UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAR 3 0 1988

Docket No. 50-416

LICENSEE: System Energy Resources, Inc. (SERI)

FACILITY: Grand Gulf Nuclear Station (GGNS), Unit 1

SUBJECT: SUMMARY OF FEBRUARY 10 AND 11, 1988 MEETING REGARDING LICENSING ACTIONS

INTRODUCTION

The purpose of the meetings was to discuss the status and scheduling of licensing activities including status of completion of license conditions, Revision 2 to the Updated Final Safety Analysis Report (UFSAR) and implementation dates for the Safety Issues Management System (SIMS). Revision 2 to the UFSAR and SIMS were discussed on February 11, 1988. Enclosure 1 is a list of attendees at the meeting. Enclosure 2 is an agenda prepared by the NRC staff. Enclosure 3 is a handout prepared by the licensee. Enclosures 4 and 5 are a Material Non-Conformance Report (MNCR) and data, respectively, related to an operating event.

PLANT STATUS

The licensee described the plant operation since restart from the second refueling outage on January 3, 1988. A four-day outage occurred because of a winding fault on the high voltage side of a main output transformer. SERI has initiated a review by transformer specialists to see whether the current surveillance tests can be enhanced to allow detection of potential faults. A two-day outage occurred because of a ruptured gasket for a manway cover on the main condenser. Condenser circulation water sprayed on the hotwell level switches, causing them to short and resulting in a low hotwell level signal which tripped feedwater pumps off and scrammed the reactor. Condenser manway covers were removed and gaskets were glued into manway cover grooves. Also a splash shield was installed over the level switches. A gasket design change is planned for a long term fix.

A Level IV violation was received because the safety evaluation for chemical cleaning of the standby service water system did not adequately support the conclusion that successful cleaning could be accomplished without degradation of the base metal or components in that neither bolt and socket welds nor crevice regions were considered. Licensee stated that the 10 CFR 50.59 evaluation was not reviewed by appropriate people and steps have been taken to assure adequate review and concurrence for future evaluations.

STATUS OF COMPLETION OF OPERATING LICENSE CONDITIONS

The licensee and staff discussed the status of completion of certain license conditions as follows.

°License Condition 2.C.(16) Containment Purge

This license condition required the submittal prior to the first refueling outage of a study of the need to purge the containment during operation. This requirement was satisfied by the licensee's submittal dated October 3, 1986. License Condition 2.C.(16) also requires the licensee to propose criteria to be used for the remainder of the plant life. By letter dated December 31, 1987, the licensee proposed purge criteria which the staff is now reviewing. The scheduled SER completion date is June 30, 1988.

°License Condition 2.C.(26) Turbine Disk Integrity

This license condition requires the inspection of discs in all three low pressure main steam turbines prior to exceeding 50,000 hours of operation. As of January 31, 1988, the main steam turbine has been operated about 18,600 hours. The first low pressure turbine was inspected, during the second refueling outage in November and December 1987. The second and third low pressure turbines will be inspected in the third and fourth refueling outages, respectively. A report giving the results of the first low pressure turbine inspection will be submitted by June 30, 1988. This report should include the method of inspection, since this is the first submittal to the NRC of a report on the inspection of a Kraftwerk Union, AG turbine.

°License Condition 2.C.(36) Emergency Response Facilities

This license condition specifies the schedule for completion of the NUREG-0737, Supplement 1 requirements. Requirements for the SPDS, DCRDR, Emergency Operating Procedures, and Emergency Response Facilities have been satisfied. Requirements for implementation of Regulatory Guide 1.97 instrumentation have been satisfied, except for implementation of a neutron flux monitor prior to startup from the third refueling outage and implementation of a Class A dose assessment model in November 1988. The NRC staff is conducting a post-implementation review and audit of the SPDS and DCRDR which is scheduled for completion in June 1988. The staff plans to appraise the emergency response facilities in November 1988.

All the other license conditions resulting from the operating license review [2.C.(6) through 2.C.(38)] have either been satisfied or have no time limit for action. Standing license conditions are 2.C.13(b) prohibiting natural circulation as an operating mode, 2.C.(23) requiring a fire protection program, 2.C.(27) prohibiting the filling of the Unit 2 circulating water system and cooling tower basin until Unit 1 flooding concerns are resolved, 2.C.(30) requiring certain qualifications for training instructions, 2.C.(32) prohibiting extension of a normal fuel cycle by operating with partial feedwater heating, 2.C.(33)(d) requiring completion of the hydrogen control research and development program and final analysis according to 10 CFR 50.44, and 2.C.(38) specifying an allowable control room leak rate. The licensee has agreed to provide a

summary describing how license conditions were satisfied (modifications and analyses) and the dates of licensee and staff documents involved.

STATUS OF REVIEW OF LICENSING ACTIONS

The status of review of licensing actions was discussed. Item B of Enclosure 2 lists the target dates for completion of major actions.

Subsequent to the meeting, the target date for TS changes to implement 10 CFR 55 regarding training and qualifications for licensed reactor operators was changed from 2/29/88 to 3/30/88 because additional information is needed to complete the review. The staff's post-implementation reviews of SPDS and DCRDR for GGNS, Unit 1, have been given a low priority relative to reviews of these items for other plants.

The review of the licensee's amendment to the GGNS Physical Security Plan (Revision 13) to implement 10 CFR Part 73, as amended, was completed and Revision 13 was found acceptable. However, an amendment to the GGNS Unit 1 Operating License is required to change the reference to the Physical Security Plan in License Condition 2.E. The staff will issue a license amendment after publication in the Federal Register of its proposed determination that the license amendment involves no significant hazard consideration (scheduled to be published March 9, 1988).

The licensee reported that the BWR Owners Group has scheduled an April 1988 submittal of a topical report on requirements for BWR post-accident neutron flux monitoring, which is addressed in Regulatory Guide 1.97. A plant specific analysis for GGNS Unit 1 based on this topical report will be submitted shortly thereafter. The licensee anticipates that the present GGNS, Unit 1 operating neutron flux monitoring system can be demonstrated to meet post-accident requirements. The current License Condition 2.C.(36) requires implementation of post accident neutron flux monitors meeting the requirements of Regulatory Guide 1.97 prior to startup from the third refueling outage (now scheduled to start in April 1989).

PROJECTED LICENSING ACTIONS

The staff expressed a desire for completion of licensing actions before they are needed for startup from the third refueling outage. Several licensing actions needed for startup from the second refueling outage were not completed until December 30, 1987, for a January 1, 1988 startup. One license amendment was issued under exigent circumstances because the 30 day comment period for the amendment did not end until January 4, 1988. The requests for amendments were submitted early enough but substantial changes were required to the analyses of no significant hazard considerations (NSHC), safety analyses, and the proposed design modifications. Such submittals cannot be noticed in the Federal Register, until satisfactory revisions to the application are made. The licensee suggested several means for completing actions sooner: early feedback from the NRC on submittals; a meeting shortly after submittal for the licensee to

present the principal features of the submittal; and quicker response to requests for additional information. The staff acknowledged difficulty in obtaining adequate margin in schedules for NRC review of refueling outage issues to account for contingencies such as a need for additional information because review priorities are primarily based on the licensee's startup date without accounting for such contingencies. For complex issues needing resolution for the third refueling outage, the licensee and staff will seek to establish firm milestones for submittal, "acceptance review," meetings, safety evaluation input, and amendment issuance. A contingency of two months should be included in the schedule to allow for a response to a request for additional information (RAI) and renoticing. The licensee will seek to improve safety analyses and improve the NSHC analyses in the initial submittal, addressing explicitly the effect of the changes in equipment or procedures on previously evaluated accidents and margins of safety. The staff will seek to obtain early feedback by "acceptance reviews" and a firm review schedule with adequate contingency.

The licensee had received Generic Letter 88-01 regarding intergranular stress corrosion cracking and Generic Letter 88-02 regarding an integrated systematic assessment plan. The licensee will respond on the dates requested in the generic letters. However, they commented that they normally receive generic letters about 2 weeks after they are issued, so a response time within 30 days of the letter date, as requested in GL 88-02, does not allow time for an in depth response.

The licensee described its plans for participation in the Technical Specification (TS) Improvement Program (pages 2 through 8 of Enclosure 2). GGNS Unit 1 is the lead plant for BWR 5/6 plants. An overview of the program is shown on page 6 of Enclosure 2. Improved TS will be submitted as Standard Technical Specifications (STS) for BWR 5/6 plants and will include reformatting (see example in pages 3-5) and revised bases. After approval by NRC, the licensee will submit a request for GGNS Unit 1 license amendment, based on the approved STS. Short term TS improvements will be sought in 1988 for fire protection (already submitted), exceptions to TS 3.0 and TS 4.0 (Generic Letter 87-09) and diesel generator surveillance testing (Generic Letter 84-15).

OPERATING REACTOR EVENTS

(1) Loss of shutdown cooling during outage

The staff commented on LER 87-021 and LER 87-022 which reported events during the refueling outage in which shutdown cooling was lost. In both LERs the safety assessment did not provide assurance that adequate procedures were understood and followed. In LER 87-021, where the RHR shutdown cooling mode was isolated for 58 minutes, there was no description of available alternate methods of shutdown cooling and coolant circulation which are required by TS to be demonstrated within 1 hour. Further, the LER states that coolant temperature remained less than 105°F, without stating where it was measured. Without flow in the RHR and

without recirculation pump operation, it is not clear how coolant temperature representative of coolant in the core could be measured. The licensee stated that operations personnel likely believed they could get the RHR system back into operation within one hour and that the recirculation pump was likely operable to measure coolant temperature. The staff indicated these considerations should have been described in the LER.

In LER 87-022, the staff noted that the title, "RWCU Isolation Due to Blown Fuse Caused by Working Conditions" (which is used in event reviews to find similar events) does not indicate that the reactor water cleanup (RWCU) system was providing shutdown cooling for the reactor at the time it was isolated. In the entire LER, only brief mention of use of the RWCU for shutdown cooling was made in the abstract and in the safety assessment. According to precalculated requirements for shutdown cooling during this portion of the outage when both RHR trains were taken out of service, both RWCU and fuel pool cooling (FPC) systems were required to be operating as alternate cooling and circulation methods. The LER safety assessment states that FPC and control rod drive systems were "available" but does not indicate they were in operation or adequate. Since both RWCU and FPC were required for shutdown cooling, when RWCU was isolated, planning should have begun to demonstrate operability of another alternate cooling method and to establish reactor coolant circulation by an alternate method. Since the isolation lasted 50 minutes some contingency plans should have been available for use if the isolation continued beyond one hour. Although a statement was made that RHR Train B was functional (e.g. capable of being operated with some manual valve realignment) no indication of the time involved in placing it in operation was mentioned. Further, a statement regarding the measurement of reactor coolant tempera-ture was not given in the LER.

The staff indicated that LER 87-021 and LER 87-022 do not reflect careful consideration of the safety aspects of using alternate cooling methods during shutdown. In justifying more extensive use of alternate shutdown cooling methods during the second refueling outage (which was approved in Amendment 38), the licensee identified the particular alternate methods that would be used and contingency plans in the event of loss of the alternate shutdown cooling method. The operations staff may have given more extensive consideration of the safety aspects than is reflected in the LERs. In this regard, however, in a site visit during this period of the outage the Project Manager observed that a licensed operator in the control room was not aware that both RWCU and FPC systems were required for shutdown cooling. In a discussion with the Outage Director, however, the licensee pointed out that the requirement for the two systems was on the outage schedule and that operations and maintenance personnel had been briefed on this requirement.

The staff commented that the safety assessments in LERs should more clearly relfect all the safety considerations involved in the event.

