	Radiation Protection Technician A reported that pipe cap had blown off drain line downstream of valve 2CF-130. One vendor was burned and transported to University Hospital. No contamination was present.
08/31/93	0036	Entered AP/2/A/5500/01, Steam Leak.
08/31/93	0115	Commenced Reactor Coolant System cooldown and depressurization pursuant to TS 3.6.1.4. Containment pressure > 0.3 PSIG. The cooldown/depressurization was also initiated to decrease steam generator pressure thereby minimizing energy addition into the containment. Lower Containment weighted average temperature reached 133 degrees F. Pressure reached 0.45 psi.
08/31/93	0140	Ice Condenser temperature > 27 degrees F., declared ice bed inoperable in accordance with TS 3.6.5.1 due to elevated temperature. TS Log entry made.
08/31/93	0300	Containment pressure returned to normal.
08/31/93	0300**	Shift Manager discussed with the Shift Supervisor the option of sending Ice Condenser Personnel into the ice condenser to evaluate the situation.

08/31/93	0300**	Shift Manager dispatched an ice condenser team to go into the ice condenser to evaluate the situation.
08/31/93	0348	Shift Manager reported that Bay 21 had indication of ice melting. One or Two doors were cracked open and would not close. (Subsequent investigation determined that Bay 22 was actually the bay affected.)
08/31/93	0445	Shift Manager reported that up to 6 feet of ice had melted in Bay 21 (actually Bay 22) and that 4 doors are not fully closed.
08/31/93	0450**	Operations Staff and Control Room personnel discussed the effect of the open ice condenser doors. A decision was reached to authorize manually hold the doors closed since containment pressures had returned to normal.
08/31/93	0500	Two ice condenser lower inlet doors were held closed by personnel and listed in the TS Log.
08/31/93	0650	Entered Mode 4.
08/31/93	0630**	Attempted to install leak repair pipe cap on leaking drain. Attempt was unsuccessful due to the volume of steam leaking.
08/31/93	0735	Entered Mode 3.
08/31/93	0835	Re-entered Mode 4.
08/31/93	0845	McGuire site management requested a Significant Event Investigation Team (SEIT.) A separate McGuire site management team was formed to investigate and determine actions necessary to recover from the event.
08/31/93	0900	Briefed NRC Region II, NRR, and AEOD via conference call.
08/31/93	1245	Decision made to continue cooldown to Mode 5 by site management team.
08/31/93	1300**	Control Room notified of the decision to proceed with cooldown to Mode 5.
08/31/93	1400	Entrance meeting held with the SEIT.
08/31/93	2241	Entered Mode 5.

09/01/93

0100**

Installed leak repair pipe cap on leaking drain and secured the leak.

** Indicates approximate times as determined through interviews and security door entry logs.

INVESTIGATIVE EFFORTS

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SEIT CHARTER

Charter of the
Significant Event Investigation Team

1.0 Purpose

The Significant Event Investigation Team (SEIT) ensures that a significant operational event is investigated in a timely, systematic, and technically sound manner, and that a complete understanding of such an event and lessons learned is achieved.

2.0 Scope

Significant operational events that should be considered for a SEIT may include, but are not limited to, the characteristics as identified in Enclosure 1.

3.0 Team Composition

The SEIT will function as the authoritative investigation team for Duke Power Company. The SEIT is composed of a Team Leader, Nuclear Services Safety Assurance Manager or alternate, and a team composed of technical area experts depending on type of event. Additionally, non-Duke personnel, such as INPO, EPRI, or Owners Groups, may be selected as SEIT members where desirable.

4.0 Method of Operation

The SEIT will be activated in response to a request from the Nuclear Station Manager, the Site Safety Assurance Manager, or the Site Vice President. The request to activate the SEIT may be made to the Manager, Nuclear Safety Assurance or to the General Manager, Nuclear Services.

SEIT activation should occur within twenty-four hours post-event. The Team Leader will promptly notify the team members and others as necessary. The SEIT will perform the event investigation to ensure that the causes and any contributing factors to the event are understood. The SEIT will also ensure that all operational safety concerns are properly addressed.

An Entrance Meeting with station management will be held to discuss the activities of the Team.

The SEIT Team Leader will discuss newly-identified concerns with the Station Manager and department management at least daily.

The following aspects will be addressed by the SEIT. Other investigative aspects will be pursued when necessary as well.

1. Development and validation of a sequence of events associated with the event. This sequence should begin with plant conditions immediately prior to the event, including known significant deficiencies in safety-related and balance-of-plant equipment, and extend until the plant is stable.
2. Evaluation of the significance of the event with regard to radiological consequences, safety system performance, and plant proximity to safety limits as defined in the Technical Specifications.
3. Identification of procedures in use at the time of the event, and used to recover from the event. Evaluation of the effectiveness of these procedures will be performed.
4. Evaluation of the adequacy of administrative controls and implementation of those controls in relation to the event.
5. Evaluation of the accuracy, timeliness, and effectiveness with which information on the event was reported to NRC. Also, event classification will be evaluated.
6. Identification of any human factors, training, or procedural deficiencies related to the event.
7. Determination of the impact of the following on the event: plant material condition; quality of maintenance; responsiveness of engineering to identified problems.
8. Evaluation of operator action during the event and subsequent plant recovery.
9. Evaluation of management involvement during the event and subsequent plant recovery.
10. For each equipment malfunction or inappropriate action to the extent practical, determine:
 - a. Root cause.
 - b. If the equipment was known to be deficient prior to the event.
 - c. If equipment history would indicate that the equipment had either been historically unreliable or if maintenance or modifications had been recently performed.

- d. Pre-event status of surveillance, testing (e.g., Section XI), and/or preventive maintenance.
- e. The extent to which the equipment was covered by existing corrective action programs and the implication of the failures with respect to program effectiveness.

5.0 Report to Management

The SEIT will hold an exit meeting with station management and will discuss results of the investigation in regards to causes, consequences, and areas of concern. Any corrective action requiring completion prior to entering subsequent modes of operation will be identified to station management. A written report will be subsequently issued, identifying all findings and recommended corrective actions.

Copies of the final report will be provided to the Senior Vice President, Nuclear, Site Vice Presidents of Duke stations and General Manager of Nuclear Services. Any generic concerns that could apply to other Duke stations will be identified under the guidelines of the Operating Experience Program. Event will be shared with industry via INPO Nuclear Network or other means as deemed appropriate by Operating Experience Assessment group of Nuclear Services.

GUIDELINES FOR SEIT ACTIVATION

- a) An event that is sufficiently complex, unique, or not well understood such as to warrant an independent investigation.
- b) An event involving loss of a safety function or multiple failures in systems intended to mitigate plant response.
- c) A significant radiological release to unrestricted areas, or personnel overexposure.
- d) A significant loss of fuel integrity, reactor coolant inventory, containment integrity or, primary or secondary pressure control.
- e) Loss of Offsite Power.
- f) Inadvertent reactivity changes.
- g) Shutdown Events:
 - unexpected transfer or loss of significant reactor coolant level
 - significant degradation of decay heat removal capability
 - primary or interfacing systems overpressurization

SEIT REPORT

GUIDELINES FOR SEIT ACTIVATION

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 - significant degradation of decay heat removal capability
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SEIT REPORT

Significant Event Investigation Team

McGuire Unit 2

Aug, 31, 1993 Steam Leak Inside Containment

Sept 4, 1993, Rev 1

I. Executive Summary

On Aug. 31, 1993 during an attempt to stop leakage by valve 2CF-130 a pipe cap came off during removal attempt on the pipe downstream of the valve resulting in a significant discharge of steam from the secondary side of S/G 2A. The increase in containment pressure resulted in opening ice condenser doors and required cooldown of the unit to terminate the leakage.

A SEIT team was assembled and arrived on site the afternoon of 8/31 to begin an independent assessment of the event and the plants corrective actions. The team has reviewed the initial transient caused by the steam leak, the resulting cooldown of the unit, maintenance activities being performed on 2CF-130, management oversight of the vendors performing the work, and the other areas related to the event as described in the following sections.

From the disassembly of 2CF-130, the cause of the valve leakage was the incorrect installation of the spring guide on the valve disc assembly. This caused the valve plug to be held off the seat and effectively locked the valve handwheel. The valve could not be closed under these conditions. Subsequent post maintenance testing failed to discover this condition until leakage was observed around the pipe cap downstream of the valve after the plant reached full temperature and pressure conditions.

The main conclusion of the team is that the initial event was primarily caused by incorrect maintenance practices associated with the previous repair of 2CF-130. The resulting leak repair was viewed as a routine activity and normal work planning process resulted in an attempt to remove the existing pipe cap and subsequent steam leak due to direct leak path through valve 2CF-130. On-line leak repairs of non-isolable leaks on high energy systems involve special considerations that need to be discussed with all involved individuals to establish a thorough understanding of the course of action by all groups.

Several other related events are discussed in the following sections with associated root causes identified. Section X is a summary of the recommended corrective actions to be completed prior to Mode 4 and long range corrective actions.

II) SEIT Team Composition

SEIT team was composed of following:

Team Leader: Morris Sample, Manager of Safety Assurance, Nuclear
Services
Rich Casler, Operations Group, Nuclear Services
Steve Hart, Maintenance Support, Nuclear Services
Tom Ryan, Manager Operational Event Analysis,
Nuclear Services
Jim Allgood, Safety Review, McGuire Safety Assurance

III) Sequence of Events

After reviewing the operating records and personnel interviews the following sequence of events was developed:

<u>Date</u>	<u>Time</u>	<u>Description</u>
08/05/93		Repaired valve 2CF130 per WO 92041833. Pipe cap replaced.
08/30/93		Performed Functional Verification valve 2CF130 per WO 93012110. This involved visual inspection for leaks following repair.
08/31/93		Attempted leak repair on pipe cap downstream of 2CF130 per WO 93063230, MP/O/A/7650/077-On-Line Leak Sealing Initial Injection, Temporary Modification, and USSI procedure USSI-NP-15 Modification Thread Injection Cap.
08/31/93	0038	RP reported that pipe cap had blown off drain line at valve 2CF130. One Vendor was burned and transported to University Hospital. No contamination was present.
08/31/93	0115	Commenced Reactor Coolant System depressurization due to Containment pressure > 0.3 PSIG. Weighted Average Temperature reached 133 degrees Pressure reached 0.45 psi.
08/31/93	0140	Ice Condenser temperature > 27 degrees, declared inoperable in TS Log.
08/31/93	0348	Shift Manager reported that there were indication of ice melting. One or two doors were cracked open and would not close.
08/31/93	0445	Shift Manager reported that ice had melted and that 4 doors are not fully closed.
08/31/93	0500	Two Ice Condenser doors were blocked closed by personnel and listed in the TS Log.
08/31/93	0650	Entered Mode 4.
08/31/93	0735	Re-entered Mode 3 due to plant heat up.
08/31/93	0835	Re-entered Mode 4.
08/31/93	1245	Decision made to continue cooldown to Mode 5.

09/01/93 0200

Leak was stopped by installation of specially modified USSI pipe cap.

IV) Radiological Consequences

The steam leak was from the secondary side of S/G 2A and did not result in any release of radioactivity inside the reactor building. The personnel involved in the work were not contaminated as a result of the leak and no offsite releases were made as a result of this event.

V) Safety System Performance

The safety system response to the initial event involved opening of the ice condenser doors in response to the increased pressure in lower containment. All but four of the lower ice doors opened during the event. Attachment 1 is the technical evaluation verifying that this response was fully satisfactory under the transient conditions.

All other system response was normal during the cooldown and depressurization of the unit.

Prior to this event, NV-1, Letdown Isolation had failed shut causing the operators to use excess letdown. During the cooldown and depressurization this caused the operators to keep pressure higher than normal during the cooldown, but still within the pressure temperature limits.

VI) Proximity to Safety Limits

During the initial transient when the leak occurred, the building pressure peaked at .41 psig which is below the actuation setpoint for safety injection and building spray. The subsequent cooldown and depressurization were well within the boundaries of the pressure/temperature cooldown curve. No other system parameters approached any safety limit or any safety system actuation setpoint.

VII) Event Response

The response of the Operations crew and management were appropriate prior to, during, and after the event with the exception of the inadvertent entrance into Mode 3 during the cooldown of the plant to stop the steam leak in containment. Operations management was present in the control room shortly after the initiating event and provided assistance to Shift Supervisor throughout the initial response to the event.

The root causes, for the re-entry into Mode 3, were the Operator at the Controls' (OATC) lack of communications with the crew on the increasing Reactor Coolant system (NC) temperature and the lack of awareness that the Mode 3 conditions were met. The OATC, after assuming the controls, allowed NC temperature to slowly increase because of his concern of being close to the over-pressure protection limit, 320 F., on the cooldown curve. NC temperature at shift change was 340 F. The OATC from the night shift had stopped the cooldown at this point because the operators try to allow at least a 20 F cushion from the 320 F limit and they wanted the plant to be as stable as possible during shift turnover.

The day shift OATC felt he needed to allow temperature to drift up higher to give him more margin from this administrative limit. The OATC communicated his intent to the Balance of Plant operator (BOP) but temperature values were not given. As the NC temperature increased to 345 F, the OATC took actions to stabilize temperature by opening the steam generator blowdown valves. After about 15 minutes the OATC noted NC temperature was still increasing. He started throttling open the condenser dump valves. He was able to stop the temperature increase at a temperature of about 366 F. Even though the OATC knows the Mode 3 criteria, it did not occur to him at this time that he had entered Mode 3.

For this particular shutdown, an important plant parameter was NC temperature. The purpose of the shutdown was to reduce a steam leak on a steam generator drain line. The plan was to cooldown the NC system far enough to allow a pipe cap to be placed on the leaking line. Based on this, the OATC should have communicated to the crew that he was allowing the temperature to increase.

The increase in temperature was noticed by the work crew in containment due to the steam leak rate increasing. They reported this to the shift supervisor. The shift supervisor investigated and noted that the NC temperature had been allowed to increase and instructed the OATC to reduce temperature down to about 340 F.

If the OATC had communicated his intent to allow temperature to increase, the discussion of this may have resulted in a crew member communicating a caution to the OATC about approach to Mode 3 conditions and could have prevented the plant from entering Mode 3 inadvertently.

The three NRC notifications were timely and appropriate. The notifications were:

- Cooldown required by Technical Specifications caused by the steam leak in containment increasing containment pressure and temperature above Technical Specifications limits.
- ESF actuation when the ice condenser doors opened due to the steam leak in containment.
- Duke Power press release to the public concerning the steam leak event inside containment resulting in a delay in the return to service of Unit #2.

The Duke Power press release was timely and appropriate.

After containment pressure had returned to normal range, Operations' management present in the control room discussed the concern that two of the ice condenser doors remained slightly open. After a thorough discussion of safety concerns and the effect this would have on further degradation of the ice bed, they made the decision to hold closed two of the 24 ice condenser doors that would not stay closed. This decision is considered to be appropriate and timely and prevented further inappropriate loss of ice inventory. This action enhanced the ability of the ice condenser to respond to any further challenge had this been necessary during the subsequent cooldown. Attachment 2 gives the technical evaluation of blocking the function of these ice doors during cooldown.

The release of steam in lower containment resulted in opening the ice condenser doors and some local ice melting in the bays adjacent to the leak. This caused water to drain from the ice condenser through drain lines into lower containment, and resulted in temperature and humidity in ice bed exceeding normal operating limits. Refreezing of this water and moisture could cause lower inlet doors to become stuck and frost buildup on ice bed structures. Thorough inspection of the ice condenser will be necessary to insure any degradation that could affect ice performance is corrected.

Recommendations

Prior to startup, the operability of ice condenser shall be fully verified including required ice inventory, lower condenser inlet doors, ice condenser drains and verification that frost buildup will not adversely affect ice condenser performance.

Prior to startup, an evaluation of all equipment in containment exposed to elevated temperature, humidity and water drained from ice condenser shall be completed to verify capability to perform it's intended function. This shall include considerations of environmental qualifications of affected components.

Emphasize to the operating crews the importance of complete communications of important plant parameters to allow the crew to function as a team to enhance the response to plant conditions.

Develop and implement actions that will heighten the awareness of the crews to the plant approaching Mode change conditions.

Document the items that need to be considered and satisfied prior to making the decision to block the ice condenser doors closed. This guidance should be placed in an operation's procedure such as the ice condenser annunciator response procedure.

VIII) Work Control Practices

All Work Control packages associated with work on 2-CF-17 from 3/92 to present were reviewed in detail including associated procedures. Station and vendor personnel were interviewed and all information and actions associated with this leak repair job were discussed. Qualifications of the vendor personnel from USSI were considered fully adequate for this activity, which had been successfully performed on previous occasions.

After these discussions it was apparent that all groups involved in the work planning and execution did not fully understand all the essential facts concerning work order 93063230 for leak repair of 2CF-130. If a thorough discussion of all available information had occurred, a different leak repair method might have prevented this event.

Incorrect use of the Work Origination Screen caused crucial information dealing with bad pipe threads not to be transferred to the printed Work Order. The Planner understood the concerns with the threads, but did not document this as-found condition in the Work Package. He did verbally communicate to the vendor interface that bad threads or cross-threading was probable. It was not clear if the vendor technician on the job was aware of this concern.

Operations was not aware of the change made in the leak repair procedure which allowed removal of the pipe cap. Operation's understanding was that this type of repair consisted of drilling a hole in the existing pipe cap and injecting a leak repair compound into the pipe cap. However, maintenance personnel believed Operations was aware of this change by their sign-off on the Maintenance Procedure, which describes the plan to remove the existing pipe cap.

The root cause involves treating this maintenance activity as a routine event which did not trigger any additional discussions outside of normal maintenance planning activities. The as-found condition of the pipe threads was not fully communicated or documented in the work package and operations personnel were not fully aware of the intent to remove the existing pipe cap in the repair process.

Recommendations:

Any maintenance activity involving the potential for a high energy release should be treated as a non-routine job and require a pre-job planning meeting with all involved groups and a thorough understanding of the maintenance activities to be performed.

Enhance the work control process to ensure all critical as-found condition information is included in the work package documentation.

IX EQUIPMENT MALFUNCTIONS

The root cause of the failure of Kerotest drain valve 2CF-130 to isolate flow was the improper reassembly of the valve due to personnel error in following the maintenance procedures. During final reassembly of the disc assembly, the spring guide was installed upside down. When inserted in the valve, the improper configuration of the spring guide prevented the disc assembly from contacting the seat, prevented the diaphragms from seating and therefore prevented the valve from properly stroking. These conditions were verified during an as-found evaluation of valve 2CF-130 in the MNS Hot Machine Shop on September 2, 1993.

Factors that possibly contributed to the personnel error were the valve location, orientation (stem down), lack of clarity in the Maintenance Procedure on how to assemble the disc/ spring guide/ spring/ disc cap, and the similar appearance of the disc assembly in the correct and incorrect configuration. All personnel were qualified to work on Kerotest valves.

The present Post Maintenance Test process would have identified this problem if the valve had been stroked during the functional verification test as required. Failure to follow the PMT procedure was a contributing root cause.

Direct monitoring of valve leakage during the system fill and initial pressurization would allow more and safer repair options before high energy conditions are achieved.

Recommendations:

Emphasize to all valve technicians the consequences of improper spring guide installation and the importance of following procedures. The consequences of this event should be included in these discussions.

Enhance the Kerotest Maintenance Procedure to emphasize proper spring guide installation prior to further use.

Enhance the Post Maintenance Test process to ensure direct seat leakage verification is performed, when practical, during fill and/or pressurized conditions.

Prior to startup, evaluate the consequences of improper maintenance on other Kerotest packless valve applications and take appropriate action.

The root cause of the ejected pipe cap was inadequate controls in the procedure to ensure minimal pressure existed prior to cap removal, aggravated by gross leakage through the drain valve and damaged pipe threads. The possibility of a combination of damaged threads, crossed threads, and inadequate thread engagement could provide a configuration that may not cause the leakage to respond as expected during loosening and agitation of the pipe cap. The vendor's previous practice has been to slowly loosen the pipe cap which allows pressure to bleed down or indicates that valve leakage is excessive. The vendor relies heavily on their training and "good practices" to conduct their unique repairs and has a remarkable safety record.

Because of the frequent installation and removal of pipe caps, the potential for thread damage is high. A method of monitoring and improving thread conditions or using connectors other than the conventional pipe threads would improve safety, integrity, and efficiency.

Recommendations:

Investigate and implement methods of improving the safety of on-line leak repairs, including pipe cap removal considerations.

Immediately suspend pipe cap removals in pressurized high energy systems until improvements are made in the method of determining any potential leakage through isolation valve.

Develop a process to ensure adequate integrity of vent and drain pipe cap threaded connections.

Investigate methods of improving the performance of vent and drain operations including new valve and cap designs/configurations.

2NC-14, a 3" Walworth globe valve, was discovered to have a pressure seal leak during unit cooldown. The bonnet leak was repaired initially by injecting sealant compound just above the seal ring through two drilled holes in the bonnet, 180 degrees apart. When leakage later developed at the yoke/bonnet threads, injection holes were drilled through the yoke and sealant compound was injected to stop the leak. This repair was evaluated as satisfying the construction code stress allowables and, therefore, in compliance with ASME Section XI. Repair of 2NC-14 would involve a complete drain-down below the coolant loops and was not judged advisable for this outage.

2NV-1, Reactor Coolant Letdown Isolation, failed closed due to a short in a wire between the terminal box and the solenoid valve, apparently from damaged insulation. Root cause of the damaged wire has not yet been determined. The conduit containing the wire showed no signs of moisture intrusion from 2NC-14 leak in the same general area. The leakage on 2NC-14 did not appear to contribute to this failure although it did influence the timing of the repair to 2NV-1. Due to the loss of normal letdown, the operators were on excess letdown during the cooldown.

Recommendation:

Further investigation of the failure mechanism for wiring on 2NV-1 should attempt to determine likely cause of failure and possible corrective action to prevent this type of failure. Installation methods for electrical leads should be reviewed to determine any potential for damage.

X) Recommendation Summary

Following is a summary of the recommendations made in the detail sections above. It is anticipated that the plant will track resolution of these recommendations to completion.

Prior to Entering Mode 4:

- A) Operability of the ice condenser shall be fully verified including required ice inventory, operation of the lower inlet doors, drains are clear and verification that frost buildup will not adversely affect performance of the ice condenser.
- B) An evaluation of all equipment in containment exposed to elevated temperature, humidity and water shall be completed to assure capability to perform function is not adversely impacted. This shall include considerations of environmental qualifications of effected components.
- C) Evaluate the consequences of improper maintenance on other Kerotest packless valve applications and take appropriate corrective actions.
- D) Immediately suspend on-line pipe cap removals on pressurized high energy systems until enhancements are made in the process for verifying amount of leakage through isolation valves.

Long Term Recommendations:

- E) Emphasize to the operating crews the importance of crew communications of important plant parameters to allow the crew to function as a team to enhance the response to plant conditions.
- F) Develop and implement actions that will heighten the awareness of the operating crew to the plant approaching Mode change conditions.
- G) Document the items that need to be considered and satisfied prior to making the decision to hold ice condenser doors closed.
- H) Any maintenance activity involving the potential for high energy release should require a pre-job planning meeting with all involved groups and a thorough understanding of the maintenance activities to be performed.

- I) Enhance the work control process to ensure all critical as-found condition information is included in the work package documentation.
- J) Emphasize to all valve technicians the consequences of improper spring guide installation and the importance of following procedures.
- K) Enhance the Kerotest maintenance procedure to emphasize proper spring guide installation prior to further use.
- L) Enhance the Post Maintenance Test process to ensure direct seat leakage verification is performed, when practical, during fill and/or pressurized conditions.
- M) Investigate and implement methods of improving the safety of on-line leak repairs, including pipe cap removal considerations.
- N) Develop a process to ensure adequate integrity of vent and drain pipe cap threaded connections.
- O) Investigate methods of improving the performance of vent and drain operations including new valve and cap designs/configurations.
- P) Further investigation of the failure mechanism for wiring on 2NV-1 should attempt to determine likely cause of failure.

Additional Followup by SEIT Team

The generic implications of this event for other Duke stations and industry will be reviewed and appropriate recommended corrective actions will be transmitted through Operating Experience Program.

ATTACHMENT 1

McGuire Nuclear Station, Unit 2

Steam Leak in Containment, 8/31/93

Why did some of the ice condenser doors not open during the event?

The ice condenser lower inlet doors are designed to open at approximately 0.007 psi (1 lb/ft²) differential pressure across the doors. This pressure is equivalent to the "cold head" pressure produced by the colder, denser air inside the ice condenser. At this pressure difference, the doors will come off the closed seat (cracked open) and a limit switch will indicate the door as being open. The lower inlet door position indication is located at the entrance to the lower ice condenser, and there is a single indicating light for each block of 8 doors/ 4 bays (ie. one light for bays 1-4, which includes 8 doors). It requires further pressure/ force to open the door off the seal. A hinge spring attached to the lower containment side of each door produces a torque of up to 195 inch-pounds (Maximum) with the door open. This correlates to a force of 7.25 lbs applied at the door handle. Without the cold head pressure difference, the doors will therefore tend to remain essentially closed (but not sealing fully) and steam flow is necessary to open and hold open the doors. During accidents such as LBLOCA/ SLB the sustained differential pressure between lower containment and the lower ice condenser would hold all lower inlet doors open.

The steam release incident of 8/31/93 created a general heat up of the lower containment and resulted in a slow pressurization. The initial pressurization cracked open some of the lower inlet doors and the cold head in the ice condenser was quickly lost. As the cold head was lost throughout the ice condenser (the portals allow for equalization across the bays), all of the of the remaining lower inlet doors then cracked off their seals (as evidenced by the sound of air rushing past the doors noticed during the initial entry) and all bay groups (w/ exception of 1-4) indicated at least one door was open to the point of tripping a limit switch. It is unknown exactly which doors, or how many doors tripped their limit switches. Because the pressurization in lower containment was fairly slow (it took approximately 10 minutes to peak) and the majority of the containment environment was non-condensibles (air), the ice condenser remained essentially equalized with the lower containment and there was never a large driving force to (fully) open all of the doors.

For the above reasons, it was as expected (normal) that several lower inlet doors did not cause the limit switch to indicate the doors were open during this event. All doors were noted to be off of their seals allowing air to pass, and were being held shut only by the spring force.

J J Nolin
Systems Engineering

ATTACHMENT 2

Evaluation of Blocking Ice Condenser Doors During Cooldown
Following the Unit 2 SG Drain Leak Event On 8/31/93

At about 12:30 a.m. on the morning of August 31, 1993, a leak in a steam generator A 1 inch drain line developed in the MNS-2 lower containment. At the time the unit was at full temperature and pressure at no-load conditions. This leak released inventory from the steam generator into containment. As a result, lower containment pressure increased by about 0.45 psi and 18°F. This pressurization caused all but two sets of ice condenser doors to open. Most of these doors were only cracked open, but 4 doors in the vicinity of the leak were fully opened. About 2,400 lbm of ice melted as a result of the leak.

After the event was diagnosed, the unit entered an orderly cooldown and depressurization at a rate of 50°F/hr to reach conditions where the leak could be isolated. This also caused the steam generator leak rate to decrease. At about 5:00 a.m., 4 1/2 hours after the start of the incident, the NC System temperature was down to 422 °F, the containment pressure had returned to its original value, and the lower containment temperature, which peaked at about 134 °F, had decreased to 124 °F. The release from the steam generator drain line was significantly reduced at this time. At about this time all of the ice condenser doors had reclosed except for two, which remained open.

At 5:00 a.m., station personnel decided to manually close (and hold closed) these two doors in an effort to minimize additional ice melt. This was decided based on the return to near-normal pressure and temperature in lower containment, which indicated that the leak had decreased and the continuing energy addition could be removed by the Containment Ventilation (VV) System. The need for the ice condenser should a subsequent event (such as a LOCA) occur was also considered. It was known that decay heat was very low due to the refueling outage, and that the stored energy in the NC System was much reduced following the cooldown to 422°F. It was recognized that blocking closed two of the 24 doors would only minimally decrease the functional capability of the ice condenser, since the remaining 22 doors would still function. The small loss of ice during the steam leak event was also recognized as only a minimal decrease from the initial inventory. Based on these factors, it was decided that the ice condenser would continue to provide a very sufficient post-accident heat sink, and that manually closing the remaining two ice condenser doors was safe and appropriate.

Had a LOCA occurred while these two doors were held shut, the ice condenser would have still performed its intended function. A large-break LOCA with the NC system temperature at 422 °F would release NC inventory and energy at a lower rate than if the reactor had been at full power. The pressure differential between the NC system and containment would be much lower initially, so that less NC inventory would be released out the break. The energy of a LOCA blowdown from these initial conditions is calculated to be about 160 E6 Btu, well below the containment design blowdown energy of 324 E6 Btu. This 50% reduction in the energy release more than offsets the reduction in the capacity of the ice condenser by closing two of the 24 doors and the assumed loss of less than 10% of the ice. The initial containment pressure peak would therefore be much lower for a large-break LOCA with the NC system at these lower pressures and temperatures than for a LOCA from full power conditions. It is also noted that the initial containment pressure peak is not the limiting pressure peak for the full power case.

The long-term pressure peak for a LOCA, which occurs following ice melt, would also be much less due to the reduced decay heat level. Decay heat at the time of ice-melt-out following a large-break LOCA from full power is about 45 MW. The decay heat at the time of the steam leak event was about 2.5 MW, or only 5.6% of the decay heat at the time of ice melt following a LOCA from full power. Even with the ice inventory slightly decreased due to the steam leak, ice meltout would take much longer due to low decay heat. The Containment Spray (NS) System is used to keep containment pressure below the 15 psig limit after the ice melts. One train of spray at 3400 gpm is capable of condensing the steam for an energy release rate of 50,000 Btu/sec. The potential boiloff from decay heat at this time is less than 2400 Btu/sec, or only 5% of the capacity of one spray train. The NS System is therefore able to keep building pressure from increasing following the initial blowdown following a LOCA at 422°F, which will only partially melt the ice inventory. No ice is required for the remainder of the event. The peak pressure would therefore remain well below the design limit of 15 psig.

Based on the above evaluation it can be concluded that the decision to block closed two doors to the ice condenser after the cooldown to 442°F was appropriate and safe, considering the availability of the remaining 22 doors, the reduced stored energy in the NC System, and the low decay heat following the outage.

Any questions, call Gregg Swindlehurst (382-5176)

SAFETY REVIEW GROUP

LER

SAFETY REVIEW GROUP LICENSEE EVENT REPORT

A review of the event on 8/31/93 is currently underway. This review will include a complete root cause analysis, safety evaluation, and will identify corrective actions required to correct the identified causes(s). There will also be a search of the Operating Experience Data Base to determine if the cause(s) and particulars of this event are recurring. The evaluation will be completed by 9/30/93, and will be submitted to the U.S. Nuclear Regulatory Commission in accordance with 10 CFR 50.73 (a) (2) (i) and 10 CFR 50.73 (a) (2) (iv). This report will be documented as LER 370/93-06.

A preliminary causal factor chart, developed during this investigation, is attached.

THE CAUSAL FACTOR CHART WILL BE PROVIDED LATER VIA FAX.

**MECHANICAL MAINTENANCE
HPES CHARTER**

TEAM CHARTER

Date: 9/1/93

Project Title: Mechanical Maintenance (MM) Investigation of Unit 2 Steam Leak involving 2CF130

Start Date: 8/31/93

Expected Completion Date: 9/7/93

Sponsor/Team Leader: Ronnie B. White, Jr.

Team Members: Mark Devine – MM Lead Investigator
Don Trapp
Maurice Horne
Jim Allgood – LER Interface

Purpose and Scope:

Coordinate/conduct MM investigation of steam leak involving 2CF130. Provide input to the LER investigation which supports determination of root cause and corrective actions for inappropriate valve repair associated with the 8/31/93 steam leak in containment event on McGuire Unit 2.

Project Background:

Repair efforts to correct leakage from a pipe cap at valve 2CF130 (secondary side tube sheet drain) resulted in pipe cap blowing off and dumping steam into lower containment. Ice condenser doors opened and some capacity of the ice condenser was used.

The unit was cooled down and depressurized to Mode 5 to facilitate repairs and recovery from the event. A SEIT was initiated to investigate the event due to the obvious significance. Mechanical Maintenance initiated an investigative effort and LER investigation was begun.

Deliverables:

Root cause investigation using HPES methodology will be used to provide input to the MNS LER investigation. This will support determination of root cause and corrective actions via the LER investigation.

Investigation will, at a minimum, address the following issues/questions:

- Determine applicable human factors and causes of unsuccessful repair efforts of 2CF130 conducted on 8/5/93.

Were the performing technicians qualified to the task?
Were applicable procedures adequate and properly used?
Was management involved in the repair efforts?
What was the initial failure mechanism of 2EOC8?
Did the work order specify any requirements for the pipe cap on the outlet of the valve?
What was the failure mechanism of the valve after the unsuccessful repair of 2EOC8?
What Post Maintenance Testing/Functional Verification was performed and when?

- Evaluate work practices used by On Line Leak Sealing vendors while performing on line leak sealing task.

Were the performing technicians technically qualified to the task?
Were the applicable procedures adequate and properly used?
What operations/control room interface occurred prior to start of job?
Was the evolution of this job significantly abnormal for On Line Leak Sealing personnel?
Was management involved in the repair efforts in the on line leak repair sealing of the 2CF130 pipe cap?

- Any other issues uncovered by this investigation will also be addressed.

Measurable Success Indicators:

Short term MM actions are completed to support unit return to service by 9/13/93.

Input to MNS LER investigation supportive of root cause determination and corrective action.

Progress Updates:

The team will initially meet daily within MM to review concerns, action responsibility and status. SEIT, LER, and NRC interface will take place as needed to bring closure to issues.

Project Goal:

Identify all corrective actions that need to take place to support an on-line date of 9/13/93.

RECOVERY PLANS

TABLE OF CONTENTS

I - REPAIR OF 2CF-130

II - ICE CONDENSER

**III - CONTAINMENT EQUIPMENT DAMAGE
AND CONTAINMENT CLEANUP**

IV - OPERATING EXPERIENCE PROGRAM

REPAIR OF 2CF-130

REPAIR OF 2CF-130

1. **RECOVERY ITEM:** After the initiating event, and an unsuccessful attempt to install the leak repair pipe cap during cooldown, 2CF-130 continued to leak past the seat. The leakage continued to pass through the drain line (with the pipe cap blown off), and continued to affect conditions inside containment. Temporary repairs to stop the leakage were needed, to be followed by permanent repairs.

Special considerations included:

- (a) preservation of as-found conditions for inspection, and
- (b) assurance of thorough post-maintenance testing.

ACTIONS:

- A. 2CF-130 was maintained in the as-found condition until disassembly.
- B. A video tape was made of 2CF-130 and the surrounding work area.
- C. With the plant in mode 5, and leakage from 2CF-130 continuing, vendor personnel successfully installed a leak repair pipe cap on the 2CF-130 pipe stub and injected leak sealant under W/O Task 93063230 01 and Temporary Modification 6286. This stopped the leakage into containment at 0100 on 9/1/93. Functional verification was performed, consisting of a visual examination of the pipe cap and a check for external leakage. 2CF-130 was not disturbed during this work.
- D. NRC personnel inspected 2CF-130 and its vicinity.
- E. After the 'A' steam generator was drained, 2CF-130 was cut out under W/O Task 93063230 03.
- F. Disassembly of 2CF-130 (which was video taped) revealed that the spring guide in the valve disk assembly had been installed upside down, "locking" the valve in the open position. Inspection showed that the pipe stub threads had been galled and that the pipe cap had been cross-threaded.
- G. Management and technicians preparing to perform subsequent repairs reviewed the problems with 2CF-130 and the pipe cap, assuring that repairs to 2CF-130 would be performed properly.
- H. The replacement 2CF-130 drain line, prefabricated with a new Kerotest valve body and down-stream threaded stub, was welded in place under W/O Task 93063230 03 and FWDS L-365 Rev 4.

- I. 2CF-130 internals were reassembled under W/O Task 93063230 02 and MP/0/A/7600/06.
- J. 2CF-130 was cycled, as part of the functional verification required by MP/0/A/7600/06. It performed satisfactorily.
- K. After the 'A' steam generator was refilled, 2CF-130 was verified to not be leaking by visual examination as part of the post-maintenance testing under W/O Task 93063230 05.

NOTE: Additional post-maintenance checks will be made during startup as follows:

- With the pipe cap off, 2CF-130 will be visually examined for leakage during mode 4 operation as the system is pressurized.
- With the pipe cap off, 2CF-130 will be visually examined for leakage at full pressure during mode 3 operation. (The pipe cap will then be installed.)
- Proper thread engagement of the pipe cap will be verified by visual examination and by observing an appropriate number of turns as it is tightened. (Proper thread engagement was informally verified after the replacement drain line was installed.)

ICE CONDENSER

ICE CONDENSER

1. **RECOVERY ITEM:** Following the leak of drain valve 2CF-130, the lower containment temperature and pressure increased, opening the ice condenser lower inlet doors. Some melting of the ice bed occurred.

ACTIONS:

- A. Following the steam leak event the ice condenser was inspected for signs of melting. Indications of melting were observed in bays 19-24. 247 baskets were weighed. The most significant melting occurred in four baskets in bay 22.
- B. The population of 247 baskets was as follows: 100% of all baskets showing visible signs of melting, plus 50% of the baskets adjacent to those showing signs of melting, plus a random sample in that bay. The weight loss from these baskets showed the ice condenser was operable.
- C. The four baskets identified in bay 22 were emptied and reloaded to enhance ice weight margin.
- D. All Ice Condenser Tech Spec surveillances were reviewed for adequacy or rerun. The most significant relative to this event that were rerun are: adequate ice mass, adequate flow passage area, and operability of lower inlet doors. See attachment for further details.

Technical Specification Surveillance Requirement 4.6.5.1.b.2 establishes Ice Condenser operability based on ice weight for a 9 month surveillance window. The requirement addresses minimum total ice inventory, as well as average basket weight with a 95% level of confidence in specific sub-groups. The technical specification minimum weights with a 95% level of confidence (2,099,790 lbs. total, 1081 lbs. average) are based on the safety margin (design basis) weight of 1,890,000 lbs. total and 983 lbs. average. The difference between these two limits address a 10% ice loss due to sublimation during the surveillance plus a 1.1% weighing error allowance. As such, meeting the requirements of the Technical Specification ensures the operability of the Ice Condenser for the 9 month interval.

The method for determining ice bed operability for the next nine months is via the ice weight surveillance and analysis performed in W/O 93063883.

Ensuring Ice Condenser operability throughout the fuel cycle was accomplished during the initial evaluation of the ice bed. Component Engineering personnel inspected the ice bed for signs of melting. Indications were observed in bays 12, 19, 20, 21, 22, 23, and 24. The most extensive melting was clearly within bay 22. As such 249 baskets in these bays and bays 11 and 13 were identified to be weighed. Valid data was collected on all but 2 baskets. The most predominant melting occurred in four baskets in bay 22. These weights are summarized in Table A.

BAY	COL	ROW	AS FOUND ICE WEIGHT (lbs.)	REPLENISHED ICE WEIGHT (lbs.)
22	3	8	990	1510
22	3	9	1016	1471
22	4	8	940	1488
22	4	9	1006	1506

The data collected from the 247 baskets is arithmetically summarized in Table B. The data was analyzed for both mean and 95% level of confidence ice weights. In all cases the current weights exceeded the Technical Specification minimum 95% level of confidence average weight of 1081 lbs. Operability at the end of the cycle was established by projecting each individual ice basket weight to 12/01/1994. The weighted average of all historical sublimation rates for the individual baskets was used for the linear projection. The four baskets originally below the 1081 lbs. limit fell below the 983 lbs. limit. As such the decision was made to replenish the baskets (replenished weights summarized in Table A). Two other baskets (Bay 24 1-1 1038 lbs. and 1-2 1060 lbs.) fell below the 1081 lbs. limit. Minimal concern exists for these basket weights as they reside within a low flow region during postulated events. The projected weight data was analyzed in the same fashion as the current weights. Again, the 95% level of confidence weights was well above the 1081 lbs. limit. This establishes the operability of the ice bed beyond the duration of the upcoming fuel cycle.

TABLE B

TOTAL ICE LOSS OF ALL BASKETS WEIGHED:	2376 lbs.	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 7:	-238	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 8:	925	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 9:	1751	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 11:	-48	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 12:	354	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 13:	83	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 19:	-567	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 20:	101	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 21:	-183	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 22:	2982	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 23:	179	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 24:	-525	
	CURRENT	PROJECTED EOC
ALL BASKETS:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1432 lbs.	1334 lbs.
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	110.57136	110.68958
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1325
ROW 7:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1389	1317
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	56.536849	58.604277
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1379	1307
ROW 8:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1438	1323
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	124.15603	122.26099
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1308
ROW 9:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1505	1338
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	109.7354	130.68957
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1495	1326

The following table lists all applicable ice condenser Tech Spec Surveillance requirements and the action taken to ensure compliance.

Surveillance Requirement Number	Surveillance Requirement	Surveillance Interval	Action Taken
4.6.5.1.a	Verify ice bed temperature < 27F.	1 / 12 hours	Normal surveillance performed by operations.
4.6.5.1.b.1	Chemical analysis of boron concentration, pH.	1 / 9 months	No additional action taken. Surveillance conducted via normal PM/PT interval. Melting of quantities observed would have negligible effect on boron concentration and pH of ice bed.
4.6.5.1.b.2	Verify adequate ice mass.	1 / 9 months	W/O 93063883 generated to perform ice mass PT. Shall Perform PT/O/A/4200/18 and MP/O/A/7150/76.
4.6.5.1.b.3	Verify adequate flow passage area.	1 / 9 months	W/O 93064579 generated to replenish baskets, as step within W/O performed Flow Channel inspection per MP/O/A/7150/10.
4.6.5.1.c	Verify structural integrity of basket.	1 / 40 months	No additional action taken. This surveillance was performed during this past outage on W/O 93011900. Velocities never approached magnitudes capable of basket damage.
4.6.5.2	Verify ice bed temperature monitoring system operable.	1 / 12 hours	Normal surveillance performed by operations.
4.6.5.3.1	Verify operability of lower inlet doors.	1 / 18 months	W/O 93063885 generated to perform lower inlet door PT. Includes testing of door position monitoring system. Tested per PT/O/A/4200/32.
4.6.5.3.2.a	Verify operability of intermediate doors - free of frost accumulation.	1 / 7 days	No additional action taken. Performed weekly by operations during upper containment walk down.
4.6.5.3.2.b	Verify operability of intermediate doors - opening force test.	1 / 18 months	W/O 93064135 generated to perform intermediate deck door PT. Tested per PT/O/A/4200/33.
4.6.5.3.3	Verify operability of top deck blanket.	1 / 92 days	W/O 93064862 generated to perform Civil walk down. PT/2/A/4700/55 performed, section addresses top deck blanket operability.
4.6.5.4.a	Verify operability of lower inlet door position monitoring system.	1 / 7 days	Normal surveillance performed by operations.
4.6.5.4.b & c	Verify operability of lower inlet door position monitoring system.	1 / 18 months	Performed as part of PT/O/A/4200/32, lower inlet door test, on W/O 93063885.
4.6.5.7	Floor drain operability	1 / 18 months	W/O 93064205 generated to perform MP/O/A/7150/08 floor drain PT.

***CONTAINMENT EQUIPMENT
DAMAGE AND
CONTAINMENT CLEANUP***

CONTAINMENT EQUIPMENT DAMAGE AND CONTAINMENT CLEANUP

1. **RECOVERY ITEM:** The leak of drain valve 2CF-130 resulted in a significant discharge of steam from the secondary side of 2A steam generator. This release of steam caused containment temperature, pressure and humidity to increase. The equipment in lower containment exposed to the elevated temperature, humidity and water must be evaluated to ensure that equipment is able to perform its design function.

ACTION ITEMS:

The following is a list of the equipment evaluated or inspected. Further documentation is included in Appendix IV.

