U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Centerior Service Company
Facility:	Perry Nuclear Power Plant
Location:	P. O. Box 97, A200 Perry, OH 44081
Dates:	November 2 - December 20, 1996
Inspectors:	D. Kosloff, Senior Resident Inspector R. Twigg, Resident Inspector
Approved by:	J. M. Jacobson, Chief Reactor Projects Branch 4

EXECUTIVE SUMMARY

Perry Nuclear Power Plant, Unit 1
NRC Inspection Report 50-440/96-17

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection.

Operations

- An operator error caused an inadvertent reactor power increase. Previously implemented corrective actions for a similar event failed to prevent the error, which involved unexpected opening of a reactor recirculation flow control valve (Section 01.2).

- Engineering's identification of the apparent relationship between chemistry sampling and jet pump flow indications demonstrated a questioning attitude that led to effective corrective actions (Section 02.1).

- An operator made two errors while performing a cumbersome high pressure core spray (HPCS) surveillance instruction (SVI), even though previous performances should have identified the instruction for correction. This SVI weakness was similar to a recently citeu violation for which corrective actions had not yet been completed (Section 04.1).

- The inspectors identified possible preconditioning issues during SVIs performed by operations. Since additional inspection is needed, the issues are considered an unresolved item (Sections 04.1 and 04.2).

- Operator and engineering response to an inspector-identified LPRM alarm demonstrated effective teamwork (Section 04.3).

- The licensee continued to use a variety of self-assessment techniques to identify issues for corrective actions. The licensee recognized weaknesses in its corrective action and work planning processes and continued to pursue improvements in those processes (Section 07.1).

Maintenance

- Continued weaknesses in planning and preparations for risk-sensitive work activities were demonstrated. However, the weaknesses were addressed and the work was completed with only minor problems. RHR flush connection check valve replacement presented the broadest example of these issues (Section M1.1).

- Plant conditions in general continued to improve; however, containment conditions declined slightly (Section M2).

- Maintenance activities related to an unexpected breaker trip were generally prompt and appropriate. However, the failure to identify the breaker defect prior to installation and during the initial shop inspection had previously been identified as a weakness. During the review of the associated LER four apparent violations of technical specifications were identified between April 9, and September 17, 1996. One of these involved a 41-hour period when the control room emergency recirculation (CRER) system was inoperable, and the actions required by Technical Specification 3.0.3 were not completed (Section M4.1).

Engineering

- The inspectors observed that a field clarification request used during breaker maintenance was inadequate. This was considered an unresolved item because additional inspection is needed to determine the extent and significance of the issue (Section E2.1).

- The licensee promptly responded to another GE fuel design analysis error. The repeated analytic errors are being tracked with a previously opened inspection follow-up item (Section E2.2).

- Engineering identified that they had failed to include the RHR flush connection check valves in the ISI program. Engineering response to the deficiency was prompt and conservative. Failure to test these check valves was a non-cited violation of Technical Specification 5.5.2, Primary Coolant Sources Outside Containment (Section E2.3).

- Several inconsistencies were noted between the UFSAR and plant practices, procedures, and parameters observed. The licensee included the inconsistencies in its corrective action program (Section E2.4).

- The licensee completed a self-assessment of its emergency service water system, identifying numerous design engineering issues. Corrective actions had not been developed (Section 7.1).

Plant Support

- The licensee made a Notification of an Unusual Event in response to a loss of offsite communications capability. Overall performance was excellent. Personnel demonstrated teamwork and concise and accurate communications. A weakness in anticipating equipment needs and procedural direction for a loss of offsite communications was overcome by personnel promptly adapting to the conditions encountered. The TSC and OSC were promptly activated, provided appropriate support to the plant, and was considered a strength (Section P2).

Report Details

Summary of Plant Status

The plant operated at full power throughout the inspection period except for short power reductions for testing, control rod realignments, and recovery from a reactor recirculation flow control valve transient.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. While in general, the conduct of operations continued to be safety-focused, an inadvertent reactivity increase occurred and is of concern.

01.2 Unexpected Increase in Reactor Reactivity

a. Inspection Scope (71707, 92901)

Operator response to a failed local reactor power range monitor led to unexpected opening of "A" Reactor Recirculation Flow Control Valve (FCV). Reactor power increased as a result of increased recirculation flow. The inspectors observed recovery efforts and reviewed relevant issues leading to the inadvertent power increase from 99% to 100.2% reactor thermal power (by heat balance).

b. Observations and Findings

On Saturday, November 9, a local reactor power range monitor failed high, causing one of six average power range monitors (APRM) to erroneously indicate increasing reactor power. The indication caused an automatic flow demand limit "runback" (partial closure) of the FCVs. The operators verified the runback was due to erroneous indication and stopped FCV motion with power at 98%. The erroneous indication was corrected. The operators had stopped FCV motion by shutting down the hydraulic power units (HPU) for the FCVs.