(2) False ECCS line break signal

The licensee provided additional information regarding the false pipe break alarm signal received during startup from the second refueling outage (LER 88-003). There are three differential pressure measurements to detect ECCS injection line breaks in the annulus between the core shroud and the reactor vessel. The ECCS lines (LPCS, LPCI-A, LPCI-B, LPCI-C and HPCS) inject water into the core outlet plenum. Pressure measured in the injection lines during power operation should reflect the pressure in the core outlet plenum. The pressure sensors are connected as follows to provide a differential pressure (delta P) signal: LPCS to LPCI-A (also referred to as RHR-A), LPCI-B to LPCI-C, and HPCS to the standby liquid control system (SLCS) penetration in the lower reactor vessel head. A pipe inside the reactor vessel connects the SLCS penetration to the space outside the fuel assemblies and above the lower core support plate. The first two delta P signals should read near zero at reactor cold shutdown and at full reactor power. The last delta P signal is expected to change as the reactor goes from cold to hot because of the change of water density inside the reactor between the core outlet plenum and the space above the lower core support plate (See IE Circular 79-24, November 26, 1979). If a large break occurs in the ECCS injection pipe in the annulus when the reactor is operating near full power, the delta P signal would change because of the lower pressure outside the core shroud compared to inside the shroud. Based on calculations, the Technical Specifications alarm setpoint for these delta P signals was made "1.2 ± 0.1 psid change from the normal indicated delta P." For a double-ended guillotine break in the line, the calculated available delta P across the core shroud is 1.76 psid at 80% power and 90% core flow and 2.8 psid at 100% power and 100% flow.

For the first two fuel cycles, the normal indicated delta Ps were calculated; and a line break signal (i.e. delta P greater than 1.2 ± 0.1 psid) was not received when going to full power. However, after startup from the second refueling outage, a line break signal was received on LPCS/LPCI-A. The indicated delta P was 1.7 psid at 84% power and 2.1 psid at 100% power. Following an unrelated scram the next day, the delta P decreased to 1.7 psid 5 minutes after the scram and to 0.65 psid over the next 1½ days (LER 88-003). The licensee concluded because of the small change in delta P after the scram that the signal was false and an actual line break had not occurred.

The licensee initiated Material Nonconformance Report (MNCR) 0015-88 (Enclosure 4). The disposition of the MNCR was to measure the pressure differentials for these three instruments as power was increased to obtain the "normal indicated delta P" above 80% power and 90% flow, which is the range of applicability of the signal (Enclosure 5). The TS setpoint was then made 1.2 ± 0.1 psid from the measured normal indicated delta P. Additional discussion of this MNCR is given in Inspection Report 50-416/87-40 dated February 22, 1988.

(3) RWCU system isolation

With the plant in hot shutdown, RWCU system isolation occurred from a differential flow signal that exceeded 45 seconds when operators were stopping one pump with reactor pressure less than 100 psig (LER 88-004). Similar isolations have occurred before when placing the RWCU in the blowdown mode (LER 87-009-01) and when starting an RWCU pump in the prepump mode (LER 87-015). In discussions of LER-009 with the Resident Inspector (Inspection Report 87-22) the licensee said they planned to revise the relevant plant directive for these evaluations to note the possibility of an RWCU isolation during valve line up. The reason given was that whether or not an isolation occurred, it would not be reportable under 10 CFR 50.73. The inspector did not agree with this position; he said the plant procedures should identify "expected" ESF actuation not "possible" actua-tions. If expected actuations do not occur, the operability of the ESF is questionable. If unexpected actuations occur, then the cause of the actuation must be found and the problem corrected. The NRC Project Manager agrees with the Resident Inspector that procedures for evolutions should only identify ESF actuations that are expected to occur.

In Revision 1 of LER 87-009 and LER 87-015, the licensee committed to perform an analysis to determine whether the TS requirement for 45 second time delay before isolation could be extended. The licensee is also considering modifica-tions of procedures to use existing manual bypass switches within times presently allowed by TS as a means to avoid unexpected RWCU isolations during valve lineups and during pump starts and stops.

(4) Information Notice No. 86-81, (IN 86-81) Supplement 1, Dated January 11, 1988

IN 86-81, Supplement 1 described corrective actions by the licensee for Fermi Unit 2 when they discovered two additional broken closure springs in Atwood and Morrill main steam isolation valves. Grand Gulf Unit 1 uses the same model valve and valve springs. The licensee was aware of this potential problem and inspected the springs in the last refueling outage and found no broken springs. The licensee has also talked to the spring manufacturer who stated the springs made for the Fermi-2 plant appeared to be from a bad batch. The licensee is continuing to investigate the potential problem.

REVISION 2 TO THE UFSAR

In the Resident Inspector's office on February 11, 1988, the Project Manager discussed Revision 2 to the UFSAR with SERI Licensing personnel. Prior to the meeting, the Project Manager had reviewed Revision 2 to the (UFSAR). The revision is a large one, including: addition of safety analyses from responses to questions in the operating license review; major changes to Chapter 3.10 "Seismic and Dynamic Analyses" to describe criteria for qualification of

replacement parts for equipment; safety analyses and descriptions for changes in TS operating limits and license conditions, and for equipment modifications implemented in the first refueling outage and; more clear identification of Engineering Safety Features (ESF) to clarify reportability requirements per 10 CFR 50.72 and 10 CFR 50.73. The licensee answered questions from the Project Manager regarding reasons for several of the changes.

In the SERI corporate office on February 11, the Project Manager audited the 10 CFR 50.59 analyses for some of the UFSAR changes, including a reference to the agreement between MP&L and SERI on offsite power, the addition of an uninterruptible power supply for the neutron monitoring system, addition of another radial well for cooling tower makeup, fuel pool cooling analyses to reflect high density spent fuel storage, changes to high energy pipe break evaluations and seismic qualification criteria initially (IEEE 344-1971) and for replacement parts (IEEE 344-1975). Results of the audit were discussed with the licensee's personnel. The licensee's files supporting these changes were adequate and 10 CFR 50.59 analyses appeared reasonable.

SAFETY ISSUES MANAGEMENT SYSTEM (SIMS)

The NRC Project Manager reviewed the licensee's draft letter updating and supplementing the licensee's previous letter dated October 2, 1987, which provided implementation completion dates for the SIMS tracking system. The licensee was requested to provide the additional information on SIMS implementation dates by March 31, 1988, considering the comments provided by the Project Manager in the meeting.

/s/

Lester L. Kinter, Project Manager
Project Directorate II-1
Division of Reactor Projects I/II

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ENCLOSURE 1

ATTENDEES AT NRC-SERI MEETING

FEBRUARY 10, 1988

Name	Affiliation
L. L. Kintner	Project Manager, Project Directorate II-1, NRC
M. L. Crawford	SERI, Licensing
J. C. Cesare	SERI, Licensing
J. L. Robertson	PLT Licensing Superintendent
F. W. Titus*	SERI, Director, Nuclear Plant Engineering
T. H. Cloninger*	SERI - Vice President, Engineering & Support
D. L. Pace	Manager, Nuclear Design
Steve Bennett	SERI Licensing Project Supervisor
Dennis Berryhill	SERI, NPE, Instrumentation & Control
Ross Butcher	USNRC Senior Resident Inspector
Juan Unda	USNRC/CSN, Assignee
Johnny Mathis	USNRC, Resident Inspector
C. R. Hutchinson*	SERI, General Manager

ATTENDEES AT PM-SERI MEETING

FEBRUARY 11, 1988

L. L. Kintner	NRC, Project Manager
Steve Bennett	SERI, Supervisor
S. Hobbs*	SERI, Manager, Licensing
P. Richardson*	SERI, Licensing

*Part Time

ENCLOSURE 2

AGENDA FOR FEBRUARY 10, 1988 MEETING

NRC - SERI

A. STATUS OF COMPLETION OF OPERATING LICENSE CONDITIONS

B. STATUS OF REVIEW OF LICENSING ACTIONS

1. Containment purge criteria during normal operation (06/30/88).
2. Safety Parameter Display System (SPDS) (06/30/88)
3. Detailed Control Room Design Review (DCRDR) (03/30/88)
4. Miscellaneous Amendments to 10 CFR Part 73
   Re Safeguards
   Operating License Amendment (03/30/88)
5. TS changes to implement 10 CFR 55
   Re Reactor Operator Licenses (02/29/88)

C. PROJECTED LICENSING ACTIONS

1. Third refueling outage licensing milestones
2. Integrated systematic assessment plan (ISAP-II) (GL 88-02)
3. Intergranular stress corrosion cracking (GL 88-01)

D. OPERATING REACTOR EVENTS

1. Loss of alternate shutdown cooling during RF02 (LER 87-021 and 87-022)
2. Increased pressure differential between LPCS and LPCI-A during third fuel cycle.
3. Isolation of RWCU system during pump startup and other system transients
4. Followup actions on IN 86-81, Supplement 1
   Re main steam isolation values

E. REVISION 2 TO UFSAR

1. Changes made after SERI determination that changes do not involve unreviewed safety question per 10 CFR 50.59 (no NRC approval)
2. Changes made to clarify reportabililty requirements per 10 CFR 50.72 and 10 CFR 50.73
3. Deletions, additions & clarifications

F. SAFETY ISSUES MANAGEMENT SYSTEM (SIMS)

ENCLOSURE 3

NRC LICENSING ACTION STATUS MEETING
FEBRUARY 10, 1988
1:30 ESC CONFERENCE ROOM #2

PLANT STATUS (PLS)

OL CONDITION STATUS (NL)

KEY LICENSING ACTIONS FOR 1988 (NL)

- o NEUTRON MONITORING
- o TS - SHORT TERM IMPROVEMENTS
  - TSIP
- o EQ, INSPECTION FOLLOWUP
- o HYDROGEN
- o ILS
- o NUREG 1150/PRA

MAJOR LICENSING RELATED INITIATIVES (NL)

- o 50.59 ENHANCEMENT PROGRAM
- o DEFICIENCY REPORTING IMPROVEMENT
- o UFSAR CHAPTER 7

POST-RFO2 SUBMITTALS (NL)

PM REQUESTED TOPICS

- o UFSAR REV. 2 (NL)
- o SIMS UPDATE (NL)
- o IN 86/81 MSIV SPRINGS FAILURE AT FERMI (PLS)
- o IMPROVING SERI/NRC INTERFACE IN SCHEDULING OUTAGE RELATED LICENSING ACTIONS (NL)
- o LPCS/LPCI BREAK DETECTION INSTRUMENTATION (PLS)

TECH SPEC REFORMATTING EFFORT

A. BACKGROUND

- o COMBINED NRC/AIF/NUMARC/OWNERS GROUP EFFORT
- o NRC ISSUED POLICY STATEMENT IN FEBRUARY, 1987
  - REDUCE VOLUME OF TECH SPECS
  - IMPROVE BASES
  - MORE OPERATOR-ORIENTED
  - REDUCE TECH SPEC RELATED CONSTRAINTS TO PLANT OPERATIONS (UNNECESSARY PLANT SHUTDOWNS)
  - MORE EFFICIENT USE OF NRC/INDUSTRY RESOURCES
- o INDUSTRY RESPONSE PROVIDED TO NRC IN NOVEMBER, 1987
  - IDENTIFIED KEY POLICY IMPLEMENTATION ISSUES
  - CONCERTED VENDOR OWNERS GROUP EFFORT
  - GGNS AND HATCH 2 SELECTED AS LEAD PLANTS FOR BWRS

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 Two standby liquid control system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

   1. With one system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

   2. With both standby liquid control system subsystems inoperable, restore at least one subsystem to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5*:

   1. With one system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or insert all insertable control rods within the next hour.

   2. With both standby liquid control system subsystems inoperable, insert all insertable control rods within one hour.

SURVEILLANCE REQUIREMENTS

4.1.5 Each standby liquid control system subsystem shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying that;

   1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

   2. The available volume of sodium pentaborate solution is greater than or equal to 4530 gallons.

   3. The heat tracing circuit is OPERABLE by determining the temperature of the pump suction piping is within the limits of Figure 3.1.5-1.

*With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

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3.1 REACTIVITY CONTROL SYSTEMS

3.1.9 STANDBY LIQUID CONTROL SYSTEM

LCO: Two Standby Liquid Control System (SLCS) subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5.