- A. E.Q. Instrumentation – Evaluation performed by McGuire Station EQ Coordinator. The readout from 3 EQ instruments (2CFLT5490, 2CFLT5500 and 2CFLT5510) were checked for stable and correct indication. These instruments were all located in the cold leg accumulator rooms adjacent to 2CF130.
- B. Target Rock Solenoid Valves – Four of four were functionally verified by cycling each valve.
- C. Fire Detectors – Twelve of nineteen zones were inspected. Ten of the twelve operated satisfactory. Smoke detectors in the two failed zones were dried and placed back in service.
- D. Resistance Temperature Detectors (RTDs) – Evaluation made as EQ instrumentation under Item A.
- E. Pressure Operated Relief Valve Acoustic Leak Monitor – Evaluation made as EQ instrumentation under item A.
- F. Reactor Coolant Pump Motors – Inspected lead box, terminations and inside of motor on pump 2A. All areas checked were dry.
- G. Valve Operators – MOVs evaluation made as EQ instrumentation under item A.
- H. Electrical Penetrations – No additional inspection required based on evaluation.

- I. Control Rod Drives – The CRDMs were checked and two cables/CRDMs appear to have shorts. Plans are to remove the CRDMs, disassemble and try to dry them. This will be completed before unit restart. Work order 93064212 is being used to perform the work.
- J. Digital Rod Position Indication – Evaluation of present rod position indications shows no malfunctioning indicators. A thorough verification can only be performed after rods are raised.
- K. Pressurizer Heaters – Evaluation of equipment construction and verification of heater amp readings indicate no further inspections necessary.
- L. Incore Instrumentation – Some water intrusion was detected. One motor starter was dried while another required replacement. Work order 93012028 was used for inspection and repair work.
- M. VL Fan Units – An evaluation was performed on the lower containment ventilation units. Based on equipment design and past operating experience, further inspection was deemed not necessary.
- N. VL Fan Unit Vibration Detection Units – Monitor cabinets were inspected for moisture and were found dry. All alarms were clear.
- O. Lower Containment Lighting Power Panels – Three of four lighting panels inside the shield wall in lower containment were inspected for moisture/water intrusion and all were found dry.
- P. Civil Concerns – A review of various codes and specifications for structural steel and concrete revealed the structure was not compromised in any way. See attachment for evaluation.
- Q. General Inspection of Electrical Equipment and Instrumentation in Area Around 2CF130 – The following instrumentation was visually inspected for damage due to close proximity to 2CF130:
 - a. 2VPPT5130 *
 - b. 2VPPT5120 *
 - c. 2VPPT5140 *
 - d. 2NVLS5070 *
 - e. 2NVLS5071 *
 - f. 2NCLT5991
 - g. 2BWPE5070
 - h. 2BWPI5070
 - i. 2BWPG5070

- The functions of these instrumentation were also verified to ensure proper readouts were being received.

- R. An engineering review of the containment temperature response was performed. It was determined that the transient did not challenge the operability of any QA condition / equipment, and that there was no discernible effect on environmental qualification life.

- S. General inspection of equipment near the discharge of ice condenser 10" floor drain for bay 22 was evaluated for potential water damage. No visible damage was found. The maximum flow rate from the ice melting was approximately 0.6 gpm.

2. **RECOVERY ITEM:** Due to the 2CF-130 steam leak there was magnetite and water on the A/D side of lower containment and a little in the A/D side of the pipe chase that needed to be cleaned prior to returning to mode 4.

SHORT TERM ACTION ITEMS:

- A. The water was vacuumed up.
- B. The horizontal surfaces (piping, valves, hangers, etc.) under 2CF-130 were wiped down.
- C. The grating under A/D S/G was removed and K-MAC cleaned the floor.
- D. The debris in the pipe chase was removed.
- E. QA has inspected the area.

***OPERATING EXPERIENCE
PROGRAM***

OPERATING EXPERIENCE PROGRAM

1. **RECOVERY ITEM:** Due to the generic implications of this event, operating experience communications were made to other Duke nuclear stations and the industry.

ACTION ITEMS:

- A. McGuire Superintendent of Mechanical Maintenance notified Oconee and Catawba via conference call and electronic mail.
- B. Nuclear Network messages (3) sent to update industry.

LONG TERM ACTION ITEMS:

- A. Duke Power, Nuclear Generation Department, Nuclear Services Department will follow thru on appropriate communication/coordination of lessons learned with all three Duke Power Nuclear Stations. Ongoing effort.

September 4, 1993

MEMORANDUM

Subject: Operational Experience Sharing - 2CF130 Incident

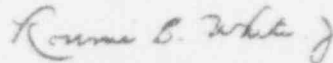
This memorandum is to document a telephone conference call conducted on 9/2/93 between myself, Don Rogers - Catawba Mechanical Superintendent, and Bill Rogers - Oconee Mechanical Superintendent to share preliminary lessons learned from the 2CF-130 incident.

During this call I shared the basic sequence of events that lead up to the pipe cap blow-out on 2CF-130. We discussed the basic technical details involved in the Modified Thread Injection Cap (MTIC) method of on line leak sealing and I answered any questions CNS and ONS had about this incident.

I encouraged CNS and ONS to:

- Review NSD-105 Operating, Test, and Maintenance Activities
- Review ETQS Standard 2404.0 Support Personnel Training and Qualifications
- Assess their current management oversight of contractors/vendors including on line leak sealing activities
- Assess their current maintenance repair methods using on-line leak sealing

At the time of this telephone conference the root cause failure of 1CF-130 was not known. The root cause has since been determined (inverted spring guide). I fax'd a copy of Mechanical Maintenance root cause failure determination report on 9/3/93 and sent them a PROFS note advising them of such.



Ronnie B. White, Jr.
Mechanical Superintendent
McGuire Nuclear Station

RBWjr/dgt

cc: Don Rogers (Catawba)
Bill Foster (Oconee)
Don Gabriel
Ernie Estep

From: RBW7324 --PRDC
To: WWF7310 --PRDC
DHG7344 --PRDC D. H. Gabriel
cc: RXB6274 --PRDC
ELB7325 --PRDC
BTH7325 --PRDC
TJS7325 --PRDC

Date and time 09/03/93 13:59:09
RRR8236 --PRDC Don R. Rogers
RPB7325 --PRDC
DWT7325 --PRDC
MXH7522 --PRDC
EEE7255 --PRDC Ernest E. Estep

From: Ronnie B. White, Jr
Subject: 2CF-130 Issues

Briefly the root cause failure of 2CF-130 (Kerotest 1500# Y-type Kerotest globe valve) was because the spring guide and spring combination was found installed in an inverted position. When inverted, the disc assembly is lifted off the seat and prevents valve closure. Another symptom of this inverted installation is that the valve handwheel will essentially not move after complete reassembly.

The post maintenance test / functional verification stated that the valve should be 1) cycled 2) visually checked. We are currently investigating how the valve could have been cycled per the functional verification since the handwheel is essentially "locked down" by the inverted assembly.

Other generic issues that the NRC AIT team have raised center around the use of "on-line leak sealing" as a repair method and management oversight of vendor / contractor activities.

We are currently reviewing our training, procedures, administrative guidance and maintenance work practices associated with the above areas.

I recommend that DNS and CNS do the same. I ask that Nuclear Services assist the stations in these areas also by looking at "best practices" already in place relating to kerotest procedures and maintenance practices. All three sites currently use "on-line leak repair" as a maintenance alternative. Nuclear Services could help us in this area by review of our practices as well as what is currently being done in the industry (via INPO contacts, etc).

We are making some short term changes to our Kerotest maintenance procedure and will follow this up with a more comprehensive look at this procedure longer term.

We have also implemented the requirement that [REDACTED] (our on line leak sealing contractor) be accompanied by Mechanical Maintenance during the signing on of any work with OPS.

We have established administrative controls prohibiting the use of the on line leak sealing technique that involves removal of pipe caps under pressure until we have fully evaluated this repair technique.

We have briefed key Mechanical managers on management oversight responsibilities regarding contractors / vendors and have increased our management oversight of maintenance activities (including activities occurring on nights, weekends, etc).

We have increased our focus on examining valve failures for root cause.

We are conducting a Mechanical HPES investigation of this event.

I will try to keep you posted on other key areas that might help you learn

from our experience.

RBW, Jr

=====
= One message has been selected. =
=====

OE 6171 I PEDERSON (DUKE) 31-AUG-93 13:51 EDT
Subject: Feedwater line leak resulting in an ESF actuation.

Unit Name..... McGuire
Reactor Type..... PWR (1180 MWe)
Reactor Manufacturer..... Westinghouse
Plant Designer..... Duke Power Company
Event Date..... 31/08/93
LER Number..... 370/93-06

During the startup of Unit 2 at McGuire Nuclear Station following a scheduled refueling outage, steam was noticed coming from a Steam Generator secondary side drain valve pipe cap. The decision was made to do an on-line leak repair by removing the pipe cap on the drain valve.

The repair crew had assembled the necessary repair equipment, and had started removing the pipe cap when the cap blew off releasing steam at an estimated 1100 psig into lower containment. One member of the repair crew was injured, and received second degree burns to his hands. The steam slightly pressurized lower containment, and some of the ice condenser doors opened.

Actions were taken to lower secondary side pressure to stop the steam leak, and the ice condenser doors were closed.

Efforts are currently underway to weigh the ice condenser baskets, and evaluate further actions. The injured worker was taken to the hospital for precautionary measures, and was released.

Plans are to cool down to Mode 5 and then evaluate further actions.

Information Contact: Jim Allgood (704)-875-5161

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=
= One message has been selected.
=
=====

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OE 6174 I PEDERSON (DUKE) 02-SEP-93 13:51 EDT
Subject: Feedwater Line Leak Resulting in an ESF Actuation.

This is a follow-up message to OE 6171.

Unit Name	McGuire
Reactor Type	PWR (1180 MWe)
Reactor Manufacturer	Westinghouse
Plant Designer	Duke Power Company
Event Date	31/08/93
LER Number	370/93-06

McGuire site management has decided not to perform any leak repair of a leaking vent cap by removing the cap while it is still pressurized. This is effective immediately, and will stay in affect until further evaluation can be completed.

Other actions that the station is taking includes:

- 1) Cutting out and replacing the leaking drain valve
- 2) Determine the failure mechanism of the valve
- 3) Replace melted ice in the ice condenser.

Information Contact: Jim Aligood (704)-875-5161

=====
= One message has been selected. =
=

OE 6180 I PEDERSON (DUKE) 03-SEP-93 18:14 EDT
Subject: Leakage on Steam Generator Drain Valve due to Improper
Reassembly during Maintenance

Unit Name	McGuire Nuclear Station
Reactor Type	PWR (1180 MWe)
Reactor Manufacturer	Westinghouse
Plant Designer	Duke Power Company
Event Date	31/08/93

This event is related to OE 6171 message. The feedwater line leak that occurred on 8/31/93 was due to leakage through a Steam Generator (S/G) drain valve (2CF-130). This valve is a 1 inch packless Kerotest globe valve, 1 Series 1513, Y-Type Globe Valve, CAD 9915-(1).

The reason valve 2CF-130 did not isolate feedwater flow was the improper reassembly of the valve due to personnel error in following the maintenance procedures. During final reassembly of the disc assembly, the spring guide was installed upside down. When inserted in the valve, the improper configuration of the spring guide would prevent the disc assembly from contacting the seat. This prevented the diaphragms from seating, and, in fact, would prevent the valve from properly stroking. These conditions were verified during an as-found evaluation of valve 2CF-130 in the McGuire Hot Machine Shop on September 2, 1993.

Information Contact: Jim Allgood (704)-875-5161

CORRECTIVE ACTIONS

TABLE OF CONTENTS

I - MAINTENANCE EXECUTION

II - POST MAINTENANCE TESTING

III - WORK CONTROL

IV - CONTROL OF PLANT DURING COOLDOWN

V - OTHER

MAINTENANCE EXECUTION

MAINTENANCE EXECUTION

1. **PROBLEM STATEMENT:** Maintenance activities to repair seat leakage on valve 2CF-130 resulted in an unisolable steam leak in Unit 2 lower containment. This led to the need to perform on line leak sealing which resulted in a personnel injury (minor burn) and opening of ice condenser lower inlet doors and some melting of ice.

CAUSE: Incorrect reassembly of valve disc and inadequate functional verification during repair of 2CF-130.

SHORT TERM ACTION ITEMS:

- A. Charter a Mechanical Maintenance investigation of this event. See Appendix V Team Charter.

Responsible Party: Mechanical Superintendent

- B. Complete disassembly investigation to determine the mechanical failure of 2CF-130. See Appendix V Disassembly and Inspection of 2CF130

Responsible Party: Mechanical Superintendent

- C. Change procedure MP/0/A/7600/06 Kerotest Y-Type Globe Valve Corrective Maintenance to clarify reassembly steps.

Responsible Party: Mechanical Superintendent

LONG TERM ACTION ITEMS:

- A. Complete the full Mechanical Maintenance HPES investigation of this incident.

Responsible Party: Mechanical Superintendent

Completion Date: September, 1993

- B. Develop a means to emphasize to valve technicians the consequences of improper spring guide installation and importance of following procedures.

Responsible Person: Mechanical Maintenance ETQS Coordinator

Completion Date: October, 1993

C. Perform Human Factors review of procedure MP/O/A/7600/06.

Responsible Party: Mechanical Support General Supervisor
Completion Date: October, 1993

D. Enhance Supervisor and Employee Work Habits packages with specific details of procedure adherence and adequacy and specific responsibilities of each in regards to oversight of activities.

Responsible Party: Mechanical ETQS Coordinator
Completion Date: October, 1993

E. Give specific event training to all Mechanical Maintenance technicians who may be involved with Kerotest valve activities.

Responsible Party: Mechanical Support General Supervisor
Completion Date: November, 1993

MAINTENANCE EXECUTION

2. **PROBLEM STATEMENT:** Affected groups do not always have adequate involvement in planning, risk assessment, and execution of on line leak sealing evolutions.

CAUSE: The current process does not clearly delineate the potential consequences for on line leak sealing of high energy systems.

SHORT TERM ACTION ITEMS:

- A. Place administrative hold on the use of the vendor's on line leak sealing repair methods that involve removal of pressurized pipe caps on high energy systems. See Appendix V Memorandum.

Responsible Party: Mechanical Superintendent

- B. Place MP/0/A/7650/77 (On Line Leak Sealing Initial Injection) procedure on Administrative Hold.

Responsible Party: Mechanical Superintendent

- C. Clarify management oversight responsibilities for on line leak sealing activities within Mechanical Maintenance. See Appendix V Memorandum to Maurice Horne.

Responsible Party: Mechanical Superintendent

- D. Brief Mechanical Maintenance managers to heighten their awareness regarding training and qualification requirements and management oversight of the activities of vendors, contractors, and other interfacing personnel. See Appendix V Memorandum.

Responsible Party: Mechanical Superintendent

- E. Operations issue a special order to suspend removal of pipe caps from pressurized high energy (water/steam systems pressurized to >600 p.s.i.) systems. See Special Order 93-13.

Responsible Party: Superintendent of Operations

LONG TERM ACTIONS:

- A. Evaluate the repair methods used which involve removal of pressurized pipe caps on high energy systems and take appropriate actions.

Responsible Party: Mechanical Equipment Section Manager

Completion Date: Required prior to removing Admin Hold on this repair method.

- B. Revise MP/O/A/7650/77 (On Line Leak Sealing Initial Injection) procedure to include pre-job briefing requirements and remove from administrative hold.

Responsible Party: Mechanical Support General Supervisor

Completion Date: Prior to Using Procedure

- C. Review all maintenance procedures for infrequently performed evolutions and revise to include pre-job briefing requirements.

Responsible Party: Mechanical Support General Supervisor

Completion Date: October, 1993

- D. Review procedure MP/O/A/7650/77 and Vendor On line Leak Sealing procedure for Human Factors conditions and technical accuracy.

Responsible Party: Mechanical Support General Supervisor

Completion Date: Before next use

***POST MAINTENANCE
TESTING***

POST MAINTENANCE TESTING

1. **PROBLEM STATEMENT:** Some Post Maintenance Testing (PMT) on unisolatable high energy components (valves, flanges, couplings, etc.), such as valve 2CF-130, is not performed until normal system conditions are reached. This limits maintenance flexibility when leaks are found.

CAUSE: Other Post Maintenance Test methods not previously identified.

SHORT TERM ACTION ITEMS:

- A. Change Post Maintenance Testing on 2CF-130 following repair to include leak checks at three points: 1) System cold with 'A' S/G secondary side filled; 2) while in mode 4, 3) at normal system temperature and pressure. All checks to be done with pipe cap removed. This item is in progress and will be completed when unit 2 reaches full temperature and pressure.

Responsible Party: Work Control Superintendent

LONG TERM ACTION ITEMS:

- A. Evaluate the effectiveness of current Post Maintenance Testing Methods on unisolatable high energy components. Objective should be to identify best maintenance options with leaking unisolatable components.

Responsible Party: Work Control Superintendent

Completion Date: December, 1993

WORK CONTROL

WORK CONTROL

1. **PROBLEM STATEMENT:** MNS has experienced a number of recent cases involving the use of vendors.

CAUSE: Lack of site specific administrative guidance addressing control of non-assigned individuals and organizations performing work on site.

SHORT TERM ACTION ITEMS:

- A. Operations management, as an interim measure, will issue a memo to all Operations Shift and Staff personnel. The memo will require that Mechanical Maintenance personnel accompany vendor personnel when interfacing with Operations for the purpose of obtaining Operations clearance authorization to perform a leak repair activity.

Responsible Party: Operations Superintendent

LONG TERM ACTION ITEMS:

- A. Develop site specific administrative guidelines that address control of non-assigned individuals and organizations performing work on the McGuire Site. These guidelines should define the roles and responsibilities of "Station Sponsors".

Responsible Party: Work Control Superintendent

Completion Date: February, 1994

2. **PROBLEM STATEMENT:** The degraded condition of the threads on the pipe cap of valve 2CF-130 were known but this information was not documented in the work package nor communicated to the work crew.

CAUSE: Oversight on the part of the Planner when assembling the work package and failure to communicate known condition to the repair technicians.

SHORT TERM ACTION ITEMS:

None

LONG TERM ACTION:

- A. Change Maintenance Procedure 2.2, Work Execution Planning, to include guidance to appropriate work planners to ensure that critical as-found information is included in work package documentation.

Responsible Party: Work Control Planning Manager

Completion Date: October, 1993

- B. The specifics of the 2CF-130 event and the significance of not including as-found condition information with the work package will be reviewed with appropriate Work Control Planners.

Responsible Party: Work Control Planning Manager

Completion Date: December, 1993

3. **PROBLEM STATEMENT:** Operations did not have a clear understanding of the leak repair method being performed on 2CF-130.

CAUSE: Did not identify the leak repair of 2CF-130 as a "non-routine" maintenance activity that warranted increased oversight and a pre-job briefing.

SHORT TERM ACTION ITEMS:

None

LONG TERM ACTION ITEMS:

- A. Develop a method to identify maintenance activities on inservice systems that have the potential to result in unit trips or transients, unisolatable leaks, or rendering safety systems or components inoperable. Ensure that these types of activities include a pre-job briefing prior to beginning work.

Responsible Party: Work Control Superintendent

Completion Date: December, 1993

***CONTROL OF PLANT
DURING COOLDOWN***

CONTROL OF PLANT DURING COOLDOWN

1. **PROBLEM STATEMENT:** During the cooldown and depressurization of unit 2, the plant re-entered mode 3, after having entered mode 4.

CAUSE: Communication between the reactor operator at the controls and the other members of the control room team was ineffective. The communication problems were a barrier to effective teamwork.

SHORT TERM ACTION ITEMS:

- A. The shift briefings will be modified to shorten them and reduce the number people in the control room.

Responsible Party: Shift Operations Manager

LONG TERM ACTION ITEMS:

- A. A reading package describing the event and addressing the communication breakdown that lead to the event will be developed and distributed to all licensed personnel.

Responsible Party: Operations Support Manager

Completion Date: September, 1993

- B. All licensed personnel involved with this event fully understood the definition of mode 3. Yet, the control room team did not recognize the unit had re-entered mode 3. A more effective method of bringing impending mode changes to the control room team's attention must be developed.

Responsible Party: Shift Operating Manager

Completion Date: December, 1993

- C. A case study training lesson for this entire event will be developed and presented to all licensed operators. Emphasis will be placed on communications and teamwork.

Responsible Party: Director of Operator Training

Completion Date: March, 1994

- D. The individual reactor operator at the controls failed to share important information and plant status with his teammates in the control room. This specific performance deficiency will be addressed with the individual, and needed coaching, counseling and remediation will be identified and conducted.

Responsible Party: Shift Operation Manager

Completion Date: September, 1993 (Coaching & Counseling)

Completion Date: December, 1993 (Remediation)

2. **PROBLEM STATEMENT:** Operators have not been specifically trained on cooling down and depressurizing while on excess letdown.

CAUSE: Our ongoing Operations training assessment program had not identified this as a weakness.

SHORT TERM ACTION ITEMS:

None

LONG TERM ACTION ITEMS:

- A. Training will be developed and conducted for all licensed operators which familiarizes them with the effects of cooling down and depressurizing while on excess letdown.

Responsible Party: Director of Operations Training

Completion Date: March, 1994

3. **PROBLEM STATEMENT:** The guidance provided in Operations procedures is not clear regarding actions to be taken following the opening of the ice condenser lower inlet doors.

CAUSE: Previous experience with the ice condenser lower inlet doors opening has been associated with ventilation imbalances. The need to have guidance following a small high energy line break was not anticipated.

SHORT TERM ACTION ITEMS:

- A. Document the basis for the decision to hold two ice condenser lower inlet closed during the recovery from this event. (See Appendix III)

Responsible Party: Superintendent of Operations

LONG TERM ACTION ITEMS:

- A. The Annunciator Response Procedure for the ice condenser lower inlet doors open alarm will be clarified to provide better guidance.

Responsible Party: Operations Support Manager

Completion Date: September, 1993

OTHER

OTHER CORRECTIVE ACTIONS

1. **PROBLEM STATEMENT:** A possibility existed that other Unit 2 Kerotest packless valves could have been mis-assembled such that they would not close properly.

NOTE: There is high confidence that no related problems exist in critical applications on Unit 1. This confidence is based as follows:

- a) the checks below revealed no further problems on Unit 2
- b) potential problems on Unit 1 should have been eliminated by post maintenance testing during the 1EOC8 refueling outage or by challenges to the functions of the valves during subsequent startup, operation at power, and shutdown.

CAUSE: Causes relate to procedures and human factors, as addressed under **CORRECTIVE ACTIONS - MAINTENANCE EXECUTION**. The purpose of the action below was to eliminate current problems, rather than prevent recurrence.

SHORT TERM ACTION ITEMS:

- A. All valve work orders performed on Kerotest valves during 2EOC8 were reviewed. The review showed that 31 packless Kerotest valves had mechanical work performed which required reassembly of the valves.

Checks were performed to eliminate the possibility that the valves were mis-assembled in the same manner as 2CF-130. A key symptom of this condition is that the valve will not move. Documentation of full valve stroking existed for 14 of the 31 valves. The remaining 17 valves were physically stroked on 9/3/93. All the valves moved properly.

In addition, checks were made to eliminate the possibility of mis-assembled non-QA valves as identified in Item 36 under **ISSUES ADDRESSED**. In this type problem, non-QA packless Kerotest valves might exhibit some seat leakage, though the valve would otherwise function properly. Of the 31 valves, 8 were non-QA. An evaluation showed that 3 of these 8 could have personnel safety implications. All 3 valves were vents or drains with down stream pipe caps. With water on the upstream side of each valve (unpressurized because of the shutdown condition), each pipe cap was removed. No seat leakage was observed. The pipe caps were properly re-installed. This was completed on 9/4/93.

All the above actions were completed prior to entry into mode 4.

APPENDIX VI tabulates the 31 valves and the checks performed on each.

LONG TERM ACTION ITEMS: None.

OTHER CORRECTIVE ACTIONS

2. **PROBLEM STATEMENT:** Because of frequent installation and removal of pipe caps, the potential for thread damage is high. A method of monitoring and improving thread conditions or using connectors other than the conventional pipe caps could improve safety, integrity, and efficiency.

CAUSE: Cause(s), other than as stated above, are unknown at this time. Cause determination will be part of the actions described below.

SHORT TERM ACTION ITEMS: None.

LONG TERM ACTION ITEMS:

- A. Develop a process to better ensure the integrity of pipe cap threaded connections.

Responsible Party: Operations Superintendent and Mechanical Maintenance Superintendent

Completion Date: The process will be defined by March, 1994 and implemented by 1EOC9.

- B. Investigate cost effective methods of improving the performance of vent and drain connections, including valve and pipe cap designs/configurations.

Responsible Party: Component Engineering Manager

Completion Date: The investigation will be complete by March, 1994. It will address implementation plans and schedules for any recommended changes.

3. **PROBLEM STATEMENT:** Letdown isolation valve 2NV-1 failed closed preventing the operators from using normal letdown and requiring the use of excess letdown during the plant recovery from the steam leak caused by 2CF-130.

CAUSE: The most likely root cause was determined to be damage to a 2NV-1 SOV lead wire during installation.

SHORT TERM ACTION ITEMS:

- A. Troubleshooting the problem, technicians went to 2NV-1 and found that the lead wires to the associated SOV were burned. The failure mode was shorting of the lead wires. An investigation into the cause of the failure was conducted. The most likely cause was determined to be damage to a lead wire during the most recent replacement of the SOV.
- B. The 2NV-1 SOV and lead wires were replaced, along with the associated conduit. Care was taken to avoid damaging the lead wires. Functional verifications and post maintenance tests were completed.

LONG TERM CORRECTIVE ACTIONS: None

APPENDICES

TABLE OF CONTENTS

- I - CONFIRMATION OF ACTION LETTER**
- II - ISSUES ADDRESSED**
- III - SUMMARY OF CONSIDERATIONS FOR
BLOCKING DOORS.**
- IV - SUMMARY OF EVALUATIONS AND
INSPECTIONS PERFORMED ON
ELECTRICAL EQUIPMENT**
- V - MAINTENANCE EXECUTION SUPPORT
INFORMATION**
- VI - CHECKS PERFORMED ON UNIT 2 PACKLESS
KEROTEST VALVES**

**CONFIRMATION ACTION
LETTER**



UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2800
ATLANTA, GEORGIA 30303-0108

SEP 01 1993

Docket No. 50-370
License No. NPF-17
CAL No. 2-93-06

Duke Power Company
ATTN: Mr. T. C. McMeekin
Vice President
McGuire Site
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

Gentlemen:

SUBJECT: CONFIRMATION OF ACTION LETTER - MCGUIRE UNIT 2

This refers to a telephone conference between Mr. E. Merschoff and you on September 1, 1993, concerning actions you will take as a result of the steam leak through the "A" Steam Generator secondary side drain line and subsequent ice condenser door actuation from increased containment pressure. We understand that Duke Power Company is actively investigating the root causes of the event and evaluating the actions that have been or will be taken in response to them. We also understand that you will take the following actions prior to entering Mode 2 for Unit 2.

1. Obtain concurrence of the Regional Administrator prior to entering Mode 2.
2. Conduct a comprehensive investigation to determine all aspects of the August 31, 1993 steam leak event.
3. Fully evaluate the recommendations of the Significant Event Investigation Team and implement appropriate corrective actions in a timely manner.

Pursuant to Section 182 of the Atomic Energy Act, 42 U.S.C. 2232, and 10 CFR 2.204, you are required to :

- 1) Notify me immediately if your understanding differs from that set forth above.
- 2) Notify me if for any reason you cannot complete the actions within the specified schedule and advise me in writing of your modified schedule in advance of the change, and
- 3) Notify me in writing when you have completed the actions addressed in this Confirmatory Action Letter.

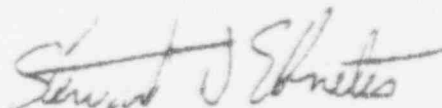
Issuance of this Confirmatory Action Letter does not preclude issuance of an order formalizing the above commitments or requiring other actions on the part of the licensee. Nor does it preclude the NRC from taking enforcement action

SEP 01 1993

for violations of NRC requirements that may have prompted the issuance of this letter. In addition, failure to take the actions addressed in this Confirmatory Action Letter may result in enforcement action.

The responses directed by this letter are not subject to the clearance procedures of the office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96 511.

Sincerely,



Stewart D. Ebnetter
Regional Administrator

cc: R. O. Sharpe
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cc: Continued see page 3

SEP 01 1993

cc: Continued
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ISSUES ADDRESSED

DUKE POWER COMPANY
MCGUIRE NUCLEAR STATION
UNIT 2 STEAM LEAK IN CONTAINMENT
AUGUST 31, 1993
ISSUES ADDRESSED

APPENDIX II

The following is a list of issues that have been identified concerning the Steam Leak inside of the Unit 2 Containment that occurred on August 31, 1993. These issues must be addressed and dispositioned prior to startup of Unit 2.

- 1a. Review Generic Letter GL 90-05 which describes a non-code primary system event that occurred at Millstone. Does this Generic Letter apply to the work performed on 2CF-1307

RESP. - RBT

STATUS: RBT to discuss. Review of the Generic Letter revealed that the event was not a code concern. See attached report.

- 1b. Review Generic Letter GL 90-05 with regards to work activities associated with 2NC-14.

RESP. - RBT

STATUS: Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repair for ASME Code Class 1, 2 and 3 Piping" requires code repairs in accordance with ASME Section XI or NRC relief if a non code repair methods is desired.

The repair of 2NC-14 was evaluated as satisfying the construction code stress allowables and, therefore is in compliance with ASME Section XI. See attached for additional information.

- 1c. What other ASME Class I components have been leak repaired, and what is the current status

RESP. - RBT

STATUS: Close with attached letter.

2. What was the Post Maintenance Test that was performed on 2CF-130.

RESP. - JWB

STATUS: RBW has discussed with the SEIT and the AIT. A full Post Maintenance Test was not completed because the valve was found leaking before reaching full temperature and pressure. W/O package indicated that the valve had been blued during repair and cycled by the mechanic.

- 3a. What oversight does McGuire Management provide for vendors

RESP. - JWB

STATUS: JWB to discuss with the SEIT and the AIT.

The SEIT and the AIT reviews are complete. NSD 105 details the high level requirements and responsibilities for station management. Leak repair personnel were trained to ETQS standard 2404.0, and were also trained and qualified to be a Level I worker (perform work without station supervision).

As an interim measure, on September 1, 1993, Operations Group management issued a memo to all Operations personnel. The memo requires that Mechanical Maintenance must accompany leak repair personnel when interfacing with Operations for the purpose of obtaining Operation's clearance authorization to perform a leak repair activity. See attached for additional information.

- 3b. A generic issue has been raised concerning McGuire's Management's oversight of vendors, and in what directives are the responsibilities for the job sponsors defined? Several recent events have occurred involving the work performed by vendors. Examples are: Copper wire found in the Unit 1 core, the fire on the roof of the Unit 1 Spent Fuel Pool, the bend rod assembly, and the leak associated with 2CF-130. What actions should be taken in both the short term and the long term to address this concern?

RESP. -JWB

STATUS: NSD 105, Control for Interfacing Individuals and Organizations, addresses responsibility for interface and control of vendors at our nuclear stations. It specifies that the Station Manager has final responsibility for directive implementation, and that his direct reports have individual responsibilities for assuring control of vendor interface.

Prior to March 6, 1990, the station operated under more specific guidance as to the control of interfacing individuals and organizations. Station Directive 2.7.1, Control Of Non-Assigned Individuals and Organizations Performing Work Or Directing Activities In the Station, described how non-assigned individuals and organizations were to be controlled. This directive outlined some of the roles and responsibilities of Station Sponsors who served as the primary contact for non-assigned individuals.

Station Directive 2.7.1 was deleted on March 6, 1990. As a result, the Station Sponsors have continued in their roles since that time without a formal documentation to guide them. See the Work Control section under the Corrective Actions tab for additional information.

4. Review the Mode change that occurred with inoperable doors (Cross over from Mode 4 to Mode 3, then back to Mode 4)

RESP. - BHH

STATUS: This item will be combined with item #6 for resolution.

5. What was the knowledge of the Operations personnel on the method to be used to leak repair 2CF-130? (Prior to work starting?)

RESP. - BHH

STATUS: BHH to discuss with the SEIT. Review with SEIT complete. Operations thought that a hole would be drilled in the cap, and then shot with leak repair material. This method had been the practice for several years. Operations was not aware that leak repair had changed their repair technique by removing the existing pipe cap, and replacing it with a modified cap. The modified cap has the leak repair connections made into the cap. However, if Operations would have known the new technique (which has been successfully used at Catawba and McGuire). It is questionable whether or not Operations would have stopped the job.

6. Describe the control of the plant during cooldown to Mode 4. What occurred that permitted the plant to heat back up to Mode 4 (Tech Spec concern crossing over modes)

RESP. - BHH

STATUS: Short term and long term items have been assigned to Operations. Refer to the Cooldown of Plant During Cooldown section under the Corrective Actions tab for additional information.

7. During the review of W/O task 92041833, a measurement was taken on August 6, 1993 for setting a new disk (2.169). The disk was then drilled and pinned. How was the measurement taken?

RESP. - RBW

STATUS: The measurement was made with a Digital Dial Caliper.

8. Why did some of the ice condenser doors not open during the event?

RESP. - RBT

STATUS: See attached report.

9. Why did two of the doors not close following the event?

RESP. - RBT

STATUS: See attached report.

10. How effective was the communication within the Control Room and between the Control Room and areas outside the Control Room during the event?

RESP. - BHH

STATUS: BHH to discuss with the SEIT and AIT. Discussions with the SEIT and the AIT are complete, and this has not emerged as a concern. However, Operations Management's expectations were not fully met during this event. The actions taken to resolve issue number 6, plus the ongoing efforts to improve crew communications will strengthen our performance in this area.

11. What was the failure mechanism of 2CF-130 ?

RESP. - RBT / RBW

STATUS: RBT and/or RBW have discussed with the SEIT and AIT. Members of the SEIT and AIT were present when the valve was disassembled. The plug in the valve was improperly assembled preventing the valve from seating.

12. What is the ASME class of the pipe downstream of the valve (B-31.1?)

RESP. - RBT

STATUS: This issue will be combined with item #1 for resolution. The pipe in question is Class G.

13. Why did the cap blow off after 1 1/4 turns vs. the standard engagement of 3 to 4 turns?
- RESP. - RBW
STATUS: Review of the cap shows that the cap was apparently cross threaded, and may not have had enough threads to engagement prior to the removal attempt.
14. The NRC wants to view the disassembly of the valve.
- RESP. - RBW
STATUS: This issue will be addressed in the resolution of issue #11.
15. Is the leak repair practice for removing pipe caps as part of their repair procedure?
- RESP. - RBW
STATUS: Yes, removing pipe caps in the manner used by leak repair is in their repair procedures.
16. Was the cap tightened before leak repair started the repair process?
- RESP. - RBW
STATUS: Per interviews with both leak repair technicians, the cap was attempted to be tighten before repairs were started.
17. What repair alternatives were considered?
- RESP. - JWB
STATUS: Discussed with the AIT. Several repair options were considered. All repair options involved a leak repair activity. The leak activity chosen was picked such that the repair would not disable the valve, and was based on past experience.
18. Were other alternatives available to determine the extent of leakage prior to removing the pipe cap?
- RESP. - JWB
STATUS: Will be addressed in the response to issue #13.
19. Consider video taping the disassembly of 2CF-130.
- RESP. - RBW
STATUS: Yes, the disassembly of the valve will be video taped.

20. The work order package indicated that a new pipe cap was checked out of the warehouse for the work on 2CF-130. Was the cap found in the vicinity of 2CF-130 the same cap?

RESP. - RBW

STATUS: It can not be determined if the cap found on the lateral support in the vicinity of the valve is the same cap. The cap had the same heat number, but each cap is not individually serialized. (No other cap was found in the vicinity of the valve).

21. Was a carbon steel cap checked out of the warehouse?

RESP. - RBW

STATUS: No. The cap checked out was Stainless Steel.

22. The cap that was found was a stainless steel cap. Should a carbon steel cap be used instead of a stainless cap?

RESP. - RBW

STATUS: No. Stainless Steel is acceptable. Valve 2CF-130 was a stainless steel valve. The other similar drain valves on the other Steam Generators are carbon steel.

23. What was the effect of high temperature and high humidity on adjacent electrical equipment? (Was the usage factor affected?)

RESP. - TDC

STATUS: (Bill Matthews has the lead) The transient did not challenge and adjacent equipment. See the attached information. See the Recovery section of this report.

24. What were the physical effects (impingement) on plant equipment from the blowing steam in the area near 2CF-130?

RESP. - RBT

STATUS: The results will be addressed in the Recovery Report being written by Component Engineering. See the Containment Equipment Damage and Containment Cleanup section under the Recovery Plans tab for additional information.

25. What were the physical effects on plant equipment of the water draining from the ice condenser drains?

RESP. - RBT

STATUS: The physical effects of plant equipment of water draining from the Ice Condenser drains was completed. The significant melting was from bay 22. The area beneath this ten inch drain was inspected and no equipment damage was found. The maximum drain rate was about 0.6 gpm. See the Ice Condenser section of the Recovery Plans for additional information.

26. Evaluate the transient cycles associated with the cooldown.

RESP. - TDC

STATUS: The cooldown has been determined to be a mild transient. See attached information.

27. Discuss the decision to block the 2 lower ice condenser doors following the event.

RESP. - BHH

STATUS: See Appendix III for additional information.

28. Ensure all Ice Condenser Tech Spec requirements are met prior to restart. Perform a full PT on the ice condenser. The PT should include the proper blocking of drains with dissolvable paper, required opening force test for the lower ice condenser doors, and ice condenser channeling.

RESP. - RBT

STATUS: This activity will be completed prior to startup and is documented in the Ice Condenser Recovery Plan.

29. Resolve the status of the Ice Condenser prior to restart. Will the Ice Condenser be operable at the end of the cycle.

RESP. - RBT

STATUS: This issue will be resolved in conjunction with item number 28.

30. What caused the failure of 2NV-1? Did spray from a leaking 2NC-14 cause this failure? The failure of 2NV-1 affected the cooldown of the unit.

RESP. - RBT

STATUS: See the Containment Equipment Damage and Containment Cleanup section under the Recovery Plans tab for additional information.

31. When work is being conducted on in-service equipment, what involvement should Operations personnel have? How should this process work? JWB and BHH will discuss and generate action items as appropriate.

RESP. - JWB

STATUS: See the Work Control section under the Corrective Actions tab for additional information.

32. What was the failure mechanism for 1NC-214, Unit 1 Head Vent Isolation?

RESP. - TDC

STATUS: Review of the work history showed that the failure mechanism to be that the disk assembly stack was too short. This caused the valve to not seat fully.

The disk assembly stack height is adjustable. The valve body dimension must be measured for each valve, and the disk assembly stack adjusted to the correct dimension before installation. The valve technician apparently mis-measured either the valve or the disk assembly. 1NC-214 is a class E valve. Therefore, the QC signoff for verifying proper disk assembly height was not required, and was N/A'd in the procedure.

The potential for this type problem on Unit 2 valves is addressed in the Other section, problem statement 1, under the Corrective Actions tab

33. What was the failure mechanism for 2KD-30 ?

RESP. - RBW

STATUS: The failure mechanism was the same as for 2CF-130. See the Maintenance Execution Section under the Corrective tab for additional information.

34. What was the failure mechanism for 1NC-61 which has a body to bonnet leak?

RESP. - RBW

STATUS: A detailed disassembly inspection revealed that 1NC-61 did not have a body to bonnet leak. The boron crystallization on the valve most likely came from a near by leak. See the attached investigation report.

35. Review Kerotest globe valve work that was performed by the crew that worked on 2CF-130 during the Unit 2 outage.

RESP. - RBW

STATUS: See issue number 36 for details.

36. Obtain a list of all Kerotest valves worked during the Unit 2 outage. System Engineering and Operations need to review the list to determine if any of the Kerotest valves may have the same problem as 2CF-130.

RESP. - TDC

STATUS: This item is closed. See the Other section under the Corrective tab for additional information.

37. Make certain that the Operating Experience that has been learned from this event has been shared between the three Duke Power Stations, and shared with the rest of the industry via Nuclear Network.

RESP. - EEE

STATUS: See the Operating Experience Program section under the Recovery Plans tab for additional information.

38. Investigate methods of improving the performance of vent and drain operation, including new valve and cap designs/configurations.

RESP. - RBT

STATUS: Addressed in other actions items.

39. Research the work history of 2NC-14.

RESP. - JWB

STATUS: Work history for 2NC-14 and 1NC-14 was collected and turned over to the NRC resident inspectors. This item is closed. Refer to issue number 1c for additional information.

40. How will non-routine work activities be identified in the future as non-routine work activities?

RESP. - JWB

STATUS: This item will be addressed as part of Issue number 31.

41. Enhance the Work Control Process to ensure that all critical as-found condition information is included in the work order package documentation.

RESP. - JWB

STATUS: This item is closed. See the Work Control section under the Corrective tab for additional information.

42. Operations logging in the TSAIL of the ice bed indicates the station considered the ice bed operable at 07:15. How did we make this determination and was it correct?

RESP. - BHH

STATUS: BHH answered this question for the AIT. The attached "Response to AIT Request For Information" covers this response. See the attached report for additional information.

September 1, 1993

To: Bruce Travis

Responses to Unit II Steam Leak in Containment (questions 1,11,12,18)

1) Review Generic Letter 90-05 which describes a non code primary system event that occurred at Milestone.

Generic Letter 90-05 is titled "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3, Piping. This letter requires code repairs in accordance with ASME section XI or NRC relief if a non-code repair method is desired.

The repair in question was performed on valve 2CF130, which is the tube sheet drain for steam generator 2A. Valve through leakage was discovered during the reactor building walk downs prior to unit startup. Since the valve is not cycled during unit operation, the desired repair method was to inject leak sealant downstream of the valve. Per welding isometric drawing MCFI-2CF57, the piping downstream of 2CF130 was constructed in accordance with Duke Power Co. piping specification MCS-1206.00-02-0002. This specification contains engineering standard MDG-ES-1B which provides instructions for installation of local vents, drains, and other minor connections. Under note H of the engineering standard, a piping class change from the piping class specified on the system to class G. Class G is a non ASME code piping classification. Therefore, generic letter 90-05 does not apply.

11) What was the failure mechanism of the valve?

As of 1300 hrs. on this date, the valve in question has not been disassembled and inspected. Based on the service application of this valve, trash lodged in the valve seat may have been a contributor. This response will be revised as more information is obtained from the valve inspection.

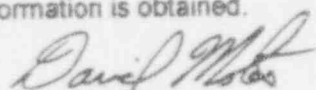
12) What is the ASME class of the pipe downstream of the valve?

