U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/92009(DRP); 50-316/92009(DRP)

Docket Nos. 50-315; 50-316 License Nos. DPR-58; DPR-74

Licensee: Indiana Michigan Power Company
1 Riverside Plaza
Columbus, OH 43216

Facility Name: Donald C. Cook Nuclear Power Plant, Units 1 and 2

Inspection At: Donald C. Cook Site, Bridgman, MI

Inspection Conducted: April 1 through May 19, 1992

Inspectors: B. L. Jorgensen
J. A. Isom
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Approved By: B. L. Jorgensen, Chief
Reactor Projects Section 2A

6-3-92
Date

Inspection Summary: Inspection from April 1 through May 19, 1992 (Report Nos. 50-315/92009(DRP); 50-316/92009(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of: plant operations; maintenance and surveillance; engineering and technical support; actions on previously identified items; reportable events; and NRC Generic Letters.

Results: No violations or deviations were identified in any of the six areas inspected. One unresolved item was identified with respect to the licensee's ability to maintain the lift setpoints for the steam generator safety valves within their required accuracy range.

The inspector evaluated the licensee's response (Enclosure 2) to loss of automatic pressurizer level control in Unit 2 caused by a valve restoration error and concluded that the overall investigation into the event was acceptable. Documentation of the investigation, however, was weak, based on the number of questions raised by the inspector which could not be addressed solely by the content of the initial investigation report.

The inspector found the operators' rapid and effective response to the main feedwater transient on Unit 1 and the material condition of the Unit 2 ice condenser to be strengths.

DETAILS

1. Persons Contacted

*A. A. Blind, Plant Manager
*J. E. Rutkowski, Assistant Plant Manager-Technical Support
L. S. Gibson, Assistant Plant Manager-Projects
*K. R. Baker, Assistant Plant Manager-Production
*B. A. Svensson, Executive Staff Assistant
*J. R. Sampson, Operations Superintendent
*T. K. Postlewait, Design Changes Superintendent
*G. A. Weber, Plant Engineering Superintendent
T. P. Beilman, Maintenance Superintendent
*G. A. Tollas, Acting Safety & Assessment Superintendent
P. G. Schoepf, Project Engineering Superintendent
L. H. Vanginhoven, Site Design Superintendent
*J. T. Wojcik,Chemistry Superintendent
D. C. Loope, Radiation Protection Supervisor
P. F. Carteaux, Training Superintendent
M. L. Horvath, Quality Assurance Supervisor
L. J. Matthias, Administrative Superintendent

The inspector also contacted a number of other licensee and contract employees and informally interviewed operations, maintenance, and technical personnel.

*Denotes some of the personnel attending the Management Interview on May 26, 1992.

2. Plant Operations (71707, 71710, 42700)

The inspector observed routine facility operating activities as conducted in the plant and from the main control rooms. The inspector monitored the performance of licensed Reactor Operators and Senior Reactor Operators, of Shift Technical Advisors, and of Auxiliary Equipment Operators including procedure use and adherence, records and logs, communications, and the degree of professionalism of control room activities.

The inspector reviewed the licensee's evaluation of corrective action and response to off-normal conditions. This included compliance with any reporting requirements.

The inspector noted the following with regard to operation of Units 1 and 2 during this reporting period:

a. Unit 1 Status:

Unit 1 began the inspection period at 100 percent power. On April 18, 1992, operators commenced a planned end of core life power coastdown at approximately 1.5 percent per day in preparation for

the Cycle 12 to 13 refueling outage. The refueling outage is scheduled to begin on June 13, 1992, for an estimated duration of 93 days.

On May 1, 1992, with Unit 1 operating at 80 percent power, operators responded quickly to a main feedwater transient and prevented a reactor trip when the main feedwater differential pressure controller failed, causing both main feedpump's speed to drastically decrease. The inspector noted that the operator response to this transient was a strength. Steam generator water level deviation alarms were received on all steam generators as levels decreased to about 39 percent (normal programmed level is 43 percent). Operators recovered from the transient by taking manual control of the main feedpumps and restored level. Instrument and Electrical technicians replaced a defective "lag" unit in the differential pressure controller and the feedwater regulating system was returned to automatic. The unit ended the inspection period at about 70 percent power with no other notable operational transients.

b. Unit 2 Status:

Unit 2 began the inspection period in MODE 6 with fuel offloaded to the Spent Fuel Pit, continuing with the cycle 8 to 9 refueling outage that began on February 22, 1992. Core reload commenced on April 23, 1992, and was complete on April 26, 1992. The unit ended the inspection period in MODE 5. Major outage-related activities performed included: Boron Injection Tank removal, Auxiliary Feedpump Emergency Leakoff Line upgrades, P-250 Computer replacement, Containment Integrated Leakrate Test, Main Turbine refurbishment, Ice Condenser ice bed weighing, Boric Acid Storage Tank Room cleanup, Erosion Corrosion monitoring and pipe replacement, Steam Generator Eddy Current testing, Incore Thimble Tube Eddy Current Testing, Motor Operated Valve testing, Emergency Diesel Generator load sequence and time response testing, Reactor Coolant Pump Seal replacement, and Pressurizer Power Operated Relief Valve refurbishment.

c. Unit 2 Unusual Event:

On April 9, 1992, the licensee declared an Emergency Plan Unusual Event due to both Unit 2 Emergency Diesel Generators (EDGs) being inoperable. Unit 2 was in a refueling outage with reactor fuel offloaded to the Spent Fuel Pit at the time of the event. The AB EDG was out of service for its planned 18 month inspection when the power supply transformer for the governor on the CD EDG failed and sounded an inverter failure alarm in the control room. The licensee replaced the entire control module, which houses the power supply transformer, on April 10, 1992. The licensee exited the Unusual Event after satisfactory testing of the CD EDG on April 11, 1992.

d. Unit 2 Containment Closeout Tour:

The inspector accompanied licensee representatives on a containment closeout tour of the ice condenser and the lower containment areas as the licensee prepared for reactor startup. The inspector performed the tour to verify general cleanliness of the containment and ice condenser, check that the entrances to the containment sumps were clear, and to observe that any equipment stored in containment was properly secured. The inspector found that the ice crew did a good job in cleaning and maintaining the ice condenser. The floor drains were clear and neatly covered with "dissolvable paper" as required by procedure. There was no buildup of frost on the turning vanes, nor were there chunks of ice on the floor. The lower inlet doors were observed to be free of obstructions. Outside of the ice condenser; however, areas were found not as clean. Operators on the tour removed pieces of wire and duct tape on some floor areas. Workers had left flashlights and some small tools in the area of the Pressurizer Power Operated Relief Valves which were likewise removed. The containment sumps and adjacent areas were observed to be clear of obstructions.