ACTIONS:

STATUS	REQUIRED ACTION	COMPLETION TIME
	OPERATIONAL CONDITIONS 1 and 2	
A. One SLCS subsystem inoperable.	A.1 Make the inoperable subsystem OPERABLE.	7 days
B. Requirements of Action A.1 NOT met.	B.1 Be in at least HOT SHUTDOWN.	12 hours
C. Both SLCS subsystems inoperable.	C.1 Make at least one subsystem OPERABLE.	8 hours
D. Requirements of Action C.1 NOT met.	D.1 Be in at least HOT SHUTDOWN.	12 hours
	OPERATIONAL CONDITION 5	
	NOTE: 1. Only applicable with a control rod withdrawn. 2. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.	
E. One SLCS subsystem inoperable.	E.1 Make the inoperable subsystem OPERABLE.	30 days
F. Requirements of Action E.1 NOT	F.1 Insert all insertable control rods.	1 hour
G. Both SLCS subsystems inoperable.	G.1 Insert all insertable control rods.	1 hour

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SURVEILLANCE REQUIREMENTS FOR

LCO 3.1.9 STANDBY LIQUID CONTROL SYSTEM

	SURVEILLANCE REQUIREMENT	FREQUENCY
SR 3.1.9	The SLCS shall be demonstrated OPERABLE by:	
SR 3.1.9.1	Verifying temperature of sodium pentaborate solution is within limits of Figure 3.1.9-1.	Once per 24 hours
SR 3.1.9.2	Verifying available volume of sodium pentaborate solution is ≥ [4587] gallons.	Once per 24 hours
SR 3.1.9.3	Verifying temperature of pump suction piping is ≥ [70] °F.	Once per 24 hours
SR 3.1.9.4	Starting both pumps and recirculating demineralized water to the test tank.	Once per 31 days
SR 3.1.9.5	Verifying continuity of explosive charge.	Once per 31 days
SR 3.1.9.6	Verifying by chemical analysis that: 1. Weight of sodium pentaborate is ≥ [5500] lbs. 2. Concentration of boron in solution is within limits of Figure 3.1.9-1.	Once per 31 days AND Within 24 hours anytime water or boron is added to solution AND Within 24 hours anytime solution temperature is below the limit of Figure 3.1.9-1
SR 3.1.9.7	Verifying each valve in flow path not locked, sealed or secured in position, is its correct position.	Once per 31 days
SR 3.1.9.8	Demonstrating minimum flow requirement of [41.2] gpm at a pressure ≥ [1220] psig is met.	Per Specification 4.0.5

(continued)

B. OVERVIEW OF PROJECT (BWR 5/6)

- o WRITERS GUIDE DEVELOPED
  - JOINT VENDOR-OWNERS GROUP EFFORT UNDER NUMARC

- o SPLIT DOCUMENT
  - APPLY NRC CRITERIA
  - COORDINATE WITH OTHER VENDOR GROUPS
  - SUBMIT TO NRC AS TOPICAL REPORT
  - GAIN NRC APPROVAL

- o TECH SPEC REFORMATTING
  - REFORMAT
  - REVISE/ENHANCE BASES (MAJOR PORTION OF WORK)
  - NO TECHNICAL CONTENT CHANGE (NO NEW ANALYSES)

- o REVISED TECH SPEC SENT TO NRC AS STS FOR BWR 5/6 (PARALLEL EFFORT FOR BWR 4, HATCH)

- o NRC APPROVES STS AS GE TOPICAL REPORT
  - BENEFITS
  - REVISION METHOD CONTROLLED THROUGH OWNER GROUP
  - NRC REVIEW & APPROVAL METHOD PROVIDED VIA ESTABLISHED METHOD (LTR)

- o GGNS DEVELOPS PLANT SPECIFIC TECH SPEC, SUBMITS TO NRC

- o KEY IMPLEMENTATION ACTIVITIES
  - PROGRAM TO CONTROL ITEMS REMOVED FROM TECH SPECS
  - ENHANCED 50.59 PROGRAM

- o NRC ISSUES NEW TECH SPECS

C. KEY WORK IN 1988/SCHEDULE/STATUS

- o GAIN NRC APPROVAL OF SPLIT DOCUMENT
  - SUBMITTED IN NOVEMBER, 1987
  - MEETING WITH NRC FEBRUARY 10 AND 11, 1988

- o REVIEW OF GGNS REFORMATTED TECH SPECS AND ENHANCED BASES
  - CURRENTLY UNDERWAY
  - TWO SECTIONS COMPLETE
    ONE CURRENTLY UNDERWAY
    SIX TO GO

- o STS SUBMITTAL EXPECTED IN NOVEMBER, 1988
  - BWR 5/6 STS BASED ON GGNS
  - BWR 4 STS BASED ON HATCH 2

- o NRC SER FOR BWR 5/6 STS: LATE 1989

- o REVISED GGNS SPECIFIC TECH SPECS
  - REWRITES IN 1989
  - SUBMITTAL IN EARLY 1990

D. SUPPORT ACTIVITIES - 1988

- o MODE 4/5 DESIGN BASIS REVIEW TO FEED ENHANCED BASES
  - SCOPING UNDERWAY

- o ENHANCED 50.59 PROGRAM
  - POLICY DEVELOPED - UNDER REVIEW
  - TRAINING PLANNED FOR MARCH, 1988
  - PROGRAM IN PLACE BY JUNE, 1988

SHORT TERM IMPROVEMENT ACTIVITIES

SOURCES

- o GGNS EXPERIENCE
  - OPERATIONAL EXPERIENCE
  - RF02 LESSONS LEARNED
- o NRC GENERIC LETTERS
  - FIRE PROTECTION
  - TECH SPEC 3.0.4/4.0.3/4.0.4
  - D/G SURVEILLANCE
- o BWROG EFFORTS
  - NUMEROUS TOPICAL REPORTS GENERATED; SUBMITTED TO NRC
  - BASED ON "PRA" CONCEPTS AND ACTUAL EQUIPMENT PERFORMANCE DATA
  - REVISED ALLOWABLE OUT OF SERVICE TIMES AND SURVEILLANCE FREQUENCIES
  - ONLY RPS TOPICAL HAS NRC SER

CONTROL/MANAGEMENT

- o DRAFT MASTER PUNCHLIST DOCUMENT
- o PROCESS OF REVIEWING & PRIORITIZING
  - PROBABILITY
  - SIGNIFICANCE (IMPACT)
- o CURRENT STATUS
  - TRACKING 26 ITEMS
  - VARYING IMPACT

2/10/88

POST-RF02 SUBMITTALS

		Schedule
1.	MSIV/ECCS Instrument Lines	
	- Submit a description of final design and evaluation to determine if all elements of a closed system outside containment are met and advise NRC when implementation of Mods and testing is complete MAEC-87/0215, 9/4/87	Submit by 2/12/88
2.	IEB 85-03 Report submittal	Submit by 2/15/88
3.	Follow-up report on stuck fuel bundle, AECM-87/0230, 11/21/87	Submit by 2/22/88
4.	Submit a summary report within 90 days of completion of ISI performed during a refueling outage	Submit by 4/5/88
5.	RF02 Startup Summary Test Report per TS 6.9.1.2	Submit by 4/5/88

ENCLOSURE 4

MEMO TO: Mr. S. F. Tanner, Manager, Quality Services, Quality Programs

FROM: D. L. Pace, Manager Nuclear Design

SUBJECT: Nuclear Plant Engineering Disposition of MNCR
Number: 0015-88

PMI:

DATE:

The enclosed original MNCR has been dispositioned by Nuclear Plant Engineering as follows:

____ Accept-As-Is ____ Repair ____ Rework ____ Interim

X Other Instrument Setpoint Change

In the case of an interim response per NPE Administrative Procedure 01-801, the original MNCR will be maintained in NPE until final disposition is made on the MNCR.

The attached MNCR requires "As-Built"

____ YES X NO

(IF YES, THE MNCR WILL BE RETURNED TO NPE FOR "As-Built".)

____ No NPE Action Required

HDB:

Attachment

cc: File (NPE), w/o
File (MNCR), w/a
Central File , w/o

MEMO TO: Mr. S. F. Tanner, Manager, Quality Services, Quality Programs

FROM: D. L. Pace, Manager Nuclear Design

SUBJECT: Nuclear Plant Engineering Disposition of MNCR
Number: 2015-88

NMI: 88/00439

DATE: January 13, 1988

The enclosed original MNCR has been dispositioned by Nuclear Plant Engineering as follows:

_____ Accept-As-Is _____ Repair _____ Rework ✓ Interim

_____ Other ____________________

In the case of an interim response per NPE Administrative Procedure 01-801, the original MNCR will be maintained in NPE until final disposition is made on the MNCR.

The attached MNCR requires "As-Built"

_____ YES ✓ NO

(IF YES, THE MNCR WILL BE RETURNED TO NPE FOR "As-Built".)

_____ No NPE Action Required

HDB: 8n

DLPace

Attachment

cc: File (NPE), w/o
File (MNCR), w/a
Central File , w/o

NPE 033/11-30-87

MNCR TRANSMITTAL FORM

TO:

() ELECTRICAL ENGINEERING
() I & C ENGINEERING
() MECHANICAL ENGINEERING
() MATERIAL ENGINEERING
● NPE - ENGINEERING
() PSRC CHAIRMAN
() NPE - OAS

() ELECTRICAL SUPERINTENDENT
() I & C SUPERINTENDENT
() MECHANICAL SUPERINTENDENT
() TECHNICAL SUPPORT
() PM&C
() PRODUCTION BUYER
() STORES SUPERVISOR
() OTHER: ____________

FROM: QUALITY PROGRAMS
TRANSMITTAL DATE 1/12/88

SUBJECT: MNCR NUMBER 0015-88
FILE NUMBERS: 0290/0490/0491/15718
TRANSMITTAL NUMBER 88 10106

MNCR

INSTRUCTIONS:

() THE ATTACHED MNCR REQUIRES ENGINEERING DISPOSITION AND EVALUATION. PLEASE COMPLETE THE APPLICABLE SECTIONS AND RETURN THE MNCR TO QUALITY PROGRAMS.

() THE ATTACHED MNCR REQUIRES A SEVEN (7) DAY EVALUATION DUE

() THE ATTACHED MNCR (COPY) HAS BEEN SCREENED AS POSSIBLY POTENTIALLY REPORTABLE UNDER 10 CFR 50.55(E) AND/OR 10 CFR 21. PLEASE EVALUATE AND RETURN A COPY OF THE EVALUATION TO QUALITY PROGRAMS.

() THE ATTACHED MNCR REQUIRES YOUR ACTION. PLEASE EXPEDITE AS SOON AS POSSIBLE.

() FOR YOUR INFORMATION THIS MNCR IS CLOSED.

● OTHER/ADDITIONAL INSTRUCTIONS Evaluation Required

CC:

() SUPV, PROCUREMENT QUALITY
() STORES SUPERVISOR
() PSRC — FOR REVIEW
● MNCR FILE

() ELECTRICAL PLANNING
() I & C PLANNING
() MECHANICAL ENGINEERING
() NPE-OAS (FOR REVIEW)
() OTHER: ____________

RECEIVED
JAN 13 1988
NUCLEAR PLANT ENGINEERING

3

MATERIAL NONCONFORMANCE REPORT (MNCR) Sheet 1 of

SECTION I/ORIGINATOR

TIL
Material Nonconformance Report (MNCR) DOCNO MNCR - 0015-88
ORIG/DATE NAME and TITLE DATE STEVE BURRIS / OPS. SUPT 1/9/88
Supplier Name Code
MPL No. E31-N080A/N680A
XREF Drwg/Spec No. - M1090A
XREF PO No. XREF PR No. XREF QIPN No. XREF Part No. Phone Con. 1/9/88 2130
SHIFT SUPERINTENDENT/SUPERVISOR NOTIFICATION REQUIRED: (X) Yes ( ) No D.C. Graves for L.G. Temple 1/9/88
ENG SUPV/DISCIPLINE SUPT/MANAGER DATE

NONCONFORMANCE: RHRA/LPCS LINE BREAK ALARM SEALED IN ≈ 0600 1/9/88. MWO WAS ISSUED TO INVESTIGATE (80257). I&C DETERMINED THE TRANSMITTER (E31-N080A) AND TRIP UNIT (E31-N680A) WERE RESPONDING PROPERLY. TRIP UNIT INDICATES 3.39 VOLTS (+1.95 psid), AND XMT READS ≈ 13.51 Ma. I&C TECH'S STATED THAT WHEN ATTEMPTING TO EQUALIZE SENSING LINES LOCALLY, FLOW WAS DETECTED IN LINES. DURING PERFORMANCE OF IN4229 (FILL+VENT), E12-F027A WAS ALSO CLOSED TO DETERMINE IF LEAK BY F041A + F042A WAS OCCURRING CAUSING RHR 'A' HX PRESSURIZATION. RHR 'A' HX WAS VENTED. WHEN F027A WAS REOPENED, HX PRESSURE JUMPED 15 PSIG INSTANTANEOUSLY.