As stated in the response to question (1), this piping was constructed and installed under Duke Power Co. piping specification class G. This piping class is not governed by ASME construction codes (section III). This piping class is governed by ANSI B31.1 (American National Standard Code for Pressure Piping, Power Piping Section)

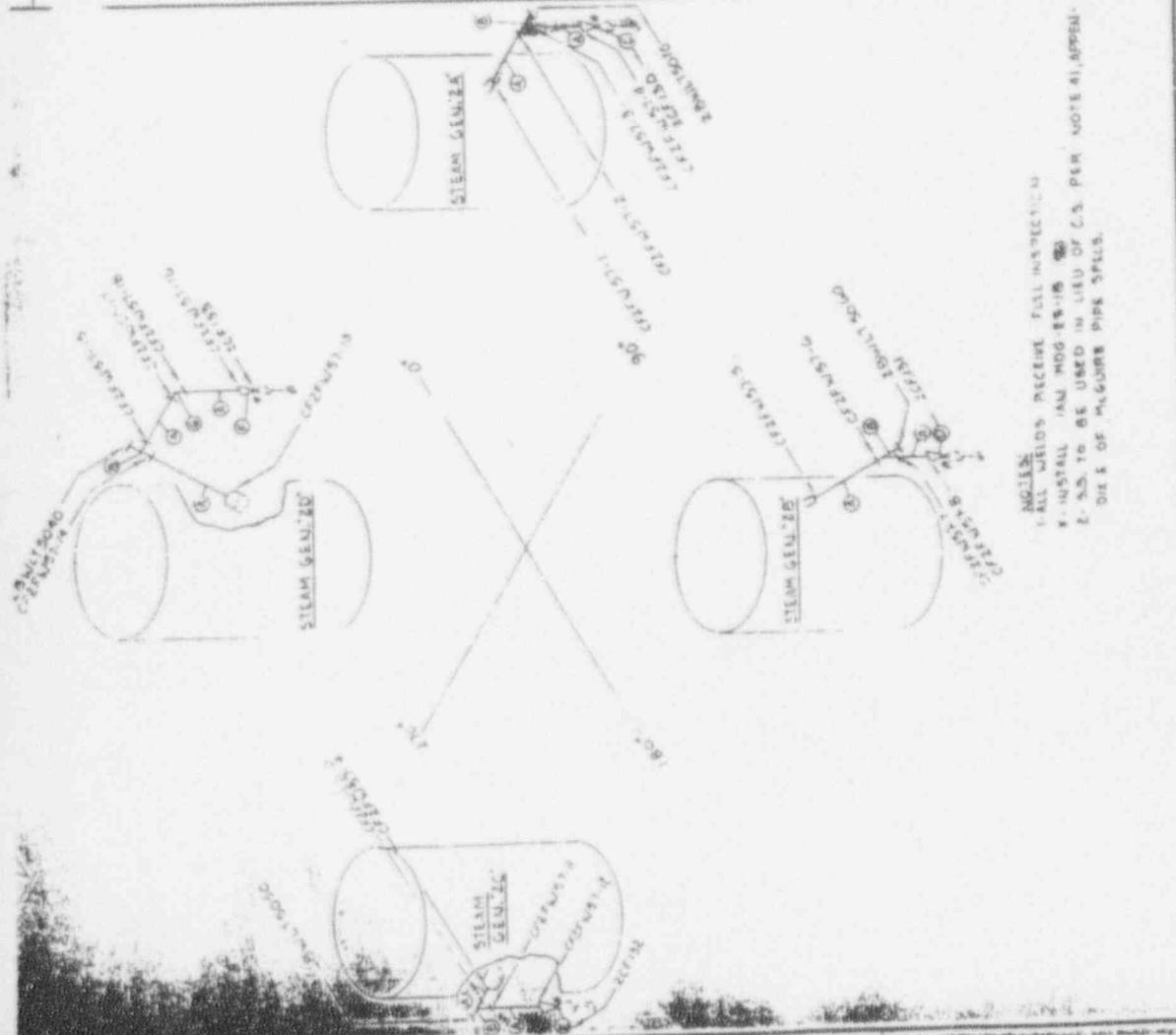
18) What repair alternatives were considered?

The leakage was detected during unit startup preparation. In order to replace or repair the valve would have required depressurization and draining of the CF system. These conditions made alternate repair methods very desirable. The leak injection method was deemed the best course of action based on the startup schedule and past successes with this repair method. The method consists of installing a piping cap with sealant injection ports, securing the leakage using the tapered plug incorporated into cap design, and injecting the cap with sealant, completing the process.

This document will be revised as additional information is obtained.


David Motes
Engineering Supervisor II

1	ORIGINATOR	STEAM GEN. 20	DATE	11-29-61
2	DESIGNER	W. J. ...	DATE	11-29-61
3	CHECKER	...	DATE	11-29-61
4	APPROVER	...	DATE	11-29-61

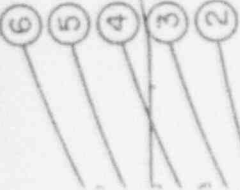


NO.	NO. BILL	DESCRIPTION	QUANTITY	UNIT	EST. VAL. (DOLLARS)
1	242.138	WELDS	10	EA.	...
2	242.138	WELDS	10	EA.	...
3	242.138	WELDS	10	EA.	...
4	242.138	WELDS	10	EA.	...
5	242.138	WELDS	10	EA.	...
6	242.138	WELDS	10	EA.	...
7	242.138	WELDS	10	EA.	...
8	242.138	WELDS	10	EA.	...
9	242.138	WELDS	10	EA.	...
10	242.138	WELDS	10	EA.	...

BILL OF MATERIAL
 DURE POWER COMPANY
 MCGUIRE NUCLEAR STATION
 LAST WELD NO. 10
 BUILDING NO. 70
 REACTOR R-26
 NUCLEAR SAFETY RELATED YES NO
 DRAWING NO. MC-2403-06-20-01
 SHEET NO. 150-0
 ASME SECT. III B
 MCFI-ECF-57
 REV. 4

BY DESIGN ENGINEERING OR
CONSTRUCTION IN ACCORDANCE
WITH THIS STANDARD

DETAILED ON DESIGN ENGINEERING
DRAWINGS



MATERIAL REQUIREMENTS

SPEC. NO.	ITEM	5 PIPE	6 SCREEN CAP
PS150, 300, 400, 800		SCH. 80, A312 304	3000# FS, A182, 304
PS154		SCH. 80, A312 304	3000# FS, A182, 304
PS200, 1800		SCH. 160, A312 304, SMLS.	3000# FS, A182, 304
PS2000		SCH. 160, A312 304, SMLS.	3000# FS, A182, 304
PS151, 301, 401, 601		SCH. 80, A312 304	3000# FS, A182, 304
PS101		SCH. 80, A312 304	3000# FS, A182, 304
PS1001		SCH. 180, A378, 304 OR A312, 304 SMLS	3000# FS, A182, 304
PS2001		SCH. 140, A312 304, SMLS OR A 378, 304	3000# FS, A182, 304
PS157		SCH. 80, A312, 304	3000# FS, A182, 304

NOTES (CONT.)

- D SEE MDS-ES-1A FOR HIGH POINT VENTS AND LOW POINT DRAINS.
- E THE CONFIGURATION SHOWN ABOVE MAY BE STRAIGHT AS SHOWN ABOVE OR MAY INCORPORATE THE USE OF FITTINGS PROVIDED THE MAXIMUM DEVELOPED LENGTH FROM THE PIPE TO THE SCREEN DOES NOT EXCEED THE LENGTH FOR EITHER SCREEN.
- F ANY CONFIGURATION NOT IN ACCORDANCE WITH NOTE E MUST BE DETAILED ON DESIGN ENGINEERING DRAWINGS. SUCH CONFIGURATIONS WILL BE SUBJECT TO STRESS ANALYSIS AS REQUIRED.
- G PS NUMBERS SPECIFIED INCLUDE ALL PS NUMBERS OF THAT PRESSURE CLASS AND MATERIAL, I.E. PS100 INCLUDES PS100, 150, 200, ETC.
- H THIS SCREEN APPLIES TO ALL PRESSURE CLASSES A, B, C, D AND E PIPING SYSTEMS IN THIS STANDARD. THE SCREEN IS TO BE INSTALLED IN THE LINE IMMEDIATELY DOWNSTREAM OF THE VALVE. THE SCREEN IS TO BE INSTALLED IN THE LINE IMMEDIATELY DOWNSTREAM OF THE VALVE. THE SCREEN IS TO BE INSTALLED IN THE LINE IMMEDIATELY DOWNSTREAM OF THE VALVE.

ED OR SAMPLED.

ING AND CHOSEN
4. SEE APPLICABLE
2 TABLES.
A PIPING DRAWING.
E PIPE NUMBER AND
E DULE NUMBER AND

DURING THE SYSTEM
FOR OPERATIONAL
ED THE VALVE IS TO

E E OR AS DETAILED
WHICH THE CAP IS
ITEM 5. SEE TABLE
Y A NON-WARDENING
DISASSEMBLED WITH
ED.

AINING OPERATION.

TABLE CODE REQUIREMENTS
SAMPLE PRINTS, TEST
TIONS. THIS STANDARD
FERENCING THESE CONNECTIONS
IPING DRAWINGS AND FOR
F DETAILS REQUIRED BUT
DRAWINGS 2

IN NOMINAL BRANCH SIZES

- I FOR HEADER SIZES 24 INCHES MPS. BUTT WELD TEES MAY BE USED IN LIEU OF 1 INCH HALF COUPLING (ITEM 2). THE USE OF A BUTT WELD REDUCER IS REQUIRED TO REDUCE TO THE 1 INCH PIPE NIPPLE (ITEM 3).
- J THE REASON FOR USING A STAINLESS STEEL NIPPLE (ITEM 3) IN CARBON STEEL SYSTEMS, IS FOR THE PURPOSE OF PROVIDING CASE OF REMOVING THE ITEM 6 CAP. IF A CARBON STEEL NIPPLE WERE UTILIZED, SOME DIFFICULTY MAY BE ENCOUNTERED DUE TO THE INHERENT CORROSION WHICH OCCURS AT THE CARBON STEEL PIPE THREADS. HOWEVER, A CARBON STEEL NIPPLE (A108 GRADE B) MAY BE USED PROVIDED A STAINLESS STEEL (A182, F304) SCREEN CAP IS USED.
- K THIS STANDARD APPLIES TO MARINE NUCLEAR STATION.
- L FOR STEAM SERVICE ABOVE 350PSI AND WATER SERVICE ABOVE 100PSI AND 220F, PIPE MUST BE SEAMLESS.
- M FOR INFORMATION ON SASH CHAIN OR PIPE NIPPLE AND CAP, SEE MDS-ES-1E.

DUKE POWER CO.

LOCAL VENTS DRAINS AND OTHER

M NDR CONNECTIONS

2	REVISED AS NOTED	DATE 10/15/11-75
1	REVISED AS NOTED	DATE 5-21-78
0	REL FOR CONSTRUCTION	DATE 10/15/77
NO.	REVISION	CHD/APPR DATE

Specification No.: MDS-1206.00-02-0002
Appendix Q
May 15, 1978
Rev. 107, 11/30/87

MDS ENGINEERING No. MDG-ES-1B
STANDARD

TABLE 8.1-1

DUKE CLASSIFICATION DESIGNATIONS AS RELATES TO APPLICABLE CODES

Duke Class	Duke QA Condition	Nuclear Safety Class	Applicable Piping Code	Designed for Seismic Loading	Safety-Related or Subject to NRC Review	Notes
A	1	1	ASME Section III, Class 1	Yes	Yes	
B	1	2	ASME Section III, Class 2 & MC	Yes	Yes	
C	1	3	ASME Section III, Class 3	Yes	Yes	(5)
D	1	2	ASME Section III, Class 2	No	Yes	
E	2	-	ANSI B31.1	No	Yes	(2)
F	4	-	ANSI B31.1	Yes	Yes	(3) (4)
G	-	-	ANSI B31.1	No	No	
H	3	-	ANSI B31.1 & Others	No	No	(6) (7)

Applicable Notes

1. (DELETED)
2. Piping systems within this classification carry a radioactive fluid; however, they are considered "non-nuclear" since a component failure would not result in a calculated potential exposure in excess of 0.17 Rem, whole body, or its equivalent to parts of the body, at the site boundary or beyond.
3. Piping systems within this classification do not carry a radioactive flowing element but are subject to seismic loading.

September 1, 1993

To: Bruce Travis

Responses to Unit II Steam Leak in Containment (questions 1,11,12,18) Revision 1

- 1) Review Generic Letter 90-05 which describes a non code primary system event that occurred at Millstone.

Generic Letter 90-05 is titled "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3, Piping. This letter requires code repairs in accordance with ASME section XI or NRC relief if a non-code repair method is desired.

The repair in question was performed on valve 2CF130, which is the tube sheet drain for steam generator 2A. Valve through leakage was discovered during the reactor building walk downs prior to unit startup. Since the valve is not cycled during unit operation, the desired repair method was to inject leak sealant downstream of the valve. Per welding isometric drawing MCFI-2CF57, the piping downstream of 2CF130 was constructed in accordance with Duke Power Co. piping specification MCS-1206.00-02-0002. This specification contains engineering standard MDG-ES-1B which provides instructions for installation of local vents, drains, and other minor connections. Under note H of the engineering standard, a piping class change from the piping class specified on the system to class G. Class G is a non ASME code piping classification. Therefore, generic letter 90-05 does not apply.

- 1A) When leaking vents/drains are secured using downstream pipe caps or leak injection devices, what analysis is performed to determine this is an acceptable. (movement of pressure boundary)

As stated in the response to question (1), a piping class change is specified at the valve seat. The downstream pipe nipple and pipe cap is provided should leakage occur across the valve seat (housekeeping concerns). It is recognized that capping of this downstream section will pressurize that section to normal system operating pressure. The Duke Power Co. piping specification requires construction of this downstream piping segment in accordance with ANSI B31.1 to the same design pressure and temperature requirements of the ASME code components upstream of the valve.

- 11) What was the failure mechanism of the valve?

2CF130 is a Kerotest 1500# "Y" type globe valve. This valve is used on numerous nuclear service applications because of the redundant external leakage prevention design features. This valve has no positive stem and disc connection. Stem forces for valve closure is transmitted through a diaphragm stack (see item 7 on attached drawing). Since no positive stem and disc connection exists, valve opening is accomplished by backing the stem away from the diaphragm stack and allowing spring force to lift the disc assembly (items 2 and 3) away from the seat. The spring force to lift the disc assembly is provided by the spring guide and spring (items 4 and 5).

When the valve was disassembled, the spring guide was found to be installed in an inverted position. When inverted, the bottom of the spring guide rests against the underside of the disc cap, lifting the disc assembly off of the seat and prevents closure of the valve.

12) What is the ASME class of the pipe downstream of the valve?

As stated in the response to question (1), this piping was constructed and installed under Duke Power Co. piping specification class G. This piping class is not governed by ASME construction codes (section III). This piping class is governed by ANSI B31.1 (American National Standard Code for Pressure Piping, Power Piping Section)

18) What repair alternatives were considered?

The leakage was detected during unit startup preparation. In order to replace or repair the valve would have required depressurization and draining of the CF system. These conditions made alternate repair methods very desirable. The leak injection method was deemed the best course of action based on the startup schedule and past successes with this repair method. The method consists of installing a piping cap with sealant injection ports, securing the leakage using the tapered plug incorporated into cap design, and injecting the cap with sealant, completing the process.



David Motes
Engineering Supervisor II

September 1, 1993

MEMORANDUM

TO: ALL Shift Operation Personnel

Subject: Entering the area in the vicinity of 2CF-130

Until further notice do NOT enter the area in the vicinity of 2CF-130 (2A S/G shell side drain) until NRC's AIT team has witnessed disassembly of the valve in the field.



Reza Djali
Operation Staff

xc: Bruce Hamilton
Al Beaver
Dennis Bumgardner
Dave Baxter

September 4, 1993

To: Bruce Travis

Subject: Responses to 2NC14 Related Questions

1) What evaluation was performed on possible repair options for 2NC14?

External leakage from 2NC14 was identified during the plant walk down at the beginning of the 2EOC8 refueling outage. This valve had not been identified in the original outage scope. The Operations Group reviewed the potential impact to the outage plan and indicated that additional system alignment and draining would be required. Work Control was notified to evaluate other scheduling or repair options, while considering the potential for additional radiological dose accumulation and outage schedule impact. Component Engineering was asked to evaluate the valve design for possible leak injection. Based on the evaluation, leak injection was determined to be an acceptable repair option. A modification package was prepared to control this activity.

2) What other ASME class 1 components have been repaired using the leak injection process?

The temporary modification log, the on-line leak sealing database (initiated 1/1/90), and the on-line leak sealing log (initiated 2nd quarter of 1984 and maintained through 1/1/90) was reviewed to identify ASME class 1 leak injections. Senior Component Engineering valve staff members were also interviewed concerning injection activities prior to 1984.

The valve tag numbers and status of each repair are as follows:

1ND1-Modified for leak injection per NSM-MG-457 in June, 1981. Valve was injected in October of 1981 and was re-injected in November of 1981. Valve was modified per NSM-MG-751 in March of 1983 for removal of injection fittings and seal welding of body to bonnet joint (pressure seal design).

1NV1-injected valve stuffing box through leak off line in May of 1989. The valve was repacked using conventional packing materials in January of 1990, returning the valve to original design configuration.

2NV1-Modified valve for leak injection per NSM-MG-20689 and injected in June of 1986. Valve was modified per ME-VN-402 to seal weld body to bonnet joint in June of 1986. Modified per ME-VN-561 to remove all injection fittings (pressure seal design).

2ND4-Injected valve stuffing box in January of 1986. The valve was repacked using conventional packing materials in April of 1986, returning the valve to original design configuration.

2NV438-Downstream pipe cap was modified per ME-VN-2039 and injected in September of 1989. The valve was replaced per ME-VN-1973 (valve item # change) in October of 1990, returning the piping/valve section to the original design configuration.

1NC93-Valve was modified per ME-VN-3 and injected in November of 1984. The valve was later deleted per NSM-MG-1-1764. The exact date of this deletion cannot be determined, but the system modification was scheduled for completion during the EOC5 refueling outage.

1NC14-Valve was modified per NSM-MG-458 for installation of leak injection hardware in July of 1981. The work request history does not indicate that sealant was injected. This valve was disassembled in June of 1993 for maintenance with no disassembly problems noted in the repair work order. This also indicates that sealant was not injected. The leak injection hardware is still in place. Injection of sealant was not required during unit startup. A work order will be generated for valve restoration during the next refueling outage.

2NC27-Valve was modified per ME-VN-569 and injected November of 1986. ME-VN-616 is referenced for removal of the leak injection hardware following valve repair. The restoration activity is not complete. A work order will be generated for valve restoration during the next refueling outage.

2NC14-This valve was modified per MGMM-3736 and injected during the 2EOC8 refueling outage. A work order will be generated for valve restoration during the next refueling outage.

1NV235-Valve was injected in May of 1990 under the temporary modification program. In November of 1991, the temporary modification was closed out through the initiation of ME-VN-2943. The valve was disassembled and repaired in June of 1992, restoring the valve to the original design configuration.

In summary, 2NC14 and 2NC27 are the only ASME class 1 components presently utilizing the leak injection sealing method.

David Motes
Engineering Supervisor II

JDM/ssr

September 1, 1993

MEMORANDUM

TO: ALL Shift Operation Supervisors
All Operation Staff

Subject: Signing of W/Os to leak repair

Until further notice do **NOT** sign "Clearance To Begin Work" on any W/O that involves leak repair unless MNT personnel are accompanying USSI personnel in the field.

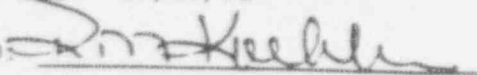


Reza Djali
Operation Staff

xc: Bruce Hamilton
Al Beaver
Dennis Bumgardner
Dave Baxter

DUKE POWER COMPANY
EMPLOYEE TRAINING & QUALIFICATIONS SYSTEM

SUBJECT: MCGUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

APPROVED: 

1.0 OBJECTIVE

This standard provides specific guidelines to ensure that organizations providing support for Mechanical Maintenance activities at McGuire Nuclear Station have an in-depth review of their training and qualifications performed prior to entering the station.

2.0 SCOPE

This standard will be implemented by Production Training Services and Construction Maintenance Department North. Contract Organizations are covered by this standard.

NOTE: The following personnel are NOT covered by this standard:

- Nuclear Production Department Mechanical Maintenance employees
- Personnel being escorted.
- CMD Personnel
- Personnel trained and qualified by a vendor organization and who utilize vendor procedures to perform work (ex., Westinghouse, B&W)
- Vendor Representatives

3.0 DEFINITIONS

CONTRACT PERSONNEL - Individuals hired through a contracting organization who will be released upon completion of the specified work activity.

VENDOR REPRESENTATIVES - Individuals who will normally be escorted and are here as advisers only.

SUBJECT: MCGUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

WORK RESPONSIBILITY LEVEL I - Individuals who have successfully completed or have been exempted from:

- * Basic Mechanical Maintenance Training
- * Work Request and Administrative Controls Training (Full or Refresher)
- * Activity Specific Training or OJT

and who have qualified to all applicable tasks. These individuals may work unsupervised in their specified work activity.

NOTE: Exemptions must be approved by the McGuire Maintenance Manager.

WORK LIMITATIONS:

If these individuals work outside their initial specified work activity they shall:

- * Be classified under Work Responsibility Level III
- * Work under the close direction of a qualified individual and/or supervisor
- * Have procedure steps co-signed by a qualified individual
- * NOT be permitted to perform Independent Verification as it relates to procedure steps.

NOTE: Any exceptions to the work limitations listed above must be made with the approval of the appropriate Mechanical Maintenance General Supervisor and the CMD-North Qualifications Group Representative/Mechanical Maintenance Employee Training and Qualification Group Representative.

WORK RESPONSIBILITY LEVEL II - Individuals who have successfully completed or have been exempted from:

- * Work Request and Administrative Controls Training (Full or Refresher)
- * Activity Specific Training or OJT

and who have NOT qualified to those Tasks associated with their specified work activity. These individuals will be allowed to:

- * Work under the direction of a qualified individual and/or supervisor in their specified work activity
- * Sign off procedure steps.

SUBJECT: MCGUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

These individuals will NOT be permitted to perform Independent Verification as it relates to procedures AND/OR components.

WORK LIMITATIONS:

If these individuals work outside their initial specified work activity they shall:

- Be classified under Work Responsibility Level III
- Work under the close direction of a qualified individual and/or supervisor
- Have procedure steps co-signed by a qualified individual
- NOT be permitted to perform Independent Verification as it relates to procedure steps
- NOT be permitted to perform Component Verification.

NOTE: Any exceptions to the work limitations listed above must be made with the approval of the appropriate Mechanical Maintenance General Supervisor and the CMD-North Qualifications Group Representative/Mechanical Maintenance Employee Training and Qualification Group Representative.

WORK RESPONSIBILITY LEVEL III - Individuals who have NOT successfully completed or have NOT been exempted from:

- Basic Mechanical Maintenance Training
- Work Request and Administrative Controls Training (Full or Refresher)
- Activity Specific Training or OJT
- Qualification to Tasks associated with their specified work activity

These individuals shall be required to work under the close direction of a qualified individual and/or supervisor.

These individuals will NOT be permitted to sign procedure steps.

These individuals will NOT be permitted to perform Independent Verification as it relates to procedures AND/OR components.

SUBJECT: ACQUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

4.0 RESPONSIBILITIES

Support personnel training and/or qualifications are provided as outlined in Section 5.0 of this standard.

5.0 PROCEDURE

5.1 The Nuclear Production Department with assistance from the Construction and Maintenance Department-North will:

- A. Identify work related activities to be performed. (e.g. Ice Condenser, Head, Valves, Pumps, ISI)
- B. Identify the remaining number of individuals needed to support the work related activities.

5.2 The Nuclear Production Department and CMD-North personnel initiating requests for workforce will:

- A. Identify the organization that will provide the remaining number of personnel to support the work related activities identified in Section 5.1-A of this standard.
- C. For support personnel supplied by Contract Organizations/Vendor Representatives the following information is shall be provided to CMD-North Training Group:
 - 1. Name of Organization(s).
 - 2. Names and social security numbers of individuals and initial work activity to which they will be assigned.
 - 3. Resumes relating to assigned work activity.

SUBJECT: MCGUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

- 5.3 The Construction Maintenance Department North, with assistance from Production Training Services, will:
- A. Review all documentation on support personnel
 - B. Interface with NPD sponsors to identify General Employee Training (G.E.T.) needs for support personnel.
 - C. Identify Training/OJT/Qualification needs (Refer to Attachment 2404.0-1 Mechanical Maintenance Training/Qualification Requirements for Support Personnel)
 - D. Develop Required Training/OJT/Qualification schedules.
- 5.4 For support personnel reporting to the station, CMD-North or NPD sponsor will, if applicable, have support personnel attend G.E.T.
- 5.5 The Construction Maintenance Department North, with assistance from Production Training Services, will:
- A. Ensure appropriate portions of the Work Request and Administrative Controls Training are administered to support personnel
 - B. Ensure appropriate Activity Specific Training is administered to support personnel
 - C. Ensure appropriate applicable OJT/Qualifications are administered to support personnel.

NOTE:

With McGuire Maintenance Manager approval, support personnel may be exempted from the requirements of Section 5.5.

- 5.6 The Construction Maintenance Department North Qualification Group will submit a Work Responsibility Level Report to:
- 1. Appropriate Sponsors
 - 2. NPD General Supervisors
 - 3. Applicable Supervisors
 - 4. CMD North Craft Managers.

SUBJECT: MCGUIRE REVIEW OF SUPPORT PERSONNEL TRAINING AND QUALIFICATIONS
DATE REVISED: 09/10/91 DATE EFFECTIVE: 02/15/88

6.0 RETRAINING/REQUALIFICATION REQUIREMENTS

- A. If support personnel return to the station within a 2 year time period, the Construction Maintenance Department North will review appropriate Training/Qualification Records to determine any Retraining/Requalification requirements.
- B. Support personnel returning to the station after a 2 year time period shall repeat all training requirements set forth in this standard.
- C. Pendant Crane Training will not be repeated unless significant changes have occurred in the lesson plan.

7.0 DOCUMENTATION RETENTION REQUIREMENTS

The Construction Maintenance Department North Qualification Group, with assistance from Production Training Services, will maintain Qualification Records.

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

NOTE: ANY "UPDATE" TRAINING WILL BE GIVEN AS REQUIRED.

WORK ACTIVITY: CANAL WATCH

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) PROCEDURE USERS TRAINING (100%)
- (2) PROCEDURE FAMILIARIZATION (100%)

WORK ACTIVITY: DIESEL GENERATOR

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) PENDANT CRANE TRAINING (20%)
- (4) FIREWATCH TRAINING (50%)

WORK ACTIVITY: EQUIPMENT HANDLING

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) PENDANT CRANE TRAINING (80%)
- (4) FORKLIFT TRAINING (50%)

WORK ACTIVITY: ICE CONDENSER

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (To Go To Level I)
- (3) PROCEDURE USERS TRAINING (To Go To Level II)
- (4) ICE CONDENSER TRAINING
- (5) PENDANT CRANE TRAINING (25%)
- (6) FORKLIFT TRAINING (10%)

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

WORK ACTIVITY: INSULATORS

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (Supervisors Only)

WORK ACTIVITY: LEAD SHIELDING

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) FIREWATCH TRAINING (30%)
- (4) FORKLIFT TRAINING (3 per team)
- (5) PENDANT CRANE TRAINING (3 per team)

WORK ACTIVITY: MACHINISTS

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) PENDANT CRANE TRAINING (100%)
- (4) FORKLIFT TRAINING (100%)
- (5) FIREWATCH TRAINING (100%)

WORK ACTIVITY: MISC. HX. MSR. MAIN COND.

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) WELDING PROCESS CONTROL TRAINING (Welders Only)
- (4) PENDANT CRANE TRAINING (20%)
- (5) FIREWATCH TRAINING (20%)

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

WORK ACTIVITY: SCAFFOLD SUPPORT

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (Supervisors Only)
- (3) FIREWATCH TRAINING (20%)
- (4) SCAFFOLD TRAINING (100%)
- (5) PROCEDURE USERS (Craft - 100%)

WORK ACTIVITY: SNUBBERS

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) SNUBBER/HANGER TRAINING (100%)

WORK ACTIVITY: STEAM GENERATOR

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) STUD TENSIONING OJT (100%)

WORK ACTIVITY: TOOL ROOM/WAREHOUSE SUPPORT

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) FORKLIFT TRAINING (100%)

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

WORK ACTIVITY: PUMPS (REACTOR COOLANT)

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) SEAL TRAINING - (Mt. Holly - 1 Week) (100%)
- (4) PENDANT CRANE TRAINING (50%)
- (5) FIREWATCH TRAINING (100%)

WORK ACTIVITY: QA ISI (IN-SERVICE INSPECTION)

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) SNUBBER/HANGER TRAINING (100%)
- (4) WELDING PROCESS CONTROL TRAINING (Welders Only)
- (5) FIREWATCH TRAINING (100%)

WORK ACTIVITY: REACTOR BUILDING COORDINATOR SUPPORT

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) CRANE ORIENTATION (100%)
- (2) MM-ORIENTATION TRAINING (100%)

WORK ACTIVITY: REACTOR HEAD

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) REACTOR HEAD PROCEDURE FAMILIARIZATION (100%)
- (4) PENDANT CRANE TRAINING (100%)

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

WORK ACTIVITY: TURBINE

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) FIREWATCH TRAINING (100%)
- (4) PENDANT CRANE TRAINING (80%)
- (5) FORKLIFT TRAINING (50%)

WORK ACTIVITY: VALVES

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) FIREWATCH TRAINING (100%)
- (4) SNUBBER/HANGER TRAINING (100%)
- (5) PENDANT CRANE TRAINING (3 per team)

WORK ACTIVITY: WELDING

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) FORKLIFT TRAINING (20%)
- (4) FIREWATCH TRAINING (100%)
- (5) WELDING PROCESS CONTROL TRAINING (100%)

MECHANICAL MAINTENANCE TRAINING/QUALIFICATION
REQUIREMENTS FOR SUPPORT PERSONNEL

WORK ACTIVITY: PAINTING

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (50% including all supervisors)

WORK ACTIVITY: PIPE EROSION

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) WELDING PROCESS CONTROL TRAINING (Welders Only)
- (4) FIREWATCH TRAINING (80%)
- (5) SNUBBER/HANGER TRAINING (Mechanics Only)

WORK ACTIVITY: POLAR CRANE OPERATORS

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) CRANE ORIENTATION (100%)
- (2) PROCEDURE USERS TRAINING (100%)

WORK ACTIVITY: PUMPS (MISCELLANEOUS)

TRAINING/QUALIFICATION REQUIREMENTS:

- (1) MM-ORIENTATION TRAINING (100%)
- (2) WORK REQUEST AND ADMINISTRATIVE CONTROLS TRAINING (100%)
- (3) FIREWATCH TRAINING (20%)
- (4) PENDANT CRANE TRAINING (10%)
- (5) FORKLIFT TRAINING (5 per team)

McGuire Nuclear Station, Unit 2

Steam Leak in Containment, 8/31/93

Question ⁸ 7) Why did some of the ice condenser doors not open during the event?

^ε 3
112193

The ice condenser lower inlet doors are designed to open at approximately 0.007 psi (1 lb/ft²) differential pressure across the doors. This pressure is equivalent to the "cold head" pressure produced by the colder, denser air inside the ice condenser. At this pressure difference, the doors will come off the closed seat (cracked open) and a limit switch will indicate the door as being open. The lower inlet door position indication is located at the entrance to the lower ice condenser, and there is a single indicating light for each block of 8 doors/ 4 bays (ie. one light for bays 1-4, which includes 8 doors). It requires further pressure/ force to open the door off the seal. A hinge spring attached to the lower containment side of each door produces a torque of up to 195 inch-pounds (Maximum) with the door open. This correlates to a force of 7.25 lbs applied at the door handle. Without the cold head pressure difference, the doors will therefore tend to remain essentially closed (but not sealing fully) and steam flow is necessary to open and hold open the doors. During accidents such as LBLOCA/ SLB the sustained differential pressure between lower containment and the lower ice condenser would hold all lower inlet doors open.

The steam release incident of 8/31/93 created a general heat up of the lower containment and resulted in a slow pressurization. The initial pressurization cracked open some of the lower inlet doors and the cold head in the ice condenser was quickly lost. As the cold head was lost throughout the ice condenser (the portals allow for equalization across the bays), all of the of the remaining lower inlet doors then cracked off their seals (as evidenced by the sound of air rushing past the doors noticed during the initial entry) and all bay groups (w/ exception of 1-4) indicated at least one door was open to the point of tripping a limit switch. It is unknown exactly which doors, or how many doors tripped their limit switches. Because the pressurization in lower containment was fairly slow (it took approximately 10 minutes to peak) and the majority of the containment environment was non-condensibles (air), the ice condenser remained essentially equalized with the lower containment and there was never a large driving force to (fully) open all of the doors.

For the above reasons, it was as expected (normal) that several lower inlet doors did not cause the limit switch to indicate the doors were open during this event. All doors were noted to be off of their seals allowing air to pass, and were being held shut only by the spring force.

J J Nolin
Systems Engineering

Question 8)
E³
9/2/93

Why did two of the doors not close following the event?

Two lower inlet doors (both on Bay 22) were still open at the time of the first personnel entry. The first maintenance technicians to enter the lower ice condenser following pressurization described the two doors to be approximately 1/3 open. The bay 22 -left door was noted to be further open than the right. A large amount of moist air was rushing through the bay 22 doors, rising to the ice bed, with sufficient flow to hold this single pair of doors open. These doors were shut by the technicians (minimal force was required) to prevent further moist air from entering the ice bed. The doors were reported to be mechanically free (not "hung up") and working properly. A review of the performance test of the doors (PT/0/A/4200/32, performed 8/25/93- one week before the event) showed that the bay 22 doors had among the lowest required opening forces (9 lbs /13 lbs opening) of the lower inlet doors in the area of the steam leak. Further, it should be noted that the left side spring was slightly weaker than the right.

It is concluded that the bay 22 lower inlet doors most likely opened first and relieved the ice bed cold head, allowing the other doors to let air pass by the door seals. The bay 22 doors remained open due to a considerable flow of moist air from lower containment which was condensing in the ice bed. The lower inlet doors are considered to have performed as designed and this was a normal response to the steam leak event.

J J Nolin
Systems Engineering

RESPONSE TO ISSUE #17
By Jack Boyle

17. 2CF-130 Repair Alternatives Considered:

- * The leak was identified late on August 29, 1993 while Unit 2 was in Mode 3 and heatup in progress. Because the leak was unable to be isolated, leak repair was the only option considered since other repair options would require the cooldown and draining of 'A' Steam Generator.
- * Leak Repair Options listed from most to least desirable are:
 - A). M.T.I.C. (Modified Threaded Inspection Cap) - method actually used.
 - * Class G repair
 - * Does not kill the valve
 - * Normally gives an alternate repair option(s)
 - * Best proven seal repair method
 - * No temporary modification paperwork required (However, one was written for 2CF-130).
 - B). Drill cap and perform injection repair.
 - * QA-1 repair
 - * Kills valve
 - * Ultimate repair requires cut-out, replacement, hydro, etc.
 - * Requires a temporary modification.
 - * Less safe option than option A.
 - C). Drill and inject valve body.
 - * QA-1 repair
 - * Kills Valve
 - * Ultimate repair requires cut-out, replacement, hydro, etc.
 - * Requires a temporary modification
 - * Less safe option than A or B.
 - D). Use of a clamp or enclosure around pipe cap.
 - * Class G
 - * Involves seismic analysis
 - * May require cut-out and replacement
 - * Requires a temporary modification
 - * Less desirable than other leak seal methods.

Unit 2 Steam Leak in Containment
Project Team Action Item 23.

September 1, 1993

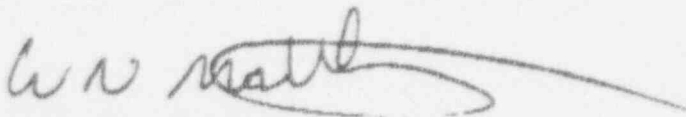
Tom Curtis, Manager
System Engineering

Subject: 2CF130 Incident
Environmental Qualification

As a result of the recent incident we have gathered ambient air temperature data in Upper and Lower Containment, Steam Generator Compartments, Incore Instrument Room and Containment Pressure. (Copies of these profiles are attached).

A preliminary review of the environmental qualification for the affected QA condition 1 equipment has been performed by Bob Smith, Nuclear Services, and Roger McCutchen, Station EQ Coordinator. It was determined that this transient did not challenge the operability of this equipment nor was there any discernable effect on the overall qualification and life of this equipment (reference the attached letter from Roger McCutchen).

A more thorough engineering analysis is continuing and a report is expected in a few days.



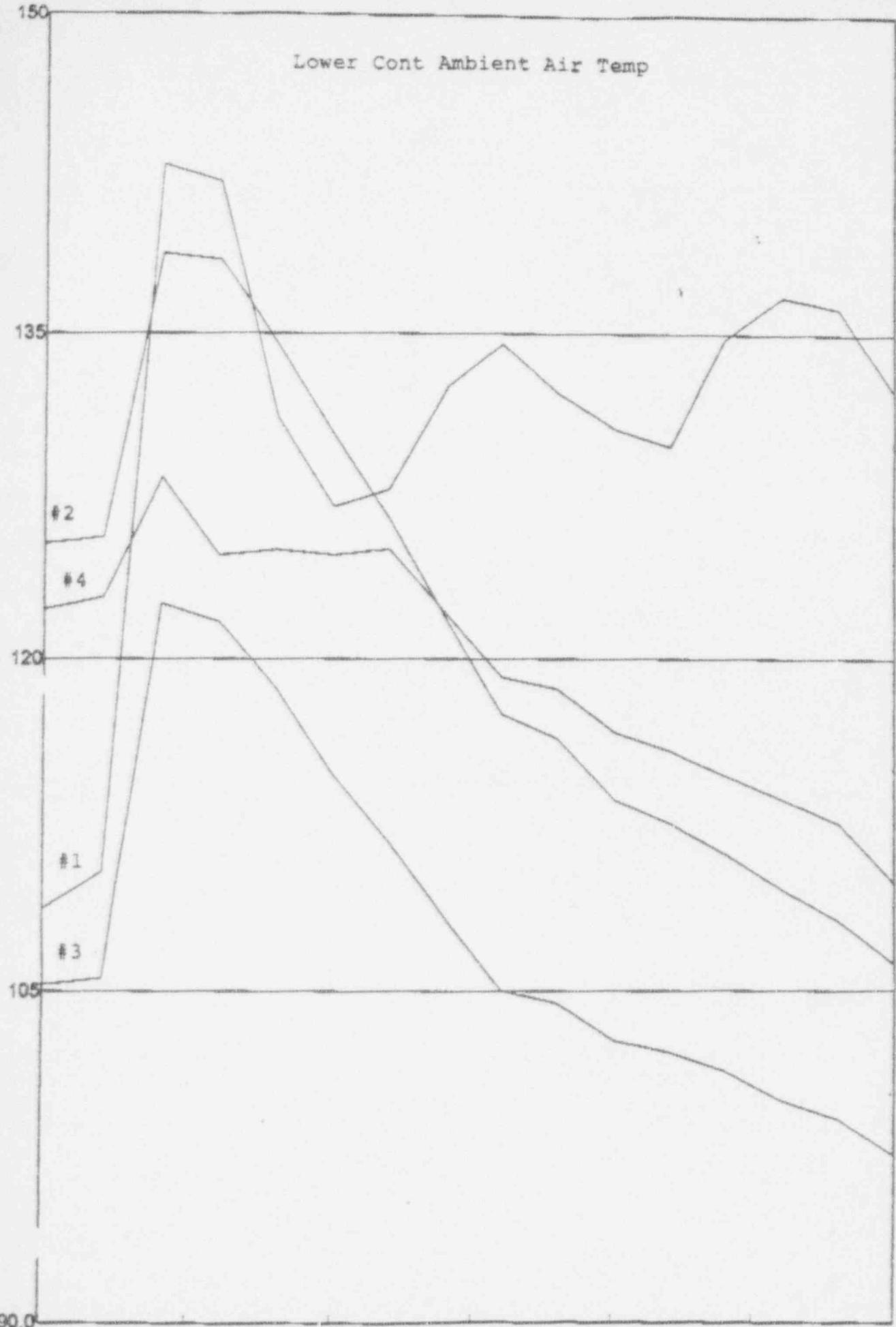
W N Matthews
Engineering Supervisor

xc: L S Reed
K D Thomas

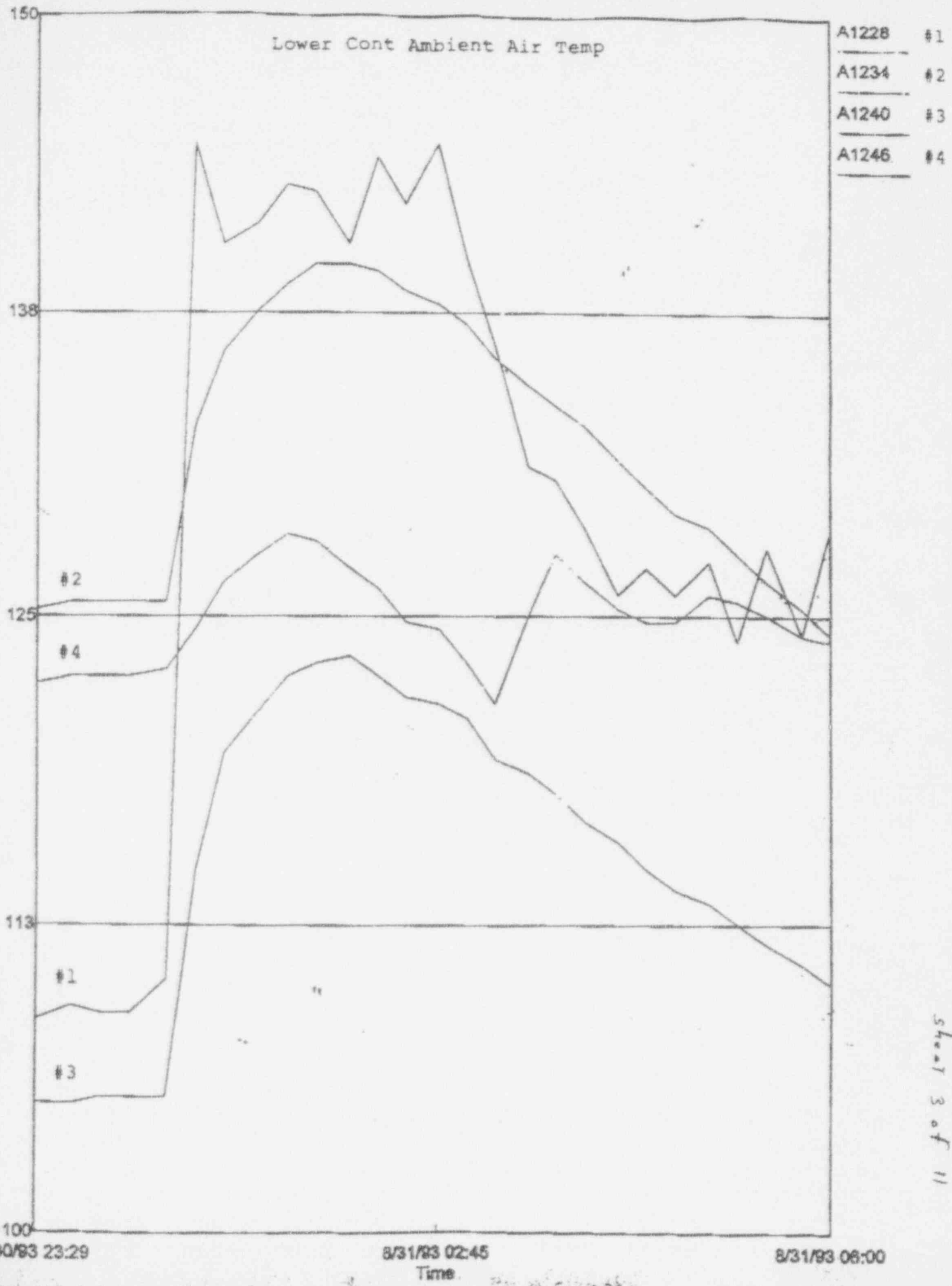
Note: This action is considered closed relative to the Project Team Action Item 23, though additional engineering documentation will be provided later. W N Curtis 9/1/93