No violations, deviations, unresolved or open items were identified.

3. Maintenance/Surveillance (62703, 61726, 42700)

The inspector reviewed the maintenance activity below. The focus was to assure the activity was conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications.

UNIT 2 EAST RESIDUAL HEAT REMOVAL (2E RHR) PUMP MECHANICAL SEAL LEAK:

The inspector reviewed a mechanical seal leak on the 2E RHR pump after the new replacement seal leaked when the pump was valved back into service. The inspector interviewed the Maintenance Department workers and supervisor and reviewed the procedure and job order package to determine whether the quality of the work was adequate, and whether the procedure was of sufficient quality to accomplish the job. The inspector concluded there was a lack of quality control during the installation of the mechanical seal. The inspector also noted several other factors that could have contributed to the quality of work during the seal installation. For example, there were less than optimal working conditions, such as working in a confined radiologically controlled area during off hours with full protective clothing and respirators. Additionally, the procedure did not require verification at the steps describing installation of the seal to ensure correct installation of critical seal components. The licensee improved the procedure shortly after this event by requiring verification at critical steps during seal installation.

The work instructions were documented on Job Order No. C6350, and the procedure used was entitled "Residual Heat Removal Pump Maintenance", **12 MHP 5021.017.001, Rev. 7, August 29, 1991. The probable cause for this event was that an error occurred during installation of the "compression unit" (part of the rotating element of the mechanical seal) which is held in place on the RHR pump shaft sleeve with three set screws. After the seal leakage was discovered, maintenance workers isolated and disassembled the RHR pump to investigate the leakage source. They found two areas of set screw marks on the shaft sleeve, one set revealing where the compression unit should have been installed, and another set about 1/4 inch from the required installation point showing the as-found condition. Because the compression unit was installed incorrectly, this condition resulted in inadequate spring tension to force the mating surfaces of the rotating and stationary elements together.

The inspector reviewed the maintenance procedure and found that the instructions were clear and the drawings were good but certain critical steps did not require verification for proper work performed. For instance, step 6.4 ("Mechanical Seal Assembly") of the procedure instructed workers to install rotary and stationary parts of the seal. While the instructions to perform the installation were clear, a verification at this point may have caught that the rotary element was installed incorrectly and prevented this event.

No violations, deviations, unresolved or open items were identified.

4. Engineering and Technical Support (37828)

The inspector monitored engineering and technical support activities at the site and, on occasion, as provided to the site from the corporate office. The purpose of this monitoring was to assess the adequacy of these functions in contributing properly to other functions such as operations, maintenance, testing, training, fire protection and configuration management.

a. Failure of Unit 1 and 2 Main Steam Safety Valves To Meet Technical Specification Lift Requirements:

The inspector reviewed the main steam safety valve surveillance history for Unit 1 from years 1975 to 1992, and for Unit 2 from years 1979 to 1992, to determine what types of failures were being experienced by the licensee and to determine whether the licensee's corrective actions over the years were reasonably satisfactory to prevent recurrence. This review was conducted to close Licensee Event Reports (LERs) discussed in paragraph 7 of this inspection report. The inspector concluded that the licensee's corrective actions over the years have been unsuccessful in correcting the main steam safety valve failures to meet the Technical Specification (TS) lift pressure requirements.

The inspector's review of the test results over the years found that the tests did not conclusively support a trend for either high or low safety valve lift failures. However, test results for Units 1 and 2 from 1990 to the present indicated that safety valve failures were predominantly attributed to safety valves lifting higher than allowed by TS.

There are 5 steam generator safety valves for each of the 4 steam generators for a total of 20 safety valves. The licensee's TS 3.7.1.1. requires that with 4 reactor coolant loops and associated steam generators in operation with one or more main steam line code safety valves inoperable, operation in MODES 1, 2, and 3 may proceed provided that, within 4 hours, either the inoperable valve is restored to operable status or the power range neutron flux high setpoint trip is reduced per Table 3.7-1. Otherwise, the plant must be placed in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. TABLE 3.7-1 requires that the neutron flux high setpoint be reduced to 87.2%, 65.4% and 43.6% for one, two and three inoperable safety valves, respectively.

The majority of failures were corrected through adjustments to the lift pressure settings or by performing a second lift which were usually within specifications. Although the licensee has not been able to determine the root cause for these failures, the inspector was informed by the licensee that they had taken the following steps to identify and minimize the cause for these lift failures:

- implemented a more accurate testing method
- internal inspections of valves at the plant and at an independent laboratory
- increased the preventive maintenance of the safety valves
- obtained vendor assistance in writing the plant procedure
- obtained vendor assistance during mechanical refurbishment of the safety valves

The inspector also reviewed LERs 315/90003, 315/89002, 315/87001, 315/86020, 316/92003, 316/90006, and 316/88004 to determine what corrective actions were proposed by the licensee over the years to prevent recurrence of these main steam safety valve failures. In the earlier LERs, the licensee believed that improved testing methods would prevent recurrence of safety valve failures. The inspector's review of the surveillance information for Units 1 and 2 determined that the change to the new test method did not appreciably affect the number of safety valve failures. In the more recent LERs, the licensee stated that a change to a greater lift pressure tolerance of plus or minus 3 percent rather than the present tolerance of plus or minus 1 percent would prevent recurrence of the problem.

The inspector found the following number of safety valve failures for Unit 1 and 2:

TABLE 1:

Unit 1:		Unit 2:	
Year:	Total:	Year:	Total:
1975	7(1)	*	*
1978	0(0)	1979	2(0)
1983	3(1)	1984	4(0)
1985	9(2)	1986	7(1)
1987	8(0)	1988	6(0)
1989	13(3)	1989	3(0)
1990	11(2)	1990	8(1)
1992	**	1992	7(0)

* No test prior to 1979.

** Unit 1 main steam safety valve tests have not been performed at the end of the inspection period. They are scheduled to be completed approximately in June of 1992.

NOTE 1: The numbers in parenthesis above represent what the safety valve failures would have been if the 3 percent testing acceptance tolerance was used.

NOTE 2: The licensee's records indicated that there were no safety valve tests performed from 1979 to 1982 and from 1980 to 1983 for Unit 1 and 2 respectively.

Because prior to year 1987, the licensee had averaged three safety valve lift pressures to determine their operability, for the purpose of the table 1, the inspector used the first lift pressure documented in the tests conducted prior to year 1987 to determining whether these safety valves would have been declared inoperable.