Each FCV (A and B) had one HPU with two subloops (1 and 2). One subloop was required to provide hydraulic force to adjust the position of the associated FCV, thereby adjusting reactor core flow and power. In October, the inspectors had informed the operators of increased noise from Subloop 'A2.' Subsequent vibration testing led the responsible system engineer (RSE) to request "limited use only" of Subloop 'A2.'

To restore automatic runback capability and return reactor power to 100% the operators began to restart the HPUs. The procedure to start a subloop required the operators to verify that fuses for the subloop solenoid valves (used to isolate the non-operating subloop and control the hydraulic pressure from the operating subloop) were not blown. Perry and other plants had experienced numerous blown fuses caused by sticking solenoid valves. One of the Subloop 'A1' solenoid fuses was found blown. After discussions with the RSE, the operators chose to start the HPU without replacing or determining the cause of the blown fuse, relying on Subloop 'A2.'

Upon starting 'A' HPU, the FCV began to open, increasing reactor power. Apparently, the valve with the blown fuse had failed open and incorrectly directed hydraulic pressure to the FCV in the open direction. About 12 seconds after the 'A' HPU pump was started, the shift supervisor stopped the unintended FCV motion by shutting down the HPU from the reactor control panel. In 1994, a similar solenoid valve failure had occurred, causing a change in reactivity at low power. As a result of that event, operator knowledge and training provided opportunity to prevent recurrence.

The inspectors reviewed computer records and observed that reactor power peaked at about 100.2% (by thermal heat balance calculated at 5-second intervals). The inspectors verified that the thermal power records were consistent with the APRM records. The records indicated that the operators had promptly reduced flow with FCV B and reduced power to 98%. This created an approximate 8% imbalance in flow between the two reactor recirculation loops. Technical Specification (TS) 3.4.1 was entered due to a greater than 5% flow mismatch between loops. The action statement for this TS required a shutdown of one of the recirculation loops (single loop operation) if the flow mismatch could not be reduced to less than 5% within 2 hours.

The acting plant manager (engineering director), operations management, reactor engineers, and RSEs promptly responded to the site. At 1 hour and 51 minutes into the 2-hour action statement, the inspectors verified that the operators had successfully driven rods in to reach 88% reactor power and increased flow in the B recirculation loop, exiting TS 3.4.1.

On Sunday, November 10, the inspectors observed that the operators used appropriate vigilance when starting Subloop 'A1' after solenoid valve replacement. The Vice President (VP) - Nuclear and the acting plant manager provided additional oversight of control room FCV operations. The VP - Nuclear briefed the inspectors on plans for a comprehensive review of the event using the plant's corrective action process. On November 11, the inspectors observed that a multidisciplinary team had been assembled to evaluate the event and relevant issues. The team's efforts were continuing at the end of the inspection period.

c. Conclusions

This event was caused by an operator error. Although reactor power did not exceed TS limits, the unexpected change in reactivity was of concern because there had been opportunities to avoid the event. For example, operator knowledge and training, and corrective actions for a previous event should have prevented this event. This event is an Unresolved Item pending further NRC review (URI 50-440/96017-01(DRP)).

O2 Operational Status of Facilities and Equipment

O2.1 Core Flow Indication Deviation

a. Inspection Scope (71707, 92901)

The inspectors reviewed the evaluation of a licensee-identified core flow indication deviation.

b. Observations and Findings

During routine reactor engineering training for core flow calibration on December 2, the licensee identified that jet pump calibrated core flow was about 3.0% higher than the measured core flow. However this difference was conservative in relation to core thermal limits. The Updated Final Safety Analysis Report (UFSAR) stated that the uncertainty in the core flow measurement was 2.5%. The reactor engineer documented this condition in PIF 96-3594. The responsible system engineer (RSE) coordinated the evaluation of this condition. One of four calibrated flow transmitters was reading higher than the other three. Several causes were postulated for the difference in readings. Maintenance and engineering personnel evaluated each postulated cause. There was no evidence that any of the postulated causes had affected the instrumentation. Based on the history and the evaluation of the postulated causes, the RSE concluded that the calibrated flow transmitter reading should be considered valid and that the measured flow indication should be adjusted conservatively to match the calibrated flow indication. The licensee adjusted measured flow electronically, by procedure, to match the calibrated flow. The reactor engineer was concerned that the difference in calibrated flow might have been an early indication of a jet pump problem. Therefore additional data monitoring of jet pump flows was established.

On December 12, the measured and calibrated flows again indicated a 3.0% difference. Detailed analysis of the data indicated the difference was inverse to the difference identified on December 2. Using this additional information the RSE looked for activities that had occurred on December 12 and prior to December 2. One common activity had been chemistry water sampling using an instrument line from one of the four calibrated jet pumps on December 12 and prior to December 2. Sampling involved opening and closing valves that isolate the sampling line from the calibrated jet pump. The licensee concluded that sampling prior to December 2 had introduced an error in the calibrated flow. The licensee had adjusted the measured flow on December 2 to correct an error in the calibrated flow unknowingly introduced by the sampling. Sampling on December 12 returned the calibrated flow to normal and revealed that the measured flow in loop B had been in error by 3% since December 2.