Deficiency Reportable Per 10 CFR 50.72, 50.73 or License Condition? (✓) No
( ) Yes, IR No
( ) Undeterminable

PRIORITY 2
Further Engineering Evaluation Required
(X) Yes, complete Att. VII
S Burris 1/9/88
Shift Supt./Supv. Date

SECTION I/OPERATIONS
LCO NO 88-033 (If Applicable)
MNCR Priority 1 (2) 3 4 (Circle One)
System/Component Declared INOP (X) Yes ( ) No
Deficiency affects operability in Mode (1) (2) (3) 4 5, None (Circle One)
Evaluated By: Steve Burris / 1/9/88
Shift Supt./Supv. Date
[signature] 1-15-88

Section II/QA Section

		YES	NO
(1)	Screening:		
	Safety Related	(✓)	( )
	Potential 50.55(e)	( )	(✓)
	Potential 10 CFR 21	( )	(✓)
	Action Required	(✓)	( )

J.E. Wideman 1/11/88
(2) Screened by: Signature/Date

Section III/QA
Hold Tags Attached
YES ( ) NO (✓)
NA
Hold TAG Numbers

QA RECORD
RTYPE - F2.08
Non QA Record
Initials
Number Of Pages
Date
Related Doc.

SECTION IV/ENGINEERING
(1) Safety Related YES (✓) NO ( )
(2) Evaluation of Probable Cause:
see attached evaluation

(3) Disposition: ( ) REWORK ( ) REPAIR ( ) ACCEPT-AS-IS ( ) REJECT (✓) Other
(4) Justification: Data indicates no line break and that instruments are working properly. Need to take data at startup and power ops to determine "normal dp" per tech specs
see attached evaluation.

OPERABILITY CONCERN RESOLUTION FORM

SHIFT SUPERINTENDENT/SUPERVISOR

Operability Concerns:

DETERMINE AFFECT OF LPCS AND/OR LPCI A SYSTEM OPERABILITY.

[signature] 11/9/88
Shift Supt./Supv. Date

List questions or concerns that must be answered by Engineering to determine operability.

ENGINEERING

Engineering Evaluation to aid Shift Superintendent Supervisor in determining operability

Data and troubleshooting show no line break and that instruments are seeing real dp. Must take data during startup and power ups to determine "normal dp" for tech spec setpoint. System and instruments are operable

[signature] 11-12-88
Engineer Date

1-12-88 | | Jerry Parker

MNCR 0015-88 evaluation
LPCS/LPCI line break detection

- During startup from RFO2 trip unit B31-N690E alarmed on high dP of about 1.7 psid at about 80% power. As power was increased to about rated and about 104% core flow, this measured dp increased to 2.1 psid. At this point the plant scrammed for other reasons, and in about five minutes when first observed the dp had dropped to 1.7 psid. Over the next 1½ days the dp gradually dropped to 0.65 psi at 140 psig Rx pressure.

- Before the scram several things were done to verify that the transmitter was seeing actual process pressure. The sensing lines were filled and vented, the transmitter and trip units calibration was checked. The transmitter was equalized under reactor pressure and gave an output for 0 psid.
- With the transmitter in service, and a DVM hooked to the output test connection, the equalizing valve was cracked open. The dp dropped some but held steady at greater than zero. As the valve was opened in steps, the dp dropped and held steady at the new value, flow could be felt through the tubing. In this position the high side isolation valve was shut and the output went to zero dp. When restored to normal lineup, the output returned to the original dp. of 2.1 psid. Also the pressure at the high and low side of the transmitter was measured with a Heise gauge and showed about two psi difference.
- All this shows that the instruments are working correctly, the instrument lines are all fully filled, and that a real dynamic differential pressure did exist.

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- We can conclusively say that there is no ~~LPCS~~ JEP 1-12-88 LPCI A line break because of the magnitude of the dp drop at the time of the scram. If there had been a line break, the dp would have shifted up JEP 1-12-88 to about 3.4 psi due to the difference in pressure across the core shroud being sensed through the broken line. When the scram occured, core flow would drop to slow speed and steam production would essentially stop. This would cause the shroud dp to drop to near zero and the sensed 3.4 psi would disappear. We actually only observed a 0.4 psi drop during the scram. This small change can be accounted for by the change in density between the LPCI and LPCS spargers due to the change from two phase steam and water flow out of the core to only water flow, and also due to the lost velocity head impacting on the JEP 1-12-88 LPCS sparger nozzles.

- Tech Spec requires the setpoint for these instruments to be ± 1.2 psi from the normal indicated dp. We have no historical data for what the normal dp is. My theoretical calculations account for a dp of 0.8 - 1.0 psid at rated conditions. Since we are looking at very small dp's and a difficult physical arrangement to calculate accurately, we must record actual dp sensed as we startup and run to determine the "normal indicated dp" referenced in Tech Specs.

J Parker 1-12-88

SYSTEM ENERGY RESOURCES, INC.

NUCLEAR PLANT ENGINEERING MNCR DISPOSITION

MNCR NUMBER 0015-88

ATTACHMENT NO. 1

PAGE 1 OF 2

1) PLANT STAFF DISPOSITION: REWORK ☐ REPAIR ☐ ACCEPT ☐ OTHER ☒

2) NPE DISPOSITION REWORK ☐ REPAIR ☐ ACCEPT. ☐ OTHER ☐ INTERIM ☒ NO. #1

JUSTIFICATION: (ATTACH ADDITIONAL SHEETS IF NECESSARY)

See page 2.

3) ☐ DISPOSITIONED PER DCP NUMBER: ____________

4) ☒ DCP NOT REQUIRED COMPLETE THE FOLLOWING:

10CFR50.59 SAFETY EVALUATION APPLICABILITY REVIEW	YES	NO
(1) CHANGE TO FACILITY AS DESCRIBED IN FSAR.		X
(2) CHANGE TO PROCEDURE AS DESCRIBED IN FSAR.		X
(3) PROPOSED TEST OR EXPERIMENT NOT DESCRIBED IN FSAR		X
(4) CHANGE TO TECHNICAL SPECIFICATION. (IF YES, PERFORM 10 CFR 50.59, SAFETY EVALUATION)		X

REVIEWER: H. D. Bumfill DATE: 1/12/88

a. 10 CFR 50.59 SAFETY EVALUATION	NOT REQUIRED PER ABOVE REVIEW	☒	ATTACHED	☐
b. ENVIRONMENTAL REVIEW	PERFORMED	☒	ON FILE	☐
c. FIRE PROTECTION REVIEW	PERFORMED	☒	ON FILE	☐
d. CALCULATIONS	PERFORMED	☐	NOT REQUIRED	☒
	REFERENCE ONLY	☐	CALCULATION NO	

e. OTHER (SPECIFY)

Design Verification, ALARA, Environmental, Fire Protection, Safe Shutdown, Pump & Valve IST, EQCF, SQAR

5) REVIEW AND APPROVAL

RESPONSIBLE ENGINEER H.D. Bumfill DATE 1/13/88

VERIFICATION REQUIRED ☐ NO ☒ YES BY: H. T. Sajnani DATE 1/13/88

INTERDISCIPLINARY REVIEW REQUIRED ☒ NO ☐ YES CGS: M.D. Withrow DATE ~~1/13/87~~ 1/13/88

PRINCIPAL ENGINEER [signature] DATE: 1/13/88

QUALITY ENGINEER David Chapley DATE: 1/13/88

MANAGER, NUCLEAR DESIGN APPROVAL: D.S. Pace DATE: 1/13/88

(FOR INTERIM ONLY)

801.2 REV. A

(8)

NPE DISPOSITION:

NPE has evaluated the measured dP da or reactor power operation (from approximately 85% - 95% power 104% flow) prior to the scram of 1/10/88 and for reactor conditions during shutdown and cooldown subsequent to the scram. Based on this evaluation, NPE has concluded that the instrumentation has not identified a failure in either the LPCI-A or LPCS piping in the reactor downcomer annulus. The line break annunciation which occurred on 1/9/88 at approximately 85% power was due to a positive shift in the normal instrument differential pressure compounded by an excessive process measurement accuracy (PMA) effect. The normal dP shift was not refined using actual plant data and may have been affected by plant refueling (Ref.: G.E. letter dated 1/12/88). The excessive PMA effect was caused by residual noncondensable gasses (most likely originating from local leak rate testing during RFO2) trapped in either or both the LPCI-A injection piping and LPCS downcomer annulus piping.

The extensive testing performed by Plant Staff I&C has demonstrated that the line break detection instrumentation (transmitter and trip units) is performing the required design functions within specified parameters. However, due to the observed anomalies in the measured values, additional data are needed in order to determine if the excessive PMA effect is temporary and if a new normal dP value is required. The data required must include the dP (psid) indicated by E31PDIS-N680A with the corresponding reactor power and flowrate (% of rated). The data should be recorded in hourly intervals after entering Mode 2 and while reactor power is increasing up through MEOD conditions at nominally full power. Judgement regarding the need for hourly data recording may be exercised during long periods of relatively stable reactor parameters.

The disposition of this MNCR is thus "Interim" pending collection and evaluation of these data. An interim disposition is justified since NPE's evaluation and Plant Staff I&C testing have determined that the instrumentation is capable of performing the required design function and that the subject annunciation and dP measurements were not indicative of a pipe failure. This interim disposition shall remain in effect for 30 days following data collection to allow sufficient time for proper evaluation and determination of a final solution. The final solution will result in a setpoint change if the normal dP shift is significant and permanent. However, no changes will be required if the evaluation concludes that the observed anomalies were temporary and the normal dP shift due to the current plant operating parameters is insignificant.

MNCR NO: 0015-88

ATTACHMENT: 2

PAGE 1 OF 1

DCP NO: N/A

LIST OF AFFECTED DOCUMENTS FOR THIS MNCR

DOCUMENT NUMBER	REVISION	CURRENT REVISION OF REFERENCE DRAWING
None		

FORM NPE 120/09-13-85

SYSTEM ENERGY RESOURCES, INC.

NUCLEAR PLANT ENGINEERING MNCR DISPOSITION

MNCR NUMBER 0015-88

ATTACHMENT NO. 1

PAGE 1 OF 4

1) PLANT STAFF DISPOSITION: REWORK ☐ REPAIR ☐ ACCEPT ☐ OTHER ☒

2) NPE DISPOSITION REWORK ☐ REPAIR ☐ ACCEPT ☐ OTHER ☒ INTERIM ☐ NO. ______

JUSTIFICATION: (ATTACH ADDITIONAL SHEETS IF NECESSARY)

Instrumentation Setpoint Change (see pages 2 thru 4)

3) ☐ DISPOSITIONED PER DCP NUMBER: ______

4) ☒ DCP NOT REQUIRED COMPLETE THE FOLLOWING:

10CFR50.59 SAFETY EVALUATION APPLICABILITY REVIEW	YES	NO
(1) CHANGE TO FACILITY AS DESCRIBED IN FSAR.	___	X
(2) CHANGE TO PROCEDURE AS DESCRIBED IN FSAR.	___	X
(3) PROPOSED TEST OR EXPERIMENT NOT DESCRIBED IN FSAR	___	X
(4) CHANGE TO TECHNICAL SPECIFICATION. (IF YES, PERFORM 10 CFR 50.59, SAFETY EVALUATION)	___	X

REVIEWER: H. D. Bufin DATE: 2/4/88

a. 10 CFR 50.59 SAFETY EVALUATION	NOT REQUIRED PER ABOVE REVIEW	☒	ATTACHED	☐
b. ENVIRONMENTAL REVIEW	PERFORMED	☒	ON FILE	☐
c. FIRE PROTECTION REVIEW	PERFORMED	☒	ON FILE	☐
d. CALCULATIONS	PERFORMED	☒	NOT REQUIRED	☐
	REFERENCE ONLY	☐	CALCULATION NO.	MC-N1111-88008

e. OTHER (SPECIFY)

Design Verification, Alara, Safe Shutdown, Pump & Valve IST, EQCF, SQAR

5) REVIEW AND APPROVAL

RESPONSIBLE ENGINEER H. D. Bufin DATE: 2/4/88

VERIFICATION REQUIRED ☐ NO ☒ YES BY: Manuel E. Ledezma DATE: 2/4/88

INTERDISCIPLINARY REVIEW REQUIRED ☒ NO ☐ YES CGS: M. D. Withrow DATE: 2/5/88

PRINCIPAL ENGINEER: [signature] DATE: 2/5/88

QUALITY ENGINEER: Daniel Chugh DATE: 2/5/88

MANAGER, NUCLEAR DESIGN APPROVAL: See MNCR Section 5 DATE: ______
(FOR INTERIM ONLY)

601.2 REV. 4

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FINAL DISPOSITION

NPE has evaluated the differential pressure (dP) data taken by Plant Staff I&C during two consecutive startups for the three core spray line break instrument channels. The data taken for these two startups indicate that there is a range of normal dP for which the instruments must be capable of detecting a line break. The two startups are bounded by a dP range of 1.5 PSID to 2.1 PSID for the LPCS/LPCI-A channel above 80% power and 90% core flow (See Attachment 3). Consequently, the normal dP referred to in the Technical Specification section 4.5.1.c.2.b) is from 1.5 to 2.1 PSID, inclusively. The LPCI-B/LPCI-C dP, on the other hand, is constant at .25 PSID and this the normal dP referred to in the Technical Specifications.