The inspector's discussion with the licensee management and engineering staff regarding the problems with maintaining the safety valves within the required lift pressure of plus or minus one percent suggested that this may be a generic industry problem. Although the failure of safety valves to lift within their required band is a long standing problem at the D. C. Cook plant, because this may be a generic industry problem, potential enforcement action requires further evaluation. This issue will be tracked as an unresolved item: 315/92009-01;316/92009-01.

b. EDDY CURRENT TESTING UNIT 2 INCORE THIMBLE TUBES:

The licensee performed Eddy Current Testing on all 58 Incore Thimbles during the current refueling outage for Unit 2 on March 6, 1992. The results of the testing showed wear, but was less severe than in the previous cycle. Of the 58 total tubes:

- 8 had indications between 30 - 40 percent through wall degradation

- 8 had indications between 40 - 50 percent through wall degradation

- 5 had indications between 50 - 60 percent through wall degradation

- 5 had indications between 60 - 70 percent through wall degradation

The licensee replaced 22 tubes during the current refueling outage as a result of the Eddy Current testing. The licensee replaced the tubes to avoid the possibility of replacing the tubes during the next refueling outage. The replacement criteria was based on indicated through wall degradation greater than or equal to 40 percent. Eighteen tubes, noted above, met this criteria. The remaining four tubes had been repositioned during the previous operating cycle and were replaced as a preventive measure.

c. EDDY CURRENT TESTING UNIT 2 STEAM GENERATOR TUBES:

Westinghouse Corporation performed Eddy Current Tests for the licensee on approximately 6.5 percent of the steam generator tubes in Steam Generators 21 and 24 in accordance with Inservice Test Program requirements. No degradation or pluggable indications were found during the licensee's review of the Eddy Current data.

No violations, deviations, or open items were identified. One unresolved item was identified involving continuing safety valve setpoint drift.

5. Actions on Previously Identified Items (92702, 92702)

a. (Closed) Unresolved Item 315/92002-01; 316/92002-01: DETERMINE PAST OPERABILITY OF EMERGENCY DIESEL GENERATORS DURING HIGH AMBIENT TEMPERATURE CONDITIONS.

On November 7, 1991, the licensee found during testing that the Unit 1 Emergency Diesel Generator (EDG) Room supply fan flow capacities were less than stated on the room ventilation design drawings. The licensee concluded that room ventilation flows would be incapable of providing adequate cooling for sustained EDG operation with outside ambient temperature greater than 80 degrees F. Previous NRC inspection reports (50-315/91014(DRP); 50-316/91014(DRP) and 50-315/91022(DRP); 50-316/91022(DRP)) described the details and the immediate NRC followup assessment.

The licensee performed EDG room ventilation testing to determine the existing air flow capacity of the system, prior to installation of "tornado dampers". The tornado dampers were

installed to protect the room ventilation structures from a design basis tornado. The as-found air flow measurements for all 4 EDGs were below the 36000 to 44000 cfm design limit, and ranged from 30294 cfm to 35654 cfm. The licensee made a preliminary calculation that showed the minimum required supply air flow for the EDG rooms was 29406 cfm, based on a maximum outdoor air temperature of 80 degrees F. The licensee decided that until a more detailed analysis was completed, if ambient outside temperatures increase to 80 degrees F. and remain there for greater than 24 hours, any diesel generator with a tornado damper installed would be declared inoperable. The licensee reasoned that they had until March 31, 1992, to complete their analysis, since FSAR Table 2.2-2 showed no occurrence of outdoor ambient temperatures exceeding 80 degrees F. between November 1 and March 31.

The licensee's corporate engineering staff completed their analysis in December 1991, finding that the EDGs would have remained operable with outdoor ambient temperatures of 137 degrees F. Their analysis; however, was based only on temperature effects on the EDG and not on other attendant equipment in their respective rooms needed for proper EDG operation. The corporate engineers were requested by the site engineering staff to perform another analysis to account for the other equipment in the room. The analysis was completed in April 1992 and concluded that the EDGs would have functioned with ambient temperatures up to 134 degrees F. The issue of past EDG operability is therefore resolved, and this item is considered closed.

b. <u>(Closed) Violation 50-316/90008-01: MAIN STEAM STOP VALVES NOT CAPABLE OF CLOSING WITHIN THE TIME REQUIRED BY TECHNICAL SPECIFICATIONS.</u>

The Unit 2 main steam stop valves were not maintained capable of closing within 5 seconds or less, as required by Technical Specification 3.7.1.5, for continued operation in MODES 1,2 and 3. This was a significant issue for which escalated enforcement was considered, and an Enforcement Conference was conducted with the licensee on February 27, 1990. The violation was classified as Severity Level IV.

The licensee responded to the violation, including a specific NRC request that stipulated underlying issues be addressed, by letter (AEP:NRC:1125B) dated April 9, 1990. Corrective actions to restore the Unit 2 stop valves to OPERABLE status were properly described. The licensee first modified the stop valves by enlarging the operating piston drain tube port holes and the equalizing steam nipples. Valve insulation was also improved. These actions were intended to limit accumulation of condensate atop the piston, which was considered the cause of the performance problems. When one Unit 2 valve failed restoration testing despite these actions, the impact of dump valve leakage on

operability of the stop valve itself became evident. The Unit 2 dump valves were repaired to eliminate leakage.

At the time of the above events, Unit 1 was in power operation with known minor leakage on some dump valves. A monitoring system, using acoustic technology, was put in place for timely detection of any change in dump valve leak-tightness. The licensee undertook an evaluation to determine whether the dump valves could be adequately maintained or whether they would have to be replaced. This review showed the maintenance on these valves had been corrective in nature rather than preventive; however, the design was compatible with high reliability with proper preventive maintenance attention. The licensee chose not to replace the valves but to intensify attention to proper maintenance. The inspector examined Unit 1 dump valves and found no indications of leakage. Unit 2 was shut down at the time of the inspection. The acoustic monitoring program and results were reviewed with the responsible engineer. Testing continues twice each week. No leakage problems occurred in Unit 1 during the current operating cycle. One valve (of eight installed) evidenced minor leakage before the Unit 2 outage. This was scheduled for repair before plant restart.

c. <u>(Closed) Violation 50-316/89021-01: LOOP 2 OVERPOWER AND OVERTEMPERATURE DELTA-T TRIP SETTINGS NOT WITHIN THE REQUIRED ACCURACY RANGE.</u>

The licensee had failed to recognize that the Loop 2 overpower and overtemperature Delta-T trip settings were not within the required accuracy range, when Unit 2 reached full power in March, 1989. A test showing the discrepancy was performed on March 31, 1989, but the channels were not declared inoperable and corrective actions taken till much later, on May 24, 1989. As a consequence, the Technical Specification requirement, to place inoperable channels in "trip," was violated.