Lower Cont Ambient Air Temp

A1228	#1
A1234	#2
A1240	#3
A1248	#4



Attachment J
Sheet 2 of 11



ATTACHMENT I
Sheet 3 of 11

Attachment 1
Sheet 4 of 11

DATE 06-22-92
PAGE NO. 197

MC-2793-10.10

DUKE POWER COMPANY
MCQUIRE 2
ANALOG INPUT POINT SUMMARY
BY SERIAL #

SERIAL NUMBER	POINT EXTERNAL POINT ID	DESCRIPTION INPUT HARDWARE IDENTIFICATION REFERENCE DRAWINGS	PROCESS RANGE UNITS	PROC LMS HIGH LOW	INPUT DEVICE	TRANSDUCER OUTPUT RANGE UNITS GAIN HV	CAB SPN ENG	REVISION DATE FUNCT. USE	L I N E
H2AVU001 A1204		UPPER CONT AMBIENT AIR TEMP A ASRT67, CHL 430-20, ZARTC MC-2790-17.01, MC-2767-09.11 MC-2784-02.01 FS=01, FLO	32-212 DEG F	125	2VUR05000	0-80 MV 80	AYS RCD	05235 A	1 2 3 4 5
H2AVU003 A1210		UPPER CONT AMBIENT AIR TEMP B ASRT67, CHL 430-21, ZARTC MC-2790-17.01, MC-2767-09.11, MC-2784-02.01 FS=01	32-212 DEG F	125	2VUR05010	0-80 MV 80	AYS RCD	05235 A	1 2 3 4 5
H2AVU005 A1216		UPPER CONT AMBIENT AIR TEMP C ASRT67, CHL 430-22, ZARTC MC-2790-17.01, MC-2767-09.11, MC-2784-02.01 FS=02	32-212 DEG F	125	2VUR05020	0-80 MV 80	AYS RCD	05235 A	1 2 3 4 5
H2AVU007 A1222		UPPER CONT AMBIENT AIR TEMP D ASRT67, CHL 430-23, ZARTC MC-2790-17.01, MC-2767-09.11, MC-2784-02.01 FS=01	32-212 DEG F	125	2VUR05030	0-80 MV 80	AYS RCD	05235 A	1 2 3 4 5

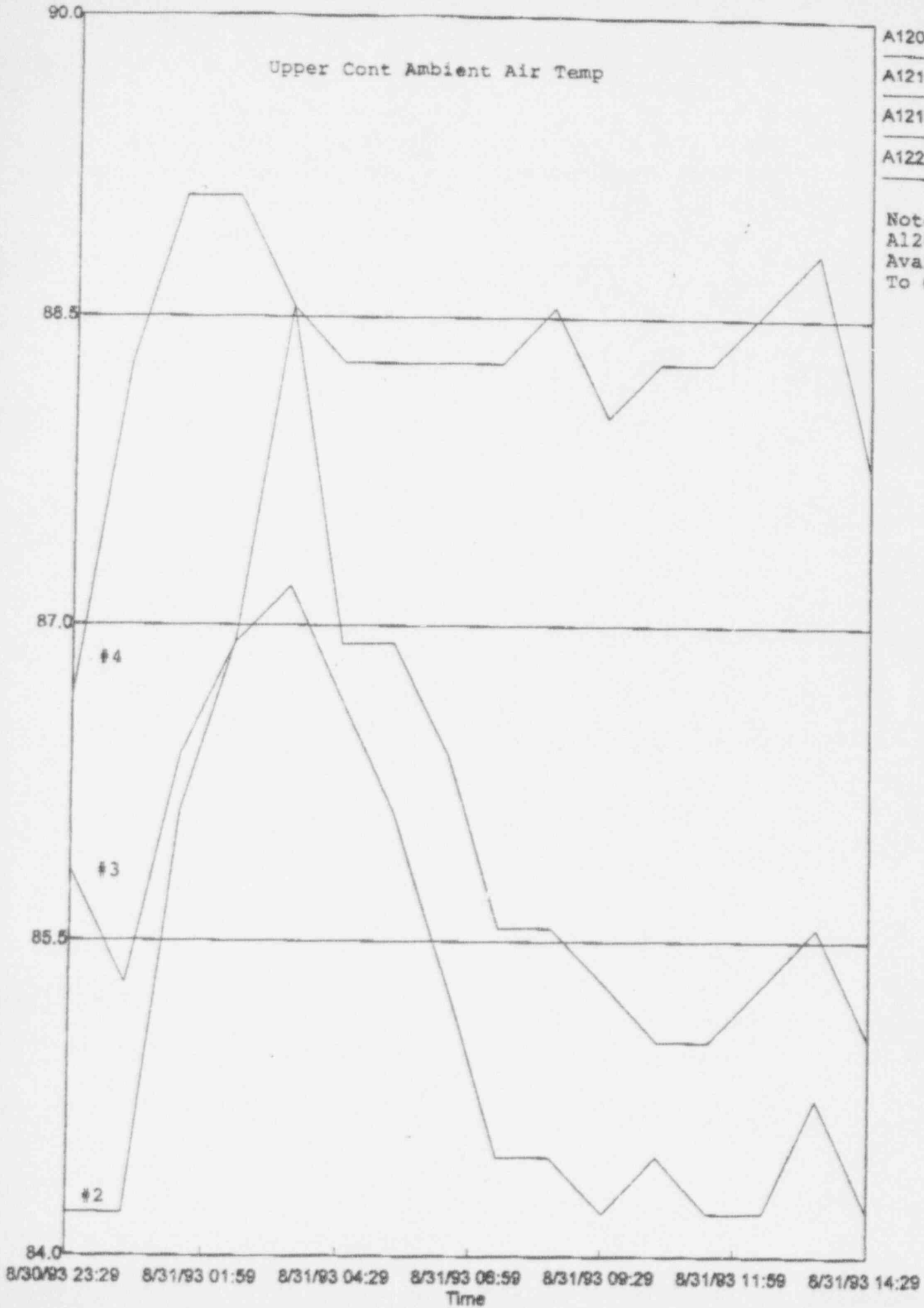
Note
#2
#3
#4

NOTE: A1204 Not Available on APD

SEP-01-1992 11:41 AM FROM DFC McGuire Engineering TO 88754013 P.06 #23

A1204 Note 1
 A1210 #2
 A1218 #3
 A1222 #4

Note 1:
 A1204 Not
 Available
 To Graph



Attachment I
 Sheet Sof 11

P. 28

88754013

K-2795-10.10

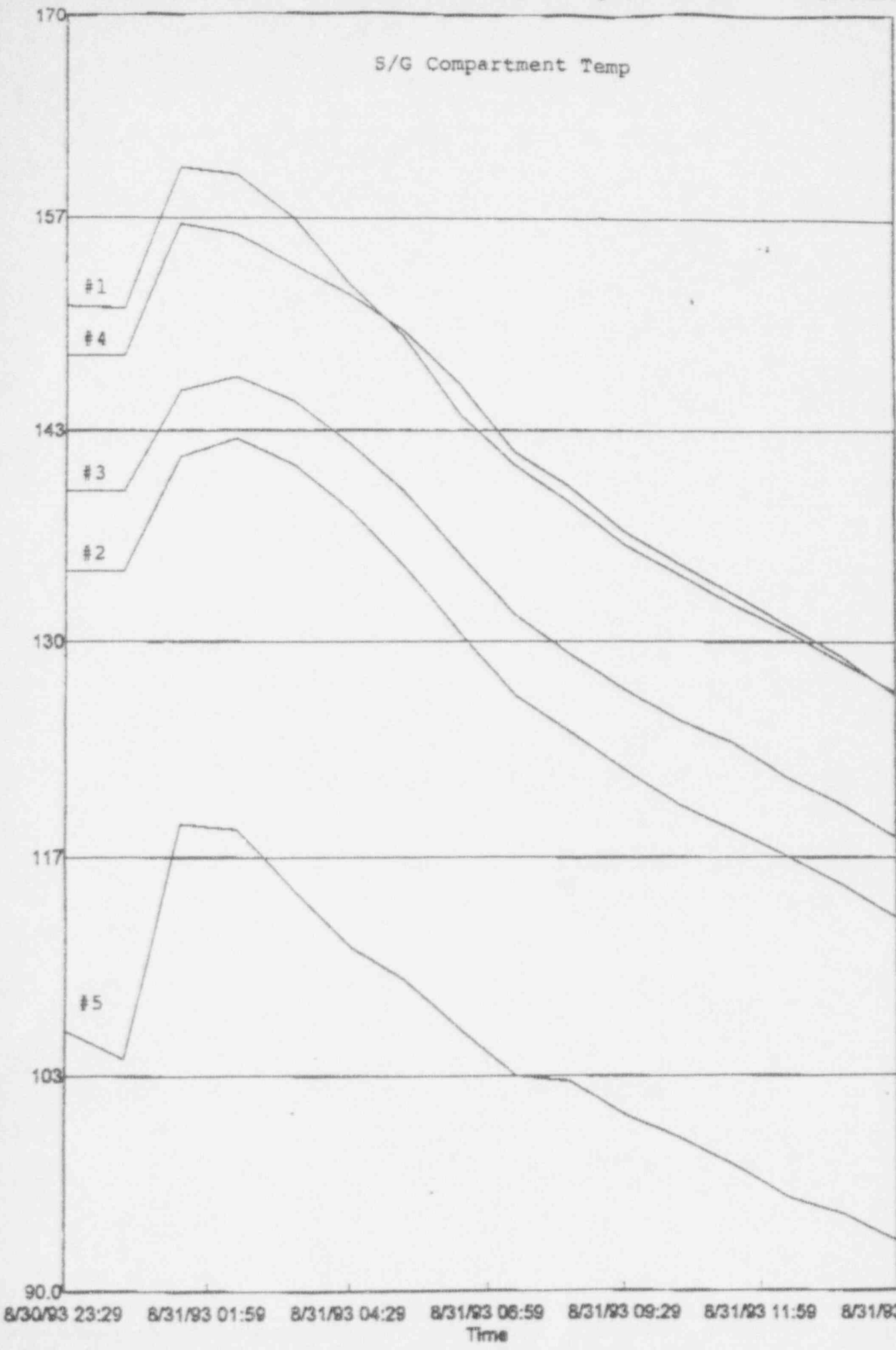
DATE 06-22-92
PAGE NO. 190

DUKE POWER COMPANY
HCGUIRE 2
ANALOG INPUT POINT SUMMARY
BY SERIAL #

SERIAL NUMBER	POINT ID	DESCRIPTION	Y	I	PROCESS RANGE UNITS	I	PRC	I	INPUT DEVICE	I	TRANSDUCER OUTPUT RANGE UNITS GAIN %V	I	CAB	I	REVISION DATE	I	FUNCTION USE
	FS=01																
ZAVL025 A1476	VL AHJ C HTR DB BEARING TEMP	ASOT60, CHL 033-12, ZARTC3	Y		0-367 DEG F		170		ZVLTE5270		0-10 HV 10		AT1 FCP		87035 A		
ZAVL027 A1482	VL AHJ D HTR DB BEARING TEMP	ASOT60, CHL 033-13, ZARTC3	Y		0-367 DEG F		170		ZVLTE5290		0-10 HV 10		AT1 FCP		87035 A		
ZAVL029 A1488	VL AHJ A HTR DRIVE END BEARING TEMP	ASOT60, CHL 033-20, ZARTC3	Y		0-367 DEG F		170		ZVLTE5220		0-10 HV 10		AT1 FCP		87036 A		
ZAVL031 A1494	VL AHJ B HTR DRIVE END BEARING TEMP	ASOT60, CHL 033-21, ZARTC3	Y		0-367 DEG F		170		ZVLTE5240		0-10 HV 10		AT1 FCP		87036 A		
ZAVL033 A1500	VL AHJ C HTR DRIVE END BEARING TEMP	ASOT60, CHL 033-22, ZARTC3	Y		0-367 DEG F		170		ZVLTE5260		0-10 HV 10		AT1 FCP		87036 A		
ZAVL035 A1506	VL AHJ D HTR DRIVE END BEARING TEMP	ASOT60, CHL 033-23, ZARTC3	Y		0-367 DEG F		170		ZVLTE5280		0-10 HV 10		AT1 FCP		87036 A		
ZAVL051 A1274	STEAM GENERATOR COMPARTMENT A TEMP	ASOT60, CHL 231-10, ZARTC7	Y		100-175 DEG F		120		ZVLTE6040		0-20 HV 20		AT3 GDR		85280 AL		#1
ZAVL053 A1280	STEAM GENERATOR COMPARTMENT B TEMP	ASOT60, CHL 231-11, ZARTC7	Y		100-175 DEG F		120		ZVLTE6020		0-20 HV 20		AT3 GDR		85280 AL		#2
ZAVL057 A1286	STEAM GENERATOR COMPARTMENT C TEMP	ASOT60, CHL 231-12, ZARTC7	Y		100-175 DEG F		120		ZVLTE6010		0-20 HV 20		AT3 GDR		85280 AL		#3
ZAVL059 A1292	STEAM GENERATOR COMPARTMENT D TEMP	ASOT60, CHL 231-13, ZARTC7	Y		100-175 DEG F		120		ZVLTE6050		0-20 HV 20		AT3 GDR		85280 AL		#4
ZAVL063 A1303	PRESSURIZER COMPARTMENT TEMP	ASOT60, CHL 131-21, ZARTC7	Y		100-175 DEG F		120		ZVLTE6030		0-40 HV 40		AT2 GDR		85280 AL		#5

S/G Compartment Temp

- A1274 #1
- A1280 #2
- A1286 #3
- A1292 #4
- A1303 #5



Attachment I
 Sheet 7 of 11

00754613

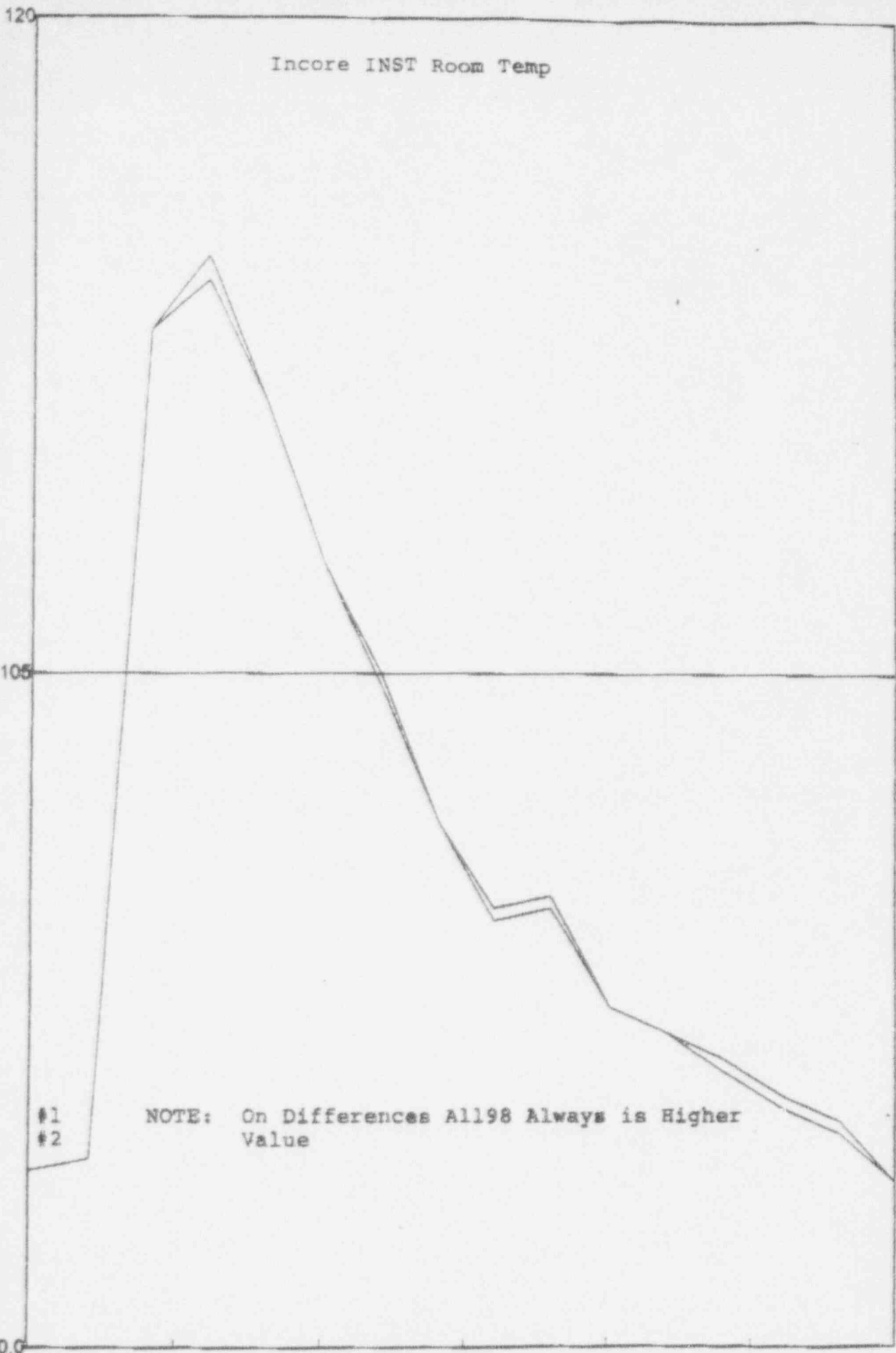
2793-10.10

DURE POWER COMPANY
 MCCLIDE
 ANALOG INPUT POINT SUMMARY
 BY SERIAL #

DATE 04-22-92
 PAGE NO. 196

POINT ID	POINT DESCRIPTION	UNIT	PROCESS RANGE	PROC LMTS HIGH LOW	INPUT DEVICE	TRANSDUCER OUTPUT RANGE UNITS GAIN HV	CAB SPW ENG	REVISION DATE FUNCT. USE	1 2 3 4 5	
VT001	INCORE INS. ROOM TEMP A	ASR167	CHL 430-12, 2ARTC	0-200 DEG F	122	EVTRO0900	0-80 HV 60	ATS RCD	04024 A	1 2 #1
VT002	INCORE INS. ROOM TEMP B	ASR167	CHL 430-15, 2ARTC	0-200 DEG F	125	EVTRO0910	0-80 HV 60	ATS RCD	04024 A	1 2 #2

Attachment 1
 Sheet 8 of 11



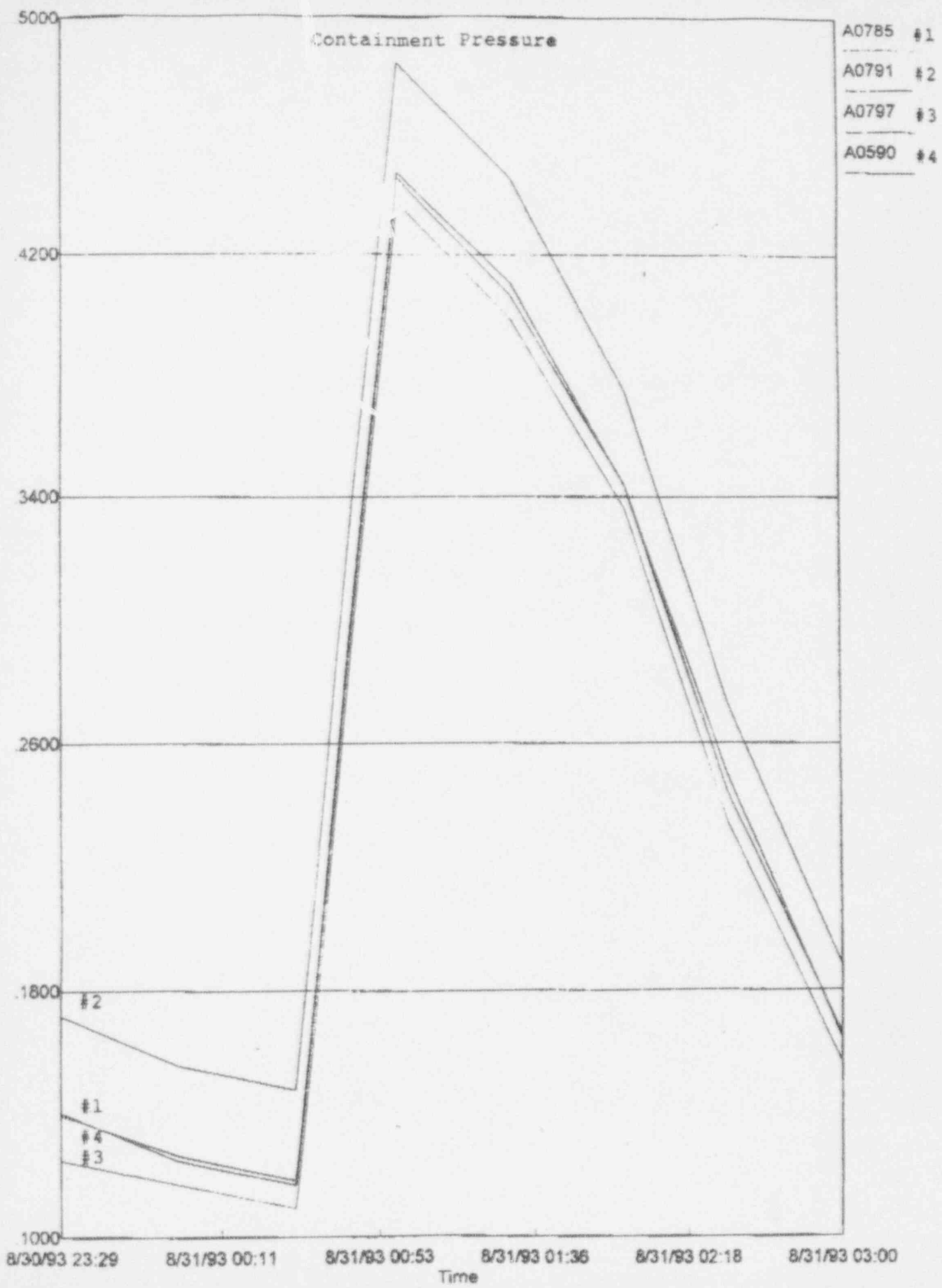
A1192 #1
 A1198 #2

NOTE: On Differences All98 Always is Higher Value

#1
 #2

Attachment I
 Sheet 9 of 11

90.0
 8/30/83 23:29 8/31/83 01:59 8/31/83 04:29 8/31/83 06:59 8/31/83 09:29 8/31/83 11:59 8/31/83 14:29
 Time



ATTACHMENT I
Sheet 11 of 11

Sept. 1, 1993

A review of Equipment Qualification criteria for instrumentation and components located in McGuire Unit 2 Lower Containment area indicates that all required Nuclear Safety Related and Post Accident Monitoring equipment is qualified to the peak postulated accident environment for lower containment of:

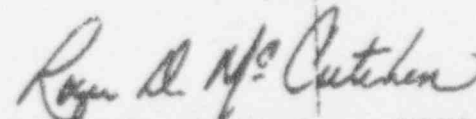
330 Deg. F
15 PSIG
100% Relative Humidity

Based upon established qualification methodology utilizing Arrhenius calculations and incorporating applicable margins, the relative short transient of 6 hours incorporating maximum peak values of:

162 Deg. F
0.90 PSIG
100% Relative Humidity

as occurred as a result of the incident relative to 2CF130.

This transient would not challenge the operability of this equipment nor would there be any discernable effect on the overall qualification and life of this equipment.


Roger D. McCutchen, TSII
Station EQ Coordinator

Unit 2 Steam Leak in Containment
Project Team Action Item 26.

Issue #26

9/1/93

COOLDOWN TRANSIENT

REACTOR VESSEL BASED ON MAX RATE OF T-HOT AND TCOLD

MAX RATE OF 75 DEG/HR

TECH SPEC LIMIT ABOVE LTOP 100 DEG/HR

(max rate/hr for any 1/2 hr; more conservative than OPS procedural guidance on CD rate monitoring)

PRESSURIZER

MAX RATE OF 70 DEG/HR

TECH SPEC LIMIT 200 DEG/HR

PRESSURIZER SURGE LINE

MAX RATE 10 DEG/MIN

BOUNDING RATE FROM PREVIOUS ANALYSIS APPROX. 25 DEG/MIN

RELATIVELY MILD TRANSIENT FROM A FATIGUE OR FRACTURE STANDPOINT.
ENGINEERING JUDGMENT INDICATES THAT TRANSIENT IS PREVIOUSLY BOUNDED.

by MT Cash (gnc)

Note: This item is considered closed.

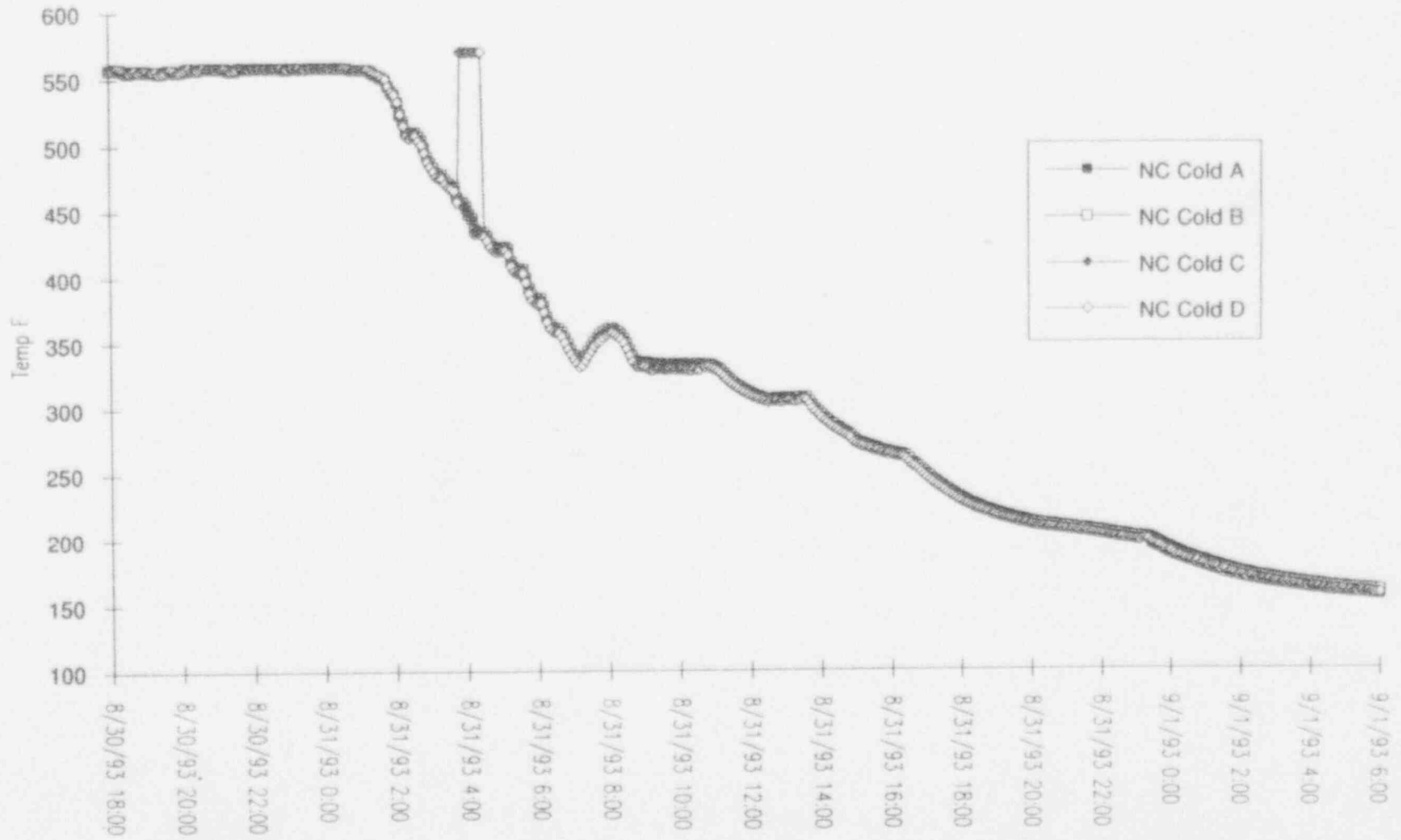
M. Luster 9/1/93

[COOL_ALW]Chart8

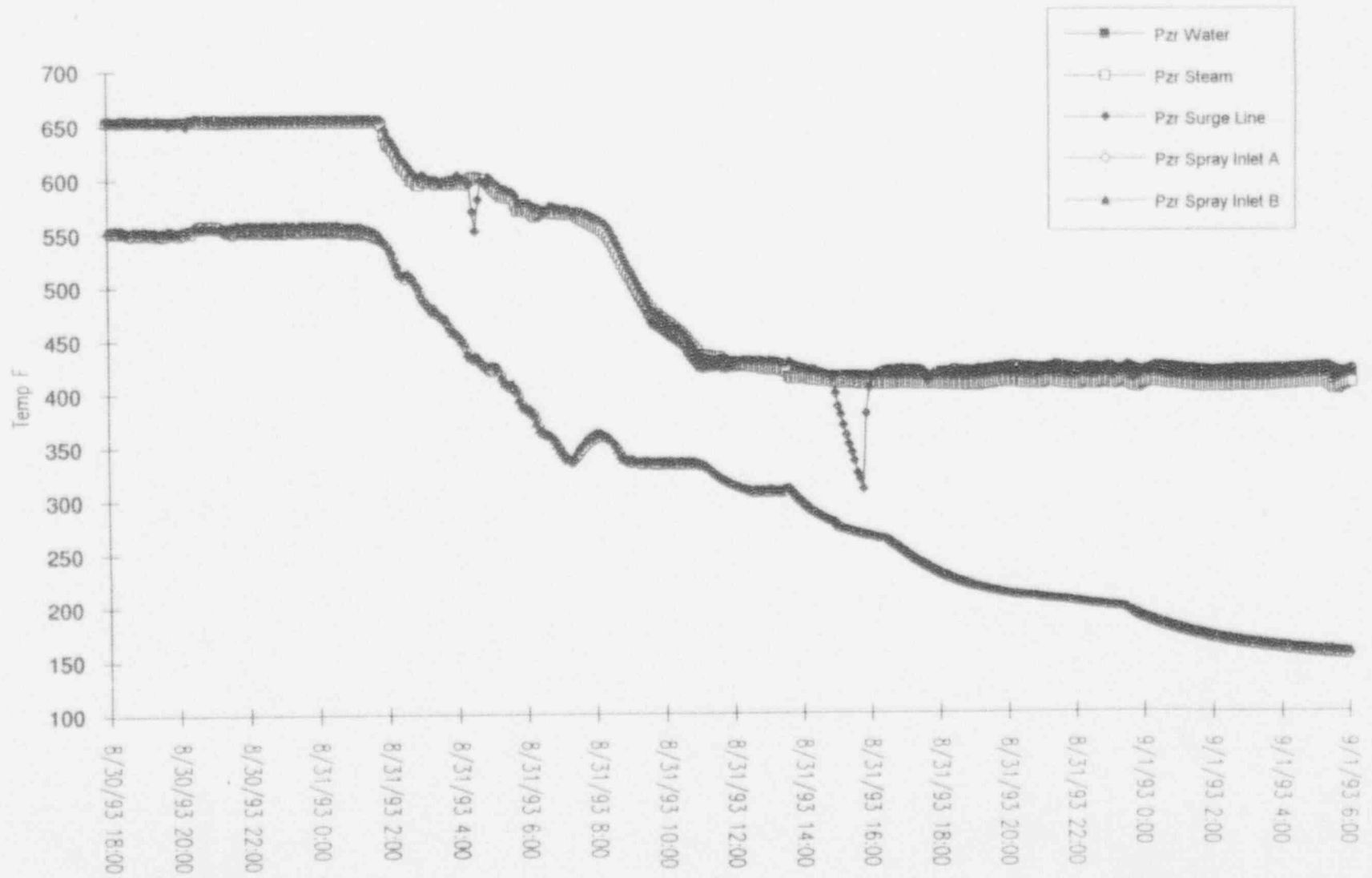
McGuire 2 Cooldown



McGuire 2 Cooldown

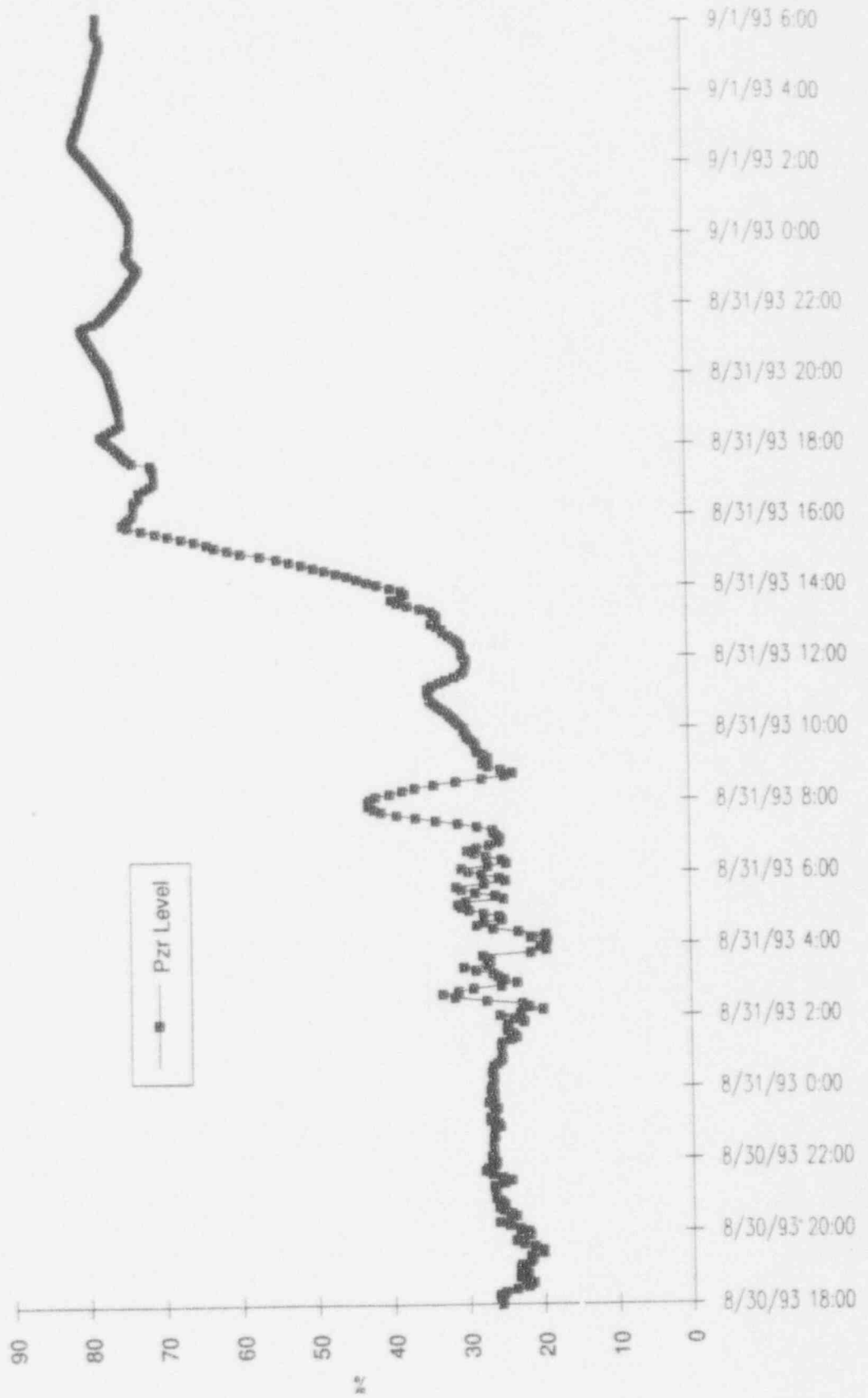


McGuire 2 Cooldown



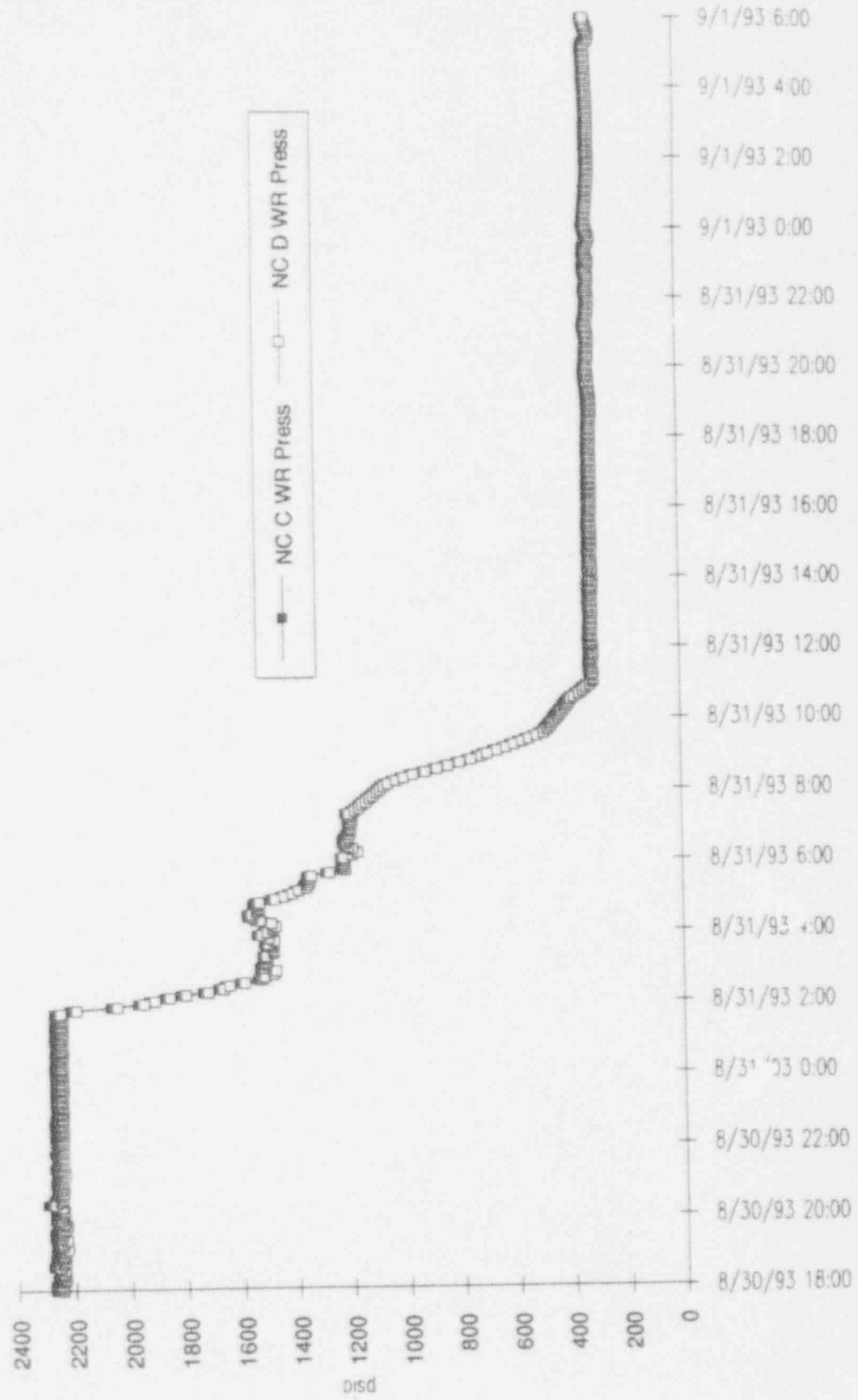
[COOL.LW]Chart9

McGuire 2 Cooldown



[COOL_XLWJ]Chart10

McGuire 2 Cooldown



SUMMARY OF CONSIDERATIONS MADE PRIOR TO AUTHORIZING BLOCKING TWO ICE CONDENSER LOWER INLET DOORS

Issue

On August 31, 1993, at approximately 0500 hours, station management authorized blocking two ice condenser inlet doors associated with bays 21 and 22. At the time, the ice condenser was required to be operable, and the action (b.) of Tech spec 3.6.5.3 was intentionally entered.

Discussion

At approximately 0445 hours on this date, the Supt. of Operations (Bruce Hamilton), Operations Staff Manager (Dennis Bumgardner), On Duty Shift Supervisor (Jerry Rumpfelt) and the On Duty Shift Manager (Joe Lukowski) met in the Control Room and discussed the prudence of blocking two of the ice condenser lower inlet doors closed. The two doors were not staying closed and maintenance workers on the scene were periodically pushing them back closed. Initially, 20 of the 24 doors had opened. Of these, 16 were pushed closed and stayed closed once the cold head of air was re-established. Two other doors occasionally reopened and were easily reclosed. Only two doors, those in bays 21 and 22, were frequently reopening. These two doors were close to the steam leak in lower containment and, by opening, they were allowing steam and warm air from lower containment to enter the ice condenser. This was resulting in melting localized areas in the ice bed according to the workers on the scene.

The option of holding the two doors shut (with personnel) and later mechanically blocking the two doors was raised. After discussing this possibility and considering the unit's current status, the Supt. of Operations authorized personnel holding the two doors shut and further authorized the use of mechanical blocking devices if necessary. All four previously mentioned members of Operations management concurred with this decision. At 0500 hours, the Shift Supervisor, entered the two lower inlet doors as inoperable and entered the action step of Tech Spec 3.6.5.3.

Basis for the Decision

These were discussed and agreed to at that time:

- The ice condenser would be rendered inoperable by this action, however, we could, and would, comply with the action item.

- The ice condenser would still have 22 doors available and capable of functioning and that more than enough ice remained in the ice bed.
- The leak was not likely to get worse; by all accounts the valve was supplying no resistance to flow.
- The probability of another leak requiring the functioning of the ice bed was very low (primary and secondary pressures were substantially lower). If another leak occurred, preserving the ice bed from further degradation would enhance our capability of handling a second leak.
- The core had been subcritical for ≈ 2 months and greater than $1/3$ of the core was fresh fuel. The decay heat load was very low compared to that assumed in the accident analysis for containment.
- Substantial energy had already been removed from the secondary piping systems in containment. S/G pressure was ≈ 250 psig. Initially, it was ≈ 1100 psig. This was much more conservative than the accident analysis.
- Substantial energy had already been removed from the primary piping systems in containment. NC temp was below 400° F and NC pressure was ≈ 1500 psig. Both down from the at power values used in the accident analysis.
- The initial pressure transient in lower containment was over and had been for more than an hour. Lower containment pressure was back to normal; within 0.2 psig of atmospheric. Lower containment temperatures were also returning to normal and were within Tech Spec 3.6.1.5 limits.
- Blocking the ice condenser lower inlet doors was discussed in terms of preventing a safety system from performing its function. Analogies to resetting the SI were discussed.

The Operations management members concluded:

- By blocking the ice condenser lower inlet doors we would make the ice condenser inoperable.