Technical Specification 3.4.1, Recirculation Loops Operating, required that the two recirculation loop flows be maintained within 5% of each other. The operators used the measured flow to compare recirculation loop flows. From December 2 until December 12, the potential existed to exceed TS 3.4.1 because of the licensee-introduced 3% error. The inspectors reviewed the operator logs and verified that TS 3.4.1 had not been violated. The licensee discontinued chemistry sampling from the jet pump sample line and continued to review the physical relationship of the sampling to jet pump indicated flows.

c. Conclusions

Engineering's identification of the apparent relationship between the chemistry sampling and jet pump flow indications demonstrated a questioning attitude that led to effective corrective actions. Additional data monitoring after the initial corrective actions facilitated an understanding of the relationship between chemistry sampling and jet pump calibrated core flow. No TS limits were challenged.

O4 Operator Knowledge and Performance

O4.1 Surveillance Procedure Weaknesses

a. Inspection Scope (61726, 71707, and 92901)

The inspectors observed a briefing conducted by the unit supervisor (US) and the subsequent performance of surveillance instruction SVI E22-T2001, "Quarterly High Pressure Core Spray (HPCS) Pump and Valve Operability Test."

b. Observations and Findings:

Some sections of the HPCS surveillance were cumbersome for the operators to implement. None of the examples observed prevented the operator from complying with the procedure. However, the operator sometimes had to stop the surveillance and discuss the procedure with the US and shift supervisor (SS) to verify his understanding of the procedure. An example was the step that appeared to require removal of all motor operated valve (MOV) test equipment, which could have prevented completion of MOV testing for E22-F010, HPCS first test valve to the condensate storage tank (CST). On another occasion, the supervising operator failed to measure valve stroke time on the first stroke of a valve, as required by the SVI. This was the result of the HPCS suction being aligned to the suppression pool instead of the CST, causing the E22-F010 valve to unexpectedly close before the operator was ready to time the valve. A note in the SVI had designated the CST as the preferred suction source, but had not indicated why. Another failure to measure valve stroke time on the first stroke occurred near the end of the test due to an operator error. Following this surveillance, the operator was assigned the task of evaluating the SVI for revision.

c. Conclusions

This SVI had been performed several times since it had been revised in March, 1995, and the cumbersome sections had not been corrected. This SVI weakness was similar to a procedure violation cited in the previous inspection report (50-440/96011-02(DRP)) for which corrective actions had not yet been completed.

Additionally the inspectors needed more information to determine whether multiple strokes of MOVs preconditioned the valves. Therefore this is an Unresolved Item (URI 50-440/96017-02(DRP)).

O4.2 Potential Preconditioning During Emergency Diesel Generator Testing

a. Inspection Scope (71707, 92901)

The inspectors observed performances of the Division 1 and 2 Emergency Diesel Generator (EDG) monthly surveillance instructions (SVI).

b. Observations and Findings:

The inspectors observed EDG pre-start evolutions that included 2 manual rolls of the EDG and a roll of about 10 revolutions with the air start system. Later, during another observation of an EDG SVI, the inspectors observed that the air start roll was about 4 revolutions. The exact number of revolutions was difficult to verify because of the rapid acceleration and high speed of the EDG flywheel. The SVI directs the operators to obtain "at least two revolutions." A recent NRC inspection at another facility concluded that 10 revolutions of a similar EDG during prestart primed the fuel system and constituted preconditioning of the EDG. The RSE stated that the fuel system at Perry did not have the same susceptibility to a loss of prime.

c. Conclusions

Additional inspection is necessary to resolve how many revolutions of the EDG would precondition the EDG. The inspectors will evaluate this issue in conjunction with the URI (50-440/96017-02(DRP)) discussed above (Section 4.1), related to possible MOV preconditioning.

O4.3 Local Power Range Monitor (LPRM) Failure

a. Inspection Scope (37551, 71707, and 92901)

The inspectors regularly reviewed reactor thermal limit computer printouts.

b. Observations and Findings:

On December 9, at about 2:30 p.m., the inspectors observed that "11CSU1B 404046D6 *** LPRM DRIFT WARNING" had been printed by the computer at 2:05 p.m. Although the thermal limit data was printed hourly, the operators logged the data once a day on the midnight shift in accordance with the TS requirements. Shortly after the inspectors asked the operator at the controls about the computer alarm, another "LPRM DRIFT WARNING" was printed at 2:35 p.m. The operators and the shift technical advisor (STA) did not understand the alarm. While the STA was contacting the reactor engineer for additional information, the operators reviewed a live LPRM computer display. No abnormal deviations were apparent.