The licensee responded to the violation by letter (AEP:NRC:1090F) dated September 15, 1989. The violation was admitted (the licensee reported it via Licensee Event Report No. 50-316/89010-LL; see Paragraph 6) and corrective and preventive actions were described. These included recalibration of the affected instruments on May 25, 1989, and restoration to full operability. In addition, test procedures were revised to ensure expedited evaluation of reactor coolant system power versus flow data, during each startup after a refueling outage. The inspector reviewed procedure **12 THP 4030 STP.219, "Thermal Power Measurement and Reactor Coolant System Flow Rate," Revision 6 dated October 12, 1990, and verified the procedure now provides for evaluation of flow data (Step 7.2) and control room instrumentation versus test data (Step 7.4). The procedure was used effectively for post-refueling startup of both units in 1990. In addition, the licensee's letter indicated that a change to

Technical Specifications would be sought to allow entry into MODE 1 with the channel not verified OPERABLE, because the verification itself requires MODE 1 conditions. The inspector found the Technical Specifications did not need changing; the subject instruments are excepted from the provisions of Specification 3.0.4, so entry to MODE 1 to do the necessary testing is allowed.

d. <u>(Closed) Unresolved Item 50-316/92006-01: Loss Of Automatic Pressurizer Level Control At Power Caused By Operator Error During Valve Restoration</u>

The inspector reviewed the licensee's May 4, 1992, response (Enclosure 2) to questions raised on the quality of the investigation regarding the loss of automatic pressurizer level control in the previous resident inspector report 50-315/92006(DRP); 50-316/92006(DRP). The rare nature of this type of operator error, which had the potential to challenge Unit 1 operation, was of concern to the inspector. After discussion with the operations department superintendent and individuals involved with the investigation, the inspector determined that the investigation was more thorough than documented on the problem report, and overall investigation into this event was acceptable. Based on the number of questions raised by the inspector which could not be addressed solely by the content of the initial investigation report, the inspector concluded that the documentation of the investigation was weak.

The inspector received the licensee's response to the following concerns identified in the previous inspection report:

1. What are management expectations with regard to taking procedures and clearances into contaminated areas? Are these expectations included in any plant procedures or instructions?

   Currently, management expectations with regard to taking procedures and clearances into contaminated areas are not referenced in any plant manager or operations procedures. However, discussion with the operational personnel and review of the licensee's response document (Enclosure 2), Attachment 1, found that the "Operations Department promotes the use of a clearance copy when entering a restricted area." Further, "the use of a clearance copy is at this time a good operating practice used by the shift personnel. A review of this practice with shift personnel (polled operating shift and training shift April 8th & 9th) identified that Supervisors polled usually request the operator to make a copy of the clearance if the Supervisor is aware that the area is restricted."

2. Is there a procedure which prohibits the breaking of a seal to change a valve position?

Currently, there is no procedure which prohibits breaking of a seal to change a valve position. However, the inspector's discussion with the operations staff indicated that most operational personnel would question the breaking of the seal during the valve restoration sequence.

3. What valve restoration sequence did the Auxiliary Equipment Operator (AEO) follow?

   The AEO correctly restored a closed valve, 2-CS-298E, to its open position then incorrectly opened a closed valve, 2-CS-300E, which should have been left closed. After which, he correctly restored a closed valve, 2-CS-301E to its open position.

4. Is there a difference between "sealed closed" and "closed" valves during placement of a clearance?

   No, for clearance purposes, there is no difference between a "sealed closed" valve and a "closed" valve.

5. Should valve abbreviations be defined in the clearance form?

   Currently, there is no requirement to define valve abbreviations on the clearance forms. The licensee stated that "a review of the use of abbreviations on clearances was conducted with shift personnel... and the results of this review noted that the operators are familiar with the abbreviations used on clearances and that questions associated with an abbreviation are answered during the job briefing."

6. Should the misoperation of valve 2-CS-300E be listed in the list of symptoms for the abnormal pressurizer level found in the "Malfunction of Pressurizer Level Control" procedure?

   No. The licensee's review concluded that the inadvertent repositioning of a manual valve does not meet the criteria for an abnormal procedure symptom, which is to list possible causes of the malfunction of a control system.

Additionally, the licensee's reply noted the following:

The significance of this event was not included because it was not required by the problem report and the details of the investigation report were adequate for plant management to make a determination that the event was not significant.

A pre-job briefing was conducted. The subsequent investigation found that the Reactor Operator (RO) discussed with the operator that 2 black seals and 1 blue seal would be needed. In addition, the RO recalled that a discussion was held to review the

restoration requirements of the 2-CS-300E valve, and that since the valve was tagged in the normally closed position the valve would remain closed and sealed." The inspector questioned the operation staff on the guidance given by the RO to the AEO for the seals since by paragraph 3.6.1. of procedure "Conduct of Operations: Valve Lineups and Position Control," OHI-4014, Rev. 3, September 7, 1990, "the independent verifier will verify the valve position, then attach a seal. For alignment of throttle valves however, the initial positioner places the seal after positioning the valves." In this case, the AEO was not the independent verifier and none of the valves positioned were throttle valves. The licensee agreed that the guidance given by the RO to the AEO with respect to the seals was incorrect.

The licensee determined that "considering the urgency of restoring the normal charging flow path and the short period of time from the time the operator was notified and took action, it is very likely that the operator did not satisfy the requirements of the RWP when exiting and reentering the roped off area."

The licensee could not determine the exact location of the restoration sheet when the AEO opened the valve. However, the licensee's subsequent interviews with the AEO indicated that to the best of his knowledge, the restoration sheet was in the charging pump room where the mispositioned valve was located.

The AEO was in the roped off area when he was paged by the control room.

Based on the licensee's response to concerns raised by the inspector, this item is closed.

6. Reportable Events (92700, 92720)

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and, as applicable, that immediate corrective action and appropriate action to prevent recurrence had been accomplished.

a. (Closed) LER 315/90014-LL: ACCESS TO AN EXTREME HIGH RADIATION AREA NOT CONTROLLED IN ACCORDANCE WITH TECHNICAL SPECIFICATIONS.