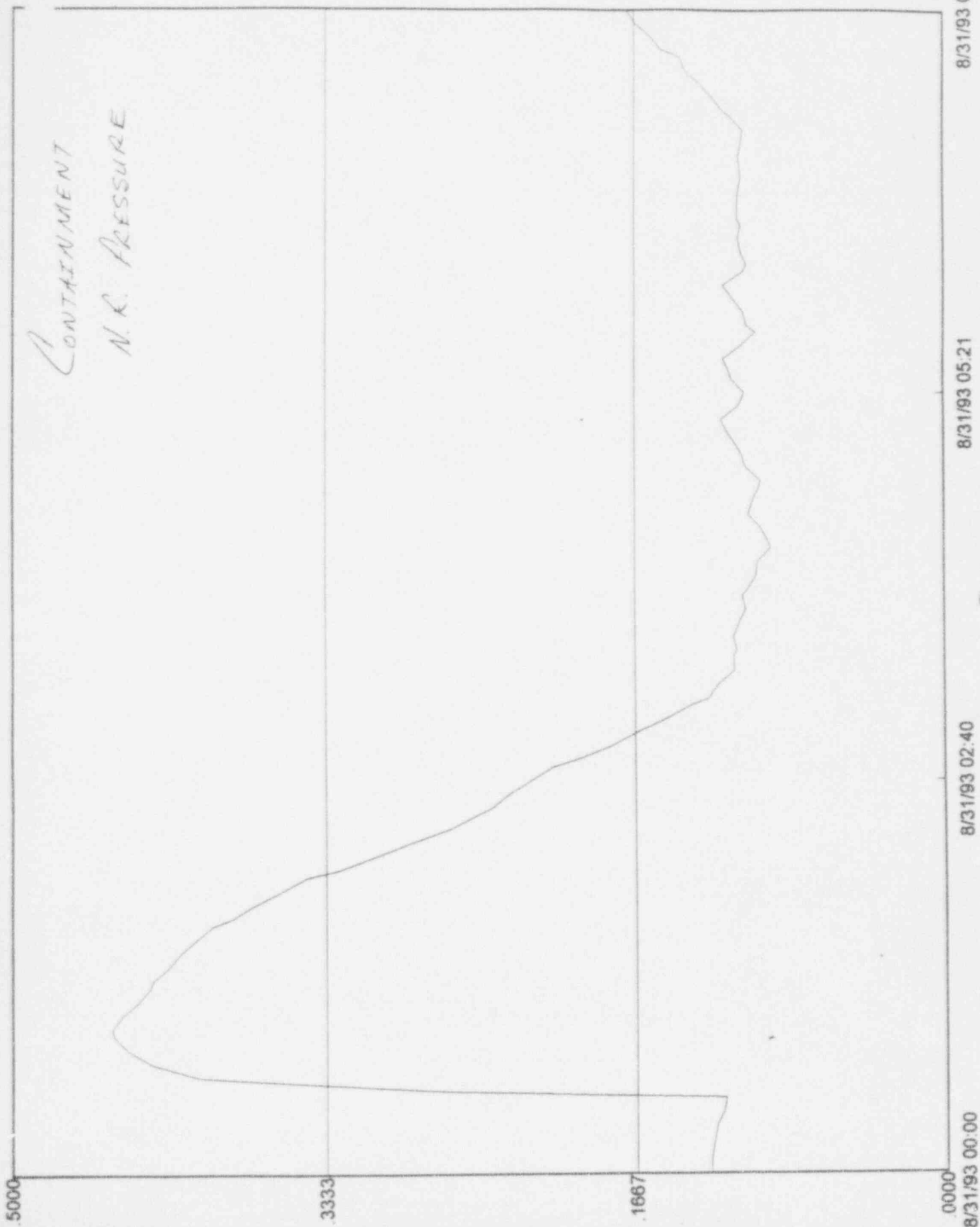
- The ice condenser would still be capable of performing its function if again called upon. Although inoperable, it had sufficient capability of handling any incident that could occur from the specific set of unit conditions in existence at that time.
- The blocking of the ice condenser lower inlet doors was the equivalent of resetting the SI. The transient requiring them to open had passed; containment pressure was again normal. Two doors were being opened by a localized pressure and/or impingement problem and not due to building pressure. Until a sufficient cold head of air could be re-established, this would continue to be a problem. The need for this ESF feature was over (for this transient).
- The ice bed was being needlessly degraded due to a localized problem. Future performance of the ice bed was being threatened by the continuation of heat and steam being admitted to the ice bed in bays 21 and 22.

Attachments

- Graphs of the following over the time interval in question
 - Lower Containment Pressure (N/R)
 - Lower Containment Temperature (weighted average)
 - S/G pressure
 - NC temperature
 - NC pressure
- Graph of typical containment pressure fluctuations
- Statement from Greg Swindlehurst, Duke Power Company Safety Analysis regarding the advisability of this decision dated 9/2/93

5090

CONTAINMENT
N.R. PRESSURE



8/31/93 08:01

8/31/93 05:21

Time

8/31/93 02:40

8/31/93 00:00

5000

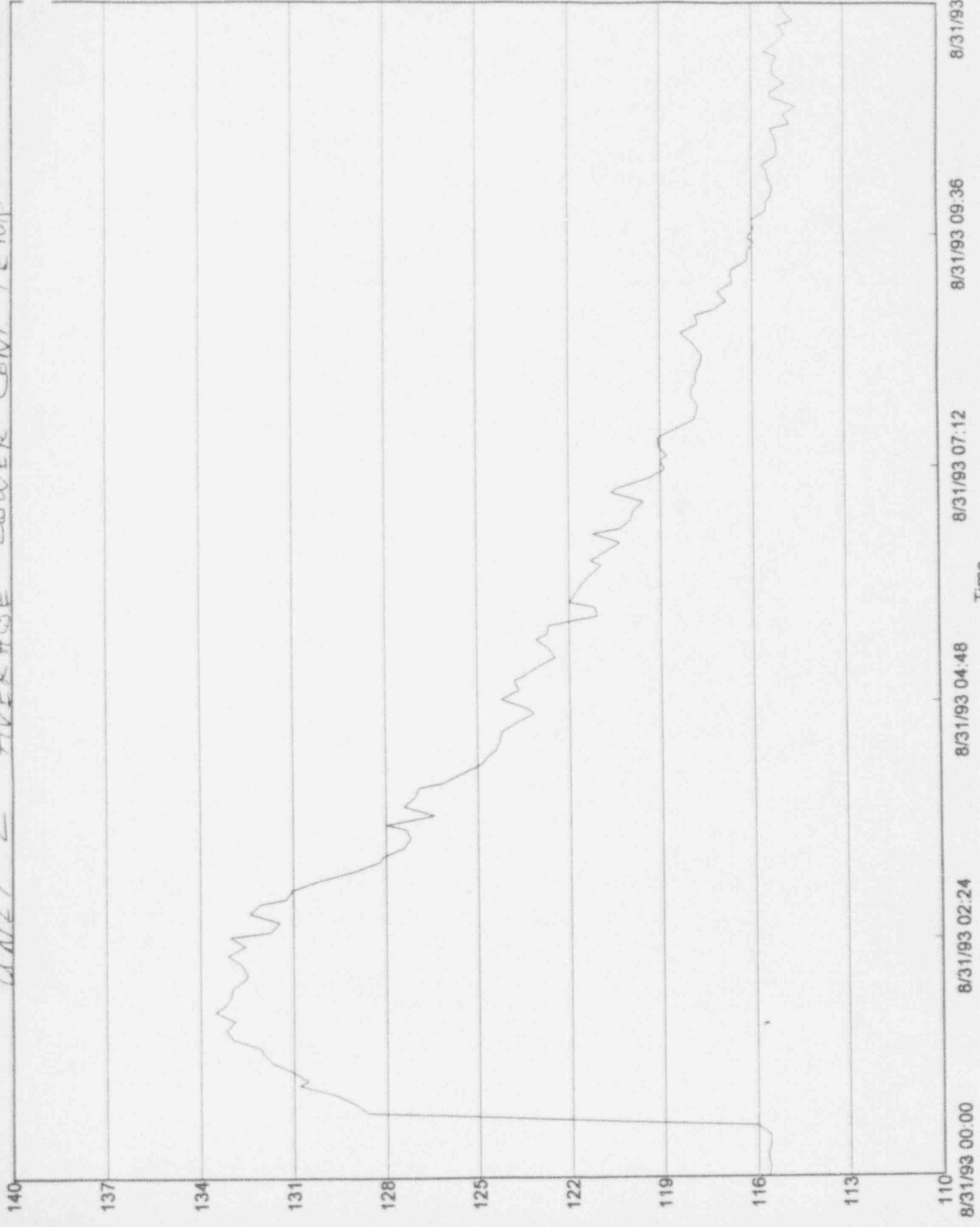
3333

1667

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WAVELENGTH AVERAGE LOWER CENT (EMU)

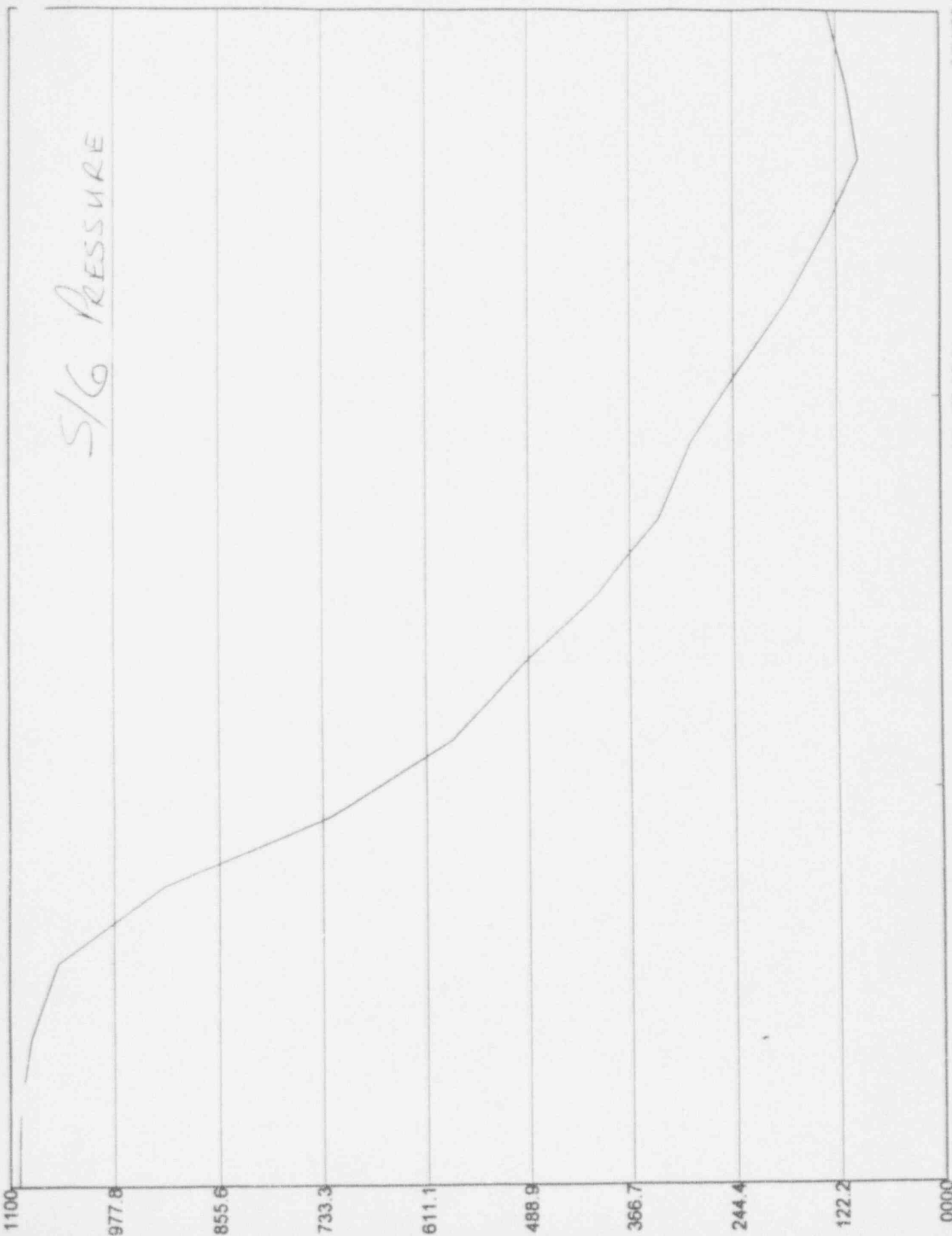
70755



1022

A1023

S/G PRESSURE



1100

977.8

855.6

733.3

611.1

488.9

366.7

244.4

122.2

.0000

8/31/93 00:00

8/31/93 02:40

8/31/93 05:21

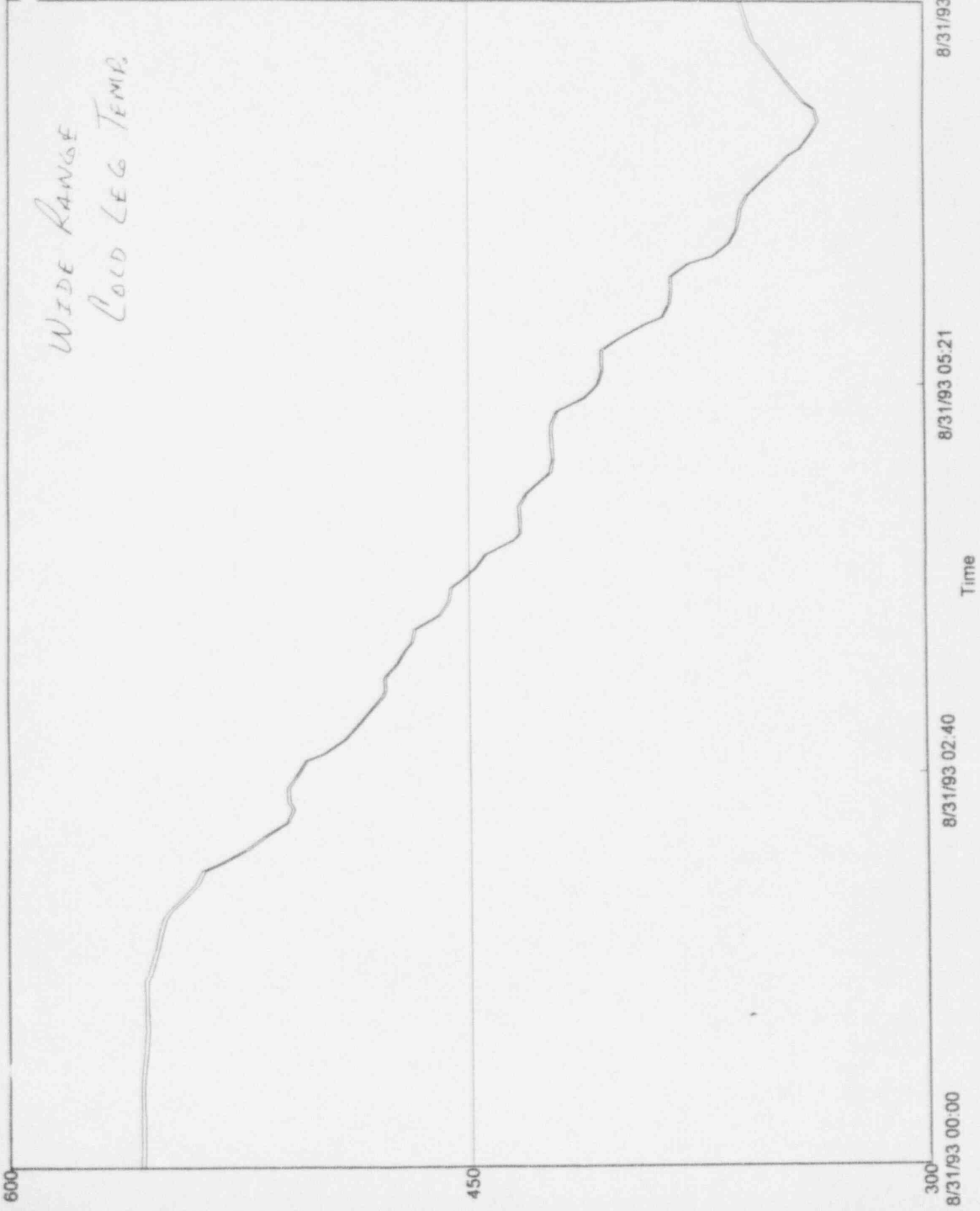
8/31/93 08:01

Time

'061

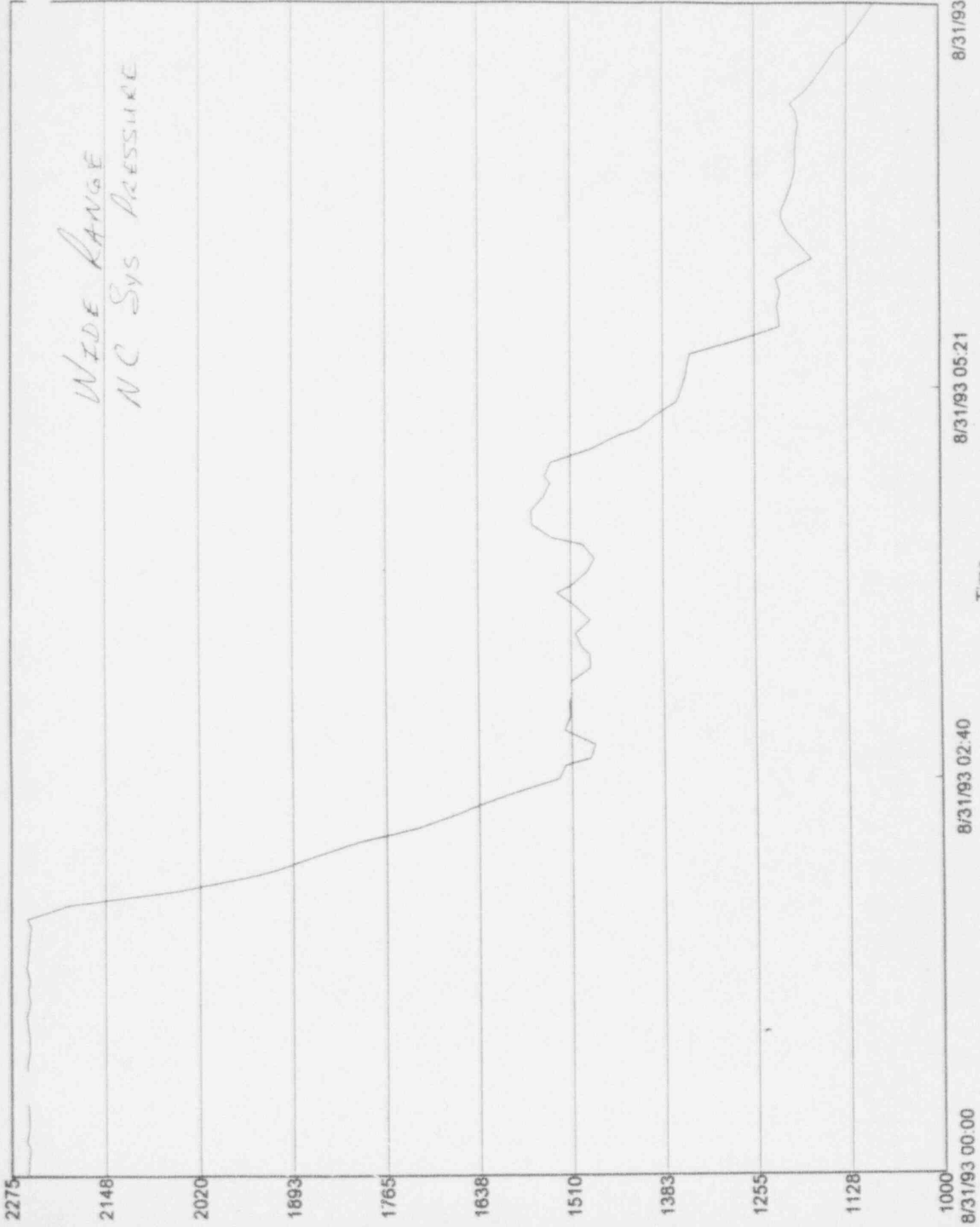
A1067

WIDE RANGE
COLD LEG TEMP.



0826

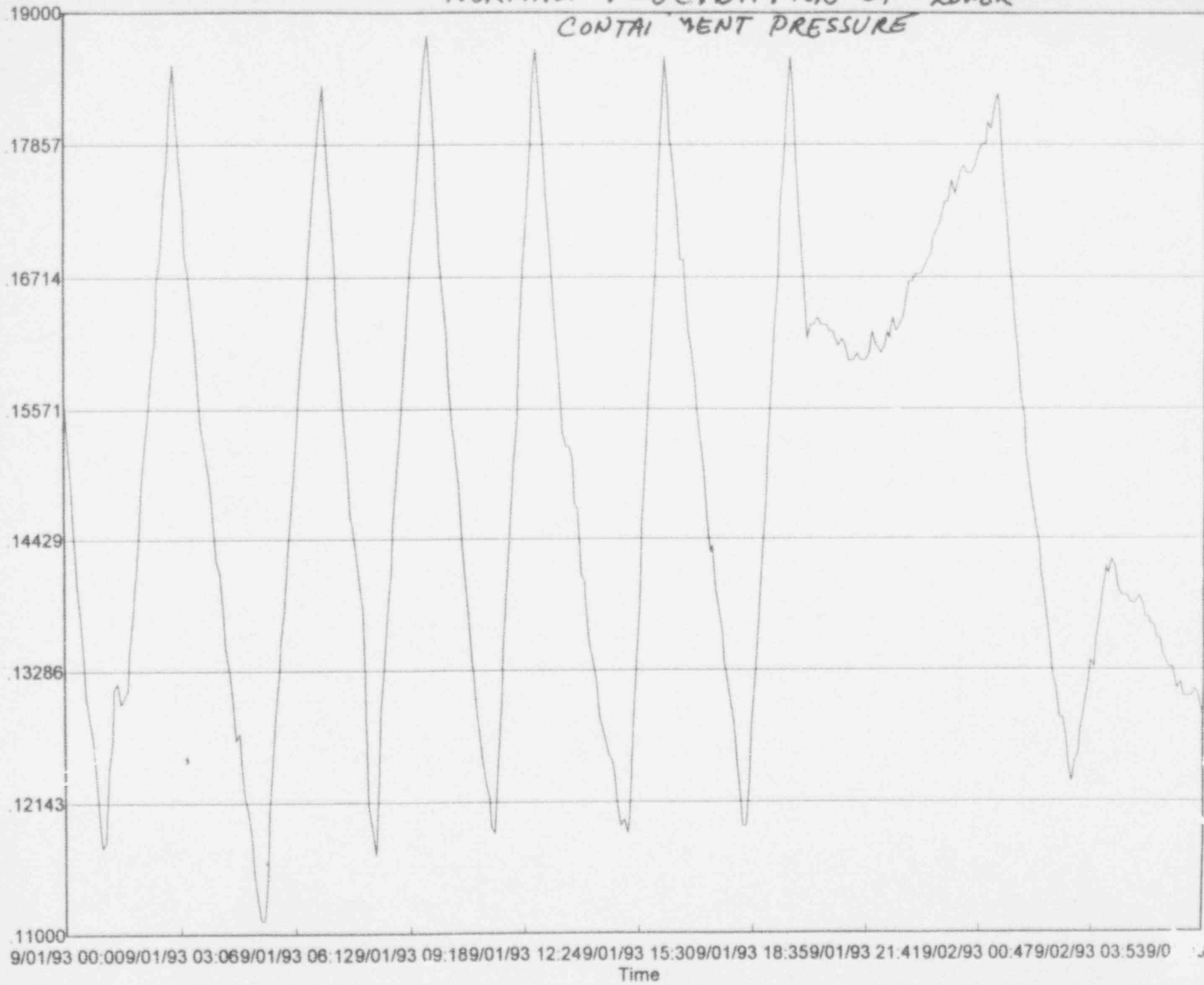
WIDE RANGE
NC Sys Pressure



Time

NORMAL FLUCTUATION OF LOWER
CONTAINMENT PRESSURE

7590



9/01/93 00:00 9/01/93 03:06:59
Time

Facsimile Cover Sheet

To: Bruce Hamilton
Company:
Phone:
Fax: 875-4888

From: From Gregg Swindlehurst
Company:
Phone:
Fax:

Date: 9/2/93
Pages including this cover page: 3

Comments:

Evaluation of Blocking Ice Condenser Doors During Cooldown
Following the Unit 2 SG Drain Leak Event On 8/31/93

At about 12:30 a.m. on the morning of August 31, 1993, a leak in a steam generator A 1 inch drain line developed in the MNS-2 lower containment. At the time the unit was at full temperature and pressure at no-load conditions. This leak released inventory from the steam generator into containment. As a result, lower containment pressure increased by about 0.45 psi and 18°F. This pressurization caused all but two sets of ice condenser doors to open. Most of these doors were only cracked open, but 4 doors in the vicinity of the leak were fully opened. About 2,400 lbm of ice melted as a result of the leak.

After the event was diagnosed, the unit entered an orderly cooldown and depressurization at a rate of 50°F/hr to reach conditions where the leak could be isolated. This also caused the steam generator leak rate to decrease. At about 5:00 a.m., 4 1/2 hours after the start of the incident, the NC System temperature was down to 422 °F, the containment pressure had returned to its original value, and the lower containment temperature, which peaked at about 134 °F, had decreased to 124 °F. The release from the steam generator drain line was significantly reduced at this time. At about this time all of the ice condenser doors had reclosed except for two, which remained open.

At 5:00 a.m., station personnel decided to manually close (and hold closed) these two doors in an effort to minimize additional ice melt. This was decided based on the return to near-normal pressure and temperature in lower containment, which indicated that the leak had decreased and the continuing energy addition could be removed by the Containment Ventilation (VV) System. The need for the ice condenser should a subsequent event (such as a LOCA) occur was also considered. It was known that decay heat was very low due to the refueling outage, and that the stored energy in the NC System was much reduced following the cooldown to 422°F. It was recognized that blocking closed two of the 24 doors would only minimally decrease the functional capability of the ice condenser, since the remaining 22 doors would still function. The small loss of ice during the steam leak event was also recognized as only a minimal decrease from the initial inventory. Based on these factors, it was decided that the ice condenser would continue to provide a very sufficient post-accident heat sink, and that manually closing the remaining two ice condenser doors was safe and appropriate.

Had a LOCA occurred while these two doors were held shut, the ice condenser would have still performed its intended function. A large-break LOCA with the NC system temperature at 422 °F would release NC inventory and energy at a lower rate than if the reactor had been at full power. The pressure differential between the NC system and containment would be much lower initially, so that less NC inventory would be released out the break. The energy of a LOCA blowdown from these initial conditions is calculated to be about 160 E6 Btu, well below the containment design blowdown energy of 324 E6 Btu. This 50% reduction in the energy release more than offsets the reduction in the capacity of the ice condenser by closing two of the 24 doors and the assumed loss of less than 10% of the ice. The initial containment pressure peak would therefore be much lower for a large-break LOCA with the NC system at these lower pressures and temperatures than for a LOCA from full power conditions. It is also noted that the initial containment pressure peak is not the limiting pressure peak for the full power case.

The long-term pressure peak for a LOCA, which occurs following ice melt, would also be much less due to the reduced decay heat level. Decay heat at the time of ice-melt-out following a large-break LOCA from full power is about 45 MW. The decay heat at the time of the steam leak event was about 2.5 MW, or only 5.6% of the decay heat at the time of ice melt following a LOCA from full power. Even with the ice inventory slightly decreased due to the steam leak, ice meltout would take much longer due to low decay heat. The Containment Spray (NS) System is used to keep containment pressure below the 15 psig limit after the ice melts. One train of spray at 3400 gpm is capable of condensing the steam for an energy release rate of 50,000 Btu/sec. The potential boiloff from decay heat at this time is less than 2400 Btu/sec, or only 5% of the capacity of one spray train. The NS System is therefore able to keep building pressure from increasing following the initial blowdown following a LOCA at 422°F, which will only partially melt the ice inventory. No ice is required for the remainder of the event. The peak pressure would therefore remain well below the design limit of 15 psig.

Based on the above evaluation it can be concluded that the decision to block closed two doors to the ice condenser after the cooldown to 442°F was appropriate and safe, considering the availability of the remaining 22 doors, the reduced stored energy in the NC System, and the low decay heat following the outage.

Any questions, call Gregg Swindlchurst (382-5176)

Issue #28

Issue #29

UNIT 2
ICE CONDENSER
POST CF LEAK INSIDE CONTAINMENT
EVALUATION SUMMARY
Rev. 0 9/1/93
N A SMITH, III

OVERVIEW

Shortly after midnight 8/31/93, 2-CF-130 developed a substantial leak. As a result lower containment temperature and pressure increased, opening the ice condenser lower inlet doors. Melting of the ice bed occurred. Visual inspection of the ice bed by Maintenance and Engineering personnel during the morning of 8/31 identified significant melting occurring in bay 22. Indications of melting were also observed in bay 12, 19 through 21, 23, and 24.

EVALUATION

W/O 9306388 was generated to weigh baskets to determine the extent of ice bed degradation. Two hundred forty nine baskets were selected for surveillance. Valid data was collected on all but two of the baskets. Of all baskets weighed, the total ice loss was estimated to be less than 3000 lbs. Four baskets were found to be below the Technical Specification minimum average of 1081 lbs., one of which was below safety margin (design basis) minimum average of 983 lbs. These four baskets are clustered in bay 22 adjacent the crane wall. Further analysis projected the weights to the end of cycle 9 (12/1/94). A total of six baskets fell below technical specification. The four baskets currently below technical specification limits are projected to be below safety margin at the end of cycle 9. Statistical analysis of the current and projected weights confirm the operability of the ice condenser and its ability to satisfy Tech Spec requirements through the end of cycle. The only technical concern in regards to the ice condensers operability is that of maldistribution of ice. This requires further evaluation and regulatory concurrence.

RECOMMENDATIONS

Option 1 (Recommended by narrow margin)

Replenish the four baskets. This would eliminate any concerns in regards to ice condenser operability. Requires a total craft labor of 4 day 18 men around the clock. Engineering support required to document operability. See attached schedule.

Option 2

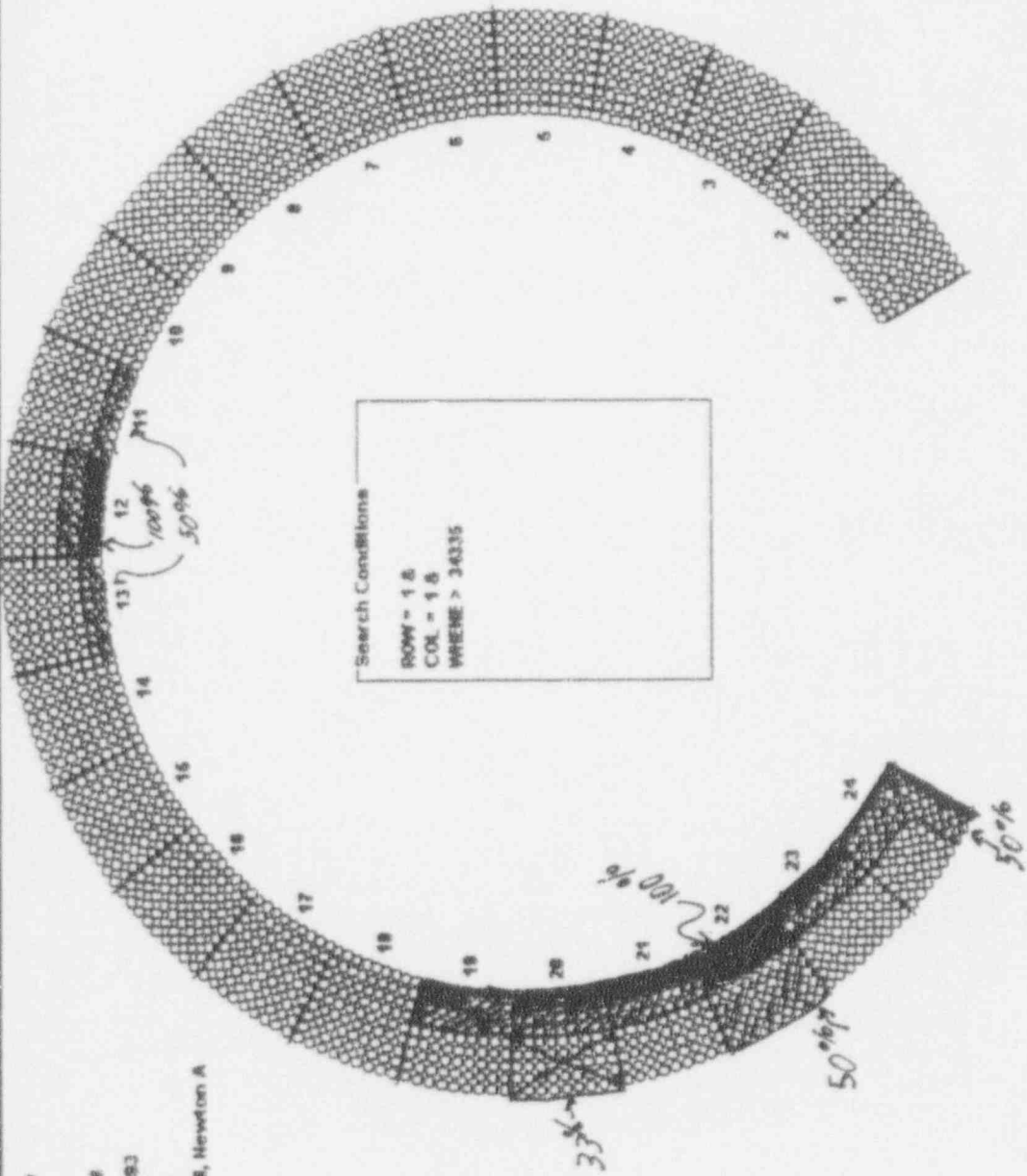
Do nothing. Perform appropriate PT's to establish operability. Address maldistribution. Requires total craft labor of 14 men around the clock 2.5 days. Additional Engineering support required. See attached schedule.

MCGUIRE NUCLEAR STATION
 UNIT 2 EOC RFO
 POST CF LEAK INSIDE CONTAINMENT ICE WEIGHT EVALUATION
 SUMMARY OF DATA

TOTAL ICE LOSS OF ALL BASKETS WEIGHED:	2376	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 7:	-238	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 8:	925	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 9:	1751	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 11:	-48	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 12:	354	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 13:	83	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 19:	-567	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 20:	101	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 21:	-183	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 22:	2982	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 23:	179	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 24:	-525	2376

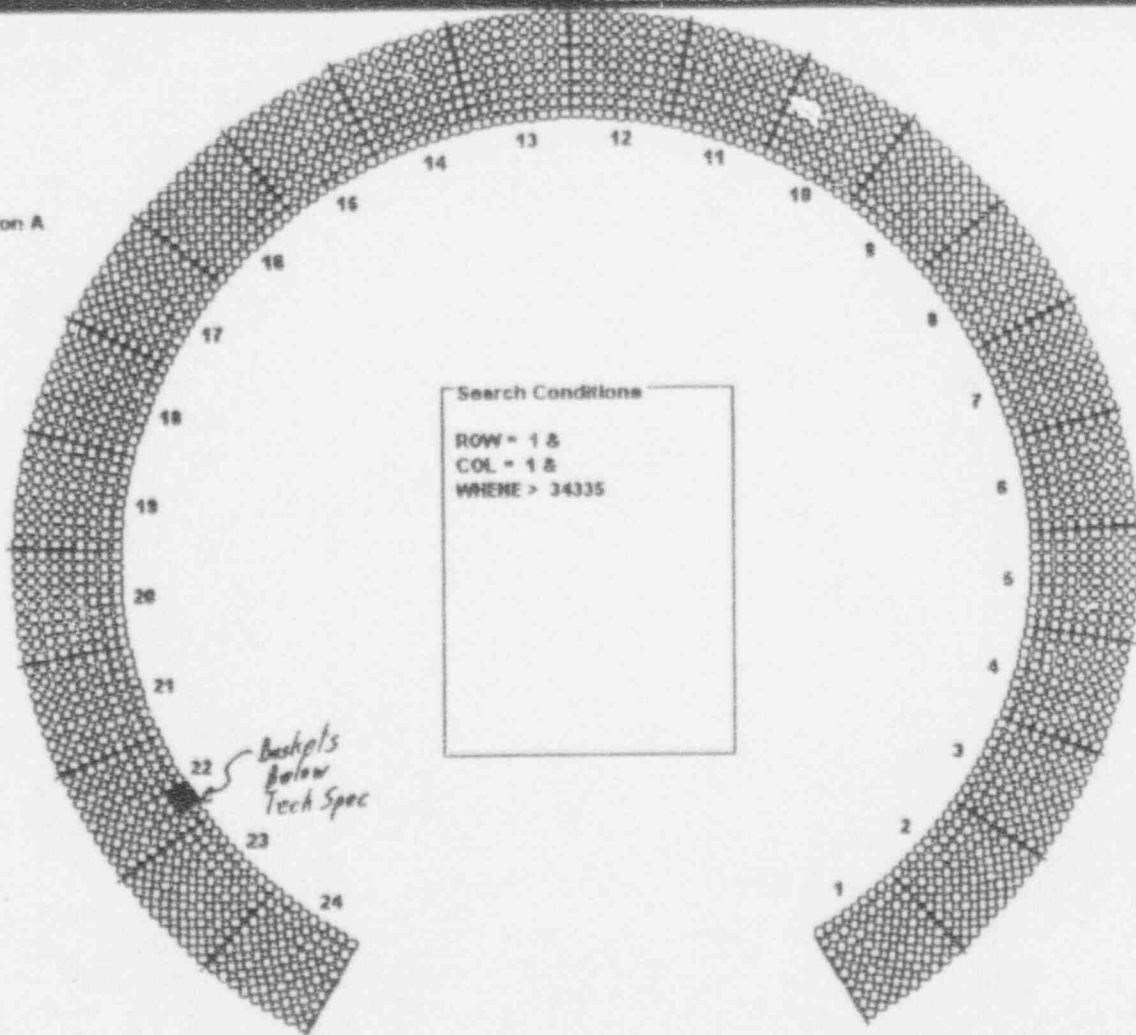
	CURRENT	PROJECTED EOC
ALL BASKETS:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1432	1334
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	110.571361	110.689584
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1325
ROW 7:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1389	1317
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	56.5366489	56.6042773
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1379	1307
ROW 8:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1438	1323
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	124.158026	122.280988
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1308
ROW 9:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1505	1338
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	109.735306	130.689566
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1495	1326

Baskets Weighed
REMAINING EMPTY



McGuire
UNIT: 2
CYCLE: B
09-02-1993
08:55:33
Smith, III, Newton A

McGuire
UNIT: 2
CYCLE: 8
09-02-1993
06:05:33
Smith, III, Newton A



MCGUIRE UNIT 2 EOC 8 RFO ICE CONDENSER MAINTENANCE SCHEDULE

ID	Name	Duration	Scheduled Start	Sep 29							Sep 5							Sep 12							Sep 19						
				W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T
1	DO NOTHING	1.5d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/4]																											
2	TECH SPEC WEIGH	2d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/4]																											
3	CLEAN INTERMEDIATE DECK DOORS	0.5d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/2]																											
4	PM/PT FLOOR DRAINS	0.5d	9/2/93 7:00pm	[Gantt bar from 9/2 to 9/3]																											
5	PM/PT LOWER INLET DOORS	0.25d	9/4/93 1:00am	[Gantt bar from 9/4 to 9/4]																											
6	REMOVE DOOR BLOCKS	0.25d	9/4/93 1:00am	[Gantt bar from 9/4 to 9/4]																											
7	QA WALKDOWN	0.5d	9/4/93 7:00am	[Gantt bar from 9/4 to 9/4]																											
8	SECURE LOWER PERSONNEL DOOR	0.25d	9/4/93 1:00pm	[Gantt bar from 9/4 to 9/4]																											
9																															
10																															
11	REPLENISH 4 BASKETS	4d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/6]																											
12	TEMP MOD VI AIR SUPPLY	0.5d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/2]																											
13	TOOL AND EQUIP INSTALLATION	0.5d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/2]																											
14	VIBRATE BASKETS	1d	9/2/93 7:00pm	[Gantt bar from 9/2 to 9/3]																											
15	INSPECT AND INSTALL CRUCIFORMS	0.25d	9/3/93 7:00pm	[Gantt bar from 9/3 to 9/4]																											
16	BLOW ICE	0.25d	9/4/93 1:00am	[Gantt bar from 9/4 to 9/4]																											
17	TECH SPEC WEIGH	2.5d	9/2/93 7:00am	[Gantt bar from 9/2 to 9/4]																											
18	LOWER IC CLEAN UP	3d	9/2/93 7:00pm	[Gantt bar from 9/2 to 9/4]																											
19	REMOVE EQUIPMENT	1d	9/4/93 7:00am	[Gantt bar from 9/4 to 9/5]																											
20	PM/PT FLOOR DRAINS	0.5d	9/4/93 7:00pm	[Gantt bar from 9/4 to 9/5]																											
21	CLEAN/TEST INTERMEDIATE DECK DOORS	0.5d	9/5/93 7:00am	[Gantt bar from 9/5 to 9/5]																											
22	PM/PT LOWER INLET DOORS	0.5d	9/5/93 7:00am	[Gantt bar from 9/5 to 9/5]																											
23	REMOVE DOOR BLOCKS	0.25d	9/5/93 1:00pm	[Gantt bar from 9/5 to 9/5]																											
24	QA WALKDOWN	0.5d	9/5/93 1:00pm	[Gantt bar from 9/5 to 9/6]																											
25	SECURE LOWER PERSONNEL DOOR	0.25d	9/6/93 1:00am	[Gantt bar from 9/6 to 9/6]																											

Project:
Date: 9/2/93

Noncritical Summary Critical
 Milestone Rolled Up

WORKFORCE ESTIMATE

NO REPLENISHMENT

-PM/PT Lower Inlet Doors	6hrs.x5
-PM/PT Floor Drains & Valves	6hrs.x2
-PM/PT Intermediate Deck Doors	4hrs.x2
-Tech. Spec. Weigh	24hrs.x24
-QC	2hrs.x2

total duration 2 1/2 days.x28

REPLENISH 4 BASKETS

-Temp. Mod. for VI Air	4hrs.x2 (4hrs.ENGR.)
-Tools & Equipment In	12hrs.x8
-Vibrate	16hrs.x4
-Inspection	2hrs.x2
-Blow Ice	4hrs.x4
-Lower Clean-Up	24hrs.x4
-Flow Channel Clean & Inspect	4hrs.x4
-Coordinator	24hrs.x2
-Complete Paperwork	5hrs.x4
-Equipment Removal	12hrs.x8

total duration 4 days x 36

McGUIRE NUCLEAR STATION UNIT 2 STEAM LEAK IN CONTAINMENT RESPONSE TO AIT QUESTIONS

RESPONSE BY: Newton A. Smith, III

DATE: 09/04/1993

QUESTION: 29

Resolve the status of the Ice Condenser prior to restart. Will the Ice Condenser be operable at the end of cycle.

RESPONSE:

Technical Specification Surveillance Requirement 4.6.5.1 b 2 establishes Ice Condenser operability based on ice weight for a 9 month surveillance window. The requirement addresses minimum total ice inventory, as well as average basket weight with a 95% level of confidence in specific sub-groups. The technical specification minimum weights with a 95% level of confidence (2,099,790 lbs. total, 1081 lbs. average) are based on the safety margin (design basis) weight of 1,890,000 lbs. total and 983 lbs. average. The difference between these two limits address a 10% ice loss due to sublimation during the surveillance plus a 1.1% weighing error allowance. As such, meeting the requirements of the Technical Specification ensures the operability of the Ice Condenser for the 9 month interval.

The method for determining ice bed operability for the next nine months is via the ice weight surveillance and analysis performed in W/O 93063883.

Ensuring Ice Condenser operability throughout the fuel cycle was accomplished during the initial evaluation of the ice bed. Component Engineering personnel inspected the ice bed for signs of melting. Indications were observed in bays 12, 19, 20, 21, 22, 23, and 24. The most extensive melting was clearly within bay 22. As such 249 baskets in these bays and bays 11 and 13 were identified to be weighed. Valid data was collected on all but 2 baskets. The most predominant melting occurred in four baskets in bay 22. These weights are summarized in Table A.

TABLE A				
BAY	COL	ROW	AS FOUND ICE WEIGHT (lbs.)	REPLENISHED ICE WEIGHT (lbs.)
22	3	8	990	1510
22	3	9	1016	1471
22	4	8	940	1488
22	4	9	1006	1506

The data collected from the 247 baskets is arithmetically summarized in Table B. The data was analyzed for both mean and 95% level of confidence ice weights. In all cases the current weights exceeded the Technical Specification minimum 95% level of confidence average weight of 1081 lbs. Operability at the end of the cycle was established by projecting each individual ice basket weight to 12/01/1994. The weighted average of all historical sublimation rates for the individual baskets was used for the linear projection. The four baskets originally below the 1081 lbs. limit fell below the 983 lbs. limit. As such the decision was made to replenish the baskets (replenished weights summarized in Table A). Two other baskets (Bay 24 1-1 1038 lbs. and 1-2 1040 lbs.) fell below the 1081 lbs. limit. Minimal concern exists for these basket weights as they reside within a low flow region during postulated events. The projected

weight data was analyzed in the same fashion as the current weights. Again, the 95% level of confidence weights were well above the 1081 lbs. limit. This establishes the operability of the ice bed beyond the duration of the upcoming fuel cycle.