At 3:37 p.m. the reactor engineer created a computer printout of recent LPRM 40-33 D power indications. The inspectors reviewed the file and observed that between 2:05 p.m. and 3:29 p.m. LPRM 40-33 D power indications varied from 48.3% to 54.7% with constant reactor power. Recent hourly thermal limit printouts had indicated that LPRM 40-33 D data had been rejected by the computer as unreliable. The inspectors verified that LPRM 40-33 D was promptly removed from service and that there were still ample LPRMs available to meet TS requirements for reliable power and thermal limit indications. The inspectors also verified that LPRM upscale and downscale annunciator alarms had been available had the LPRM drift increased.

c. Conclusions

Although the operators and the STA did not understand the inspector-identified computer alarm, they immediately contacted the reactor engineer who provided the operators with appropriate guidance. Corrective actions were completed promptly. This demonstrated effective operations and engineering teamwork. The operators reviewed the thermal limits data as required by the technical specifications.

O7.1 Licensee Self-Assessment Activities (40500)

a. Inspection Scope

The inspectors observed or reviewed the following self-assessment activities that addressed multiple functional areas, as well as operations:

- Licensee routine manager's meetings
- Planning meetings for residual heat removal (RHR) check valve work
- Special Perry onsite review committee (PORC) meeting to evaluate work planned for the RHR check valves
- Potential issue forms (PIF)
- Meetings of the task force evaluating the FCV power increase

b. Observations and Findings

The meetings were attended by appropriate personnel and there was substantive discussion of specific issues. The planning meetings and PORC meeting related to the check valve work emphasized conservative operations and identified weaknesses in the planning process. About 430 PIFs were written during the inspection period by a variety of personnel who represented a wide cross section of plant organizations. The task force evaluating the FCV power increase was thorough.

c. Conclusions

The licensee continued to use a variety of self-assessment techniques to identify and evaluate issues that required corrective actions. The licensee recognized weaknesses in its corrective action and work planning processes and continued to pursue improvements in those processes.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707, and 92902)

Using Inspection Procedures 61726, 62707, and 92902, the inspectors observed all or portions of the following maintenance and surveillance testing (SVI) activities:

- Periodic Test Instruction (PTI) C11-P0001 control rod drive hydraulics control system tuneup
- EME R85-13011 1E22C0001 Perform megger and general maintenance checks (see Section E2.1)
- SVI E22-T1202 HPCS system flow rate low channel functional test
- SVI E22-T1200 HPCS system discharge pressure high channel functional test
- IMI E2-42 (Instrument Maintenance Instruction) filling and venting of suppression pool level instrument lines
- SVI E22-T2001 Quarterly HPCS pump and valve operability test
- SVI E22-T1319 diesel generator start and load Division III
- SVI R43-T1317 diesel generator start and load Division I
- SVI R43-T1318 diesel generator start and load Division II

The inspectors observed the following work activities associated with testing and replacement of RHR check valves. The inspectors reviewed the planning activities and associated procedures for the evolution and potential recovery plans.

- WO 96-5120 P11 Establish freeze seal
- WO 96-5115/6 E12F0063A/0086 Drain piping and replace check valves
- WO 96-5139 E12F0063A Test 8" check valve removed from E12 'A'

b. Observations and Findings

The inspectors found that most of the observed work activities were performed without any concerns. Those activities where concerns were identified are discussed in Sections 04.1, 04.2, E2.1, and E2.3.

The replacement and testing of the residual heat removal (RHR) check valves (see Section E2.3) which provided isolation from the condensate transfer and storage system (P11), required extensive planning and preparation because of potential consequences of postulated failures during the work activities. Those consequences included flooding of a division of RHR, reactor shutdown, and loss of P11. Flooding of a division of RHR was possible because freeze seals of 8-inch P11 supply lines were necessary to effect replacement. The inspectors observed questioning attitudes on the part of the licensee staff throughout the preparations for the evolution. Responses to the questions exposed weaknesses in the planning for the evolution. Conservative resolution of the weaknesses delayed implementation for approximately 2 weeks. The inspectors reviewed contingency plans for freeze seal failure. All contingencies had been identified and actions were taken to minimize postulated impacts.

The inspectors observed coordination and implementation of the activities. The inspectors identified some minor concerns, the most significant was a vent valve left open on a nitrogen supply bottle, making the bottle useless. Several nitrogen bottles had been staged so this had no impact on the work. The planned activities were completed with minimal interruptions.

Management review and oversight of the planning, as well as implementation, of the evolution was thorough and conservative. However, there was no management participation in the post-job critique.

c. Conclusions

Continued weaknesses in planning and preparations for risk-sensitive work activities were demonstrated. However, the weaknesses were identified and addressed and the work was completed with only minor problems.