On October 25, 1990, the licensee discovered that the door to the Seal Water Injection Filter Room was unlocked for 1 hour 27 minutes. The area was designated as an Extreme High Radiation Area (EHRA), defined as an area having a dose rate in excess of 1000 mr/hr. The EHRA designation required that the door be locked or guarded to prevent unauthorized entry. The door was locked by Radiation Protection personnel shortly after it was discovered to be open.

The door was found open by a Maintenance Mechanic while preparing to change the seal water injection filter. The dose rate in the area was found to be 4000 mrem/hr at 18 inches from the Seal Water Injection Filter Housing. The licensee's investigation into this event did not reveal any prior unauthorized entries into the room. The licensee examined the thermoluminescent dosimeter (TLD) results of all their employees for the month in which this event occurred and did not find any exposures over administrative limits.

To prevent this event from recurring, all the EHRA doors were tested, adjusted or modified, as necessary, such that all EHRA doors close and lock automatically with no human intervention required. Also, the licensee issued a Standing Order entitled, "Extreme High Radiation Area Key Accountability and Door Verification", Rev. 0., October 29, 1990, that requires an independent verification to ensure that EHRA doors are properly locked or guarded.

b. <u>(Closed) LER 316/90004-LL: REACTOR PROTECTION SYSTEM ACTUATION CAUSED BY A POWER RANGE, NEUTRON FLUX, HIGH NEGATIVE RATE SIGNAL.</u>

On June 11, 1990, a Unit 2 reactor trip occurred when the reactor protection system generated a power range neutron flux high negative rate signal. At the time of the reactor trip, Maintenance personnel had initiated surveillance testing of the fire protection system ionization and infrared detectors. A technician was on top of control rod power cabinets working on overhead fire detectors. The licensee's investigation found that the reactor trip was likely caused by the technician vibrating sensitive reactor protection system equipment as he walked on top of the cabinets.

Prior to unit startup, the licensee performed extensive checks of the Rod Control System and found no firm evidence of reactor protective system equipment failure. All control rods were tested and performed satisfactorily. The preventive maintenance program for the rod control cabinets and rod control motor-generator sets was enhanced to include periodic inspection of power supply buswork and bus disconnect switches. Additionally, the policy prohibiting standing or walking on energized enclosures was reiterated to the involved personnel.

c. <u>(Closed) LER 50-316/89010-LL: PLANT OPERATING OUTSIDE LCO DUE TO INABILITY TO DETERMINE RCS LOOP DELTA-T (AND CALIBRATION VALUES) PRIOR TO ENTRY INTO APPLICABLE MODE.</u>

This event report concerns the Unit 2 Technical Specification violation discussed and closed in Paragraph 5.c. above. The LER is closed based on the licensee's corrective actions taken to address this violation.

d. (Closed) LER 50-316/90002-LL: MAIN STEAM ISOLATION VALVE INOPERABILITY - DUE TO CONDENSATE ACCUMULATION ON VENT SIDE OF OPERATING PISTON

This event report concerns the Unit 2 Technical Specification violation discussed and closed in Paragraph 5.b above. The LER is closed based on the licensee's corrective actions taken to address this violation.

e. (Closed) LERs 50-315/89002-LL; 50-315/90013-LL; 50-316/90006-LL; 316-92003-LL: FAILURE OF THE MAIN STEAM SAFETY VALVES TO MEET TECHNICAL SPECIFICATION LIFT SETPOINT REQUIREMENTS

These event reports continuing problems with failure of main steam safety valves to maintain lift setpoint within range requirements established in the respective Unit Technical Specification. The history of steam generator safety valve performance includes a number of earlier failures in addition to those documented in these reports. The problem is generic, not isolated, as evident from its repetitive nature involving both units. These LERs are being administratively closed, while the matter of adequate corrective action for the generic problem involving repetitive safety valve setpoint drift is considered an Unresolved Item as discussed in Paragraph 4.a above.

f. (Closed LER 316/90008-LL: DEGRADATION OF DIVIDER BARRIER SEAL LOCATED BETWEEN CONTAINMENT WALL AND CRANE WALL

The licensee has satisfactorily completed all required immediate corrective actions as detailed in section 6.c of Inspection Report 50-315/92002(DRP); 50-316/92002(DRP). Therefore, this item is closed. However, the inspector was concerned that the present inspection method would not detect similar cracks in the future. There are no inspection requirements to check the seal surfaces (which are not visible with the seals installed), and there is no engineering evaluation that the new type of seals will not be susceptible to the problems exhibited by the old seals. Therefore, development of means to detect future seal degradation is considered an open item 316/92009-02.

No violations, deviations, or unresolved items were identified. One open item was noted involving adequacy of means to monitor the containment divider barrier seal.

7. NRC Compliance Bulletins, Notices and Generic Letters (92703; TI 2515/113)

(Closed) Generic Letter 88-17: LOSS OF DECAY HEAT REMOVAL

The inspector verified that the remaining licensee actions necessary to comply with the requirements of Generic Letter 88-17: LOSS OF DECAY HEAT REMOVAL have been completed or scheduled. In section 9 of inspection

report 50-315/91017(DRP); 50-316/91017(DRP), the inspector noted that the licensee needed to complete the following to satisfy the requirements of GL 88-17.

- install RHR pump motor current transducer
- install an annunciator for detecting approaching RHR malfunction caused by air ingestion
- issue an emergency procedure for loss of RHR during reduced inventory conditions

The ability to monitor and trend RHR pump motor current was installed and successfully used for the reduced inventory condition during the current Unit 2 refueling outage. The RHR pump motor current modification is scheduled to be installed on Unit 1 during its outage in June of 1992. The licensee also installed annunciators for both East and West RHR pump motor currents and issued an abnormal procedure "Loss or RHR While Partially Drained or At Mid-Loop," 01-OHP-4022.017.001, Rev. 0, 12/16/1991 and "Loss of RHR While Partially Drained or At Mid-Loop," 02-OHP-4022.017.001, Rev. 0, 12/16/1991 for Unit 1 and 2, respectively. In addition, the licensee has written "Mid-Loop Monitoring System Set Up Calibration," procedure 12 IHP 6030.IMP.155, Rev. 0, 2/28/1992 for calibrating the mid-loop cart. Based on the completed and planned RHR pump motor current modifications, installed RHR pump motor annunciators, and the new abnormal procedures for loss of RHR at reduced inventory, this Generic Letter is closed.

No violations, deviations, unresolved or open items were identified.

8. Unresolved Items

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An Unresolved Item disclosed during the inspection is discussed in Paragraph 4.

9. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed by the inspector and which involve some action on the part of the NRC or licensee or both. An Open Item disclosed during the inspection is discussed in Paragraph 6.