TABLE B

	CURRENT	PROJECTED EOC
TOTAL ICE LOSS OF ALL BASKETS WEIGHED:	2376 lbs.	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 7:	-238	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 8:	925	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN ROW 9:	1751	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 11:	-48	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 12:	354	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 13:	83	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 19:	-567	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 20:	101	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 21:	-183	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 22:	2982	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 23:	179	
TOTAL ICE LOSS OF ALL BASKETS WEIGHED IN BAY 24:	-525	
ALL BASKETS:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1432 lbs.	1334 lbs.
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	110.57136	110.68958
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1325
ROW 7:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1389	1317
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	56.536849	58.604277
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1379	1307
ROW 8:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1438	1323
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	126.15603	122.26099
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1423	1308
ROW 9:		
MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1505	1338
STANDARD DEVIATION OF ALL BASKETS WEIGHED:	109.7354	130.68957
95%LOC MEAN BASKET WEIGHT OF ALL BASKETS WEIGHED:	1495	1326

McGUIRE NUCLEAR STATION
UNIT 2 STEAM LEAK IN CONTAINMENT
RESPONSE TO AIT QUESTIONS

RESPONSE BY: Newton A. Smith, III

DATE: 09/04/1993

QUESTION: 28

Ensure all Ice Condenser Tech Spec Requirements are met prior to restart. Perform a full PT on the Ice Condenser. The PT should include the proper blocking of the drains with dissolvable paper, required opening force test of the lower ice condenser doors, and ice condenser channeling.

RESPONSE:

The following table lists all applicable ice condenser Tech Spec Surveillance requirements and the action taken to ensure compliance.

Surveillance Requirement Number	Surveillance Requirement	Surveillance Interval	Action Taken
4.6.5.1.a	Verify ice bed temperature < 27F	1 / 12 hours	Normal surveillance performed by operations.
4.6.5.1.b.1	Chemical analysis of boron concentration, pH.	1 / 9 months	No additional action taken. Surveillance conducted via normal PM/PT interval. Melting of quantities observed would have negligible effect on boron concentration and pH of ice bed.
4.6.5.1.b.2	Verify adequate ice mass.	1 / 9 months	W/O 93063883 generated to perform ice mass PT. Shall Perform PT/O/A/4200/18 and MP/O/A/7150/76.
4.6.5.1.b.3	Verify adequate flow passage area.	1 / 9 months	W/O 93064579 generated to replenish baskets, as step within W/O performed Flow Channel inspection per MP/O/A/7150/10.
4.6.5.1.c	Verify structural integrity of basket.	1 / 40 months	No additional action taken. This surveillance was performed during this past outage on W/O 93011900. Velocities never approached magnitudes capable of basket damage.
4.6.5.2	Verify ice bed temperature monitoring system operable.	1 / 12 hours	Normal surveillance performed by operations.

Surveillance Requirement Number	Surveillance Requirement	Surveillance Interval	Action Taken
4.6.5.3.1	Verify operability of lower inlet doors.	1 / 18 months	W/O 93063885 generated to perform lower inlet door PT. Includes testing of door position monitoring system. Tested per PT/O/A/4200/32.
4.6.5.3.2 a	Verify operability of intermediate doors - free of frost accumulation.	1 / 7 days	No additional action taken. Performed weekly by operations during upper containment walk down.
4.6.5.3.2 b	Verify operability of intermediate doors - opening force test.	1 / 18 months	W/O 93064135 generated to perform intermediate deck door PT. Tested per PT/O/A/4200/33.
4.6.5.3.3	Verify operability of top deck blanket.	1 / 92 days	W/O 93064862 generated to perform Civil walk down. PT/2/A/4700/55 performed, section addresses top deck blanket operability.
4.6.5.4 a	Verify operability of lower inlet door position monitoring system.	1 / 7 days	Normal surveillance performed by operations.
4.6.5.4 b & c	Verify operability of lower inlet door position monitoring system.	1 / 18 months	Performed as part of PT/O/A/4200/32, lower inlet door test, on W/O 93063885.
4.6.5.7	Floor drain operability	1 / 18 months	W/O 93064205 generated to perform MP/O/A/7150/08 floor drain PT.

Sept. 4, 1993

Memorandum

To: Maurice Horne

From: J.D. Johnson

Subject: 1NC-61 Investigation

Valve 1NC-61 was noticed while technician were working valve 1NM-6. The technician noticed boron around the bonnet of 1NC-61. 1NC-61 is the isolation valve for 1NM-6. The valve was later cut out and brought to the Hot Machine Shop. 1NC-61 was disassembled and evaluated in accordance with procedure TM/0/A/9300/22.

1NC-61 was in the open position when evaluation started. A measurement was taken from top of yoke to valve body. This measurement is $2 \frac{3}{16}$ with a six inch scale. Visually there is evidence of leakage of some kind around external threads of yoke. Internally the valve body and yoke has no signs of damage. The diaphragm ledge and all seven diaphragms show no damage. The disc assembly and seat area in valve body is free of damage. After all the measurements were taken and recorded, the disc assembly is short by .027". The disc assembly blued 360 degree contact after being short .027". During disassembly it took approximately 2,800 psi to break the yoke loose. It takes 2,700 psi on the hydraulic wrench to yield 800 foot pounds of torque. This is the required torque for a 3/4 & 1 inch Kerotest valve. There is no evidence of leakage internally above the diaphragms.

Surveyed valve location after obtaining RP's initial survey of valve and general area. There is crystallization on the air duct and support that runs beneath 1NC-61. There is crystallization on the piping, wall and floor in the general area of 1NC-61. According RP,s survey 1NM-6 had boron on it prior to the initial repair during Unit One outage. Lying on duct work looking up thru the grading above 1NC-61 there is signs of leakage thru the grading. See attached survey sheet for radiation and contamination levels.

J.D. Johnson
TST Group

SURVEY DATA SHEET

Reviewed By: R. Brown

PERFORMED BY: MARK STEVENS UNIT 1 % POWER: 0% RWP/SWP: 1783
 COMPONENT/AREA: U-1 UC UNIT 2 % POWER: 100% DATE DUE: 5-12-93
 TEST/TIME PERFORMED: 5:12 AM TYPE OF SURVEY: R&R Smear ROOM #: U-1 UC
 STR. N: VALVE MAINTENANCE ELEVATION: NA
 STR. IT TYPE/NUMBER: RO-2 76693
 NA-GAMMA COUNTER/NUMBER: RM-14 766171
 PHA COUNTER/NUMBER: NA
 SAMPLER/NUMBER: NA

- G/A 6' RADIUS FROM NM-6A 10-15 mR/LR
- O/C w/ VALVE BODY PRIOR TO DISASSEMBLY 10 mR/hr Y
60 mrad/hr B
- SMEAR ON VALVE BODY EXTERNALS ~~(10 mrad/hr)~~
(~~NEED~~ VISIBLE, ~~SLIGHT~~ LEAKAGE)

- G/A SMEARS NM-6A VICINITY
 - ① 2K
 - ② 3K
 - ③ 6K
 - ④ 2K

- Remove YOKE ASSEMBLY
 - Approx 250 ml ~~leaking~~ ^{leak} OF WATER LEAKS OUT INTO BAG < 1 mR/hr
 - A/S TAKEN 10 min B/Z < 100 cpm ON FRISKER
- SMEARS: ① YOKE 2 mrad
 ② VALVE INTERNAL 2 mrad
 DOSE RATES 2 mR/hr Y
 6 mrad/hr B

- DISC/STEM ASSEMBLY CANNOT BE REMOVED @ THIS TIME - EXIT AREA TO EVALUATE - ~~A/S TAKEN~~

COPY

SURVEY RESULTS:
 Highest Contact Reading: 15 mR/hr mR/hr
 Highest General Area: 15 mR/hr mR/hr
 Highest dpm Beta-Gamma: 10 mrad/hr dpm/100cm
 Highest dpm Alpha: NA dpm/100cm

Routine Logbook Signed: NA
 Signs/Plan Views Updated: NA
 Beta radiation detected? Yes
 (Circle one)

Remarks:
 Additional information on other side/attached? (Circle One) YES NO

SYMBOLS: DIRECT FRISK SMEARS GENERAL AREA CONTACT NEUTRON

SURVEY DATA SHEET

Reviewed By: _____

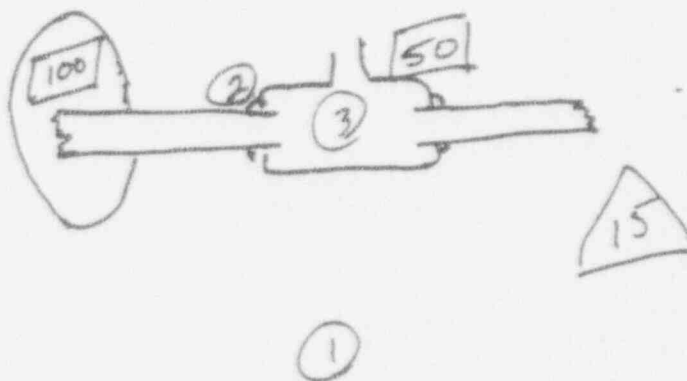
PERFORMED BY: R. FISHER
 UNIT 1 % POWER: 0%
 UNIT 2 % POWER: 0%
 DATE PERFORMED: 9-2-93 10:00
 TYPE OF SURVEY: RAD/SMEAR/NA
 OPERATION: GRIND WELD AND REMOVE/REPLACE VALVE
 INSTRUMENT TYPE/NUMBER: RSO-57
 RATA-GAMMA COUNTER/NUMBER: RM-14 26136
 ALPHA COUNTER/NUMBER: NA
 AIR SAMPLER/NUMBER: RADECO 1

RWP/SRWP: 1066
 DATE DUE: NA
 ROOM #: NA
 ELEVATION: NA

SMEARS ^{or CCPM} 100/100cm²

1. 800 FLOOR
2. 500 WELD ^{AREA} AFTER GRINDING
3. 20th VALVE

COPY



THE VALVE WAS DIFFICULT TO WORK DUE TO LOCATION. THE WORKERS GROUND THE WELD BUT COULD NOT GET TO THE BACK SIDE OF THE WELD... THEY COULDN'T REMOVE THE VALVE WE HAD WATER LEAKING W/ NO CATCH CMT. DEVICE SO & THE WORKERS GOT WET (BUT NOT CONTAMINATED) I STOPPED WORK GOT A CATCH CMT. & WORKERS RE-DRESSED. WORK WAS PERFORMED ON THE VALVE LATER THAT MORNING.

SURVEY RESULTS:

Highest Contact Reading: 100 ^X mR/hr
 Highest General Area: 15 mR/hr
 Highest dpm Beta-Gamma: 800 CCPM ^X dpm/100cm
 Highest dpm Alpha: NA dpm/100cm

Routine Logbook Signed: NA
 Signs/Plan Views Updated: NA
 Beta radiation detected? N/A
 (Circle one) No Yes

Remarks: SUBMITTED FOR REVIEW

Additional Information on other side/attached? (Circle One) YES NO

Legend: DIRECT FRISK SMEARS GENERAL AREA CONTACT NEUTRO

McGUIRE NUCLEAR STATION
SURVEY DATA SHEET

Reviewed By: RL

PERFORMED BY: M. Stevens UNIT 1 % POWER: 0 RWP/SRWP: 1783
 COMPONENT/AREA: U-1-41 NM-6-A UNIT 2 % POWER: 100 DATE DUE: 5/12/93
 DATE/TIME PERFORMED: 5/12/93 TYPE OF SURVEY: RAD smear ROOM #: U-1 41C
 LOCATION: Valve Mount on DM-6A ELEVATION: _____
 INSTRUMENT TYPE/NUMBER: R02-26660
 BETA-GAMMA COUNTER/NUMBER: Kn-14 26171
 ALPHA COUNTER/NUMBER: NA
 AIR SAMPLER/NUMBER: NA

14:15 Continuing work on NM-6A

VALVE DISC IS BORED OUT & TAPPED IN ORDER
 TO REMOVE → HAS BEEN WIPED DOWN TO
 20,000 dpm/100cm² A/S TAKEN DURING DRILLING

14:30 DISC Removed

~~Disc~~ Dose Rates

COPY

DISC ~~at~~ $< 1 \text{ mR/hr}$ on γ
 12 mrad/hr on B^-
 Smear $70,000 \text{ dpm}/100\text{cm}^2$

Workers EXIT - INTERNALS Thrown in
 metal TRASH workers will LAP VALVE
 at later time

SURVEY RESULTS: 12 mrad/hr P
 Highest Contact Reading: 1 mR/hr X mR/hr
 Highest General Area: NA mR/hr
 Highest dpm Beta-Gamma: 70,000 dpm/100cm
 Highest dpm Alpha: NA dpm/100cm
 Routine Logbook Signed: N
 Signs/Plan Views Updated: A
 Beta radiation detected? N
 (Circle one) No
Yes

Remarks:
 Additional information on other side/attached? (Circle One) YES NO

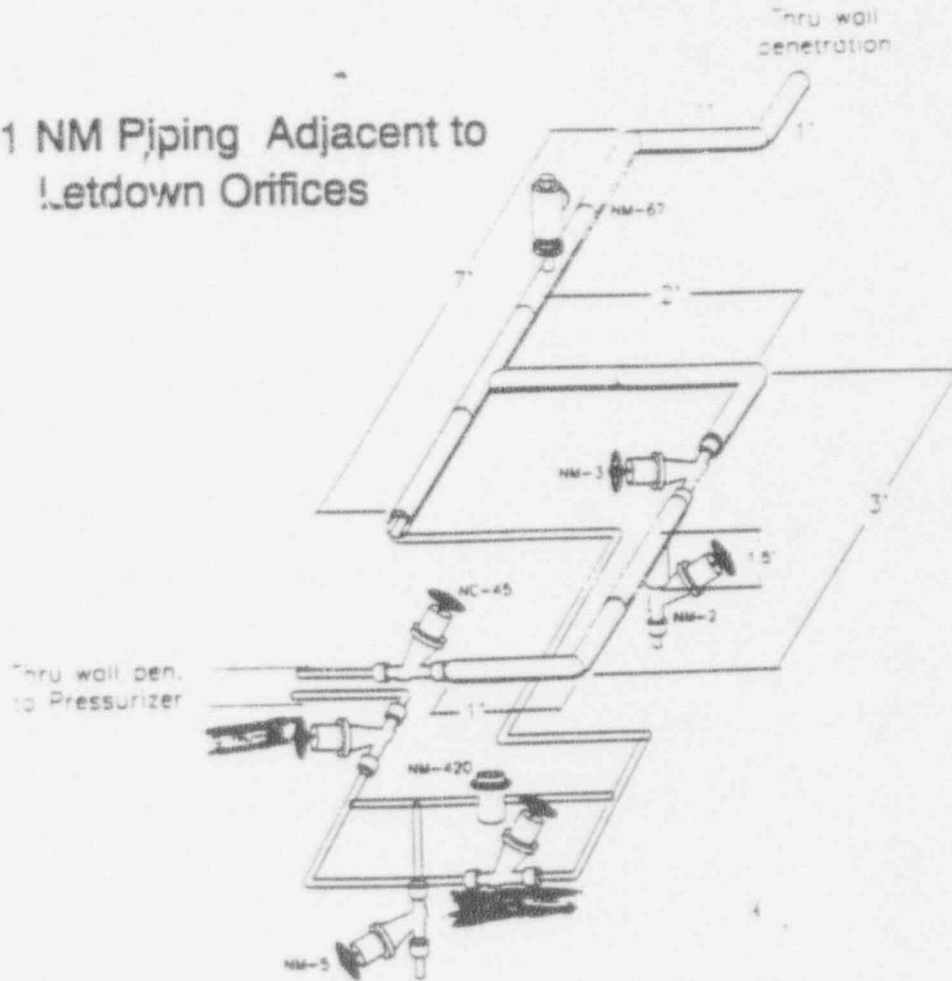
SYMBOLS: DIRECT FRISK SMEARS GENERAL AREA CONTACT N

McGUIRE NUCLEAR STATION SURVEY DATA SHEET

REVIEWED BY: _____

PERFORMED BY: _____ UNIT 1 % POWER: _____ RWP / SRWP: _____
 COMPONENT / AREA: _____ UNIT 2 % POWER: _____ DATE DUE: _____
 DATE / TIME: _____ TYPE OF SURVEY: _____ ROOM #: _____
 OPERATION: _____
 INSTRUMENT TYPE / NUMBER: _____
 BETA-GAMMA COUNTER / NUMBER: _____
 ALPHA COUNTER / NUMBER: _____
 AIR SAMPLER / NUMBER: _____

Unit 1 NM Piping Adjacent to
Letdown Orifices



SURVEY RESULTS:
 HIGHEST CONTACT READING: _____
 HIGHEST GENERAL AREA: _____
 HIGHEST DPM BETA-GAMMA: _____
 HIGHEST DPM ALPHA: _____

DPM/100CM
DPM/100CM

ROUTINE LOGBOOK SIGNED: _____
 SIGNS / PLAN VIEWS UPDATED: _____
 BETA RADIATION DETECTED? N/A
 (CIRCLE ONE) YES NO

REMARKS: _____
 ADDITIONAL INFORMATION ON OTHER SIDE / ATTACHED (CIRCLE ONE) YES ON
 GENERAL CONTACT NEUTRON

From: SHC7324 --PRDC Date and time 09/03/93 13:23:05
 To: TCM8380 --PRDC Ted McMeekin TDC7309 --PRDC
 EMG7351 --PRDC Mac Geddie RPM7390 --PRDC Richard Michael
 JWF7327 --PRDC Jeff Foster BHH7328 --PRDC Bruce Hamilton
 JWB7393 --PRDC Jack Boyle JNP7310 --PRDC Norman Pope
 RBW7324 --PRDC Ronnie B. White, J MAS7325 --PRDC Mary Ann Seagle
 WWD7324 --PRDC Bill Die1 CAD7323 --PRDC Claude Drye
 LES7323 --PRDC Larry Smith

From: Stephen H. Carter
 McGuire Planning Manager
 875-4620 SHC7324 MGOIWC
 Subject: Kerotest Valves for Unit 2

During 2EOC8, we disassembled and worked on 33 Kerotest Globe valves of various sizes and purposes. They are:

2BB-127	N2 Supply to S/G 2A					
2BB-177	S/G 2A Blowdown Vent	X				
2BB-187	S/G 2A Blowdown Header Hi Pt Vent	X				
2CF-90	S/G 2D Inlet Drain	X				
2CF-130	S/G 2A Shell Drain	X				
2CF-169	S/G 2D CF Hi Pt Vent					X
2CF-191	Unknown - Not in Data Base					
2CM-844	H P Heater Drain Sample Isol	X				
2FW-33	ESF FWST to Recirc Pumps		X			
2KD-30	D/G Lube Oil Cooler Drain	X				
2NB-259	Unknown - Not in Data Base			X		
2ND-36	B ND Pump Disch Sample Drain	X				
2ND-60	Isol Valve for NI-183 Test Vent					X
2ND-79	NS-18 Upstream Hi Pt Vent	X				X
2ND-83	ND to NI Pumps Hi Pt Vent					X
2ND-85	NC Pumps Outlet X-Over Block Hi Pt Vent					X
2ND-88	Hi Pt Vent Upstream of 2ND-35					X
2NI-95	ESF Test Header Inside Cont Isol		X			
2NI-166	NI Pumps to Cold Leg Loop 3 Isol	X				
2NI-352	Accum N2 Supply Inside Cont Isol			X		
2NM-22	ESF NC Loop 2A Sample Inside Cont Isol		X			
2NM-25	ESF Hot Leg 4 Sample Line Inside Cont Isol		X			
2NS-78	NS Pump 2A Suct Lo Pt Drain	X				
2NS-81	NS Pump 2A Vent to Drain Header	X				
2NS-82	NS Pump 2B Vent to Drain Header	X				
2NV-69	NC Pump 2C Byp Return Line Vent	X				
2NV-285	Charging Pump 2A Overflow	X				
2NV-890	NV Supply to NC Inside Vent Isol	X				
2NV-891	NC LD to Regen HX Vent Isol	X				
2NV-893	NC LD to Regen HX #1 Vent Isol	X				
2SM-83	A Stm Line Drain					
2SM-95	C Stm Line Drain					
2SM-101	D Stm Line Drain					

9/3/93 Full Cycle Vent.
 Full Cycle Functional Verification prior to study.
 Full Cycle for I.R.T.
 Full Cycle per PT/2/14200/19
 Full Cycle - Conformance File.

AIT REQUEST FOR INFORMATION

REQUEST # _____ DATE: 9.2.93

AIT TEAM MEMBER: L Baldwin

AREA: _____

QUESTION: IN ACCORDANCE WITH T.S. 36.5.1 THE ICE BED WAS
DECLARED IMPASSABLE BASED POINT 4 TEMPERATURE BEING > 27°F. ON AT 0140
8/31/93. AT 0715 ON 8/31/93 THE T.S. WAS NO LONGER APPLICABLE
BECAUSE ALL POINTS WERE < 27°F. KNOWING THAT SOME OF THE
ICE IN THE CONDENSER WAS MELTED - HOW DID McGUIRE DETERMINE
THAT THE ICE THAT WAS STILL AVAILABLE MET THE
REQUIREMENTS OF SURVEILLANCE IN ACCORDANCE WITH T.S
46.5.1

NEED: N/A

ASSIGNED TO: B Hamilton

RESPONSE: _____

MNS CONTACT FOR ADDITIONAL INFO:
NAME B Hamilton
PHONE # 4214

RESPONSE TO AIT REQUEST FOR INFORMATION

At approximately 0140, the control room SRO logged the ice bed for Unit 2 inoperable. The reason was that an RTD (point #4) exceeded 27 degrees F. At that time, the control room staff recognized the lower inlet doors had opened and either steam, or hot air or both was causing this temperature rise. The control room staff did not have any idea how much ice may have melted (if any) at 0140 when the declaration was made. Based on previous operability and successful surveillances, the control room staff did not declare the ice condenser inoperable based on any of the other four items specified for operability;

- a) chemistry requirements for the ice
- b) flow channels
- c) total ice weight
- d) number of baskets.

Later that morning (approx. 0300 hours) we began to assess the status of the Unit 2 ice bed. Localized melting was noted in several bays, with the heaviest damage confined to one bay. The engineer responsible for the ice condenser relayed to the control room staff that he was confident the ice condenser would still meet the tech spec weight requirements. This statement was repeated in the 0630 outage meeting. This engineer is very familiar with both the ice condenser and the surveillance requirements of Tech Spec 3.6.5.1.

At approximately 0715, the control room SRO logged the Unit 2 ice bed operable again. This was based on the RTD indications all returning to within the 27 degree F. limit specified in Tech spec 3.6.5.1 and upon visual inspection by knowledgeable individuals responsible for the ice condenser. It was recognized at this time that the ice bed surveillances must be conducted to answer the questions still remaining about ice bed operability specifically regarding the ice weight. This would have to be completed before returning the unit to service.

At approximately 1030, the on duty shift supervisor requested guidance on the plans for the unit. He pointed out that Tech Spec 3.6.5.1 had been cleared and the only spec we had directing us to continue a cooldown and depressurization to Mode 5 was Tech Spec 3.6.5.3 regarding the ice condenser lower inlet doors. He realized that Tech Spec 3.6.5.3 could be cleared soon and we would have no requirements to continue the cooldown and depressurization.

This on duty Shift Supervisor's request generated a series of discussions among members of Operations management. These discussions resulted in the Superintendent of Operations making a recommendation to the Station Manager at 1200 hours to continue the cooldown and depressurization to Mode 5. The basis for this recommendation was Operations discomfort with maintaining Mode 4 while questions were being raised about the ice bed operability.

Members of station and engineering management met with the Site VP at 1230. After discussing the merits of continuing to Mode 5 or staying in Mode 4 a decision was made to enter Mode 5 and enter the ice bed weight spec (3.6.5.1.d) for tracking pending an engineering evaluation. The control room SRO logged this at 1300.

**SUMMARY OF CONSIDERATIONS
FOR BLOCKING DOORS**

SUMMARY OF CONSIDERATIONS MADE PRIOR TO AUTHORIZING BLOCKING TWO ICE CONDENSER LOWER INLET DOORS

Issue

On August 31, 1993, at approximately 0500 hours, station management authorized blocking two ice condenser inlet doors associated with bays 21 and 22. At the time, the ice condenser was required to be operable, and the action (b.) of Tech spec 3.6.5.3 was intentionally entered.

Discussion

At approximately 0445 hours on this date, the Supt. of Operations (Bruce Hamilton), Operations Staff Manager (Dennis Bumgardner), On Duty Shift Supervisor (Jerry Rumpfelt) and the On Duty Shift Manager (Joe Lukowski) met in the Control Room and discussed the prudence of blocking two of the ice condenser lower inlet doors closed. The two doors were not staying closed and maintenance workers on the scene were periodically pushing them back closed. Initially, 20 of the 24 doors had opened. Of these, 16 were pushed closed and stayed closed once the cold head of air was re-established. Two other doors occasionally reopened and were easily reclosed. Only two doors, those in bays 21 and 22, were frequently reopening. These two doors were close to the steam leak in lower containment and, by opening, they were allowing steam and warm air from lower containment to enter the ice condenser. This was resulting in melting localized areas in the ice bed according to the workers on the scene.

The option of holding the two doors shut (with personnel) and later mechanically blocking the two doors was raised. After discussing this possibility and considering the unit's current status, the Supt. of Operations authorized personnel holding the two doors shut and further authorized the use of mechanical blocking devices if necessary. All four previously mentioned members of Operations management concurred with this decision. At 0500 hours, the Shift Supervisor, entered the two lower inlet doors as inoperable and entered the action step of Tech Spec 3.6.5.3.

Basis for the Decision

These were discussed and agreed to at that time:

- The ice condenser would be rendered inoperable by this action, however, we could, and would, comply with the action item.

- The ice condenser would still have 22 doors available and capable of functioning and that more than enough ice remained in the ice bed.
- The leak was not likely to get worse; by all accounts the valve was supplying no resistance to flow.
- The probability of another leak requiring the functioning of the ice bed was very low (primary and secondary pressures were substantially lower). If another leak occurred, preserving the ice bed from further degradation would enhance our capability of handling a second leak.
- The core had been subcritical for ≈ 2 months and greater than 1/3 of the core was fresh fuel. The decay heat load was very low compared to that assumed in the accident analysis for containment.
- Substantial energy had already been removed from the secondary piping systems in containment. S/G pressure was ≈ 250 psig. Initially, it was ≈ 1100 psig. This was much more conservative than the accident analysis.
- Substantial energy had already been removed from the primary piping systems in containment. NC temp was below 400° F and NC pressure was ≈ 1500 psig. Both down from the at power values used in the accident analysis.
- The initial pressure transient in lower containment was over and had been for more than an hour. Lower containment pressure was back to normal; within 0.2 psig of atmospheric. Lower containment temperatures were also returning to normal and were within Tech Spec 3.6.1.5 limits.
- Blocking the ice condenser lower inlet doors was discussed in terms of preventing a safety system from performing its function. Analogies to resetting the SI were discussed.

The Operations management members concluded:

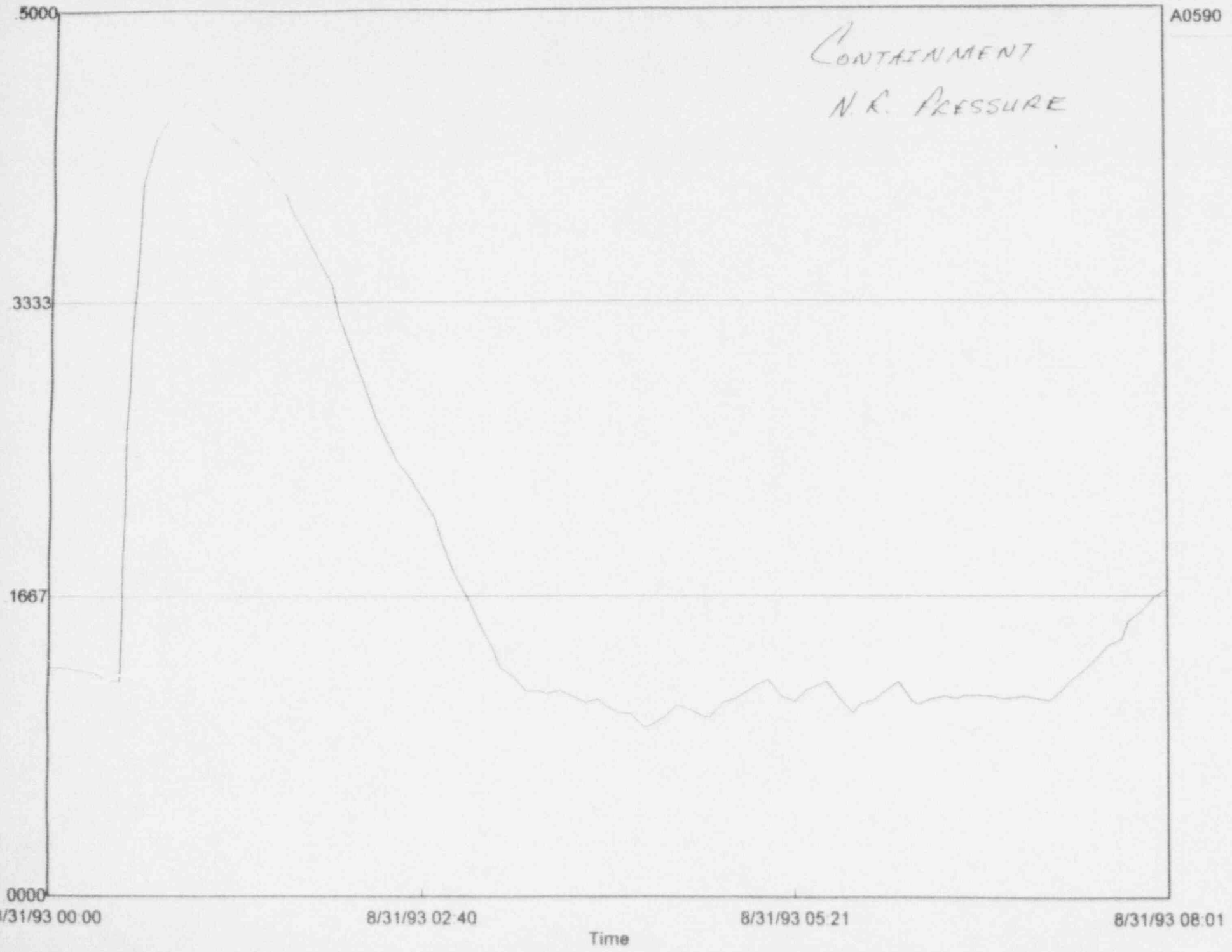
- By blocking the ice condenser lower inlet doors we would make the ice condenser inoperable.

- The ice condenser would still be capable of performing its function if again called upon. Although inoperable, it had sufficient capability of handling any incident that could occur from the specific set of unit conditions in existence at that time.
- The blocking of the ice condenser lower inlet doors was the equivalent of resetting the SI. The transient requiring them to open had passed; containment pressure was again normal. Two doors were being opened by a localized pressure and/or impingement problem and not due to building pressure. Until a sufficient cold head of air could be re-established, this would continue to be a problem. The need for this ESF feature was over (for this transient).
- The ice bed was being needlessly degraded due to a localized problem. Future performance of the ice bed was being threatened by the continuation of heat and steam being admitted to the ice bed in bays 21 and 22.

Attachments

- Graphs of the following over the time interval in question
 - Lower Containment Pressure (N/R)
 - Lower Containment Temperature (weighted average)
 - S/G pressure
 - NC temperature
 - NC pressure
- Graph of typical containment pressure fluctuations
- Statement from Greg Swindlehurst, Duke Power Company Safety Analysis regarding the advisability of this decision dated 9/2/93

CONTAINMENT
N.R. PRESSURE



UNIT - AVERAGE LOWER CONT. TEMP.

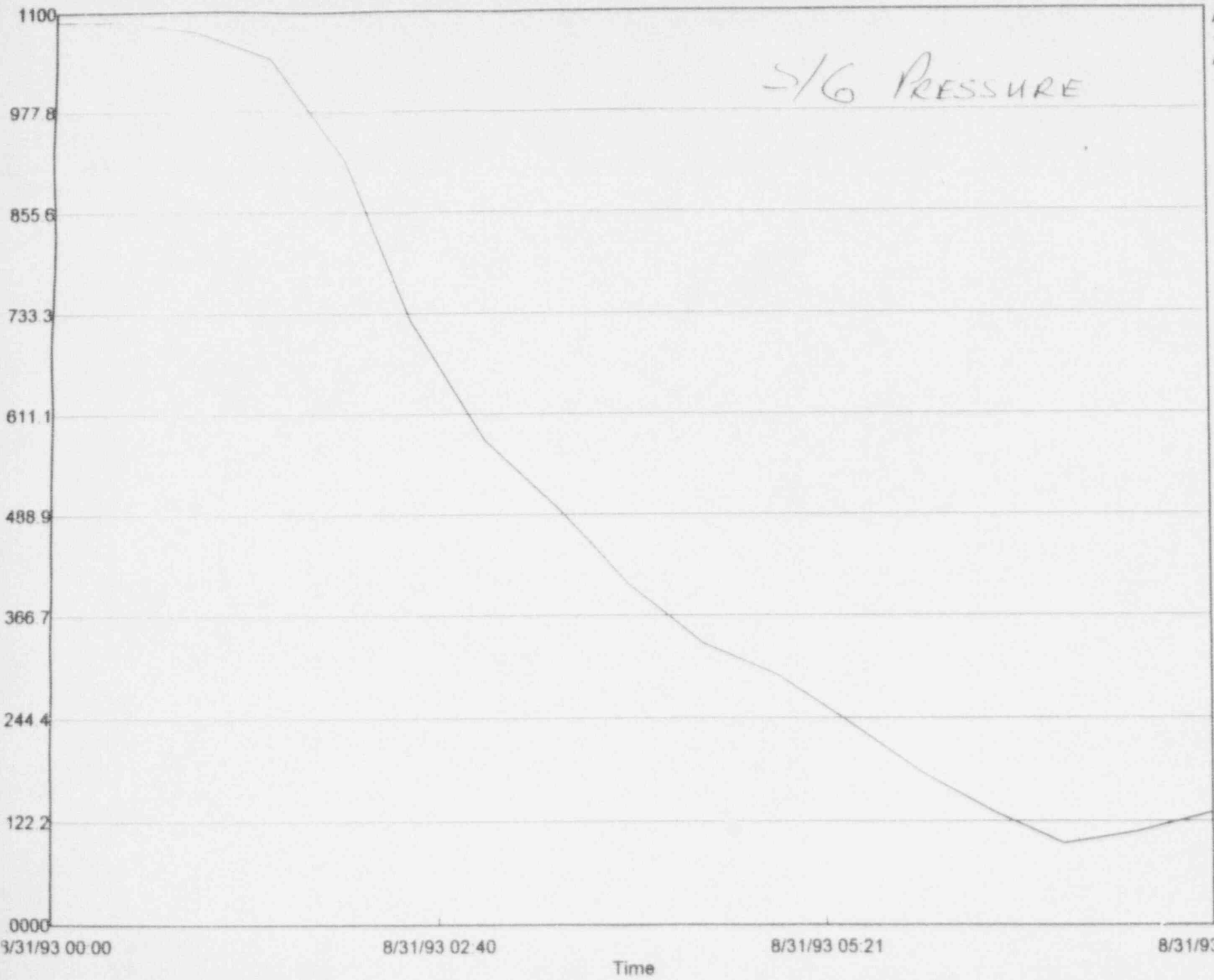
P0755



A1022

A1023

S/G PRESSURE



8/31/93 00:00

8/31/93 02:40

8/31/93 05:21

8/31/93 08:01

Time

WIDE RANGE
NC Sys PRESSURE



600

A1061

A1067

WIDE RANGE
COLD LEG TEMP.

450

300

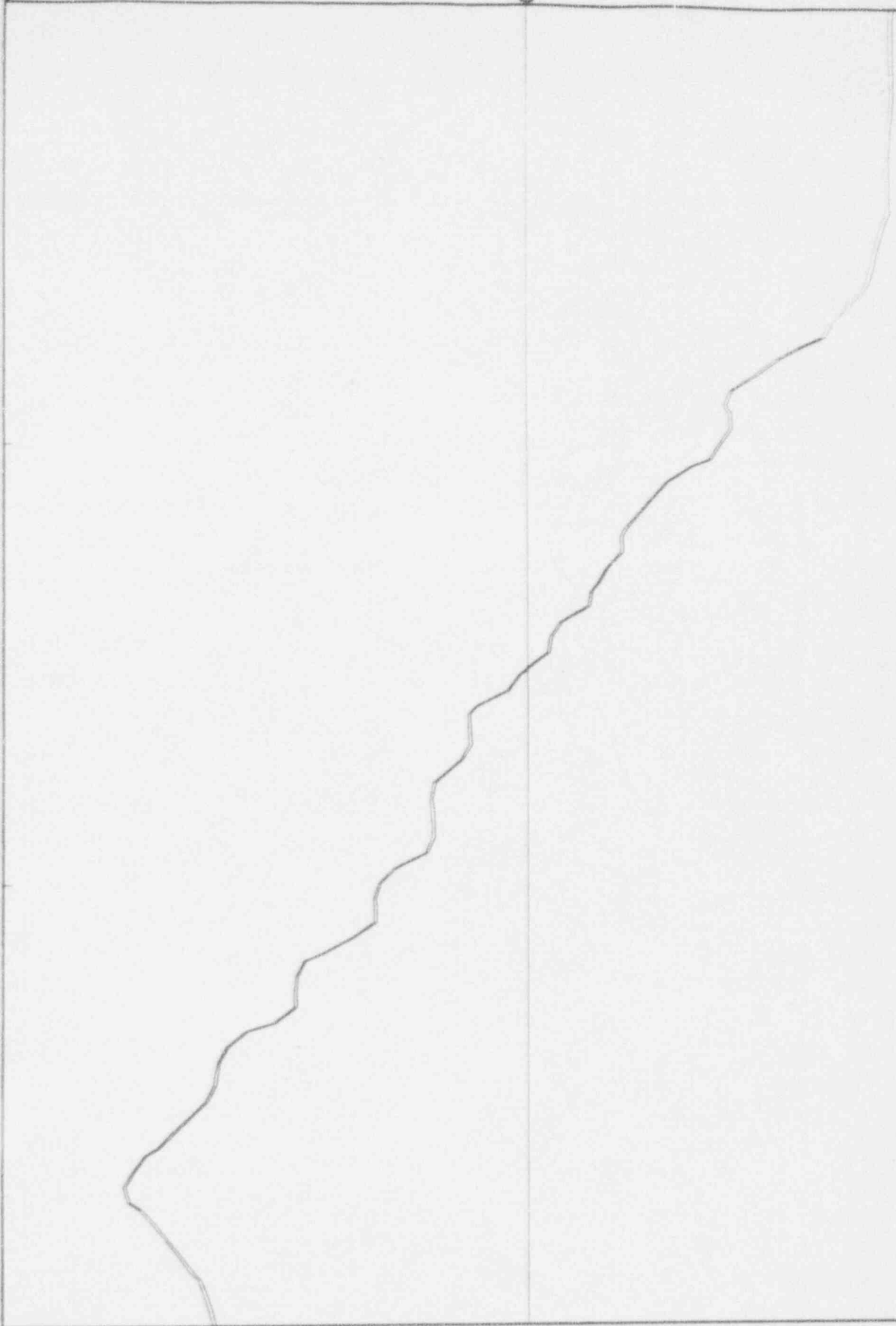
8/31/93 00:00

8/31/93 02:40

8/31/93 05:21

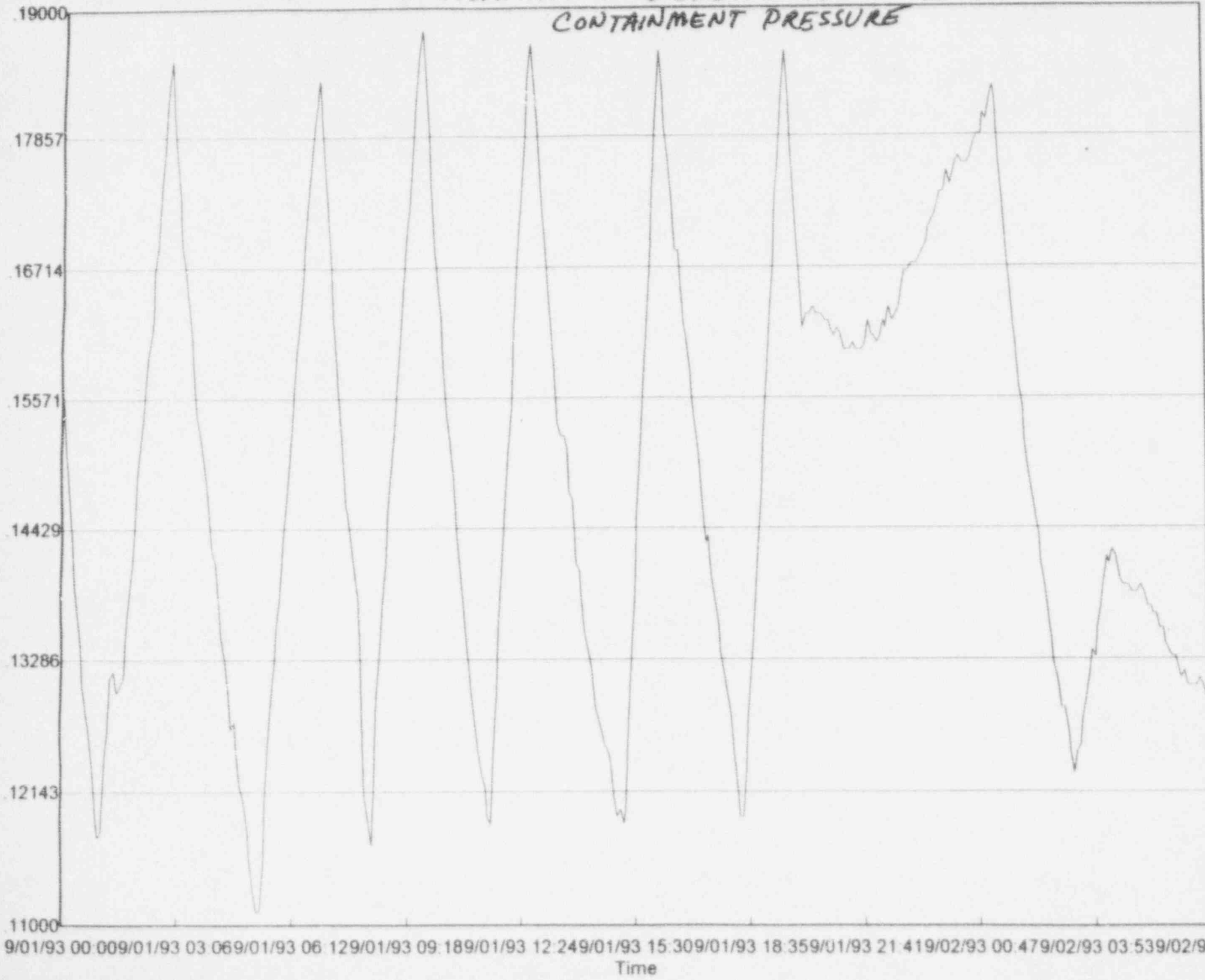
8/31/93 08:01

Time



NORMAL FLUCTUATION OF LOWER
CONTAINMENT PRESSURE

A0590



Facsimile Cover Sheet

To: Bruce Hamilton
Company:
Phone:
Fax: 875-4888

From: From Gregg Swindlehurst
Company:
Phone:
Fax:

Date: 9/2/93
Pages including this
cover page: 3

Comments:

Evaluation of Blocking Ice Condenser Doors During Cooldown
Following the Unit 2 SG Drain Leak Event On 8/31/93

At about 12:30 a.m. on the morning of August 31, 1993, a leak in a steam generator A 1 inch drain line developed in the MNS-2 lower containment. At the time the unit was at full temperature and pressure at no-load conditions. This leak released inventory from the steam generator into containment. As a result, lower containment pressure increased by about 0.45 psi and 18°F. This pressurization caused all but two sets of ice condenser doors to open. Most of these doors were only cracked open, but 4 doors in the vicinity of the leak were fully opened. About 2,400 lbm of ice melted as a result of the leak.