M2 Maintenance and Material Condition of Facilities and Equipment

a. Inspection Scope (71707, 92720)

The inspectors observed the material condition of facilities and equipment during routine inspections of the plant and during inspection of maintenance and surveillance activities. Material condition problems observed by the inspectors had been identified by the licensee, monitored, and scheduled for repair.

b. Observations and Findings

The licensee continued to maintain most areas of the plant with minimal material condition problems. Improvements included roof leakage repairs, painting of the emergency service water pumphouse and replacement of control rod drive pumps. Equipment repairs continued and included replacement of 13,800 VAC transformers and retubing of a non-safety heat exchanger.

Some minor equipment problems were identified by the inspectors in containment. Examples identified by the inspectors included water leakage from a HVAC cooler with water dripping two levels below onto a scram discharge isolation vent valve, high vibration levels on the HPU Subloop 'A2' pump (see Section O1.2 b.), a missing light cover, and loose fan belts on a HVAC cooler.

c. Conclusions

Plant conditions in general continued to improve; however, containment conditions declined slightly.

M4 Maintenance Staff Knowledge and Performance

M4.1 Loss of Control Room Ventilation Safety Function Due to Degraded Breaker

a. Inspection Scope (37551, 62707, 92700, and 92902)

The inspectors reviewed LER 96-008-00, "Degraded Breaker Results in Loss of Safety Function and Exceeding Technical Specification Action Statements." Additional inspection related to this event was also documented in Inspection Report 50-440/96011.

b. Observations and Findings

1. Description of the Event

On September 16, 1996, at approximately 1:51 p.m., with the plant at full power, a 480 volt alternating current (VAC) circuit breaker EF-1-D-09 unexpectedly tripped on overcurrent. This occurred about 2 minutes after fuel handling building (FHB) heating, ventilation, and air conditioning (HVAC) supply fan "B" was started (exhaust fan "B" was already running). The breaker trip removed power from safety-related Division (Div) 2 motor control center (MCC) EF-1-D-09. Since there was no apparent reason for the breaker trip, the shift supervisor declared the MCC inoperable and had the breaker removed for further inspection. Initial inspections and testing of the removed breaker and other equipment did not reveal any reason for the breaker trip.

Technical Specification (TS) Limiting Condition for Operation (LCO) 3.8.7, Action A.1 required the MCC to be restored to operability within 8 hours. If operability could not be restored within 8 hours then TS LCO Action C.1 required the plant to be in Mode 3 (hot shutdown) within the next 12 hours. Clear specific written and verbal instructions were promptly given to the shift supervisor on preparing the plant for an orderly shutdown upon approaching the end of the action statement time limit. One of the replacement breakers was almost ready for use at 9:51 p.m., when the action statement time limit was reached. The licensee determined that if it began reducing plant power within 6 hours of entering LCO Action C.1, there would be ample time for an orderly shutdown. Since breaker replacement was imminent, plant power was not reduced. The breaker was replaced and power was restored to the MCC at 11:32 p.m. At 12:44 a.m. on September 17, upon completion of a review of inspection and testing done on the MCC and the new breaker, the shift supervisor declared the MCC operable and exited the TS action statement.

On September 20, the responsible system engineer (RSE) identified that two current transformer (CT) wire connections were reversed on the breaker. On September 26, the RSE confirmed with the breaker vendor that the reversed connections would have caused the breaker to trip at about 350 amps instead of the expected 660 amps. The RSE determined that the breaker had been installed on March 10, 1996, during the fifth refueling outage (RFO5). A load analysis by the licensee determined that the breaker would have tripped if a postulated loss of off-site power (LOOP), loss of coolant accident (LOCA), or a LOOP coincident with a LOCA were to have occurred whenever FHB exhaust fan 'B' had been energized. This analysis was based on the breaker's reduced trip setpoint in conjunction with the automatic reconnection of safety loads required by plant design.

Therefore, whenever FHB exhaust fan 'B' had been in operation, MCC EF-1-D-09 and its loads, including the Div 2 CRER subsystem, had been inoperable. A review of operating logs also determined that the Div 1 CRER subsystem was out-of-service (OOS) for maintenance from August 5 at 4:46 a.m. to August 6, 1996, at 10:25 p.m., about 41-hours and 39 minutes. Therefore, during this period both trains of the CR HVAC emergency recirculation (CRER) mode were inoperable; a loss of safety function. During this period, the plant was in Mode 1 (power operation), however TS LCO 3.0.3 was not entered as required.

From March 10, 1996 (when the improperly wired breaker was installed) to September 16, 1996, several safety functions were lost on several occasions, the most significant being the loss of safety function for the control room recirculation system.