LPCS/LPCI-A SETPOINTS
(Reference Calculation No. MC-N1111-88008)

NPE has performed setpoint calculations for the LPCS/LPCI-A channel. The setpoint for LPCS line break detection (E31-N680A) was conservatively calculated based the upper bound of the normal dP range (2.1 PSID) and the available dP across the shroud at 80% power and 90% core flow (1.76 PSID). The setpoint for LPCI-A line break detection (E31-N680E) was conservatively calculated based on the lower bound of the normal dP range (1.4 PSID) and the same available dP across the shroud (1.76 PSID). The results of these calculations are summarized below.

	NORM dP	AL	AV	NTSP
LPCS	2.10	> .34	> .44	> .49
LPCI-A	1.50	<3.26	<3.15	<3.10

In order to prevent conflict with the existing Technical Specification requirements, the actual setpoints to be used will be based on the above bounding normal dP values and the requirement that the setpoints be 1.2 +/- .1 PSID change from the normal indicated dP. The actual setpoints and tolerances to be used are summarized below.

	NORM dP	MIN	NTSP	MAX
LPCS	2.10	0.80	0.90	1.00
LPCI-A	1.50	2.60	2.70	2.80

These setpoints are conservative when compared to the calculated values and provide adequate LER and spurious trip avoidance margin.

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It should be noted that there will be reactor operating conditions, particularly in Mode 2, for which the LPCS line break channel may be in alarm; i.e., the dP will be less than .90 PSID. However, the design function of this instrumentation is to detect a completely severed and separated line break for reactor operating conditions at or near rated power and core flow. The measured dP and, consequently, any alarm derived from this dP, is meaningless at significantly less than rated power and flow conditions. Based on recommendations from GE, these setpoints have been calculated using an 80% power and 90% core flow analytic limit. Any alarm received from this instrumentation at less than 80% power or less than 90% core flow is therefore outside the design function requirements of the instrumentation and no conclusions may be drawn regarding whetner a line break has occurred. This interpretation is consistent with the recommendations of SIL 300. The NRC concurred with these recommendations in IE Circular No. 79-24.

LPCI-B/LPCI-C SETPOINTS
(Reference Calculation No. MC-N1111-88008)

NPE has also performed setpoint calculations for the LPCI-B/LPCI-C channel. As stated above, the measured dP was constant at .25 PSID. These setpoints were conservatively calculated based on this constant, normal dP and the available dP across the shroud at 80% power and 90% core flow (1.76 PSID). The results of these calculations are summarized below.

	NORM dP	AL	AV	NTSP
LPCI-B	.25	>-1.51	>-1.40	>-1.36
LPCI-C	.25	< 2.01	< 1.90	< 1.85

Again, in order to prevent conflict with the existing Technical Specification requirements, the actual setpoints to be used will be based on the above constant, normal dP and the requirement

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that the setpoint be 1.2 +/- .1 PSID change from the normal indicated dP. The actual setpoints and tolerances to be used are summarized below.

	NORM dP	MIN	NTSP	MAX
LPCI-B	.25	-1.05	-.95	-.85
LPCI-C	.25	1.35	1.45	1.55

These setpoints are also conservative when compared to the calculated values and provide adequate LER and spurious trip avoidance margin.

There should be no reactor operating conditions for which either channel will be in alarm. However, the design function of this instrumentation is identical to that of the LPCS/LPCI-A channel and, consequently, any alarm received from this instrumentation at less than 80% power or less than 90% core flow is outside the design function requirements of the instrumentation and no conclusions may drawn regarding whether a line break has occurred.

HPCS SETPOINT

The setpoint for the HPCS line break channel will be provided as part of the final disposition of MNCR 0823-83.

CONCLUSIONS

The setpoints for this instrumentation have been determined in accordance with information and recommendations provided by GE in SEGE-88/004 (Attachment 2) and are consistent with the design function requirements of the instrumentation. It is important to note that this instrumentation has no nuclear safety related function. This instrumentation was incorporated into all BWR designs in response to the NRC's desire to provide some measure of core spray and injection piping integrity inside the vessel but outside the shroud. This instrumentation is only capable of detecting a fully severed and separated line break at reactor operating conditions of high power and high core flow. Consequently, no conclusion can be drawn regarding whether a line break has occured based on minor changes in the measured dP.

FINAL DISPOSITION

The normal dP may vary with core alterations and it will therefore be necessary to take this same data during startup following each refueling outage. This data should be transmitted to NPE for evaluation to determine if new setpoints are necessary for the instrumentation to meet the design function requirements.

X

ACTION FOR RESOLUTION OF THE NONCONFORMANCE

The disposition of this MNCR is "Other" since, based on the above discussion, resolution of nonconformance will simply require revision of Surveillance Procedure 06-IC-1E31-R-0021 to incorporate the setpoints and tolerances listed below.

TRIP UNIT	MIN	NTSP (Desired)	MAX
E31-N680A	0.80	0.90	1.00
E31-N680E	2.6	2.70	2.80
F31-N680B	-1.05	- .95	- .85
E31-N680F	1.35	1.45	1.55

All of the above values are in units of PSID.

NPE also recommends revision of appropriate alarm response instructions to clarify response to ECCS out of service alarms initiated by this line break instrumentation. This clarification should state that no conclusions can be drawn regarding whether a line break has occurred if reactor power is below 80% or if core flow is below 90%.

X

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ATTACHMENT 2
TO MNCR 0015-88
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GENERAL ELECTRIC

"JCLEAR ENERGY BUSINESS OPERATIONS
GENERAL ELECTRIC COMPANY • 175 CURTNER AVENUE • SAN JOSE, CALIFORNIA 95125
MC 396, (408) 925-2937

January 29, 1988

RECEIVED
FEB 2 - 1988
NUCLEAR PLANT
ENGINEERING

Mr. F. W. Titus
Director, Nuclear Plant Engineering
System Energy Resources, Inc.
Grand Gulf Nuclear Station
P. O. Box 429
Port Gibson, MS 39150

Grand Gulf Nuclear Station
Background Information on Core
Spray Line Break Detection
SEGE-88/004

Dear Fred:

Some years ago, several operating BWR plants expressed concern that they were encountering instrumentation reading difficulties for the core spray break detection system. In September of 1979, GE issued a Service Information Letter (SIL) No. 300 to our BWR customers regarding this concern. Also, in November of 1979, the USNRC issued an IE Circular No. 79-24 which described a core spray break detection set-point problem at an operating BWR. This IEC discussed the contents of the GE SIL-300 including the recommendations for the determination of alarm setpoints based upon individual plant conditions.

The following information is provided to enhance your understanding of the core spray break detection feature and to provide GE's recommendations on establishing "normal" ΔP and alarm setpoints based on our knowledge to date.

A. The core spray break detection feature has neven been classified as nuclear safety related. It was incorporated into the BWR design in response to the NRC's desire to provide additional information to the reactor operators to demonstrate some measure of core spray integrity outside of the shroud but inside of the reactor vessel. There has never been any GE or NRC requirement for any direct or automatic action safety function to be initiated by this break detection feature nor was any such direct safety action intended by its design. To date, the NRC has approved all GE BWR designs which have incorporated this non-nuclear safety related break detection feature into the plant designs.

B. The purpose of the core spray line break instrumentation is to detect a break in the core spray piping inside the reactor vessel (between the nozzle and the shroud) during operation at <u>rated power</u> conditions. If a break occurs, the instrumentation should provide this information by annunciation in the control room. At lower power levels there is not enough ΔP to provide meaningful signal output information. This fact is consistent with the original design intent of the break detection feature since the BWR plants normal operation is at the higher power levels where

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the most meaningful ΔP information is available as a function of reactor power and core flow. Again the ΔP information does not result in any overt safety action since its purpose is for high power operating status information only.

C. Only a major break in the core spray line (i.e., a doubled ended and separated break) is detectable by the ΔP break detection scheme. 1X

D. The sensitivity of the break detection system is low because leakage flow will not produce a measureable pressure difference between the sparger and a break in the annulus region unless the flow is essentially unrestricted (i.e., the pipe is open to the annulus). If such a break did occur, the core spray would contribute to core flooding, thereby being an effective contribution to ECCS. A single failure of a core spray line has been considered in the ECCS safety analysis.

E. The Tech Spec Surveillance Requirements on Page 3/4 5-5, paragraph 4.5.1.c.2.b), describe the HPCS, LPCS, and LPCI setpoint to be at a 1.2± 0.1 psid change from the normal ΔP. The value of 1.2 psid is based upon the following considerations:

   1. The total available ΔP which exists between the inside and outside of the core shroud.

   2. The analytical limit of 1.76 psid is based upon 90% core flow since 100% core flow conditions do not exist all of the time. A calculated 2.8 psid analytical limit would exist at 100% reactor power and 100% core flow. This data is based upon information contained in GE's Design Record files.

   3. The break detection instrumentation has accuracy, calibration, and drift characteristics which must be considered when establishing the setpoint.

F. Recommendations for ΔP setpoints:

   1. The alarm setpoints and limits are arbitrary, but they should be conservatively chosen and may be different than those of other operating BWRs depending upon plant specifics.

   2. The ΔP setpoint should be established as a change from the "normal" ΔP value. This "normal" ΔP should be established with the reactor at greater than 80% power and core flow at greater than 90%. The "normal" ΔP is a function of both reactor power and core flow.

   3. The break alarm should be set from the "normal" ΔP point. This setpoint trip (input from the E31 system) should be established as a variation on either side of the "nominal" ΔP point. Minor oscillations (noise) should be ignored since a real break will provide a steady indication.

4. If a break occurs in either the LPCI or LPCS line, the ΔP indication for the broken line will decrease with respect to the ΔP indication from the unbroken line.

If you have any questions on this material, please give me a call.