After the event was diagnosed, the unit entered an orderly cooldown and depressurization at a rate of 50°F/hr to reach conditions where the leak could be isolated. This also caused the steam generator leak rate to decrease. At about 5:00 a.m., 4 1/2 hours after the start of the incident, the NC System temperature was down to 422 °F, the containment pressure had returned to its original value, and the lower containment temperature, which peaked at about 134 °F, had decreased to 124 °F. The release from the steam generator drain line was significantly reduced at this time. At about this time all of the ice condenser doors had reclosed except for two, which remained open.

At 5:00 a.m., station personnel decided to manually close (and hold closed) these two doors in an effort to minimize additional ice melt. This was decided based on the return to near-normal pressure and temperature in lower containment, which indicated that the leak had decreased and the continuing energy addition could be removed by the Containment Ventilation (VV) System. The need for the ice condenser should a subsequent event (such as a LOCA) occur was also considered. It was known that decay heat was very low due to the refueling outage, and that the stored energy in the NC System was much reduced following the cooldown to 422°F. It was recognized that blocking closed two of the 24 doors would only minimally decrease the functional capability of the ice condenser, since the remaining 22 doors would still function. The small loss of ice during the steam leak event was also recognized as only a minimal decrease from the initial inventory. Based on these factors, it was decided that the ice condenser would continue to provide a very sufficient post-accident heat sink, and that manually closing the remaining two ice condenser doors was safe and appropriate.

Had a LOCA occurred while these two doors were held shut, the ice condenser would have still performed its intended function. A large-break LOCA with the NC system temperature at 422 °F would release NC inventory and energy at a lower rate than if the reactor had been at full power. The pressure differential between the NC system and containment would be much lower initially, so that less NC inventory would be released out the break. The energy of a LOCA blowdown from these initial conditions is calculated to be about 160 E6 Btu, well below the containment design blowdown energy of 324 E6 Btu. This 50% reduction in the energy release more than offsets the reduction in the capacity of the ice condenser by closing two of the 24 doors and the assumed loss of less than 10% of the ice. The initial containment pressure peak would therefore be much lower for a large-break LOCA with the NC system at these lower pressures and temperatures than for a LOCA from full power conditions. It is also noted that the initial containment pressure peak is not the limiting pressure peak for the full power case.

The long-term pressure peak for a LOCA, which occurs following ice melt, would also be much less due to the reduced decay heat level. Decay heat at the time of ice-melt-out following a large-break LOCA from full power is about 45 MW. The decay heat at the time of the steam leak event was about 2.5 MW, or only 5.6% of the decay heat at the time of ice melt following a LOCA from full power. Even with the ice inventory slightly decreased due to the steam leak, ice meltout would take much longer due to low decay heat. The Containment Spray (NS) System is used to keep containment pressure below the 15 psig limit after the ice melts. One train of spray at 3400 gpm is capable of condensing the steam for an energy release rate of 50,000 Btu/sec. The potential boiloff from decay heat at this time is less than 2400 Btu/sec, or only 5% of the capacity of one spray train. The NS System is therefore able to keep building pressure from increasing following the initial blowdown following a LOCA at 422°F, which will only partially melt the ice inventory. No ice is required for the remainder of the event. The peak pressure would therefore remain well below the design limit of 15 psig.

Based on the above evaluation it can be concluded that the decision to block closed two doors to the ice condenser after the cooldown to 442°F was appropriate and safe, considering the availability of the remaining 22 doors, the reduced stored energy in the NC System, and the low decay heat following the outage.

Any questions, call Gregg Swindlchurst (382-5176)

**SUMMARY OF EVALUATIONS AND
INSPECTIONS PERFORMED ON
ELECTRICAL EQUIPMENT**

SUMMARY OF EVALUATIONS AND INSPECTIONS PERFORMED
ON ELECTRICAL EQUIPMENT, INSTRUMENTATION,
AND CIVIL STRUCTURES FOLLOWING STEAM AND WATER
BLOWDOWN FROM 2CF130

Friday, September 3, 1993

FOLLOWING THE RELEASE OF STEAM TO LOWER CONTAINMENT THROUGH A MALFUNCTION OF BLOWDOWN VALVE 2CF130, IT WAS DECIDED TO PERFORM AN INSPECTION OR EVALUATION OF VARIOUS EQUIPMENT IN LOWER CONTAINMENT TO DETERMINE THE IMPACT OF THE STEAM & WATER ON THAT EQUIPMENT.

THE DETERMINATION OF WHICH EQUIPMENT TO BE INSPECTED WAS BASED ON ENGINEERING JUDGEMENT AND INFORMATION FROM OCONEE NUCLEAR STATION ON WHAT THEY INSPECTED AND FOUND AFTER AN INSTRUMENT LINE BLEW OFF IN 1991.

THE FOLLOWING IS A LIST OF THE EQUIPMENT EVALUATED OR INSPECTED:

1. E.Q. INSTRUMENTATION - EVALUATION PERFORMED BY McGUIRE STATION EQ COORDINATOR. THE READOUT FROM 3 EQ INSTRUMENTS (2CFLT5490, 2CFLT5500 AND 2CFLT5510) WERE CHECKED FOR STABLE AND CORRECT INDICATION. THESE INSTRUMENTS WERE ALL LOCATED IN THE COLD LEG ACCUMULATOR ROOMS ADJACENT TO 2CF130. SEE ATTACHMENT 1 FOR EVALUATION.
2. TARGET ROCK SOLENOID VALVES - 4 OF 4 WERE FUNCTIONALLY VERIFIED BY CYCLING EACH VALVE. SEE ATTACHMENT 2 FOR WORK ORDER NUMBERS AND COMMENTS.
3. FIRE DETECTORS - 12 OF 19 ZONES WERE INSPECTED. 10 OF THE 12 OPERATED SATISFACTORY. SMOKE DETECTORS IN THE 2 FAILED ZONES WERE DRIED AND PLACED BACK IN SERVICE. SEE ATTACHMENT 3 FOR WORK ORDER NUMBER AND COMMENTS.
4. RESISTANCE TEMPERATURE DETECTORS (RTDs) - EVALUATION MADE AS EQ INSTRUMENTATION UNDER ITEM # 1.
5. PRESSURE OPERATED RELIEF VALVE ACOUSTIC LEAK MONITOR - EVALUATION MADE AS EQ INSTRUMENTATION UNDER ITEM # 1.
6. REACTOR COOLANT PUMP MOTORS - INSPECTED LEAD BOX, TERMINATIONS AND INSIDE OF MOTOR ON PUMP 2A. ALL AREAS CHECKED WERE DRY. SEE ATTACHMENT 4 FOR WORK ORDER NUMBER AND COMMENTS.
7. VALVE OPERATORS - MOVs EVALUATION MADE AS EQ INSTRUMENTATION UNDER ITEM # 1.
8. ELECTRICAL PENETRATIONS - NO ADDITIONAL INSPECTION REQUIRED BASED ON EVALUATION. SEE ATTACHMENT 8 FOR EVALUATION.

- 9.# CONTROL ROD DRIVES - THE CRDMs WERE CHECKED AND TWO CABLES/CRDMs APPEAR TO HAVE SHORTS. PLANS ARE TO REMOVE THE CRDMs, DISASSEMBLE AND TRY TO DRY THEM. THIS WILL BE COMPLETED BEFORE UNIT RESTART. WORK ORDER 93064212 IS BEING USED TO PERFORM THE WORK.
- 10.# DIGITAL ROD POSITION INDICATION - EVALUATION OF PRESENT ROD POSITION INDICATIONS SHOWS NO MALFUNCTIONING INDICATORS. A THOROUGH VERIFICATION CAN ONLY BE PERFORMED AFTER RODS ARE RAISED.
11. PRESSURIZER HEATERS - EVALUATION OF EQUIPMENT CONSTRUCTION AND VERIFICATION OF HEATER AMP READINGS INDICATE NO FURTHER INSPECTIONS NECESSARY. SEE ATTACHMENT 9 FOR EVALUATION AND DATA.
12. INCORE INSTRUMENTATION - SOME WATER INTRUSION WAS DETECTED. ONE MOTOR STARTER WAS DRIED WHILE ANOTHER REQUIRED REPLACEMENT. WORK ORDER 93012028 WAS USED FOR INSPECTION AND REPAIR WORK. SEE ATTACHMENT 11 FOR COMMENTS.
13. VL FAN UNITS - AN EVALUATION WAS PERFORMED ON THE LOWER CONTAINMENT VENTILATION UNITS. BASED ON EQUIPMENT DESIGN AND PAST OPERATING EXPERIENCE, FURTHER INSPECTION WAS DEEMED NOT NECESSARY. SEE ATTACHMENT 5 FOR EVALUATION COMMENTS.
14. VL FAN UNIT VIBRATION DETECTION UNITS - MONITOR CABINETS WERE INSPECTED FOR MOISTURE AND WERE FOUND DRY. ALL ALARMS WERE CLEAR. SEE ATTACHMENT 6 FOR WORK ORDER NUMBER AND COMMENTS.
15. LOWER CONTAINMENT LIGHTING POWER PANELS - 3 OF 4 LIGHTING PANELS INSIDE THE SHEILD WALL IN LOWER CONTAINMENT WERE INSPECTED FOR MOISTURE/WATER INTRUSION AND ALL WERE FOUND DRY. SEE ATTACHMENT 12 FOR WORK ORDER NUMBER AND COMMENTS.
16. CIVIL CONCERNS - A REVIEW OF VARIOUS CODES AND SPECIFICATIONS FOR STRUCTURAL STEEL AND CONCRETE REVEALED THE STRUCTURE WAS NOT COMPROMISED IN ANY WAY. SEE ATTACHMENT 10 FOR EVALUATION.

INCOMPLETE ACTIVITY AS OF 9/3/93, 1700.

17. GENERAL INSPECTION OF ELECTRICAL EQUIPMENT AND INSTRUMENTATION IN AREA AROUND 2CF130 - THE FOLLOWING INSTRUMENTATION WAS VISUALLY INSPECTED FOR DAMAGE DUE TO CLOSE PROXIMITY TO 2CF130:

- A. 2VPPT5130 *
- B. 2VPPT5120 *
- C. 2VPPT5140 *
- D. 2NVLS5070 *
- E. 2NVLS5071 *
- F. 2NCLT5991
- G. 2BWPE5070
- H. 2BWPI5070
- I. 2BWPG5070

* THE FUNCTIONS OF THESE INSTRUMENTATION WERE ALSO VERIFIED TO ENSURE PROPER READOUTS WERE BEING RECEIVED.

A GENERAL AREA INSPECTION REVEALED LITTLE INDICATION THAT STEAM/WATER IMPINGEMENT DUE TO THIS EVENT WAS GOING TO BE A PROBLEM. SEE ATTACHMENT 7 FOR WORK ORDER NUMBER AND COMMENTS.

Sept. 1, 1993

A review of Equipment Qualification criteria for instrumentation and components located in McGuire Unit 2 Lower Containment area indicates that all required Nuclear Safety Related and Post Accident Monitoring equipment is qualified to the peak postulated accident environment for lower containment of:

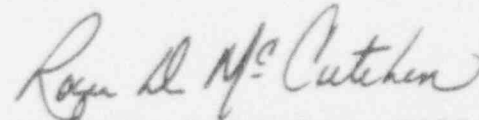
330 Deg. F
15 PSIG
100% Relative Humidity

Based upon established qualification methodology utilizing Arrhenius calculations and incorporating applicable margins, the relative short transient of 6 hours incorporating maximum peak values of:

162 Deg. F
0.90 PSIG
100% Relative Humidity

as occurred as a result of the incident relative to 2CF130.

This transient would not challenge the operability of this equipment nor would there be any discernable effect on the overall qualification and life of this equipment.



Roger D. McCutchen, TSII
Station EQ Coordinator

Help Data Print Roadmap Exit

W/O Task : 93012355 02 Task Status: COMPLETE Status Date : 09/02/93
 Title : PERFORM FUNC VERIF _____ Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000444789 _____
 Equipment: MNC VA 0275B _____ Mfr. Code : TARGET ROCK_
 Component: MNC SV 0275 _____ Model No. : 79L-009 _____
 Work Item: _____ Serial No.: 10 _____

=====

Last Update By: WBD8265_ Last Update Date: 09/02/93
 QUESTION, AND AGREES THAT IT IS A INDICATION PROBLEM ONLY. OPS RETEST_ WBD8265_
 PERFORMED ON 8/24/93 WITH SATISFACTORY RESULTS. VALVES WERE CYCLED _____ WBD8265_
 AFTER STEAM LEAK TO VERIFY OPERABILITY PER RON BLAKE. CDH 9/2/93 _____ WBD8265_

More: -

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Pwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93012356 02 Task Status: COMPLETE Status Date : 09/02/93
 Title : PERFORM FUNC VERIF Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000444788
 Equipment: MNC VA 0274B Mfr. Code : TARGET ROCK_
 Component: MNC SV 0274 Model No. : 79L-009
 Work Item: Serial No.: .7

=====

Last Update By: WBD8265_ Last Update Date: 09/02/93
 QUESTION, AND AGREES THAT IT IS A INDICATION PROBLEM ONLY. OPS RETEST_ WBD8265_
 PERFORMED ON 8/24/93 WITH SATISFACTORY RESULTS. VALVES WERE CYCLED_ WBD8265_
 AFTER STEAM LEAK TO VERIFY OPERABILITY PER RON BLAKE. CDH 9/2/93_ WBD8265_

More: -

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93012357 02 Task Status: COMPLETE Status Date : 09/02/93
 Title : PERFORM FUNC VERIF _____ Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000444787 _____
 Equipment: MNC VA 0273AC _____ Mfr. Code : TARGET ROCK_
 Component: MNC SV 0273 _____ Model No. : 79L-009 _____
 Work Item: _____ Serial No.: 6 _____

=====

Last Update By: WBD8265_ Last Update Date: 09/02/93
 QUESTION, AND AGREES THAT IT IS A INDICATION PROBLEM ONLY. OPS RETEST_ WBD8265_
 PERFORMED ON 8/24/93 WITH SATISFACTORY RESULTS. VALVES WER CYCLED _____ WBD8265_
 AFTER STEAM LEAK TO VERIFY OPERABILITY PER RON BLAKE. CDH 9/2/93 _____ WBD8265_

More: -

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93012358 02 Task Status: COMPLETE Status Date : 09/02/93
 Title : PERFORM FUNC VERIF Resp. Facility: MC
 Facility : MC Unit: 2 UTC : 0000444786
 Equipment: MNC VA 0272AC Mfr. Code : TARGET ROCK
 Component: MNC SV 0272 Model No. : 79L-009
 Work Item: Serial No.: 8

=====
 Last Update By: WBD8265 Last Update Date: 09/02/93
 QUESTION, AND AGREES THAT IT IS A INDICATION PROBLEM ONLY. OPS RETEST WBD8265
 PERFORMED ON 8/24/93 WITH SATISFACTORY RESULTS. VALVES WERE CYCLED WBD8265
 AFTER STEAM LEAK TO VERIFY OPERABILITY PER RON BLAKE. CDH 9/2/93 WBD8265

More: -
 RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063778 01 Task Status: NOHOLDS_ Status Date : 09/02/93
 Title : REPAIR EFA ZONES AS LISTED Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000483006
 Equipment: EFA LP XX26 Mfr. Code : CONRAC
 Component: Model No. : 9620
 Work Item: Serial No.: UNKNOWN001034295

=====
 Last Update By: CDH8265_ Last Update Date: 09/02/93
 ALL PREQ. MET CDH RESET THE FOLLOWING ZONES,166,173,175,176,180,165, CDH8265_
 172,167,174, AND 168. CLEANED DETECTORS IN ZONES 164 AND 170. SMOKED CDH8265_
 DETECTORS TO VERIFY PROPER OPERATION. CDH8265_
 CHECKED SUPERVISORY CIRCUITS TO VERIFY PROPER OPERATION. CDH8265_
 PERFORMED FUNCTIONAL VERIFICATION BY OBSERVING NO ZONES IN ALARM AND CDH8265_
 NO TROUBLES EXISTED. CDH WBD TEM 09/02/93 CDH8265_

More:
 RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

As a result of the containment steam leak incident, 12 out of the 19 EFA fire zones in containment went into alarm. The detector inventory of the zones that alarmed consisted entirely of Dual Chamber Ionization Detectors which are designed to negate the effects of atmospheric changes (ie: pressure, humidity, etc). However, excessive humidity (condensation) can be misread as combustion particles by the sensors.

Inspection/Troubleshooting/Repair:

Typical nuisance alarms may be reset at the Fire Detection Computer provided the cause of alarm has disappeared. Ten of the 12 zones which came in alarm were able to be reset through the computer, indicating the source was no longer present. The two remaining zones consisted of 12 ionization detectors which were cleaned/dried before resetting was possible. All detectors in these zones were smoke tested to verify proper operation after cleaning.

Data Gathering Panels (DGPs) for all fire detection zones are located outside containment, therefore no physical inspection was performed. However, a system condition check was made to verify proper operation of all DGPs, using the Fire Detection Computer. No "ALARM" or "TROUBLE" conditions existed for the affected zones after the completion of the inspection/repairs.

Concerns:

Fire zones in containment have no control actions besides activating sirens. If accelerated detector degradation occurs due to the exposure of the detectors to water, the diagnostics of the EFA System as well as the semi-annual PMS will detect any detector failures.

Help Data Print Roadmap Exit

W/O Task : 93063924 02 Task Status: L/COMPLT Status Date : 09/02/93
 Title : INSPECT NCP MOTOR 2A LEAD TERMINATIONS. Resp. Facility: MC
 Facility : MC Unit: 2 UTC : 0000438998
 Equipment: MNC MR 0001 Mfr. Code : WESTINGHOUSE
 Component: Model No. : UNKNOWN00056853
 Work Item: Serial No.: UNKNOWN001001896

=====

Last Update By: JRB8597 Last Update Date: 09/02/93
 STARTED WORK 9/2/93 CHECKED WITH OPERATIONS TO BEGIN WORK. CHECKED RED JRB8597
 TAGS AND BRAKER IN OPEN POSITION. INSPECTED INSIDE LEAD BOX AND JRB8597
 TERMINATIONS FOR MOSITURE. INSIDE OF MOTOR WAS DRY. CHECKED LEAD BOX JRB8597
 GASKET WAS GOOD, PUT MOTOR COVER BACK ON AND MADE SURE IT SEALED AND JRB8597
 CALKING AROUND BOXWAS GOOD. CREW 322 JRB8597 KRS3183 DEG5600 30MHR JRB8597

More:
 RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

ATTACHMENT 4

From: MGS1796 --PRDC

To: JTM3369 --PRDC

Jeffery T. Miller

Date and time

09/01/93 14:43:28

Subject: VL, Lower Containment Ventilation, Fan Motors

Jeff, per our previous discussion, a lower containment atmosphere of 10% R.H. would not detrimentally affect the operability or material condition of the VL fan motors. This is based on the configuration of the VL Air Handling Unit: the motor is housed inside the air handling unit housing; a water drip baffle is arranged on the return air side, between the fan and cooling coil. The baffle is designed to prevent condensate from the cooling coil from being sprayed on the fan blades as well as the motor. In addition, I talked with Al Batts, MEC, and he noted the satisfactory operation of the VL fan motors with the spray nozzles forcing water on the outside of the cooling coils.

Thank you,

Mike Schell

ATTACHMENT 5

1/1

Help Data Print Roadmap Exit

W/O Task : 93063924 03 Task Status: NOHOLDS_ Status Date : 09/02/93
 Title : INSPECT VL VIB MON CABINETS FOR MOISTURE Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : _____
 Equipment: MVL LP 9100 _____ Mfr. Code : _____
 Component: _____ Model No. : _____
 Work Item: _____ Serial No.: _____

=====

Last Update By: DEL8265_ Last Update Date: 09/03/93

9/2/93 DEL JEC *** CONTACTED OPS AND RP. CHECKED ON HVAC PANEL AND DEL8265_
 NO ALARMS WERE FOUND ON ANY OF THE FOUR VL UNITS, ALSO CHECKED THE IRS DEL8265_
 MOD. IN THE CABLE SPREAD ROOM TO VERIFY NO ALARMS. WENT TO A/D AND B/C DEL8265_
 FAN ROOMS AND OPENED THE CABINETS CONTAINING THE VIB MON. EQUIP. ALL DEL8265_
 FOUR CABINETS WERE DRY , AND NO EVIDENCE OF ANY MOISTURE HAD BEEN IN DEL8265_
 THE CABINETS . ALL VENT FANS WERE RUNNING AND ALL VIB EQUIP WAS CLEAN DEL8265_
 AND OPERATING CORRECTLY. _____ DEL8265_

More:
 RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063924 01 Task Status: NOHOLDS_ Status Date : 08/31/93
 Title : INSP ATTACHED LISTED INST(S) FOR DAMAGE. Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 000464031
 Equipment: MCF VA 0130 Mfr. Code : BROTTEST
 Component: MCF MV 0130 Model No. : UNKNOWN00069695
 Work Item: Serial No.: YN15-6

=====
 Last Update By: DEL8265_ Last Update Date: 08/31/93
 8/31/93 DEL JEC***** OBTAINED PRINTS AND PERMISSION TO BEGIN WORK. DEL8265_
 2MVPPT5130 1.25 INWC ABSOLUTE DEL8265_
 2MVPPT5120 0 INWC PRE-FILTER DEL8265_
 2MVPPT5140 .4 INWC CARBON FILTER DEL8265_
 2MNVLS5070 COMP. D1495 NOT HI ALARM PANEL 2AD7-1.1 NO ALARM DEL8265_
 2MNVLS5071 COMP. D1494 NORMAL ALARM PANEL 2AD7-2.1 NO ALARM DEL8265_
 x2MNCLT5991 COMP. A0608 NOT IN SERVICE , VAVLED OUT (FOR DRAIN DOWN) DEL8265_
 2MBWPE5070 2MBWPI5070 2MBWPG5070 COMP. A1517 -25% (ALL S/G ARE AT DEL8265_
 -25% , A1523 A1529 A1535) DEL8265_
 THIS INFO IS AS OF 2200 8/31/93 WITHOUT GOING IN THE RX BUILDING. DEL8265_

More:

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063924 01 Task Status: NOHOLDS_ Status Date : 08/31/93
 Title : INSP ATTACHED LISTED INST(S) FOR DAMAGE. Resp. Facility: MC
 ility : MC Unit: 2_ UTC : 0000464031_____
 Equipment: MCF VA 0130____ Mfr. Code : KEROTEST_____
 Component: MCF MV 0130____ Model No. : UNKNOWN00069695_
 Work Item: _____ Serial No.: YN15-6_____

=====
 Last Update By: JEC8265_ Last Update Date: 09/02/93
 THIS INFO IS AS OF 2200 8/31/93 WITHOUT GOING IN THE RX BUILDING. DEL8265_
 09/01/93 DEL,JEC **** CONTACTED RP (GENE NEAL) DISCUSSED SCOPE OF JOB JEC8265_
 AND HAD PRE-JOB MEETING. JEC8265_
 ENTERED LOWER CONTAINMENT AND UPON INITIAL INSPECTION FOUND THEIR WAS JEC8265_
 NO INDICATION OF ANY DAMAGE TO INSTRUMENTION DUE TO WATER OR HIGH JEC8265_
 PRESSURE STEAM. THE FOLLOWING IS A LIST OF MATERIAL CONDITIONS THAT JEC8265_
 NEEDS TO BE ADDRESSED. JEC8265_
 2MBWLT5070 (THIS INSTRUMENT AND AIR IS ISOLATED DURING NORMAL OPER) JEC8265_
 THE REGULATOR LEAKS, AIR LINE FEEDING THE TRANSMITTER IS CRIMPED (1/4" JEC8265_
 COPPER, PARKER) JEC8265_

More: --

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063924 01 Task Status: NOHOLDS_ Status Date : 08/31/93
 Title : INSP ATTACHED LISTED INST(S) FOR DAMAGE. Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000464031_____
 Equipment: MCF VA 0130____ Mfr. Code : KEROTEST_____
 Component: MCF MV 0130____ Model No. : UNKNOWN00069695_
 Work Item: _____ Serial No.: YN15-6_____

=====
 Last Update By: JEC8265_ Last Update Date: 09/02/93
 COPPER, PARKER) _____ JEC8265_
 2MNCLT5990 (INSTRUMENT IS VALVED OUT AND NOT USED DURING NORMAL OPER.) JEC8265_
 HIGH SIDE TEST "T" CAP MISSING. CABLE ENTRANCE EQ SEAL. _____ JEC8265_
 2MNCLT5991 (INSTRUMENT IS VALVED OUT AND NOT USED DURING NORMAL OPER.) JEC8265_
 INSTRUMENT NOT FOUND IN LOWER CONTAINMENT AT THIS TIME. LOCATED IN IAE JEC8265_
 HOTSHOP PER CHARLIE HOLCOMB (IAE TECH). _____ JEC8265_
 2MBBSV1400 (I&C LIST SHOWS THIS INSTRUMENT DELETED) REGULATOR AND SOL. JEC8265_
 STILL MOUNTED WITH 6' OF 3/8" COPPER TUBING HANGING OUT OF THE OUTPUT JEC8265_
 SIDE OF THE SOLENIOD VALVE. LOCATED ON INNER CRANE WALL 35 DEGREE 740 JEC8265_
 ELEVATION. _____ JEC8265_

More: --+

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063924 01 Task Status: NOHOLDS_ Status Date : 08/31/93
 Title : INSP ATTACHED LISTED INST(S) FOR DAMAGE. Resp. Facility: MC
 ility : MC Unit: 2_ UTC : 0000464031_____
 Equipment: MCF VA 0130____ Mfr. Code : KEROTEST_____
 Component: MCF MV 0130____ Model No. : UNKNOWN00069695_
 Work Item: _____ Serial No.: YN15-6_____

=====
 Last Update By: JEC8265_ Last Update Date: 09/02/93

ELEVATION. _____ JEC8265_
 COVER FOUND MISSING OFF OF A 2 1/2" LB TWO SCREWS WERE IN THE LB BODY, JEC8265_
 TWO SCREWS MISSING. LOCATED AT INNER CRANE WALL 41 DEGREES EL. 755 _____ JEC8265_
 BEHIND "A" PUMP MOTOR. STEEL ARMORED JACKETED CABLE IS RUN IN CONDUIT. JEC8265_
 AS STATED BEFORE THESE ARE MATERIAL CONDITION ITEMS AND IN NO WAY WAS _____ JEC8265_
 CAUSED BY OR AFFECTED BY THE 2CF130 PROBLEM. _____ JEC8265_
 ONE ITEM THAT WAS AFFECTED BY THE WATER WAS A LIGHTING FIXTURE GLOBE _____ JEC8265_
 WAS FILLED APPROX. 3" OF WATER. LOCATED AT INNER CRANE WALL 30 DEGREES JEC8265_
 737 ELEVATION. _____ JEC8265_
 GENERATED WORK REQUEST (93030237) TO CORRECT MATERIAL CONDITION ON _____ JEC8265_

More: -+

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

Help Data Print Roadmap Exit

W/O Task : 93063924 01 Task Status: NOHOLDS_ Status Date : 08/31/93
 Title : INSP ATTACHED LISTED INST(S) FOR DAMAGE. Resp. Facility: MC
 Facility : MC Unit: 2_ UTC : 0000464031_____
 Equipment: MCF VA 0130____ Mfr. Code : KEROTEST_____
 Component: MCF MV 0130____ Model No. : UNKNOWN00069695____
 Work Item: _____ Serial No.: YN15-6_____

=====
 Last Update By: JEC8265_ Last Update Date: 09/02/93
 GENERATED WORK REQUEST (93030237) TO CORRECT MATERIAL CONDITION ON _____ JEC8265_
 2MBBSV1400 AND THE MISSING 2 1/2" LB COVER. _____ JEC8265_

More: -

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Fwd F9=More Detail F12=Cancel

ELECTRICAL PENETRATIONS

There will be no additional need to inspect Electrical Penetrations (D G O'Brien and Conax) as a result of the Unit 2 CF pipe cap leak event. The penetration junction boxes are designed for venting and draining should water/moisture intrude. Cables entering the penetrations are rated for wet or dry locations. These cables terminate to hermetically sealed modules using connector plugs that are provided with elastomeric elements that environmentally seal each cable conductor, preventing conductive contaminants from reaching the pin/socket contact mating surface. Electrical Penetrations are designed and qualified for chemical spray and steamline break temperatures in excess of 325 deg F and 100 percent relative humidity. The conditions presented during the event were well below the design qualifications of all installed Electrical Penetrations.

Danny L Hepler
Component Engineering
McGuire Nuclear Station

9-3-93

MEMORANDUM TO FILE

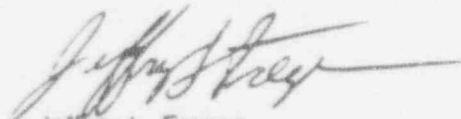
Subject: Pressurizer Heater Delta Box Integrity After 2CF-130 Valve Incident

Research into the possibility of moisture intrusion into the Unit 2 Pressurizer Heater Delta Boxes due to the 2CF-130 incident shows no degradation of heater capacity and no abnormalities in heater operation.

All heater groups have operated or are operating at their maximum capacities since the event occurred. This coupled with the fact that the terminal strips for the Delta connection are inclosed inside of NEMA 4 enclosures which are sealed with RTV sustain the conclusion that no moisture intrusion occurred. These terminal strips and boxes were redone as recent as 3.5 years ago and have not been disturbed since.

Attached are graphs of the operation of the heater groups showing maximum amperage output during their operation. Some of the heaters have been in frequent, almost continuous use, and show no reduction in capacity.

Based on these two facts I see no reason to suspect that any moisture was able to get into the Delta boxes.

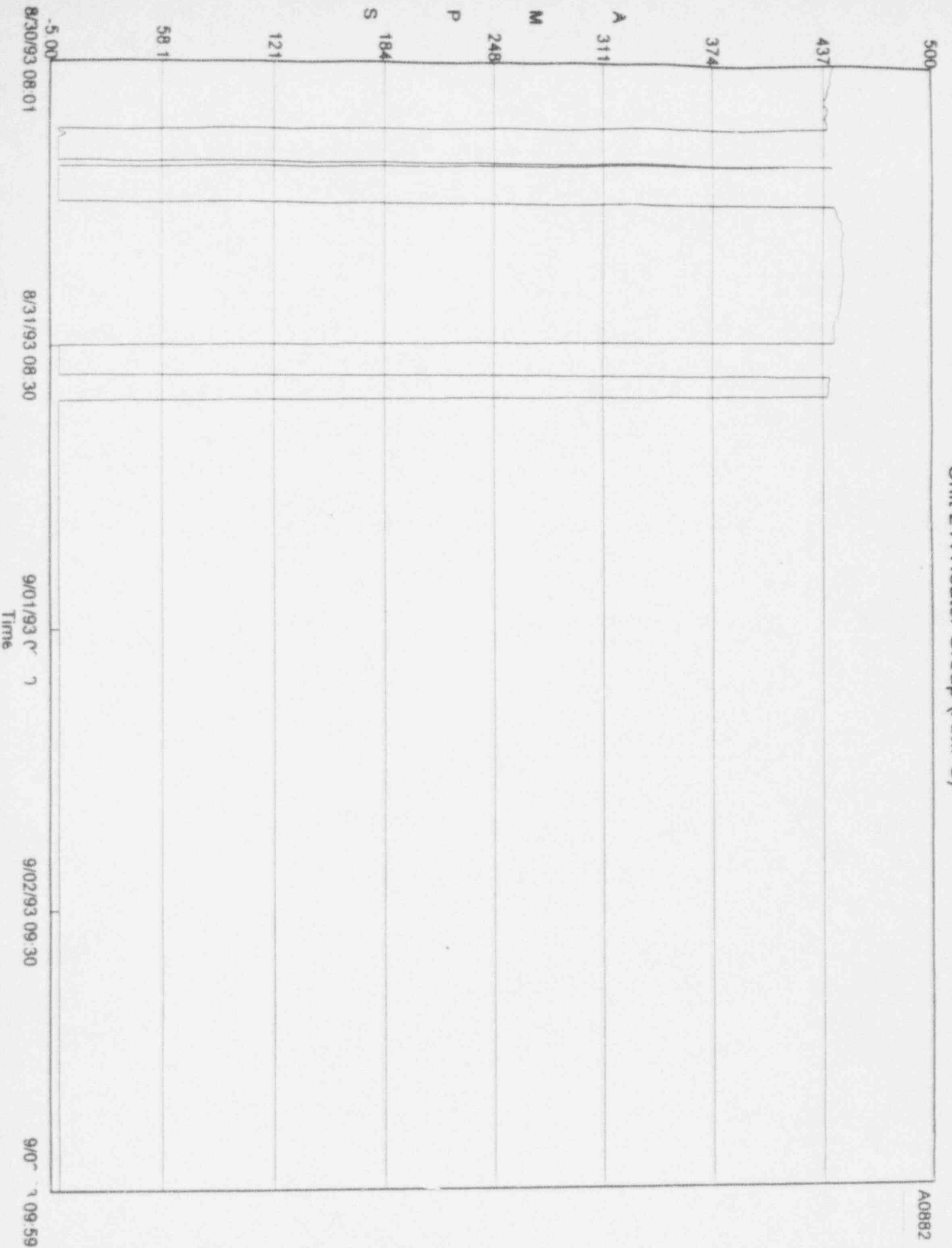


Jeffrey L. Freeze
MNS/CE

ATTACHMENT 9

1/5

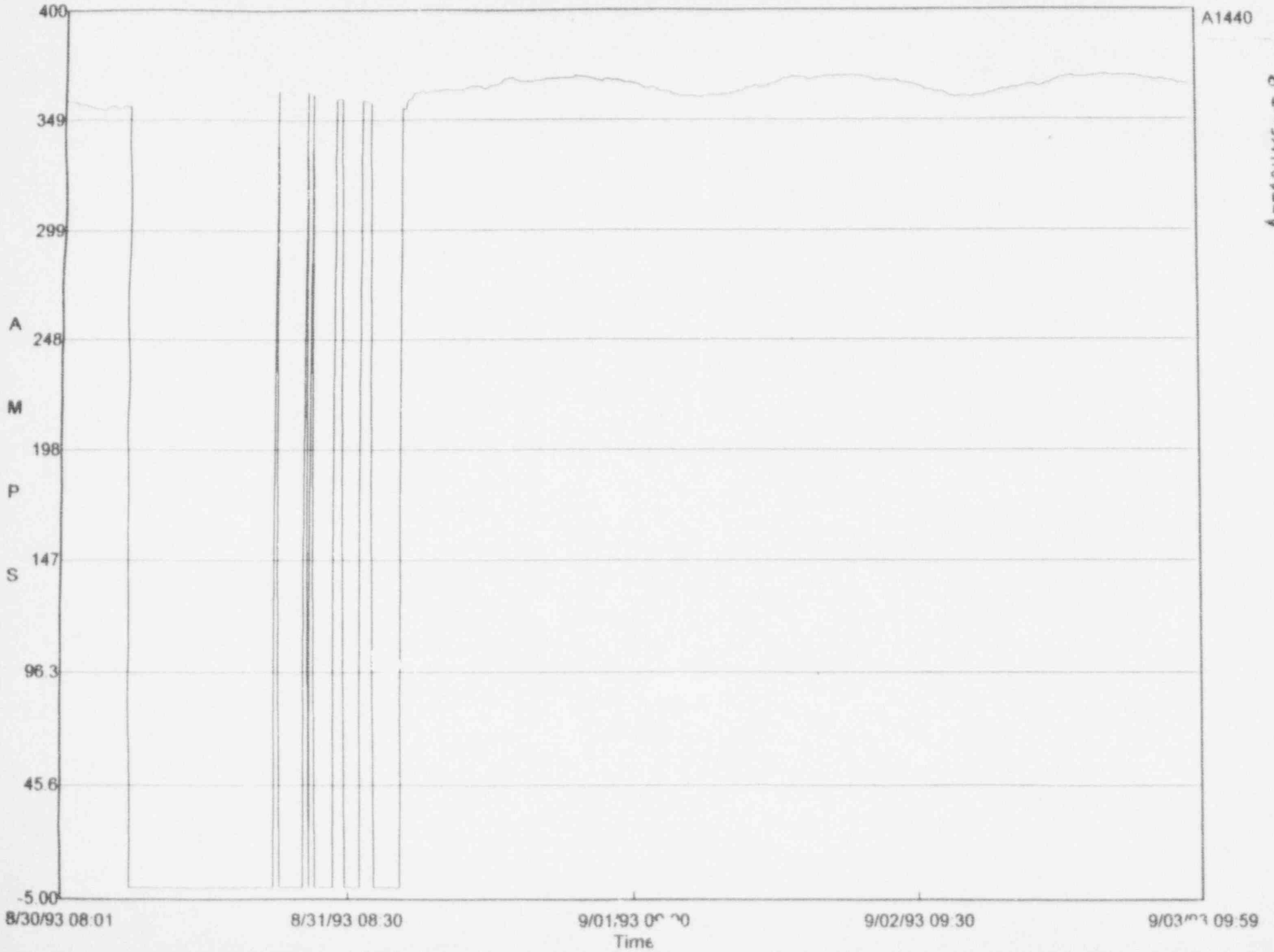
Unit 2 A Heater Group (AMPS)



A0882

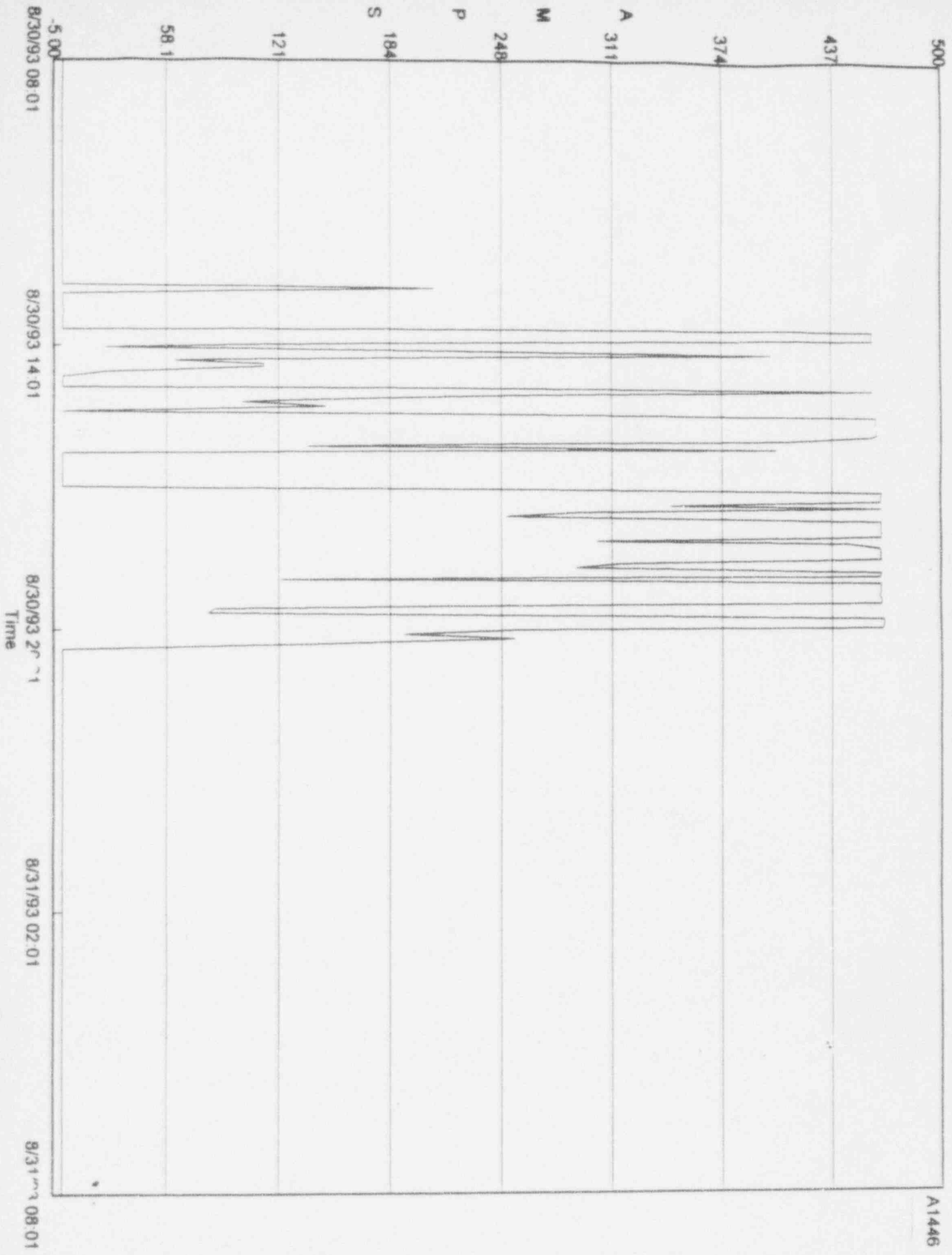
Unit 2 B Heater Group (AMPS)

A1440



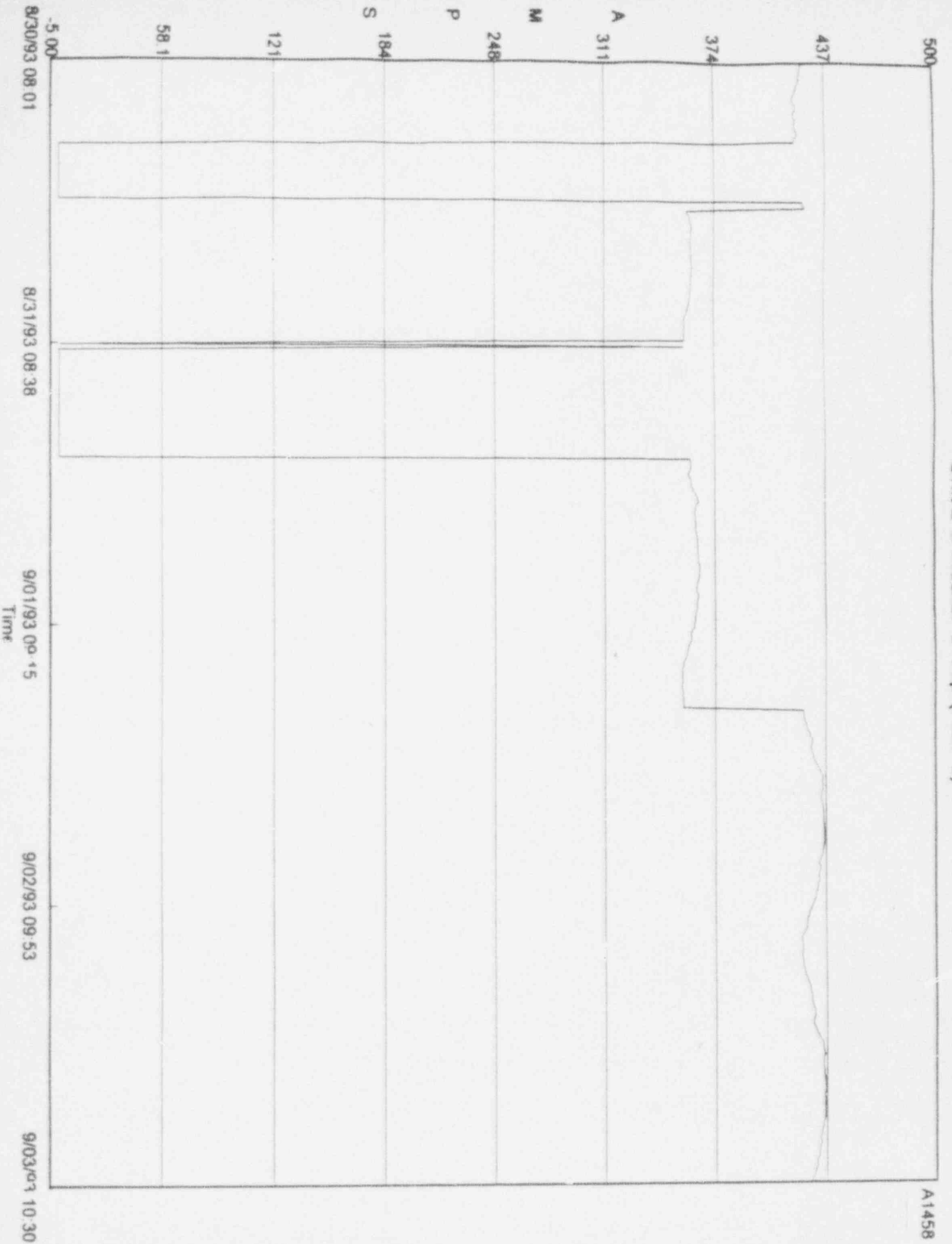
ATTACHMENT 9
3/5

Unit 2 C Heater Group (AMPS)



A1446

Unit 2 D Heater Group (AMPS)



A1458

September 3, 1993

RW Pierce

Ref: McGuire Nuclear Station, Unit 2
Unit 2 Steam Leak in Containment
File Nos: MC-1134.02

Our review of the August 31, 1993 steam leak (2CF-130) inside Unit 2 containment has concluded that the steam/water spray and elevated temperature which resulted in lower containment had negligible impact to structural steel and concrete. The structural capability of steel and concrete in containment was not compromised in any way.