2. Breaker Description

The affected breaker was a K-line 600 Series breaker manufactured by ABB Company, Inc. in December 1995, with a POWER SHIELD solid state trip device. The trip device received breaker load current input data from three current transformers (CT), one for each phase. Each CT had two wires for its load current data. The A phase CT wires had been reversed where they attached to a terminal board near the bottom of the breaker, reversing the CT load data polarity. When the solid stated trip device combined the CTs input data, it developed a current indication about twice as large as intended. Vendor testing confirmed a trip setpoint reduction from 660 amps (110%) to 350 amps.

This same breaker had tripped on July 3, 1996, when it was touched by a non-licensed operator. Although this trip was not caused by the wiring error, the licensee had an opportunity to identify the problem by inspecting the breaker.

3.0 Motor Control Center description

Most of the loads supplied by MCC EF-1-D-09 MCC were associated with HVAC as shown by the following Div 2 load list:

- CR HVAC Supply Fan 'B'
- CR HVAC Return Fan 'B'
- CRER Fan 'B'
- FHB HVAC Exhaust Fan 'B'
- FHB HVAC Exhaust Electrical Heater 'B'
- FHB HVAC Supply Fan 'B'
- Emergency Closed Cooling Pump Area Ventilation Fan 'B'
- MCC Switchgear and Battery Room Recirculation Fan 'B'
- MCC Switchgear and Battery Room Exhaust Fan 'B'
- Control Complex Cooling System Chiller 'B' Oil Pump.
- Standby Liquid Control Auxiliary Mixing Tank Transfer Pump B
- ATWS Uninterruptible Power Supply - Alternate Supply

4.0 Control Room HVAC System Description

The control room heating, ventilation, and air conditioning (CRHVAC) system provided cooling, heating, ventilation, and when required, smoke removal, for the control room. In addition, the emergency recirculation mode of CRHVAC provided the necessary particulate and gaseous filtration of the air supplied to the control room areas during emergency and other abnormal conditions to reduce the radiation dose for control room personnel. The system included two identical, redundant subsystems (A and B).

The control complex chillers provided chilled water to the cooling coils of their respective CRHVAC train as well as to the cooling coils for other safety-related areas in the control complex. During accident conditions, the CRHVAC would transfer from normal operation to emergency recirculation.

5.0 Sequence of Events

3/10/96 480 VAC supply circuit breaker EF1D09, manufactured by ABB, was installed during RFO5. Six other similar 480 VAC breakers were installed at about the same time.

3/11/96 FHB Exhaust Fan and Heater 'B' started. This made MCC EF-1-D-09 inoperable, however the plant was in Modes 4 (cold shutdown) or 5 (refueling) with no irradiated fuel movement and the MCC was not required to be operable.

3/13/96 FHB Exhaust Fan and Heater 'B' shut down. MCC EF-1-D-09 was operable again.

4/09/96 Plant entered Mode 1. MCC EF-1-D-09 was now required to be operable.

4/11/96 FHB Exhaust Fan and Heater 'B' started at 8:00 a.m., MCC EF-1-D-09 inoperable. TS LCO 3.8.7 was entered (not recognized). TS LCO action statement A.1 was exceeded at 4:00 p.m.

4/17/96 CRER 'A' declared inoperable at 3:00 a.m. for maintenance, plant was then in TS LCO 3.0.3 (not recognized). At 5:19 a.m. FHB Exhaust Fan and Heater 'B' was shut down. TS LCO 3.8.7 exited. TS LCO 3.0.3 exited without exceeding action statement time limit.

4/20/96 Train A CRER declared operable.

5/08/96 FHB Exhaust Fan and Heater 'B' started at 2:35 a.m., MCC EF-1-D-09 inoperable, and TS LCO 3.8.7 was entered (not recognized). TS LCO action statement A1 was exceeded at 10:35 a.m.

5/31/96 Plant placed in Mode 4 after an unrelated scram. This placed plant in compliance with TS LCO 3.8.7.

6/10/96 Plant entered Mode 2 at 5:44 a.m. This mode change with MCC EF-1-D-09 inoperable violated TS LCO 3.0.4.

6/11/96 Plant entered Mode 1 at 2:00 p.m. This mode change with MCC EF-1-D-09 inoperable violated TS LCO 3.0.4.

6/17/96 At 8:43 a.m. FHB Exhaust Fan and Heater 'B' shut down. TS LCO 3.8.7 was exited.

6/25/96 FHB Exhaust Fan and Heater 'B' started at 12:45 a.m., MCC EF-1-D-09 inoperable, TS LCO 3.8.7 was entered (not recognized) and its action statement A.1 was exceeded at 8:45 a.m.

8/05/96 CRER 'A' declared inoperable at 4:07 a.m. for maintenance, plant was then in TS LCO 3.0.3 (not recognized).

8/06/96 TS LCO requirement to place the unit in Mode 4 by 5:07 p.m. was not met.

8/06/96 CRER 'A' declared operable at 10:55 p.m., TS LCO 3.0.3 exited.