Very truly yours,

A. R. Smith

A. R. Smith
Grand Gulf Engineering Services Manager

cc: T. H. Cloninger J. E. Cross C. R. Hutchinson
D. J. Kemppainen J. E. Nichols D. L. Pace
File: E21

(BARB3:SEGE-88/004)

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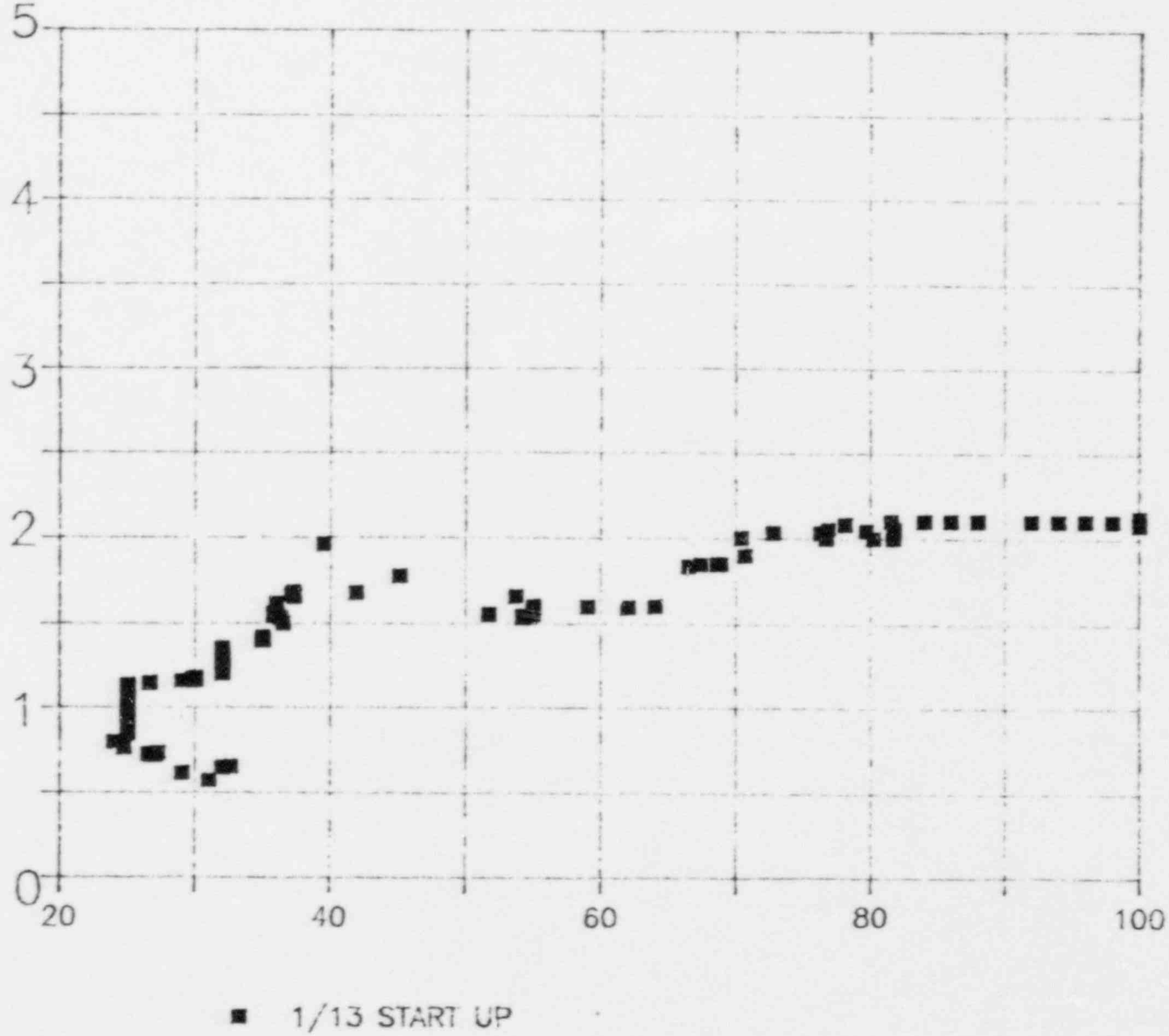
CORE FLOW vs. DP



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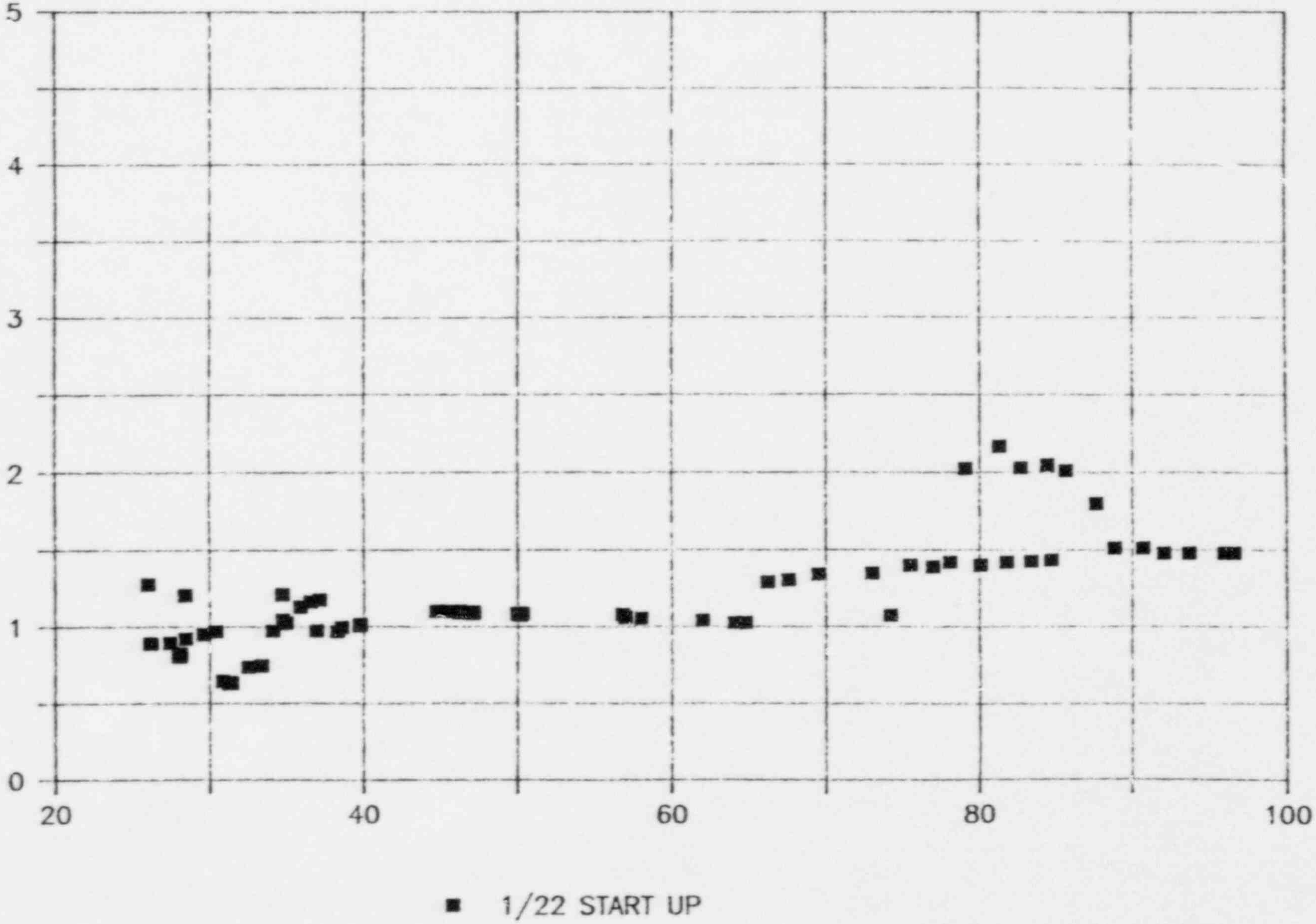
Core Flow v. DP



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DCP NO: N/A

LIST OF AFFECTED DOCUMENTS FOR THIS MNCR

DOCUMENT NUMBER	REVISION	CURRENT REVISION OF REFERENCE DRAWING
None		

FORM NPS 120/09-13-85

ENCLOSURE 5

MWO I80257

(1)

Time	E31-N680A			E31-N680B		
	Meter	Volts	Rx Press	Meter	Volts	
10 JUN 88 2000	1.5	3.28	545	.25	3.01	
2100	1.5	3.28	540	.25	3.01	
2200	1.4	3.27	520	.25	3.01	
2300	1.4	3.27	490	.25	3.01	
2400	1.5	3.26	465	.25 ~~.20~~	3.01	
11 JUN 88 0100	1.5	3.25	450	.25	3.01	
0200	1.5	3.25	420	.25	3.01	
0300	1.25	3.24	400	.25	3.01	
0400	1.25	3.23	380	.25	3.01	
0500	1.20	3.23	355	.25	3.01	
0600	1.20	3.23	345	.25	3.01	
0700	1.20	3.22	325	.25	3.01	
0800	1.20	3.21	236	.25	3.02	
0900	1.20	3.20	217	.25	3.02	
1000	1.20	3.20	199	.25	3.02	
1100	1.20	3.20	199	.25	3.02	
1200	1.00	3.19	180	.20	3.01	
1300	1.00	3.19	175	.20	3.01	
1400	.90	3.18	160	.20	3.01	
1500	.80	3.17	140	.20	3.01	
1600	.80	3.17	135	.20	3.01	
1700	.80	3.16	125	.20	3.01	
1800	.80	3.16	120	.20	3.01	
1900	.80	3.16	120	.20	3.01	
2000	.80	3.16	120	.20	3.01	
2100	.80	3.15	120	.20	3.01	
2200						

MWO# I 80257 (2)

Time	E31-N680A		Rx Press	E31-N680B		
	Meter	volts		Meter	volts	
11 JAN 88 2300	.80	3.15	120	.20	3.01	
2400	.80	3.15	120	.20	3.01	
12 JAN 88 0100	.80	3.15	120	.20	3.01	
0200	.80	3.15	120	.20	3.01	
0300	.80	3.15	120	.20	3.01	
0400	.75	3.14	120	.20	3.01	
0500	.75	3.14	120	.20	3.01	
0600	.75	3.14	120	.20	3.01	
0700	.75	3.14	120	.20	3.01	
0800	.75	3.136	140	.25	3.017	
0900	.75	3.13	140	.25	3.01	
1000		3				
1100						
1200						
1300						
1400		~~3.124~~				
1500	+.70	3.124	130	.25	3.017	
1600						
1700						
1800						
1900						
2000						
2100						
2200						
2300						
2400	.5	3.11	90	.25	3.01	

[MWO I80257]

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TIME	E31-N680A		Rx Press	E31-N680B	
	METER	VOLTS		METER	VOLTS
13JAN88					
0100	.5	3.11	105	.25	3.01
0200	.5	3.11	105	.25	3.01
0300	.5	3.11	105	.25	3.01
0400	.5	3.10	105	.25	3.01
0500	.5	3.10	105	.25	3.01
0600	.5	3.10	105	.25	3.01
0700	.5	3.10	105	.25	3.01
0800	.5	3.10	105	.25	3.02
0900	.5	3.10	105	.25	3.01
1000	.5	3.10	105	.25	3.01
1100	.5	3.10	105	.25	3.01
1200	.5	3.10	110	.25	3.01
1300	~~.5~~	~~3.10~~	~~120~~	~~.25~~	~~3.02~~ 1-13-88
1400					
1500	.5	3.10	120	.25	3.02
1600					
1700					
1800					
1900					
2000					
2100					
2200					
2300					
2400					