10. Management Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) on May 26, 1992, to discuss the scope and findings of the inspection. In addition, the inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.

ENCLOSURE 2

Indiana Michigan
Power Company
Cook Nuclear Plant
P.O. Box 458
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616 465 5901

INDIANA
MICHIGAN
POWER

May 4, 1992

James A. Isom
Senior Resident Inspector
U. S. Nuclear Regulatory Commission
D. C. Cook Nuclear Plant
One Cook Place
Bridgman MI 49106

Dear Mr. Isom:

NRC Inspection Report 50-315/92006(DRP); 50-316/92006(DRP) reported the results of the NRC routine safety inspection activities of the D. C. cook Plant for the period of February 19 through March 31, 1992. In this inspection report, Unresolved Item 50-316/92006-01 was identified regarding the investigation and documentation of an event where automatic pressurizer level control was lost at power due to an operator error. This error occurred during a valve position restoration following a routine clearance evolution for maintenance activities. The purpose of this letter is to provide a written response to the unresolved item to assist in your evaluation and final resolution of this issue.

This unresolved item is a significant concern as it applies to the Cook Plant Corrective Action Program. As you are aware, a fundamental aspect of our program is a "graded" approach to the investigation and analysis of identified problems. This graded approach enables the assignment of resources for root cause analysis to those events and problems which represent the highest potential for safety impact. In addition, our process has achieved a very low threshold for reporting possible problems. Although this level of reporting is very desirable, it is dependent on the ability to assess significance and apply problem solving resources appropriately.

During our follow-up of the questions for the subject unresolved item, approximately ten person-days were required for interviews, analysis, and documenting the results. This detailed level of investigation and documentation cannot be supported as a matter of routine for problems of this nature. If this level of follow-up is required for events of a similar significance, the basis and effectiveness of our graded approach to corrective action will be placed at risk.

The responses to your questions regarding the details of this investigation are included in Attachment 1. These details were reviewed with you at a meeting on April 10, 1992, by the Operations Superintendent. Although additional information not identified in the original investigation was raised

through the follow-up to these questions, the root cause determination and corrective actions were not altered by this information.

Our analysis of the plant response agrees with your assessment of minor operational significance. Attachment 2 of this letter provides a summary of the results of our system engineer calculations and simulator test run. However, the Problem Assessment Group (PAG) and the Operations Department determined that the broader issue of "valve mis-positioning" had a higher level of safety significance. As a result, this event was investigated by an individual qualified under the plant's Human Performance Evaluation System. The broad issue of "valve positioning" formed the basis for the problem report investigation and corrective actions to ensure that the human performance issues were not caused by significant generic process weaknesses.

It has been recommended that this particular valve mis-positioning be added to the Operations procedure for "malfunction of Pressurizer Level Control." Since there are any number of combinations of valve lineup errors which could cause this and other significant control system malfunctions, it is not practical, nor our policy, to include these human process errors in our abnormal procedures. Valve positioning is strictly controlled through appropriate administrative controls (including job briefings), skill of the operator, and independent verification when necessary.

It is our conclusion, based on the significance of this specific event, that the investigation was appropriately detailed, identified the correct root cause for resolution and implemented adequate corrective actions. In general, the value added by identifying all contributing factors, though not relevant to the primary cause, may not offset the cost to determine those factors. It is our position that the time spent in such intensive investigations will clearly reduce management's ability to focus in detail on broader issues with higher safety significance.

We would welcome the opportunity to discuss this unresolved item further in the future.

Respectfully,

A. Alan Blind

A. Alan Blind
Plant Manager

Attachments

c: D. H. Williams, Jr.
E. E. Fitzpatrick
A. A. Blind
J. R. Padgett
G. Charnoff
NFEM Section Chief
A. B. Davis - Region III
B. M. Jorgensen - Region III

bc: W. G. Smith, Jr.
S. J. Brewer
M. E. Barfelz
D. H. Malin
M. L. Horvath
P. A. Barrett
J. B. Shinnock
J. F. Stang, NRC - Washington DC

ATTACHMENT 1

RESPONSE TO NRC COMMENTS RE: PR 91-1288

Comment No. 1: Problem report investigation did not discuss the significance of the event.

As a normal convention, the Operations Department does not state specifically that a review was completed to determine the event significance in all problem reports. Although significance determination statements are not always included, they are routinely completed as part of the investigation for all condition and problem reports. The decision to include a statement of significance is based on our consideration for the "primary" audience of the report. For a condition or problem report the primary reader is plant management, the context of the report are not intended for all readers. Therefore, considering the experience and background of the plant management, if the details of the investigation section of the report adequately presents support that the event is not significant as defined by PMI-7030 (Condition Reports and Plant Reporting), a separate statement in the report to address the significance of the event is not included. But if the investigation required a detailed interpretation of a plant safety function concern or compliance to regulatory requirements, more detailed information as to the significance of the event will be included. Then, a significance determination statement as a conclusion to the investigation will be made so that the plant management reviewing the report can assess the interpretations and conclusions presented in the report.

Using the above review and documentation process, the determination was made that the details presented in the PR 91-1288 investigation report were adequate for plant management to make a determination that the event was not significant. This conclusion was based on the following.

1. At the start of the event, the charging flow rate was about 120 gpm. The VCT level decreased about 4% (approximately 76 gal.) before the start of the automatic makeup. Considering the charging flow rate and VCT level decrease, it is estimated that the transient started about 40 seconds prior to the automatic makeup alarm which alerted the control room operators to the off normal condition.

2. At the point of the VCT automatic makeup, the operator took manual control and stabilized the plant. Prior to operator action, the Pressurizer level increased about 3% (approximately 225 gal.) to about 55 % level, which is well below the high PZR level alarm of 70%.

3. In parallel to the prompt actions taken by the control room operators to restore charging flow and to manually control pressurizer level, the operators promptly notified the operator in the plant performing the clearance restoration to determine if the clearance restoration being performed by the operator was the reason for the indicated decrease in charging flow and increase in PZR level.

Considering the short period of time from the start of the transient to the automatic makeup alarm; the prompt actions taken by the operators to stabilize PZR level and notify the operator in the plant; and the relatively small change in PZR and VCT levels, the determination was made that the PZR transient was not a significant event, as defined in PMI-7030.

Comment No. 2: The problem report did not address that the AEO did not inform the US that he had opened CS-300E when contacted by the control room operator.