9/16/96	EF1D09 tripped after start of FHB Supply Fan 'B'. Breaker replaced. Initial inspection by licensee and ABB representative did not reveal cause of the breaker trip.
9/17/96	MCC EF-1-D-09 declared operable with replacement breaker.
9/20/96	RSE's breaker inspection revealed that the phase A CT wires were landed on the incorrect terminal block locations, reversing the phase A load current data polarity.
9/26/96	RSE discussion with the vendor indicated that reversed CT polarity would cause the solid trip device to indicate a current about twice the expected value. This configuration would cause a breaker trip at a lower current.
9/27/96	The licensee inspected the CT lower leads on three of the seven breakers installed during RFO5. No problems were identified.
10/01/96	The inspectors contacted a compliance engineer for additional information on the solid state trip devices. The RSE informed the inspectors of the reversed polarity effect. The inspectors observed the as-found wiring configuration.
10/02/96	The inspectors observed licensee inspections of the CT lower leads on the last three of the new 480 VAC breakers installed in RFO5. No problems were identified
10/ 4/96	The licensee identified two occasions where a CRER loss of safety function had occurred. The NRC was notified in accordance with 10 CFR 50.72.
10/10/96	Vendor's laboratory test confirmed that the affected breaker trip setpoint was about half of the intended trip setpoint. The licensee performed a review which identified multiple safety function losses.
11/ 4/96	Licensee Event Report (LER) 96-008-00: "Degraded Breaker Results in Loss of Safety Function and Exceeding Technical Specification Action Statements" issued in accordance with 10 CFR 50.73.

6.0 Root Cause

The licensee concluded that the root cause of this event was a manufacturing wiring error which caused the affected breaker to exceed its trip setpoint with less than expected current flow. The inspectors concluded that the root cause was inadequate preinstallation testing, inspection, or postinstallation testing of the breaker, which failed to identify the manufacturing error. The difference was not significant because the licensee had developed remedial or corrective actions to address both potential root causes.

7.0 Safety Significance

A review by the licensee identified loss of safety functions on multiple occasions due to the breaker trip setpoint reduction. The licensee recognized that in the event of a LOOP/LOCA with FHB exhaust fan 'B' operating, the breaker would have tripped, causing loss of CRER 'B.'

In the event of a postulated accident with breaker EF1D09 tripping coincident with Div 1 EDG being inoperable, a direct loss of CRER, emergency closed cooling (ECC) pump area, and MCC switchgear and battery room ventilation systems resulting in a loss of safety functions would have occurred that could have impacted the mitigation of an accident. As a result of the loss of ECC pump area ventilation, with no operator action, increasing temperature could have caused a loss of the ECC safety function resulting in eventual inoperability of low pressure core spray (LPCS), low pressure coolant injection (LPCI), reactor core isolation cooling (RCIC), containment spray, suppression pool cooling, and the hydrogen analyzers. Loss of MCC switchgear and battery room ventilation could also have resulted in a similar loss of safety systems over an extended period of time, if room temperatures rose to unacceptable levels.

The licensee performed calculations that indicated that it would take more than 2 hours for each of the affected areas to reach a high enough temperature to affect equipment in the rooms. The inspectors observed the licensee perform a field time study to verify that the required equipment could be restored within 30 minutes by manual operator action. This action used existing procedures for MCC restoration with which the operators were already familiar.

8.0 Licensee Corrective Actions

As part of the licensee's immediate corrective actions for this event, the defective breaker was replaced, the six similar breakers installed during RF05 were checked for similar wiring errors, and the operability of other similar breakers was evaluated.

The following additional corrective actions were also accomplished:

- A refurbished breaker supplying the redundant division of ventilation equipment was checked for proper polarity.

- A field time study was performed to validate the time needed to restore MCC EF-1-D-09 during a postulated accident.

- Maintenance instructions were changed to check the wiring of the CTs and to test for correct polarity.

- A review of safety-related breakers was performed to determine if further testing was required to verify proper breaker operation.

The following long term actions had been developed but not completed by the end of the inspection:

- The vendor was to provide documentation that training on this event was provided to breaker assembly personnel.
- The RSE began gathering information from other utilities to determine if similar problems had been identified.
- Half (12 breakers) of the similar refurbished breakers that were not normally subjected to a current above the faulted trip setpoint were to be checked for wiring errors.
- Engineering was to provide a prioritized list of safety-related breakers to be checked for wiring errors.

9.0 Technical Specification Apparent Violations

MCC EF-1-D-09 was inoperable on multiple occasions due to the breaker trip setpoint reduction between March 11, and September 16, 1996. On this basis, the following apparent violations were identified:

- Technical Specification LCO 3.0.3 requires that when an LCO is not met and the associated actions are not met, the unit shall be placed in a mode in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

  1. Mode 2 (startup) within 7 hours;
  2. Mode 3 (hot shutdown) within 13 hours; and
  3. Mode 4 (cold shutdown) within 37 hours.