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E31-N680A and HPCS data

Date	Time hourly	Rx power %	Rx press. psig	Core flow %	E31-N680A meter ± psi	E31-N680A DVM volts	HPCS E31-N681 meter ± psi
1-13-88	2100	~.2%	254	31%	+.5	+3.114	-2
	2200	.7%	368	29%	+.6	+3.123	-2.4
	2300	1.5%	405	32%	+.6	+3.129	-2.5
1-14-88	0000	~1.8%	405	32.6%	.6	3.13	-2.5
	0200	~1.0%	701				
	0300	~1.5%	701	26.5%	.7	3.145	-3.25
	0400	~1.4%	701	27.25%	.7	3.146	-3.25
	0500	~1.4%	701	27.06	.7	3.145	-7.25
	0600	~1.4%	701	27.06	.7	3.144	-3.25
	0700	~1.4%	7·1	27.1	.7	3.144	-7.3
	0800	~1.5%	765	26.7	.7	3.144	-3.3
	0900	~1.8%	868	24%	.7	3.152	-3.6
	1000	~2.0%	920	24%	.8	3.159	-3.5
	1100	3.0%	950	25%	.9	3.168	-3.9
	1200	3.0	949	25%	1.0	3.175	-4.0
	1300	3.0	948	25	1.0	3.181	-4
	1400	3.0	948	25	1.0	3.187	-4
	1500	3.0	948	25	1.0	3.189	-4
	1600	3.0	950	25	1.0	3.193	-4
	1700	3.0	950	25	1.0	3.198	-4
	1800	-34.5	950	25	1.0	3.204	-4
	1900	4.5	950	25	1.0	3.211	-4
	2000	4.5	950	25	1.0	3.215	-4
	2100	4.5	950	25	[illegible].0	3.219	-4
	2200	4.5	950	25	1.1	3.222	-4
	2300	4.5	950	25	1.1	3.224	-4
1-15-88	0000	~3%	950	25	1.1	3.226	-4
	0100	~3%	950	26.6%	1.1	3.228	-4
	0200	~4%	950	26.6	1.1	3.229	-4
	0300	~5.2	950	29%	1.1	3.231	-4
	0400	~5%	950	30%	1.1	3.231	-4
	0500	~5	950	29.8	1.1	3.231	-4
	0600	~5	950	30	1.1	3.233	-4
	0700	5	950	29.8	1.1	3.234	-4
	0800	5.5	950	30	1.2	3.235	-4
	0900	5.5	950	32	1.2	3.240	-4
	1000	5.2	950	32	1.2	3.244	-3.9
	1100	5.1	950	32	1.2	3.250	-3.8
	1200	5.3	950	32	1.25	3.253	-3.8
	1300	5.0	950	32	1.3	3.256	-3.8
	1400	5.0	950	32	1.3	3.258	-3.8
	1500	5.0	950	32	1.3	3.259	-3.8
	1600	9.0	950	32	1.3	3.262	-3.8
	1700	20	950	32	1.4	3.271	-3.8
1-15-88	~~1800~~		950	35	1.4	3.284	-3.8

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E31-N680A and HPCS data

Date	Time hourly	Rx power %	Rx press. psig	Core flow %	E31-N680A meter ± psi	E31-N680A DVM volts	HPCS E31-N681 meter ± psi
1-15-88	1800	18	950	35	+1.4	3.280	-3.8
	1900	18	950	35	+1.4	3.280	-3.8
	2000	18	950	35	+1.4	3.280	-3.8
	2100	18	950	35	+1.4	3.280	-3.8
	2200	18	950	35	+1.4	3.280	-3.8
	2300	23	950	35	+1.4	3.280	-3.8
1-16-88	0000	27	957	~~35~~ 36.5	+1.5	3.300	-3.7
	0100	23.5	957	36.3	+1.5	3.306	-4.0
	0200	23.9	957	35.8	+1.5	3.309	-4.0
	0300	23.3	957	35.9	+1.5	3.312	-4.0
	0400	27.0	957	35.8	+1.5	3.312	-4.0
	0500	36.7	961	36.0	+1.5	3.323	-4.0
	0600	35	960	37.3	+1.6	3.330	-4.1
	0700	37.21	962	37.1	+1.6	3.333	-4.1
	0800	38.5	962	41.86	+1.6	3.335	-4.1
	*0900	41.5	968	37.2	+1.6	3.336	-4.0
	1000	45.5	972	39.5	+1.6	3.342	-4.0
	1100	51.	972	45.1	+1.6	3.355	-4.0
	1200	53.4	974	53.7	+1.6	3.331	-4.0
	1300	58	975	51.7	+1.7	3.310	-4.0
	1400	62.7	980	51.7	+1.7	3.310	-4.0
	1500	62.5	990	54.2	+1.7	3.309	-4.0
	1600	63	980	54.2	+1.5	3.307	-4.0
	1700	68	980	55	+1.5	3.311	-4.0
	1800	72	988	55	+1.5	3.315	-4.0
	1900	75	990	55	+1.5	3.317	-4.0
	2000	74	990	55	+1.5	3.317	-4.0
	2100	77	~~990~~ 997	55	+1.5	3.320	-4.0
	2200	78	998	59	+1.5	3.320	-4.0
	2300	79	999	62	+1.5	3.319	-5.4
				64	+1.5	3.320	-5.7
1-17-88	0000	80%	1000		+1.8	3.367	-5.8
	0100	79.9	1000	66.5%	1.7	3.370	-5.8
	0200	79.6	1000	67.4	1.8	3.374	-5.8
	0300	79.7	1000	61.6	1.8	3.378	-5.8
	0400	79.6	1000	68.6	1.8	3.378	-5.8
	0500	80.1	1001	68.7	1.8	3.380	-5.9
	0600	84.5	1003	70.67	1.8	3.	-5.9
	0700	85.9	1007	70.9	1.8	3.406	5.9
	0800			72.8	1.9		
	0900						
	1000						
	1100						
	1200						
	1300						

* 0830 Recieved RHR A Line Break status - Xferring to fast speed

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E31-N680A AND HPCS DATA

DATE 1-17-88

TIME	RX PWR %	RX PRESS PSIG	CORE FLOW WT %	E31-N680A METER	E31-N680A DVM	HPCS E31-N631
0000	80%	1000	66.5%	+1.6	3.361	-5.8
0100	79.9%	1000	67.4%	1.7	3.37	-5.8
0200	79.6%	1000	68.6%	1.7	3.37	-5.9
0300	79.7%	1000	68.6%	1.8	3.37	-5.8
0400	79.6%	1000	68.9%	1.8	3.37	-5.9
0500	80.1%	1001	70.67%	1.8	3.33	-5.8
0600	84.5%	1003	70.4%	1.8	3.0	-5.8
0700	85.9%	1007	72.8%	1.9	3.406	-5.8
0800	87%	1010	76.72	1.9	3.4	-5.8
0900	88%	1010	76.87	1.9	3.41	-5.8
1000	88%	1010	78.12	1.9	3.416	-5.8
1100	88.6%	1010	79.67%	2.0	3.409	-5.8
1200	89.3%	1010	81.71%	2.0	3.40	-5.9
1300	89.4	1010	81.77	2.0	3.41	-5.9
1400	89.04	1010	76.29	2.0	3.406	-5.9
1500	91.34	1010	80.20	2.0	3.4	-5.9
1600	92	1014	81.54	+2.0	3.42	-5.9
1700	93	1016	~~94~~ 84%	+2	3.42	-6.1
1800	93	1016	~~95~~ 84%	+2	3.42	-6.1
1900	94	1017	~~97~~ 86%	+2	3.42	-6.1
2000	96	1020	~~99~~ 88%	+2	3.42	-6.1
2100	96	1020	~~99~~ 88%	+2	3.42	-6.1
2200	97	1020	~~103~~ 92%	+2	3.42	-6.1
2300	98	1021	94%	+2	3.42	-6.1

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E31-N680A AND HPCS DATA   DATE 1-18-88

TIME	RX PWR	RX PRESS	CORE FLOW	E31-N680A METER	E31-N680A DVM	HPCS E31-N601
	%	PSIG	WT %			
0000	98	1023	96	+2	3.420	-6.4
0100	99	1024	98	+2	3.429	-6.4
0200	100	1025	100	+2	3.425	-6.4
0300	99.9	1025	100	+2	3.416	-6.4
0400						
0500						
0600						
0700						

ACHIEVED 100% PWR

NA

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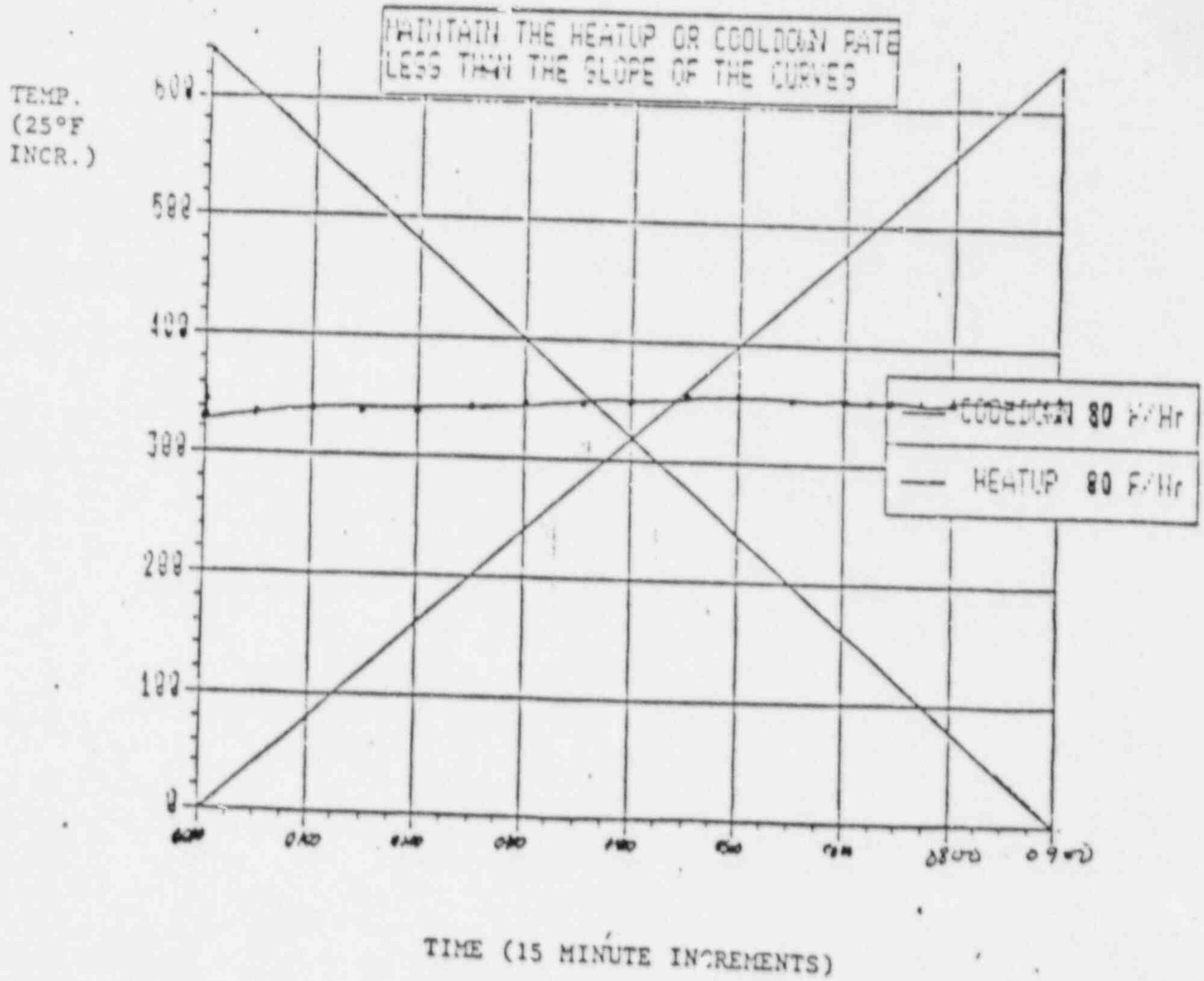
DATA SHEET II