The video tape of the incident area and leakage was reviewed. The steam leak was likely blowing onto the 1 5/8" thick flanges of the lower lateral support of Steam Generator 2A. The distance from the steam leak to the concrete floor below is approximately 23 feet. The impact of any type of jet impingement loading from the steam leak onto the lower lateral support steel or the concrete floor below is considered to be relatively insignificant considering relative size/strength of these structural members.

The McGuire Nuclear Station Plant Environmental Parameters Manual identifies this area in lower containment as pipe rupture zone 2725S02. This zone is subject to a high temperature steam environment and water spray up to 330 degrees fahrenheit. The maximum peak temperature inside containment during the steam leak was 162 degrees fahrenheit (reference WN Matthews' 9/1/93 letter to Tom Curtis concerning 2CF130 Incident - Environmental Qualification).

The impact of this elevated temperature to structural steel is considered negligible. AISC 7th Edition notes that "Short-time elevated temperature tensile tests on the steels permitted by the AISC Specification indicate that steels having similar metallurgical characteristics have similar ratios of elevated - and room - temperature yield and tensile strengths". Referring to the material allowables for A36 in a later date ASME Boiler and Pressure Code, the reduction in yield stress due to the elevated temperature experienced during the steam leak is approximately 6%. This reduction in yield stress can be neglected based on the short-time duration of the elevated temperature and inherent design margins.

The impact of this elevated temperature on concrete is also considered negligible. ACI 318-63 (Building Code Requirements for Reinforced Concrete) does not specifically address the effect of elevated temperatures on concrete. Later date ACI 349-85 (Code Requirements for Nuclear Safety Related Concrete Structures) does address limiting concrete temperatures so as to limit concrete stresses to design allowables as follows: "For accident or any other short-term period, the temperature shall not exceed 350 F for

ATTACHMENT 10

1/2

the interior surface. However, local areas are allowed to reach 650 F from fluid jets in the event of a pipe failure." The short-term elevated temperature experienced during the steam leak is well bounded by this statement; therefore, the impact to concrete in lower containment is negligible.

In conclusion, the structural capability of steel and concrete in containment was not compromised in any way during this steam leak. Also note that a visual inspection/walkdown of snubbers in the area of the steam leak is planned prior to restart as coordinated by Eddie Black.

If there are any questions please contact me at extension 5688.



JS Thrasher
Engineering Supervisor

cc: RB Travis
TD Curtis
WE Shaban
Micrographics

From: ELO8260 --PRDC
To: JTM3369 --PRDC

Date and time 09/03/93 14:09:11

FROM: Ed L. Owens 875-4600
McGuire Nuclear Station
Component Engineering
Subject: in-core instrumentation system

-f,
The only effects that leak on Unit two had on the in-core system was that we lost one motor starter for "A" drive. It appears that moisture got inside the starter and caused it to short phase-to-phase. A second starter, (for "B" drive got some moisture in it, but after drying it out it functioned properly. The starter for "A" drive has already been replaced. If there are any hidden problems that arise from this, I will let you know.

Ed

ATTACHMENT 11

1/1

Help Data Print Roadmap Exit

W/O Task : 93064662 01 Task Status: L/COMPLT Status Date : 09/03/93
 Title : INSPECT PANELS 2LR4,2LR5, AND 2LR6 Resp. Facility: MC
 Facility : MC Unit: 2 UTC :
 Equipment: ELN PN 2LR4 Mfr. Code :
 Component: Model No. :
 Item: Serial No.:

=====

Last Update By: RDL8265 Last Update Date: 09/03/93

ALL PREREQUISITES MET. 9/3/93 RDL8265
 INSPECTED INSIDE OF LIGHTING PANELS 2LR4, 2LR5 AND 2LR6 FOR MOISTURE RDL8265
 OR WATER. NO WATER WAS FOUND IN EITHER PANEL. RDL8265
 S.BEAN RDL8265

More:

RECORD COMPLETION COMMENTS, F9 TO STEP THROUGH TASK COMPLETION PANELS
 F1=Help F4=Prompt F5=Search F7=Bkwd F8=Pwd F9=More Detail F12=Cancel

**MAINTENANCE EXECUTION
SUPPORTING INFORMATION**

TEAM CHARTER

Date: 9/1/93

Project Title: Mechanical Maintenance (MM) Investigation of Unit 2 Steam Leak involving 2CF130

Start Date: 8/31/93

Expected Completion Date: 9/7/93

Sponsor/Team Leader: Ronnie B. White, Jr.

Team Members: Mark Devine – MM Lead Investigator
Don Trapp
Maurice Horne
Jim Allgood – LER Interface

Purpose and Scope:

Coordinate/conduct MM investigation of steam leak involving 2CF130. Provide input to the LER investigation which supports determination of root cause and corrective actions for inappropriate valve repair associated with the 8/31/93 steam leak in containment event on McGuire Unit 2.

Project Background:

Repair efforts to correct leakage from a pipe cap at valve 2CF130 (secondary side tube sheet drain) resulted in pipe cap blowing off and dumping steam into lower containment. Ice condenser doors opened and some capacity of the ice condenser was used.

The unit was cooled down and depressurized to Mode 5 to facilitate repairs and recovery from the event. A SEIT was initiated to investigate the event due to the obvious significance. Mechanical Maintenance initiated an investigative effort and LER investigation was begun.

Deliverables:

Root cause investigation using HPES methodology will be used to provide input to the MNS LER investigation. This will support determination of root cause and corrective actions via the LER investigation.

Investigation will, at a minimum, address the following issues/questions:

Part 1• Determine applicable human factors and causes of unsuccessful repair efforts of 2CF130 conducted on 8/5/93.

- 1 – Were the performing technicians qualified to the task?
- 2 – Were applicable procedures adequate and properly used?
- 3 – Was management involved in the repair efforts?
- 4 – What was the initial failure mechanism of 2EOC8?
- 5 – Did the work order specify any requirements for the pipe cap on the outlet of the valve?
- 6 – What was the failure mechanism of the valve after the unsuccessful repair of 2EOC8?
- 7 – What Post Maintenance Testing/Functional Verification was performed and when?

Part 2• Evaluate work practices used by On Line Leak Sealing vendors while performing on line leak sealing task.

- 1 – Were the performing technicians technically qualified to the task?
- 2 – Were the applicable procedures adequate and properly used?
- 3 – What operations/control room interface occurred prior to start of job?
- 4 – Was the evolution of this job significantly abnormal for On Line Leak Sealing personnel?
- 5 – Was management involved in the repair efforts in the on line leak repair sealing of the 2CF130 pipe cap?

Part 3• Any other issues uncovered by this investigation will also be addressed.

Measurable Success Indicators:

Short term MM actions are completed to support unit return to service by 9/05/93.

Input to MNS LER investigation supportive of root cause determination and corrective action.

Progress Updates:

The team will initially meet daily within MM to review concerns, action responsibility and status, SEIT, LER, and NRC interface will take place as needed to bring closure to issues.

Project Goal:

Identify all corrective actions that need to take place to support an on-line date of 9/05/93.

Key Results:

**PART 1 Human Factors and Causes of Unsuccessful Repair Effort on
2CF130**

Item 1 Were the performing technicians qualified to the task? Yes.

- Technician was trained to performed work on Kerotest valves on 4/27/92.
- The technician that performed the task of reassembly of the valve is qualified to perform work on Kerotest valves. He was qualified on 10/20/92 by a GSD qualifier.

Item 2 Were applicable procedures adequate and properly used?

- Procedure MP/0/A/7600/06 Kerotest Y Type Globe Valve Corrective Maintenance had some discrepancies logged. Discrepancies were in reference to "Fastners" and did not have any technical impact to this job. Procedure also contained human factor problems that have been incorporated in a procedure change on 9/3/93.
- Hot copies of the procedure and work order were taken into containment, during disassembly and reassembly of 2CF130.

Corrective Action:

- IMMEDIATE: Review and make appropriate changes to procedure MP/0/A/7600/06 Kerotest Y Type Globe Corrective Maintenance from a human factors stand point and for technical accuracy.

Responsible: Danny Green

Date: Complete

- LONG TERM: The procedure will also be evaluated for both technical accuracy and human factors.

Responsible: Tobey Self/Mark Devine/Danny Green

Date: 10/30/93

Item 3 Was management involved in the repair efforts?

- It is undetermined at this time the amount of supervisory involvement associated with this task or if a pre-job briefing was conducted.
- Technical oversight – Mechanical TST group was called to look at the valve and instructed technicians to lap seat and then they would reinspect the valve body. The second TST member went into the area and inspected the valve seats.

Item 4 What was the initial failure mechanism? (2EOC8)

- According to Section 5 of Work Order 92041833 01, when the valve was disassembled, technicians "found metal shavings inside the body." The Diaphragms were crushed and stem assembly bearings were broken. This caused seat leakage through the valve.

Item 5 Did Work Order 92041833 01 specify any requirements for the pipe cap on the outlet of the valve during 2EOC8?

- Work Order task (92041833 01) required the pipe cap to be removed and cleaned, apply sealant to the pipe threads and reinstall the cap. After this task if the cap still leaked the technician was instructed to proceed to the next task. The next task was to perform leak repair of the pipe cap.

Section 5 of the work order (92041833) states: "Pipe cap galled" and was dated 3/14/92. On 3/15/92, approximately $\frac{1}{8}$ " was cut from the pipe nipple and the nipple rethreaded. Pipe cap was reinstalled, and when the system was pressurized, it continued to leak. On 3/16/92, the pipe cap was removed and a special M.T.I.C. (Modified Thread Injection Cap) was installed. An on line leak seal vendor injected the cap and secured the leak.

There is no documentation of thread condition from 3/16/92 through 8/30/93 when the valve and cap was detected leaking.

Item 6 What was the failure mechanism of the valve after the unsuccessful repair of 2EOC8?

- Upon disassembly of valve 2CF130 on 9/2/93, it was discovered that the spring guide (part of the disc assembly) was installed incorrectly. The disc assembly assembled incorrectly would not allow the disc seat and the body seat to come in contact with each other, therefore not allowing the valve to seal. Further investigation has revealed that other spring guides have been installed incorrectly.

Item 7 What Post Maintenance Testing / Functional Verification was performed and when?

- Procedure MP/0/A/7600/06 Step 11.12.3 states "Verify that the gland screws do not contact the handwheel/chairwheel with the valve in the closed position." The technician stated that he cycled the valve to verify this step.
- The Work Order package has "Mechanical Equipment Functional Verification Methods Documentation Form" which requires the technician to perform activities identified. For this Work Order task, the planner identified two methods to perform an adequate functional: (1) -under valves- Cycle * (2) Visual Inspection - The

technician indicated that these methods had been successfully completed by his signature on the Functional Sheet.

- Cycle – discussions with the technician indicated cycling the valve means opening and closing the valve. Technician also shared his knowledge that total travel of this type of Kerotest valve is 1 ½ turns.
- The "Functional Verification" form has documentation stating that the full temperature and pressure verification would be performed under work order 93012110. This work order is to inspect several components at system full temperature and pressure.

PART 2 Evaluate Work Practices used by On Line Leak Sealing Vendors while performing on line leak sealing task.

Item 1 Were the performing technicians technically qualified to the task?

Yes

- The vendors have their own training program for their employees. This training also includes a strong focus on safety.
- The vendors are qualified by NSD 105.1 and by ETQS Standard (2404.0) that states: Work Responsibility Level I – Individuals who have successfully completed or have been exempted from: (1) Basic Mechanical Maintenance Training (2) Work Request and Administrative Control Training (Full or Refresher) (3) Activity Specific Training or OJT.
- The vendors have been performing this work activity for an extended period of time and have been successful in their efforts.

Item 2 Were the applicable procedures adequate and properly used?

- The vendor Procedure was adequate but is being reviewed for technical accuracy and for proper caution steps. Mechanical Maintenance management will not allow this procedure to be used before it is verified to be accurate and contain proper caution steps.
- Vendor procedure was filled out correctly and no steps were missed or incorrectly performed.

Item 3
job?

What Operations/Control Room interface occurred prior to start of

- In procedure MP/0/A/7650/77 (On-Line Leak Sealing Initial Injection) Step 11.3.2 provides a detailed description of repair to be performed.
Step 11.3.2 gives direction to see Attachment 1 of procedure MP/0/A/7650/77.

The attachment reads as follows:

STEP 11.3.2

Detailed description of repair to be performed.

A seat leak has developed in 2-MCF-VA-0130. This component can not be isolated to perform proper maintenance repair at this time. The recommended type of temporary repair is: Vendor to remove existing pipe cap. Install 1" M.T.I.C., Install 1/8" sealant injection valves. Inject nuclear grade sealant to stop leak.

This step in the procedure has slots to be signed by the following: Responsible Component Engineering Rep. or Maintenance Technical Support Rep., Mechanical Engineering Supervisor or Maintenance Section Manager, Vendor Rep, Design Engineer, Controlling Group Staff Rep.

The above personnel determine necessary corrective action to be taken.

- The On Line Leak Sealing vendors went to the Control Room and received permission to begin work from the Unit Senior Reactor Operator prior to starting Work Order task.

Item 3 Corrective Action

- Ensure that operations personnel are present at pre-job briefings involving on line leak sealing activities.

Responsible: Mechanical Maintenance Management
Date: 9/12/93 or whenever any on line leak sealing activities occur.

Item 4 Was the evolution of this job significantly abnormal for vendor personnel?

- On Line Leak Sealing vendors have performed this task many times at all of Duke Power Nuclear sites. This task is a normal process for On Line Leak Sealing Vendor and has been for at least a year. The abnormal part is this valve cap from (2CF130) was under full system pressure and temperature due to inadequate valve maintenance. The vendor procedure assumes adequate thread engagement. The pipe cap in this case was determined after the fact to have been cross threaded with minimal

thread engagement. Normally when the task is performed there is a relative small amount of leakage by the valve seat and small amount of steam in comparison to the leak on 8/30/93.

Item 5 Was management involved in the repair efforts in the on line leak sealing of the 2CF130 pipe cap? Yes.

- Mechanical Maintenance management was not directly involved in this repair. Mechanical Maintenance Management (Superintendent and Section Manager) were aware of the planned activities of the vendor. Operations has generated a policy stating that vendors are required to have a Duke Power management sponsor with them during signing on of Work Orders by the SRO (Senior Reactor Operator).
- During the outage, Mechanical Maintenance provides technical oversight for valves, both day and night shifts.
- On Line Leak Sealing personnel are ETQS qualified to: "Work Responsibility Level I." On Line Leak Sealing Vendor has been through or been exempted from the same training of a Mechanical Maintenance technician.
- On line leak sealing personnel have been exempted from Mechanical Basic training, but have received all administrative training that all other qualified individuals receive. Maintenance Management has assured (prior to 2EOC8) that on line leak sealing personnel were qualified to their specified task.

Corrective Action:

Ensure that Mechanical Maintenance management is directly involved and aware of all vendor activities within their work scope.

PART III Any other issues uncovered by this investigation will also be addressed.

- An HPES investigation will be conducted and a report will be written as a supplement to the LER (370/93-06).

9-3-93

THE DISASSEMBLY AND INSPECTION OF VALVE 2-CF-130

2-CF-130 is a 1 inch stainless steel Kerotest y-type globe valve, Duke Item number 09J-501. It is a shell drain valve for steam generator 2A.

EVENTS

Late evening 8-30-93 vendor personnel attempted to safely remove a leaking pipe cap threaded onto an approximate 5 inch nipple down stream of drain valve 2-CF-130.

The pipe cap was blown off the nipple after it was unscrewed approximately 1 1/2 turns. According to standards, a pipe cap of this type should have hand tight thread engagement of three turns before tightening with a wrench is required.

The resulting leakage could not be controlled by the vendors. It appeared there was no restriction of flow through valve 2-CF-130.

System pressure had to be decreased in order for the leak to be stopped. A modified pipe cap was installed on the nipple and the leak was stopped late evening 8-31-93.

Plans were made to cut the valve out of the system. A temporary maintenance procedure was developed, written, and implemented on 9-1-93. This procedure was written to control the cut out and inspection of the valve.

The valve was cut out of the system and taken to the hot machine shop at approximately 4 PM 9-2-93.

The disassembly and inspection began approximately 1 1/2 hour later. The following agencies/groups were represented: USNRC, Duke SEIT, Component Engineering, and Mechanical Maintenance. Radiation Protection assisted with the disassembly.

INSPECTION

Valve had a nipple welded in the down stream side with a modified pipe cap installed on it. The upstream side had been tapped shut when the valve was cut out.

Tape was removed from the upstream socket weld opening. Looking in this opening a portion of the disc and valve seat were visible with a flashlight. The disc appeared to be approximately $3/8$ inch off the body seat indicating a full open position. It is unusual for the disc to be that far off of the body seat in a valve of this type. A boroscope was inserted for a more detailed inspection of the disc and body seat. No damage or debris was observed with the boroscope.

The valve handle could not be rotated at all in either direction. Normal handle movement is approximately $1 \frac{1}{4}$ turns full open to full closed.

The distance of $2 \frac{7}{16}$ inches was measured from the top of valve body to top of yoke.

Packing screws were hand tight as required by procedure.

The yoke was loosened with a hydraulic wrench. No sticking or galling was observed.

The yoke, bonnet, and stem assembly were removed from the valve body. The diaphragms in the body did not appear to be in contact with the diaphragm seating surface. The seven inconel diaphragms were removed. A crimp was noted down through one area of the entire diaphragm stack that worsened from top diaphragm to bottom diaphragm. The diaphragm seating surface in the body was not damaged.

The disc assembly was removed. It was clearly evident the spring and spring guide had been installed incorrectly in the disc assembly. The spring and spring guide were installed correctly in relationship to each other but were installed exactly backward in relationship to the disc and disc cap. The center of the disc cap had a noticeable dimple in it approximately $1/2$ inch in diameter. This surface should have been smooth and convex. Some minor indications of scoring were evident around the outside diameter of the disc

cap. No other damage was evident. The disc seat and in body seat were not damaged.

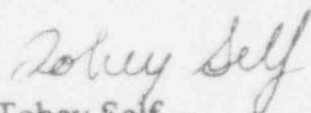
The overall disc assembly length was 2.154 inches. This length was documented to have been 2.169 inches when the disc assembly was installed. The dimple in the disc cap would attribute to this discrepancy.

The pin was easily removed from the disc assembly. It was evident the pin had been slightly bent as required by procedure to keep it from falling out of the assembly. The disc assembly was screwed apart with no problem. Some force was required to separate the disc cap and spring guide. This was apparently due a residue or very minor debris. The parts would not stick together after being separated the first time. No other damage was observed. The disc seating surface was not damaged.

No damage was found in the valve body. The valve seat was not damaged.

CONCLUSION

The displayed inability of this valve to stop or slow down fluid flow is attributed to the valve being assembled incorrectly. The spring and spring guide had been installed backward in their relation to the disc and disc cap. While in this condition the disc is maintained approximately 2 times further away from the body seat than it would be if the valve were assembled correctly. Also while in this condition the disc assembly can not operate because the valve body, spring guide and disc cap become mechanically connected to one another when torque is applied to the yoke during valve assembly. The disc cap and disc can not be moved towards the valve seat. The valve can not shut off flow if the disc does not contact the valve seat. This condition rendered the valve handle on 2-CF-130 totally inoperable. It also caused the 1 inch valve to display flow characteristics of a 1 inch diameter open pipe.



Tobey Self

Technical Specialist II

Mechanical Maintenance

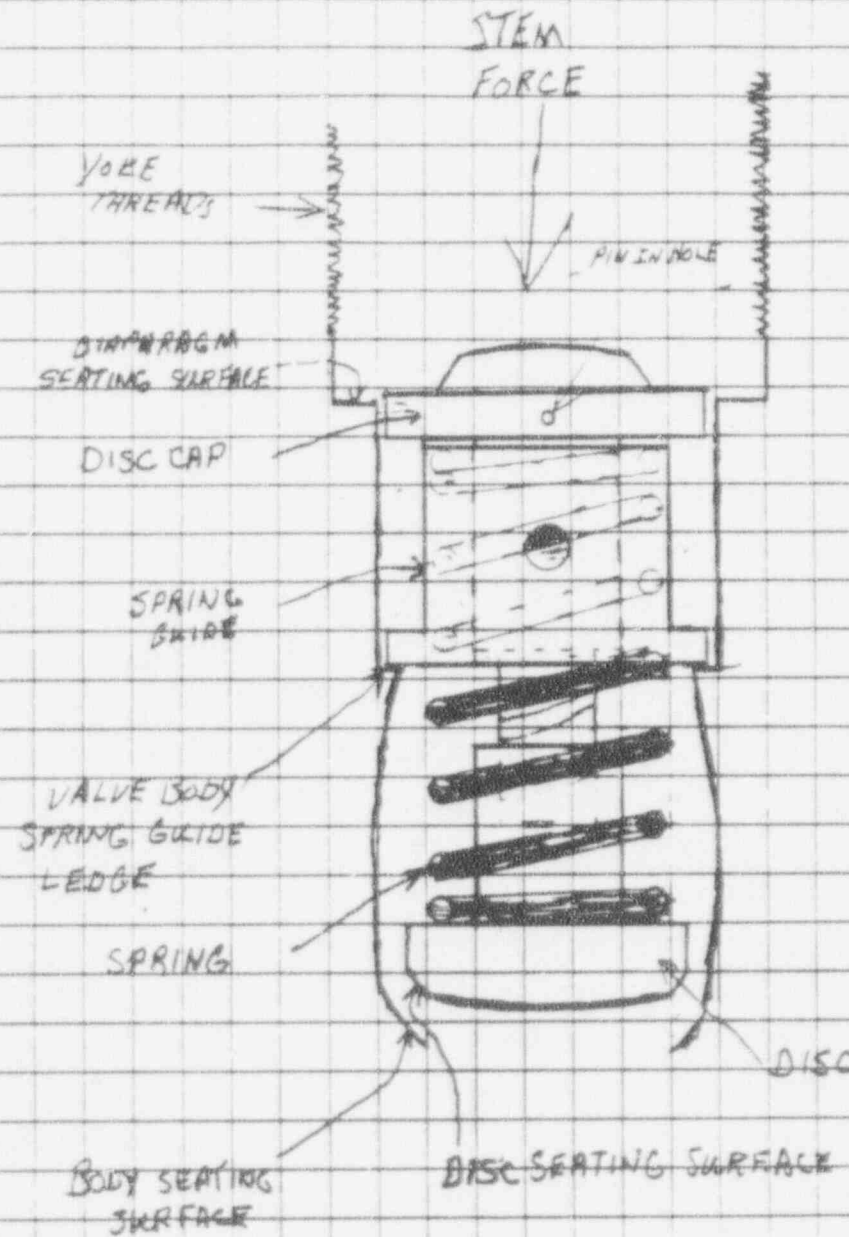
McGuire Nuclear Station

Station _____ Unit _____ Rev. _____ File No. _____ Sheet _____ Of _____

Subject HEADTEST INTERNALS AS FOUND IN VALVE 2-CF-130 INSPECTION 9-2-93

By TOBEY SELE Date 9-3-93

Prob No. _____ Checked By _____ Date _____



DISC ASSEMBLY WITH SPRING & SPRING GUIDE INSTALLED UPSIDE DOWN

STEM FORCE CAN'T MOV. DISC CAP AND DISC TOWARD SEAT

SPRING IS SERVING NO PURPOSE IN THIS CONFIGURATION

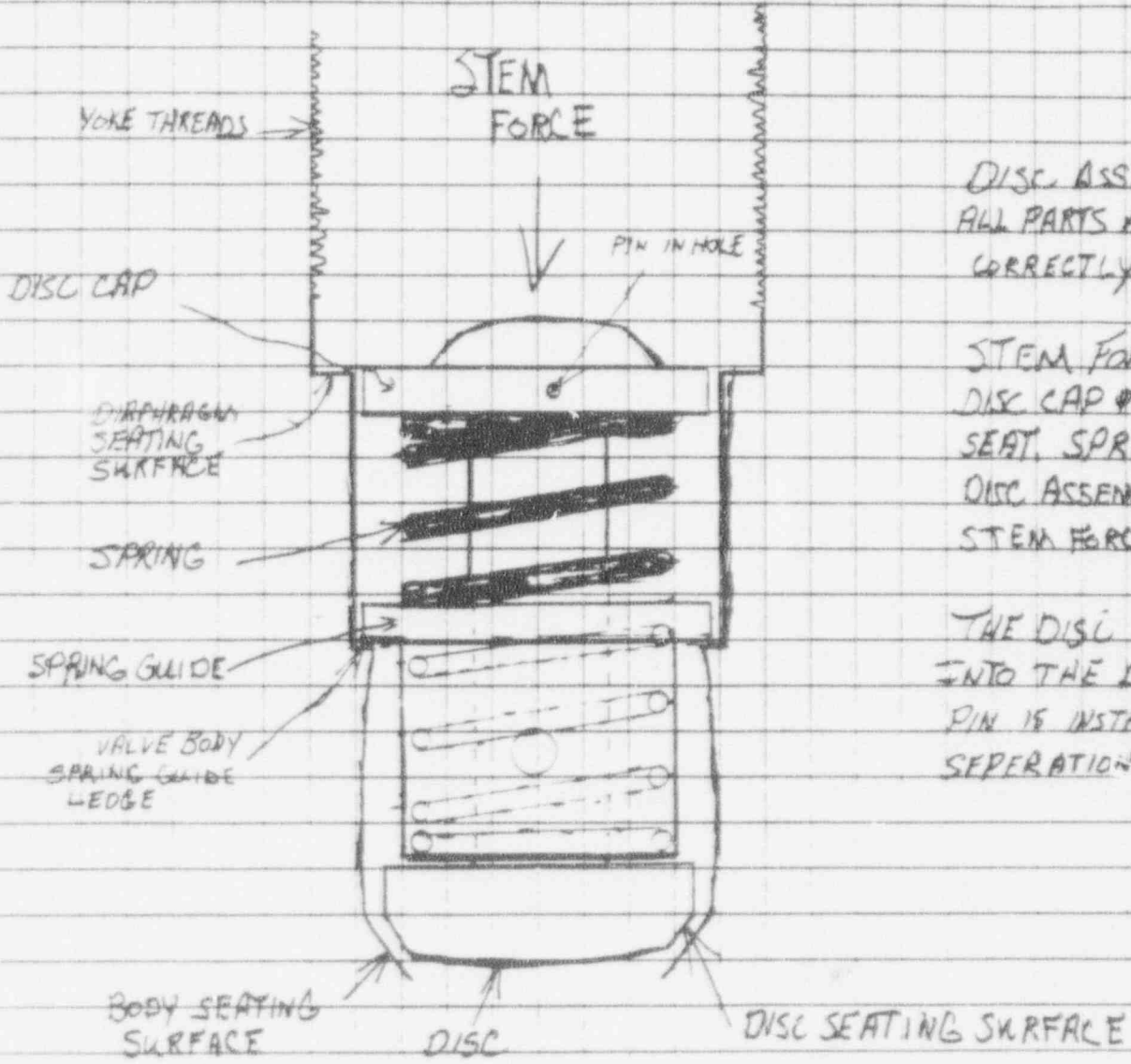
THE DISC IS THREADED INTO THE DISC CAP. THE PIN IS INSTALLED TO PREVENT SEPERATION.

Station _____ Unit _____ Rev. _____ File No. _____ Sheet _____ Of _____

Subject KEROJETEST INTERNALS NORMAL

By TOREY SELF Date 9-3-93

Prob No. _____ Checked By _____ Date _____



DISC ASSEMBLY WITH ALL PARTS ASSEMBLED CORRECTLY

STEM FORCE MOVES DISC CAP & DISC TO BODY SEAT. SPRING OPENS DISC ASSEMBLY WHEN STEM FORCE IS REMOVED

THE DISC IS THREADED INTO THE DISC CAP. THE PIN IS INSTALLED TO PREVENT SEPERATION

Duke Power Company
10CFR50.59
Procedure Change Summary

MP/0/A/7600/06

Description Of Change:

Deleted : old Step 2.1.9 and 2.3.12

Add Steps: 2.1.9, 2.1.10, 2.1.11, 2.1.12, 2.3.12, 2.3.13, 2.4, 2.4.1, 6.2,

Added Note before 6.1

Changed: 8.1.5

Added: **CAUTION** before Section 11.2

Change Note before 11.2

Deleted: old Steps 11.6.1 and 11.6.2. Added new Step 11.6.1

Added : Substeps A and B after 11.8.3

Changed: Step 11.8.7 and added Table 1: Disc Assembly

Added: Words digital OR to Step 11.9.8

Changed: Step 11.9.10 and added Table 1: Disc Assembly. Combined 11.9.11 with 11.9.10

Changed And Combined: Old Step 11.9.16 and 11.9.17 into 11.9.15 And added Table 2: Disc Assembly With Disc Cap Pin

Changed: Step 11.10.2 And added Table 3: Disc Assembly

Added: Note between A and B of Step 11.10.2

Changed : Step 11.10.9 combining 11.10.10, Caution, and added Table 1: Disc Assembly

Changed and Combined: Old 11.10.15 and 11.10.16 into 11.10.14 and added Table 2: Disc Assembly With Disc Cap Pin

Added: Note and Step 11.11.1

Added: **CAUTION** before Step 11.11.6

Added: Step 11.11.12

Deleted: Old Step 11.12.1

Added: Step 11.12.3

Changed: Cap Screws to fasteners in Section 11.13

Changed: Step 11.14.5 and 11.15.17

Changed: Cap Screws to Fasteners on Enclosure 13.11

Reason For Change:

To enhance procedure and clear up discrepancies

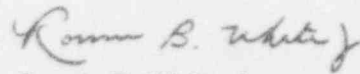
September 3, 1993

Memorandum

To: Maurice Horne Tobey Self Steve Carter
Bruce Travis Jack Boyle Mackie Handsel
Bruce Hamilton Bob Hall Doug Kolb - USSI

Due to our experience with the blow-out of the pipe cap on 2CF-130, on line leak repair methods that involve the removal of pressurized pipe caps on high energy systems shall NOT be used until further notification.

Procedures which involve the removal of pressurized pipe caps on high energy systems, such as Procedure USSI-NP-15, shall be considered on administrative hold until further evaluation and notification.


Ronnie B. White, Jr.
Mechanical Superintendent
McGuire Nuclear Station

cc: Don Gabriel
Steve Hart
Mac Geddie
Doc Michael
J. P. Sherrill
Don Rogers - CNS
Bill Foster - ONS
Don Trapp
Danny Green
Ernie Estep

September 4, 1993

MEMORANDUM

To: Maurice Horne

Subject: Management Oversight Responsibilities for On Line Leak Sealing Repair Activities

On September 2, 1993 I discussed the management oversight of on line leak sealing activities with Maurice Horne (acting Section Manager for valve maintenance activities).

During these discussions we clarified that management oversight for on line leak sealing activities would clearly reside in the valve maintenance Section Manager's area of responsibility and accountability.

Management oversight of these activities should encompass as a minimum.

- Training/Qualification requirements and management oversight responsibilities as defined by ETQS Standard 2404.0 Support Personnel Training and Qualifications and NSD 105 Operating, Test, and Maintenance Activities

- Fitness for Duty considerations

- Oversight of maintenance activities performed. This includes risk assessment of the activity including the necessity for pre-job briefings.

- Expectations relating to:

- Personnel Safety
- Housekeeping
- Administrative/Procedure Activities
- Work Quality
- Productivity

Ronnie B. White, Jr.

Ronnie B. White, Jr.
Mechanical Superintendent
McGuire Nuclear Station

Attachment

RBWjr/dgt

cc: Tobey Self
Bruce Travis
Bruce Hamilton

**Full Responsibilities
Superintendent of Mechanical
Ronnie B. White, Jr.**

**Mech Equipment #1
Section Manager
Benny Harley**

- Pumps
- Compressors
- Desal
- Airlocks
- Cranes
- Includes Mgmt oversight of vendors
- Refueling
- Doors:
+ Closure
+ Keying
- Pump Tech Support

**Mech Equipment #2
Temporary
(Maurice Horne)**

- HVAC
- Ice Condenser
- Valves
- PM Packing Program
- Valve Tech Support
- Snubbers/Hangers
- On Line Leak Sealing
- Management Oversight of Vendors



**Civil Services
Section Manager
Maurice Horne**

- Insulation
- Builders:
+ Scaffolding
+ Platforms
+ Grout
+ Concrete Repair
+ Metal Building Repair
+ Carpentry
- Coatings:
+ Foaming of Fire Barriers/Penetrations
PM and PTs
+ Hazardous Waste and Reg Program
- Lead Shielding
- White Space Upgrade

**Mech Services
Section Manager
Bobby Bosian**

- Hydro
- Machine Shops
- Metal Fab Shops
- Welding
- Mechanical Modifications
- Pipe Erosion
- Major Rigging

**Mechanical Shift
General Supervisor
Eddie Beebe**

- Supports operating unit(s)
- Initial Emergency Response
- Emerg/Tech Spec component maintenance/repair
- Plant support during weather crisis
- Fire Brigade Activities
- Component Troubleshooting
- Filter/Strainer Change-Outs
- PMs:
+ Oil Sampling
+ Coupling Alignments
+ Vibration Measurements
+ Shift Lubrication Programs
+ Heat Exchanger
+ Quarterly Building & Roof Drain Inspections
+ Portable Welding Machine Maintenance
+ Air Compressor Maintenance
- Mechanical Outage Coordination

**Mechanical QA
Temporary
Don Trapp**

- Tech Support:
+ Review of maintenance procedures
- + Review of Work Packages to include NSMs, Process Control, and Work Requests
- + Review of Hydro Packages
- + Coordinate Inservice Inspection
- + Administer ANVANI Contract
- + Material Condition / Housekeeping Program
- QC:
+ Inspect nuclear maintenance work in the Mechanical, Civil, and Welding areas
- + Perform Preservice and Inservice Inspections in the Mechanical and Welding areas as specified by ASME Code, Section XI
- + Assist in Welder Certification / Recertification process
- + Fire Barrier Inspections

**Mechanical Support
General Supervisor
Don Trapp**

- Safety - ALARA
- Procedures
- Administrative Functions (clerical)
- Budget/Cost Control
- Lower Tier Programs/Monitoring (HFES/MHA/P3/P4)
- Facilities
- Environmental Compliance
- Outage Support (ETQS and Tech Support)
- Relief Supervision
- Computer Coordination
- Spare Parts/Materials
- Goals Development
- Communications/Media
- ETQS Program
- Scheduling of Training
- Mech Reps - NSM Planning
- Tech Support ISI Welding and Hydrostatic Testing
- Special Projects
- Social Activity/Recognition
- Policy/Benefits/Staffing
- Programs/Directives
- Strategy/Planning/Assessment
- Emergency Planning
- Off-Site Workforce Coordinator
- INPO Contact

2 NC 14 Leak Repair Activity
Pre-Job Meeting
9/1/93

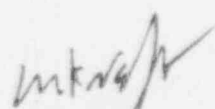
The subject meeting was held in Work Control Center to cover pre-job detail/discussion with USSI personnel. The following personnel were in attendance:

M. K. Nazar	WCC Duty Manager
Maurice Horne	Mech Mnt Section Manager
Larry Dunn	USSI
Dwaine Dameron	USSI
Tobey Self	Mech Mnt Tech Support
Terry McGee	RP
Scott Randolph	Outage Management
Doug Kolb	USSI
Garland Cloer	Safety
David Motes	Component Eng Supervisor
Greg Holbrooks	Component Eng

The following topics were discussed:

- 1) USSI will drill through two previously installed injection holes that penetrate the valve body. This additional drilling will extend the current holes through the yoke to the yoke to bonnet interface. Nuclear leak sealant will be injected into this interface to stop system leak-by-path. This work will be performed under Mech Mnt procedure MP/0/A/7650/77 and minor change VN-3736B.
- 2) System Condition
Primary system is at 300#, 155 F with A train of ND in service
- 3) RP Information
 - * 4 R contact on valve
 - * 500 MR general area
 - * Contamination level is 75 M-Rad
 - * Dress requirement is plastics
- 4) Safety Information
Safety is in process of performing area temperature survey to determine stay time requirement. The required stay time will be communicated to USSI Supervisor prior to access to reactor building.

cc: E. M. Geddie
R. B. White


M. K. Nagar
Section Manager
McGuire Nuclear Station

September 3, 1993

MEMORANDUM TO FILE

In order to strengthen our understanding of the management controls associated with interfacing individuals and organizations (e.g., vendors, contractors involved in maintenance activities) we conducted a Mechanical Maintenance management briefing on 9/2/93 as a part of our daily outage meeting.

Steve McCurry of Site Training and Mike Ray of MM ETQS gave us an overview of NSD-105 **Operating, Test and Maintenance Activities** and ETQS Standard #2404.0 **Support Personnel Training and Qualifications**.

Included in this briefing were:

Ronnie B. White, Jr., Mechanical Maintenance Superintendent
Don W. Trapp, General Supervisor
Maurice X. Horne, Section Manager
Eddie L. Beaver, General Supervisor
Bobby P. Bostian, Section Manager
C. Z. Bearden, QA Supervisor (for Rick Branch, MM QA General Supervisor)

Copies of ETQS Standard 2404.0 **Support Personnel Training and Qualification** and the **Introduction and Responsibilities** section of NSD 105 were given to all attendees.

As a team we discussed the importance of the training and qualification requirements and management oversight of the activities of vendors, contractors, and other interfacing personnel.

Ronnie B. White, Jr.
Ronnie B. White, Jr.
Mechanical Superintendent
McGuire Nuclear Station

RBWjr/dgt

cc: Maurice Horne
Benny Harkey
Rick Branch
Mike Ray
Bruce Caldwell
Bobby Bostian
Don Trapp
Eddie Beaver
Steve McCurry
Ernie Estep

September 4, 1993

MEMORANDUM

To: Ronnie B. White, Jr.

Subject: Discussion on Management Oversight and Management Involvement

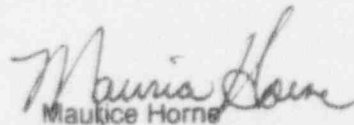
On Wednesday, September 1, 1993, I discussed with Doug Kolb, USSI some changes that we were implementing immediately.

The immediate change is that Mechanical Maintenance will be the interface between USSI and Operations. This will apply to other vendors as well.

I have also discussed this change with Tobey Self. Tobey and I discussed our involvement and the roles we will continue as management involvement and oversight to ensure maintenance and other affected groups are aware and understand all maintenance activities of all vendors.

I have discussed with Tobey (and will communicate to the remainder of my direct reports) that we will continue to meet on a daily basis to discuss daily work activities.

One item that will be discussed with all is the requirement to have pre-job briefings on all non-routine jobs which will include all affected work groups.


Maurice Horne
Nuclear Section Manager
McGuire Nuclear Station

MXH/dgt

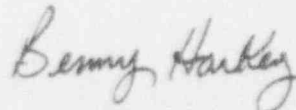
September 2, 1993

**Maintenance Expectations - Vendors
Refueling / Crane Crews**

Attendees:

J. W. Bowles
Bud Pate
Rocky Hunt
Bill Hare
Buddy Rhoades
Randy Mahaffey
Roger Smith
Paul Payne
James Johnson
B. T. Harkey

We discussed the importance of holding a thorough pre-job briefing with management taking the lead in laying out a plan of action for any work involving vendors or outside help. Made everyone aware that each of them had an obligation to call a time out or to stop work if for any reason they felt uncomfortable with what was taking place or that conditions had changed from the pre-job briefing. Also, made everyone aware that the bottom line is we (Mechanical Maintenance) have the final responsibility and accountability for any work that a vendor performs and that we look at this work as if we are actually doing it for safety and quality considerations.



Benny Harkey
Nuclear Section Manager
McGuire Nuclear Station

BTH/dgt

**CHECKS PERFORMED ON UNIT 2
PACKLESS KEROTEST VALVES**

APPENDIX VI

CHECKS PERFORMED ON UNIT 2 PACKLESS KEROTEST VALVES

VALVE #	DESCRIPTION	CHECKS PERFORMED					
		1	2	3	4	5	6
2BB-177	SG 2A blowdown vent	X					X
2BB-187	SG 2A blowdown hdr hi pt vent	X					X
2CF-90	SG 2D inlet drain	X					
2CF-130	SG 2A shell drain	X					
2CF-169	SG 2D CF hi pt vent					X	X
2CM-844	H P heater drain sample isol	X					
2FW-33	ESF FWST to recirc pumps		X				
2KD-30	DG lube oil cooler drain	X					
2NB-259	(valve description not available)			X			
2ND-36	B ND pump disch sample drain	X					
2ND-60	isol valve for NI-183 test vent				X		
2ND-79	NS-18 upstream hi pt vent	X					
2ND-83	ND to NI pumps hi pt vent				X		
2ND-85	NC pumps ol x-over blk hi pt vent				X		
2ND-88	hi pt vent upstream of 2ND-35				X		
2NI-95	ESF test header inside cont isol		X				
2NI-166	NI pumps to cold leg loop 3 isol	X					
2NI-352	accum N2 supply inside cont isol			X			
2NM-22	ESF NC lp 2A smpl inside cont isol		X				
2NM-25	ESF hot lp 4 smpl inside cont isol		X				
2NS-78	NS pump 2A suct lo pt drain	X					
2NS-81	NS pump 2A vent to drain header	X					
2NS-82	NS pump 2B vent to drain header	X					
2NV-69	NC pump 2C byp return line vent	X					
2NV-285	charging pump 2A overflow	X					
2NV-890	NV supply to NC inside vent isol	X					
2NV-891	NC LD to regen HX vent isol	X					
2NV-893	NC LD to regen HX #1 vent isol	X					
2SM-83	A stm line drain		X				
2SM-95	C stm line drain		X				
2SM-101	D stm line drain		X				

- 1) Full cycle stroke on 9/3/93.
- 2) Full cycle functional verification previously performed.
- 3) Full cycle stroke performed for the Integrated Leak Rate Test.
- 4) Full cycle stroke performed in procedure PT/2/A/4200/19.
- 5) Full cycle stroke performed during filling of the condensate system.
- 6) Leak check performed with the pipe cap removed on 9/4/93.