Considering that the inadvertent opening of 2-CS-300E was the event being investigated, the inadequate communication by the operator to identify the nature of the error to the control room did not contribute to the inadvertent opening of the valve. Since the inadequate communications did not contribute to the event but was identified as a poor operating practice during the investigation, the use of good communications was addressed as part of the "Lessons Learned" memo (included in the report documentation package) for the findings of the investigations.

Comment No. 3: The problem report did not address whether a pre-job briefing was completed.

The Operations Department places a great deal of emphasis on good job briefing. Currently OSO.083 (Shift Briefings and Guidelines for Operational Evolutions), OP-30 (Clearance Error Avoidance Program), and OHI-4012 (Conduct of Operations - Shift Turnover) all contain guidelines related to job briefings. In addition, recently the above guidelines were reviewed and a survey was sent to operations personnel as part of the Operations Department job briefing assessment. The results of this assessment are scheduled to be incorporated into a job briefing guideline.

As part of each condition and problem report investigation, the Operations Department considers the quality of the job brief. If this review shows that the job brief was good or the details of the job brief do not contribute insight to the error that was made, the details of the job brief are not included in the report.

As a part of this investigation, an Event Causal Factor Chart (Human Performance Evaluation System root cause analysis process) was completed. As part of this chart, the job briefing was charted. The details of the charting noted that the Reactor Operator who conducted the job briefing with the AEO included a review of each tag and tag requirement. The RO also discussed with the operator that 2 black seals and 1 blue seal would be needed. In addition, the RO recalled that a discussion was held to review the restoration requirements of the 2-CS-300E valve, and that since the valve was tagged in the normally closed position the valve should remain closed and sealed.

The prompt to the operator to take an additional seal along for a valve that was expected to be closed and sealed was a good operating practice (tool of the trade). The intent was not for the operator to take a seal because the seal was expected to be needed, the intent was for the operator to take the seal in case the installed seal had been damaged during the maintenance activities in the area of the valve. If the operator then identified that the seal had been damaged, a seal would be available without having to leave the area to get a seal. Since the clearance restoration is the control process for returning the component to a normal alignment, the valve position was being controlled by the clearance tag and therefore, verification of the seal integrity during the restoration was important.

Comment No. 4: When the operator was paged and identified that he had made an error, did the operator violate the RWP?

At the time the operator was paged the operator had already opened 2-CS-300E (East CCP Discharge To RCP Seal Water Injection Filters Inlet Valve) and was in the process of opening 2-CS-301E (East CCP Discharge Valve), which permitted the charging flow to be diverted from the normal charging path.
2-CS-300E and 2-CS-301E are located within a few feet of each other in the charging pump room, and at the time of the clearance they were both within the roped off area. Therefore, to respond to the page via the PA in the charging pump room, the operator had to leave the roped off area and then re-enter the roped off area to close 2-CS-300E.

During the investigation of this problem report, the operator was not questioned on the RP practices used to exit and re-enter the controlled area. The operator was doing what was necessary to restore the plant to a safe condition, and therefore the process used was not questioned.

A discussion was held with the involved operator to identify the method used to exit and re-enter the roped off area on 4-8-92. Due to the time passed since the event, the operator could not recall the RP practices used.

Considering the urgency of restoring the normal charging flow path and the short period of time from the time the operator was notified and took action, it is very likely that the operator did not satisfy the requirements of the RWP when exiting and re-entering the roped off area. Condition reports for the period of time surrounding this event were reviewed to identify if a report had been written to document any actions taken by the operator that were not per the RWP. A condition report was not identified.

Therefore, the conclusion can be made that the operator left the roped off area with some portion of his ANTI-C clothing on and then re-entered the area due to the urgency that he placed on the need to restore the valve to the open position. The requirements of the RWP per 12 PMP 6010.RPP.006 (Radiation Work Permit Program) and 12 PMP 6010.RPP.300 (Contamination Control Program) may not have been met and RP should have been notified.

Following this comment review, the actions taken by the operator to exit and re-enter the roped off area should have been included in the investigation and any violation of the PMP's should have been documented.

The RP practice used by the operator to close 2-CS-300E is not a factor that contributed to this event and therefore the conclusions drawn from the review of this comment do not alter the root cause determination for this event.

Comment No. 5: What are the expectations for taking clearance paperwork into a contaminated area?

Per 12 PMP 6010.RPP.300 (Control of Equipment and Materials in a Restricted Area) personnel items such as flashlight, notebook, clipboard or similar items may be taken in to a restricted area provided the item is frisked by the user when exiting a restricted area. Although, the original clearance attached to a clipboard would be permitted by the PMP provided it was frisked out following the exit from the area, the Operations Department promotes the use of a clearance copy when entering a restricted area. The use of a copy is promoted so that if the copy is contaminated and cannot be frisked out of the area, the steps and signatures can be transferred to the original.

The use of a clearance copy is at this time a good operating practice used by the shift personnel. A review of this practice with shift personnel (polled operating shift and training shift April 8th & 9th) identified that Supervisors polled usually request the operator to make a copy of the clearance if the Supervisor is aware that the area is restricted. The non supervisory personnel polled understood that the taking a copy of a clearance into a restricted area is a good operating practice and routinely evaluate the need for a copy dependent on the reasons for the restrictions on the area.

The issue presented in the problem report was not that the operator failed to take a copy of the clearance with him into the roped off area, the issue was that by not having the clearance in hand the operator did not take with him a good tool to provide a means to self-check. As an acceptable alternative, the operator could have self-checked by leaving the clearance at the step-off pad and checking the valve number, noun name, and restoration position just prior to performing the task and again immediately

after the task. During the interview with the involved operator, the operator stated that he had a mind set that the 2-CS-300E and 2-CS-301E were to be restored to the open position and therefore he left the clearance outside the boundary and performed the restoration of the valves by memory.

The operator positioned a valve and hung a tag from memory which is not an accepted operating practice and is not consistent with our written self-check training.

Comment No. 6: No written requirement that the valve seal is a barrier.

The term "barrier" as defined by the INPO HPES process for human performance root cause analysis, includes physical barriers (examples: engineering safety features, safety and relief devices, conservative design allowances, locked doors, radiation shielding), administrative barriers (examples: policies and practices, training and education, methods of communications, supervisory practices), plus "many more". During the performance of the human performance root cause analysis, the following barriers were considered that failed related to the involved operator.

The operator training, experience, inadequate reference to the clearance and the seal were all barriers that failed. The seal was a barrier not because of a procedure or administrative requirement associated with the seal but rather because the involved operators interaction with the seal caused the operator to question his actions, but the operator did not follow up to resolve the question.