SCRAM RECOVERY

HEATUP/COOLDOWN RATE

SAFETY RELATED



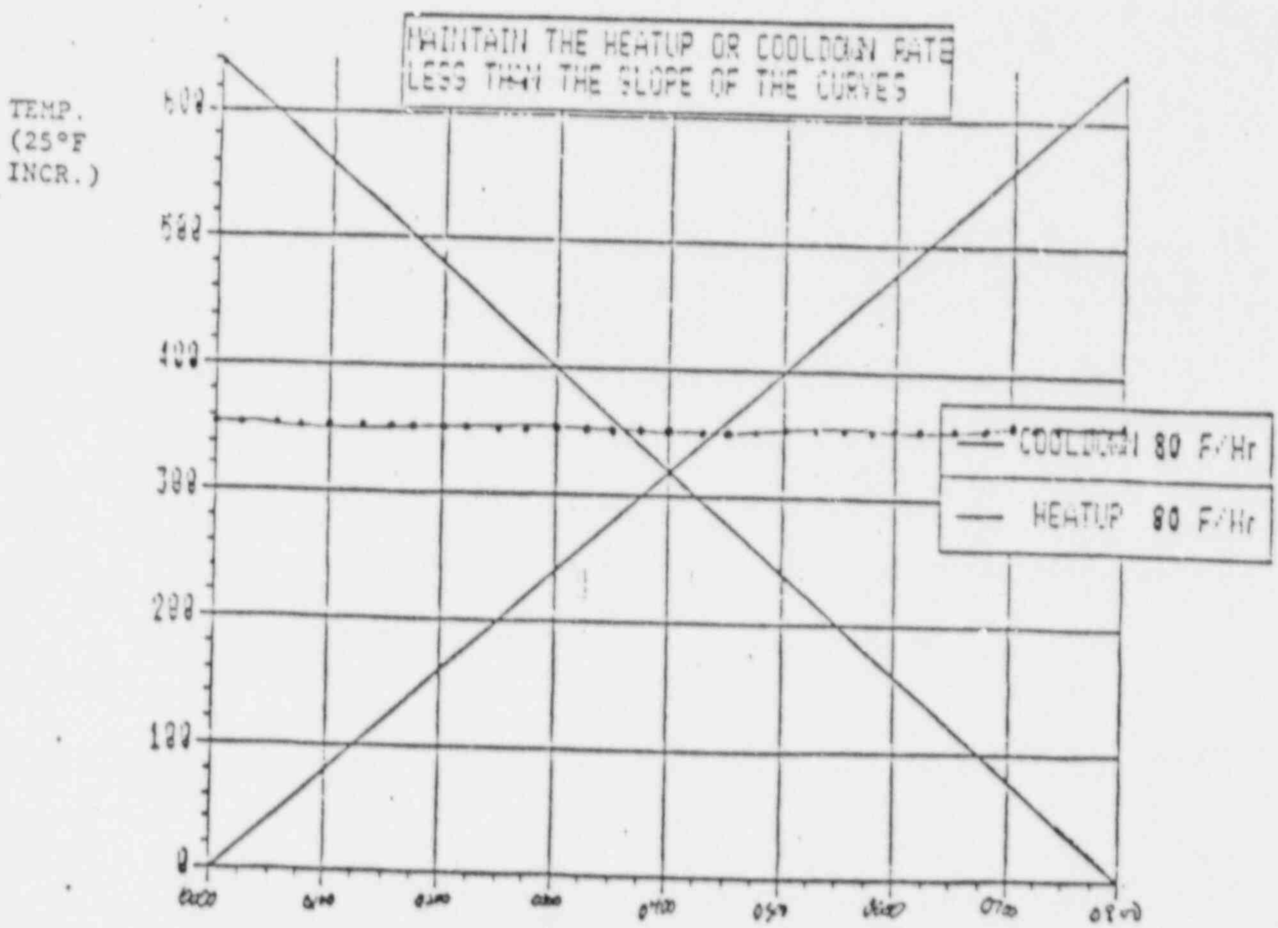
(9)

DATA SHEET II

SCRAM RECOVERY

HEATUP/COOLDOWN RATE

SAFETY RELATED



TIME (15 MINUTE INCREMENTS)

10

MNCR 0015-88
E31N680A&B and HPCS Data

DATE	TIME	Rx Power %	Rx Press. psig	CORE FLOW % WT%	E31N680A meter +-psi	E31N680A DVM volts	E31N680B meter	E31N681 meter
1-22-88	0100	0	242	30.87	+.75	3.129	+.25	-2.2
	0200	0	231	31.31	+.7	3.127	+.25	-2.2
	0300	0	224	31.27	+.65	3.126	+.25	-2.2
	0400	0	220	31.44	+.6	3.126	+.2	-2.15
	0500	1.0	403	32.50	+.65	3.147	+.2	-2.6
	0600	1.0	412	33.37	+.7	3.149	+.2	-2.6
	0700	2.5	677	27.98	+.8	3.162	+.2	-3.4
	0800	2.5	678	28.08	+.8	3.161	+.2	-3.4
	0900	2.5	679	28.1	+.8	3.165	+.2	-3.4
1-22-88	1000	4.0	950	28.42	+.8	3.184	+.25	-3.8
	1100	3.5	950	27.42	+.9	3.179	+.25	-3.8
	1200	3.0	966	26.19	+.9	3.178	+.2	-3.5
	1300	3.0	966	26.15	+.9	3.178	+.2	-3.5
	1400	4.0	966.8	29.60	+1.0	3.190	+.25	-3.8
	1500	7.0	967.5	30.4	+1.0	3.194	+.25	-3.9
	1600	7.8	967.2	34.12	1.0	3.195	.25	-3.8
	1700	12.41	969.07	36.87	1.0	3.195	.25	-3.9
	1800	13.0	969.64	36.94	1.0	3.195	.25	-3.9
	1900	12.53	969.45	38.3	1.0	3.194	.25	-3.9
	2000	15.06	971.21	38.57	1.0	3.199	.25	-3.9

DATA SHEET I

SCRAM RECOVERY

HEATUP/COOLDOWN RECORD

SAFETY RELATED

	RECIRC SUCT		REACTOR VESSEL					
TIME	A SUCT	B SUCT	HEAD FLANGE	BOTTOM HEAD	SHELL FLANGE	BOTTOM DRAINS	REACTOR PRESSURE	INIT/DATE
0130	358	355	360	280	351	350	126	ER / 1-12-88
0200	357	355	359	280	349	350	125	ER / 11-12-88
0230	356	356	358	280	348	350	124	ER / 11-12-88
0300	356	355	356	280	346	350	124	ER / 11-12-88
0330	356	355	354	281	345	350	124	ER / 11-12-88
0400	356	355	354	281	344	349	124	ER / 11-12-88
0430	356	354	352	280	342	349	125	[illegible] / 11-12-88
0500	357	356	350	281	340	350	125	ER / 11-12-88
0530	357	356	349	281	339	350	126	ER / 11-12-88
0600	358	356	348	281	339	351	127	ER / 11-12-88
0630	359	357	346	282	337	351	128	ER / 11-12-88
0700	359	357	345	282	335	352	128	ER / 11-12-88
0730	358	358	342	282	333	352	128	MZL / 11-12-88
0800	358	357	341	282	332	352	128	MZL / 11-12-88
0830	357	357	339	282	332	351	128	MZL / 11-12-88
0900	357	357	338	282	332	352	128	MZL / 11-12-88
0930	358	358	338	282	329	352	128	MZL / 11-12-88

Reference Tech. Spec. 3/4.4.6

Reviewed:

Control Room Operator ______________ __________ Shift Supervisor ______________

MNCR 0015-88
E31N680A&B and HPCS Data

DATE	TIME	Rx Power %	Rx Press. psig	CORE FLOW %	E31N680A meter +-psi	E31N680A DVM volts	E31N680B meter	E31N681 meter
1/22/88	2100	18.20	973.0	39.75	1.0	3.201	.25	-3.9
	2200	18.24	973.2	39.77	1.0	3.203	.25	-3.9
	2300	17.97	970.57*	34.96	1.0	3.205	.25	-3.9
1/23/88	0000	17.88	955.61	34.75	1.0	3.209	.25	-3.9
	0100	25.66	959.25	35.90	1.1	3.226	.25	-4.0
	0200	30.11	962.25	36.54	1.2	3.233	.25	-4.1
	0300	40.50	966.75	37.10	1.2	3.235	.25	-4.1
	0400	47.0	970.87	45.0	1.2	3.220	.25	-4.1
	0500	46.4	970.87	44.7	1.2	3.220	.25	-4.1
	0600	46.39	971.25	45.75	1.2	3.220	.25	-4.1
	0700	46.22	971.25	46.25	1.2	3.220	.25	-4.1
	0800	~32	955	~26	1.2	3.255	.25	-4.1 ~~4.4~~ 1-23-88
	0900	~36	960	34.7	1.2	3.242	.25	-4.1 ~~4.4~~ Rc 1-23
	1000	~36	960	~28.4	1.2	3.241	.25	-4.1
	1100	~55	975	~47.1	1.2	3.219	.25	-4.1
	1200	~58	978	~46.2	1.2	3.218	.25	-4.1
	1300	~62	980	~46.7	1.2	3.219	.25	-4.1
	1400	~62	980	~46.7	1.2	3.219	.25	-4.1
	1500	~62	980	~47.1	1.2	3.217	.25	-4.1
	1600	63	984	56.8	1.2	3.216	.25	-4.1

*-value appears to be psia

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E31N680A&B and HPCS Data

DATE	TIME	Rx Power %	Rx Press. psig	CORE FLOW %	E31N680A meter +-psi	E31N680A DVM volts	E31N680B meter	E31N681 meter
1/23/88	1700	69.5	990	50.2	1.2	3.215	.25	-4.1
	1800	70.8.	991	50.1	1.2	3.216	.25	-4.1
	1900	70.0	990	50	1.2	3.216	.25	-4.1
	2000	69.2	989.6	50.3	1.2	3.217	.25	-4.2
	2100	69.6	990	50	1.2	3.217	.25	-4.2
	2200	69.5	990	50	1.2	3.217	.25	-4.2
	[illegible]00	72.2	992	50.2	1.2	3.217	.25	-4.2
1-24-88	0000	71.0	991.5	50.0	1.2	3.217	.25	-4.2
	0100	72.6	995.63	57.0	1.2	3212	.25	-4.2
	0200	72.8	996.0	57	1.2	3.212	.25	-4.2
	0300	72.7	996.0	58	1.2	3.211	.25	-4.2
	0400	75.0	999.0	62.0	1.1	3.208	.25	-4.2
	0500	76.7	1000.13	64.1	1.1	3.205	.25	-5.0
	0600	77.6	1000.5	64.8	1.1	3.205	.25	-5.9
	0700	82.5	1003.1	66.25	1.4	3.258	.25	-6.0
	0800	83.3	1004	67.6	1.4	3.261	.20	-6.0
	0900	84.5	1005 ~~1019.9~~ [illegible]	69.54	1.4	3.268	.20	[illegible] ~~6.0~~ -6.
	1000	86.6	1008	73.04	1.4	3.270	.20	-6.1
	1100	87.1	1008	74.21	1.4	3.275	.20	-6.1
	1200	87.9	1009	75.5	1.4	3.280	.20	-6.1

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Hourly E31N680A&B and HPCS Data

DATE	TIME	Rx Power %	Rx Press. psig	CORE FLOW %	E31N680A meter +-psi	E31N680A DVM volts	E31N680B meter	E31N681 meter
1-24-88	1300	89.09	1011	78.08	1.4	3.284	.20	-6.1
	1400	90.24	1012	80.08	1.4	3.280	.20	-6.1
	1500	91.1	1014	81.8	1.5	3.284	.20	-6.2
	1600	91.6	1014.4	83.4	1.4	3.285	.25	-6.1
	1700	92.2	1015.2	84.7	1.4	3.287	.25	-6.1
	1800	90.89	1013.3	76.96	1.4	3.278	.25	-6.1
	1900	92.3	1014.8	79.08	1.9	3.405	.25	-6.1
	2000	93.4	1016.3	81.29	2.1	3.434	.25	-6.1
	2100	93.8	1017.6	82.68	2.1	3.406	.25	-6.1
	2200	94.56	1018.4	84.42	2.0	3.410	.25	-6.1
	2300	95.5	1019.3	85.67	2.0	3.402	.25	-6.1
1-25-88	0000	96.44	1020.4	87.67	1.9	3.360	.25	-6.1
	0100	96.93	1021.13	88.87	1.6	3.303	.25	-6.1
	0200	97.5	1022.0	90.7	1.6	3.303	.25	-6.1
	0300	98.1	1023.41	~~92.2~~ 92.1	1.5	3.296	.25	-6.1
	0400	99.36	1024.88	93.75	1.5	3.296	.25	-6.1
	0500	100.04	1026.37	96.04	1.5	3.296	.25	-6.1
	0600	100.05	1026.0	96.17	1.5	3.296	.25	-6.1
	0700	100.04	1026.0	96.62	1.5	3.296	.25	-6.1
	0800	100% PWR						

MEETING SUMMARY DISTRIBUTION

Docket 50-415
NRC PDR
Local PDR
PD21 R/F
EAdensam
Project Manager L. Kintner
OGC-B
EJordan
JPartlow
NRC Participants
ACRS (10)

NRC PARTICIPANTS

L. Kintner
R. Butcher
J. Unda
J. Mathis