The involved operator had completed systems training and was qualified to perform the Auxiliary Building tour, and therefore the expectation is that the qualified operator would have known that the 2-CS-300E is normally in the sealed closed position. The operator did not adequately review the clearance to identify the correct restoration position for 2-CS-300E on the clearance. 2-CS-300E was sealed closed and during the interview the operator stated that he questioned to himself why the valve was sealed, but he allowed his "mind set" that the valve was to be sealed open to override the need to take the time to recheck the clearance or ask his supervisor.

Comment No. 7: What sequence did the involved operator perform the clearance restoration?

Upon entering the charging pump room, the operator first restored 2-CS-298E (2-QMO-225 Outlet Valve) which was located in a non-restricted area. The operator then entered the roped off area and opened 2-CS-300E (Discharge to RCP Seal Water Injection Filters Inlet Valve), followed by 2-CS-301E (E CCP Discharge Valve). Upon opening 2-CS-300E, the charging flow was diverted from the normal charging flow path to the RCP Seals.

Comment No. 8: Is there a requirement to seal closed a valve when a clearance tag is placed on a normally sealed closed valve? Is there a difference between "closed" and "sealed closed" on the clearance equipment position sheet?

In addition to providing clearance points to remove equipment from service, the Clearance Permit System is the procedural method in place to ensure the proper restoration of equipment placed under a clearance. When a clearance is placed on a normally sealed closed valve, the clearance tag becomes the means for controlling the valve in the closed position. Therefore, the fact that the valve is sealed closed is secondary to the requirements of the clearance tag position and "closed" in the placement position is acceptable.

For this event, since 2-CS-300E is a normally closed valve and therefore would be restored to the sealed closed position, leaving the seal on the valve should have enhanced the clearance restoration process.

Comment No. 9: OHI-4014 states that "Valve Position" abbreviations are defined in the "Valve Legend" at the bottom of each lineup sheet. Should the same convention be used on Clearance Equipment Position sheets?

The use of a valve position abbreviation legend was implemented to enhance the "human factor" attributes of valve lineup sheets. Since the present issue of OHI-4014, the Operations Procedure group philosophy has changed. In accordance with PGG.004.001 (Operation Department Procedure Group Guidelines - Generic Writing Instructions) valve positions on lineup sheets are stated rather than abbreviated. On the next revision of OHI-4014 the valve legend requirement will be updated.

A review of the use of abbreviations on clearances was conducted with shift personnel (polled operating shift and training shift April 8th & 9th). The results of this review noted that the operators are familiar with the abbreviations used on clearances and that questions associated with an abbreviation are answered during the job briefing.

In addition, a review of this comment with Operations Department Staff personnel noted that the clearance data base design for the positions listed in the "Placement Position" and "Restoration Position" are human factored such that the position read identical to the labels in the plant. Also, the discussions noted that the present format of the Equipment Position Sheet would not provide the space needed to include a legend without the elimination and alteration of other valued information on the data sheet.

Following the consideration of this comment, the conclusion is made that the addition of an abbreviation legend on the Equipment Position Sheet is not warranted based on the limited space available on the form, the standard conventions used, and the consideration of the trade offs required to include a legend.

Comment No. 10: Add the inadvertent opening of 2-CS-300E to the symptoms section of the Malfunction of Pressurizer Level Control System?

The Malfunction of Pressurizer Level Control System (2-OHP 4022.003.002) and Loss of Letdown or Charging Flow (2-OHP 4022.003.001) abnormal procedure were reviewed for the addition of the symptom of inadvertent opening of 2-CS-300E. Following this review, it is concluded that the addition of this step would not enhance the procedures for the following reasons:

1. A review of this comment with the Operations procedure group identified that the purpose of the symptoms section of an abnormal procedure is to present a list of possible causes of the malfunction of a control system. The inadvertent repositioning of a manual valve does not does fit this criteria. In other words, this would be a human intervention and not a cause.

2. In addition to the symptoms listed in the abnormal procedures the licensed operators are trained to consider work activities that are in process in the plant at the time of an off normal indication for consideration as to the possible effects of this activity on the symptoms noted in the control room.

Considering that the inadvertent opening of a manual valve does not meet the criteria for an abnormal procedure symptom, and that the control room operators did recognize that the clearance restoration being completed on the charging system may effect the normal charging flow and paged the operator performing the clearance restoration in parallel to the response to the indications in the control room, the addition of the inadvertent manual opening of the 2-CS-300E valve to the symptoms would not enhance the abnormal PZR level and charging procedures.

Following a careful review of the comments and questions presented by the Resident NRC inspector, it is concluded that no additional facts related to this problem report have been identified that will alter the conclusion of the initial problem report investigation and report.

In response to Comment No. 4, due to the time that has elapsed since this event the involved individual operator could not recall the details of his actions. Therefore, no additional actions directed at this individuals actions are possible at this time. This issue will be addressed with the ACC section to ensure that an investigation concerning similar RP practices are properly documented. In addition, a letter to the Shift Supervisors to review the PMP requirement to notify RP personnel under similar circumstances has been issued.

CALCULATIONS REGARDING PLANT RESPONSE
TO OPENING CS-300 WHILE AT POWER

The ECCS (emergency core cooling system) System Engineer was asked to perform an evaluation to predict the Plant response to an inadvertent opening of CS-300E with no operator action while the Plant is at power. Specifically, how long will it take to reach the following setpoints, pressurizer high-level deviation alarm, pressurizer high-level alarm, and the pressurizer high-level reactor trip.

The initial conditions presented for this evaluation were as follows:

- Plant is at stable, steady-state conditions.
- Charging and letdown flow balanced - 120 GPM letdown.
- VCT level approximately 18%.
- Pressurizer level approximately 52%.
- Annunciators (such as VCT make-up) not in auto, PW pump pressure low or failure, primary water flow deviation, boric acid flow deviation, pressurizer level deviation, pressurizer level high, pressurizer level high as well as the clicking noise made by blender operation would not be acted on by the control room operators.

The calculations demonstrate that, with no operator action, auto make-up to the VCT will commence in approximately five minutes, pressurizer level deviation alarm in 21 minutes, pressurizer level high alarm in 87 minutes, and the reactor trip from pressurizer high level would occur in just under three hours.

In addition, On April 11, 1992, a simulator exercise was conducted in an attempt to recreate the event on the simulator. The results of this exercise were inconclusive. The simulator instructors were very clear on the point that the simulator, in this case, may not reflect actual Plant response. There is no Plant data available that can be used to verify that the simulator response to opening CS-300E would parallel actual plant response.