  From August 5 to August 6, for about 41 hours, with the CRER system inoperable, which required entry into TS LCO 3.0.3, the licensee failed to initiate action within 1 hour to place the unit in mode 4 within 37 hours. This is an apparent violation (EEI 50-440/97017-03(DRP)).

- Technical Specification LCO 3.0.4 prohibits entry into a new mode when an LCO is not met and the associated actions do not permit continued operation in the new operating condition. The plant operating condition was changed when LCOs were not met on two occasions: when the plant was taken to mode 3 on June 10, at 5:44 a.m., and when the plant was taken to mode 1 on June 11, at 2:00 p.m. Therefore, this LCO was apparently violated on those occasions (EEI 50-440/96017-04(DRP)).

- Technical Specification LCO 3.8.7 Action A.1 required an inoperable Div 2 AC electrical subsystem (MCC EF-1-D-09) to be restored to operable status within 8 hours. Moreover, Actions C.1 and C.2 required the unit to be placed in at least mode 3 within the next 12 hours and in mode 4 within the next 36 hours if MCC EF-1-D-09 was not restored to operable status. This LCO was apparently violated on several occasions (reference paragraph M4.1.b.5, Sequence of Events) (EEI 50-440/96017-05(DRP)).

- Technical Specification LCO 3.7.3 Action A.1 required the inoperable CRER 'B' subsystem to be restored to operable status within 7 days. Moreover, action statements B.1 and B.2 required the unit to be in mode 3 within 12 hours and in mode 4 within 36 hours if the inoperable CRER subsystem was not restored to operable status within the time required by Action A.1. This LCO was apparently violated on several occasions (reference paragraph M4.1.b.5, Sequence of Events) (EEI 50-440/96017-06(DRP)).

c. Conclusions

From April 11 to September 17, 1996, four apparent violations of technical specifications occurred, including one for a 41-hour period with the CRER system inoperable during which the actions required by TS 3.0.3 were not completed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Field Clarification Request Use During Maintenance

a. Inspection Scope (37551 and 62707)

The inspectors observed maintenance perform a general check of the HPCS pump electrical breaker. Subsequently, the inspectors reviewed a related field clarification request (FCR).

b. Observations and Findings

The craft were instructed by the maintenance supervisor to visually inspect the breaker for any abnormalities. The craft identified cracks in the corners of the molded coil sensor assemblies for GR-5 ground fault relays. The cracks radiated from the lower two mounting bolts (four bolts total) outward to the edge of the plate. The supervisor stated that FCR 016809 addressed the issue and that a number of breakers exhibited the same deficiency. The inspectors reviewed the FCR and identified the following:

- The FCR was completed in 1992.
- The FCR did not include a documented basis for the conclusion that the breaker condition was acceptable.
- The extent of the condition (i.e., what other breakers had similar problems) was not addressed by the FCR.

- General Electrical Instruction (GEI) 0104, Step 5.1.2 stated, "Inspect the relay for imperfections, damage ...
NOTE: ... The sensor is acceptable to use provided that the sensor is not loose, the crack is not through the entire cross section, or the internal coil is not visible."

The inspectors discussed the issues with engineering and PIF 96-3768 was issued. The acting engineering manager stated that engineering had been working on improving the FCR process as a result of other identified problems.

c. Conclusions

The age of the FCR and the fact that it did not consider extent of condition made its current use for multiple breakers questionable. Since the FCR did not include a documented basis the inspectors could not evaluate whether it was acceptable for even the original breaker that it addressed. The instructions provided in GEI-0104 were inadequate. The quality of this FCR and its use for justification of a deficiency in a safety related component requires additional inspection to determine the extent and significance of the issue and is an Unresolved Item (URI 50-440/96017-07(DRP)).

E2.2 General Electric (GE) Fuel Design Error

a. Inspection Scope (37551)

The licensee received verbal notification from GE Nuclear Fuel of an error to the Cycle 6 loss of coolant accident (LOCA) analysis. The inspectors evaluated engineering's evaluation of and response to the error.

b. Observations and Findings

Preliminary calculations indicated an increase in the LOCA peak clad temperature (PCT) of approximately 15° Fahrenheit (F), which exceeded the PCT limit of 2200° F established in 10 CFR 50.46. The licensee documented the issue with PIF 96-3507. GE recommended, and the licensee promptly implemented, a limit of 0.970 for the Maximum Average Planar Heat Generation Ratio (MAPRAT); normally limited to 1.000. The inspectors verified that the operators were briefed and aware of the new limit. The errors were related to GE 11 fuel that Perry was using during Cycle 6. GE reviewed its analysis and identified excess conservatism. Reduction of the conservatism compensated for the error and allowed the plant to return its MAPRAT limit to 1.000. This issue will be evaluated in the future as part of a previous Inspection Follow-up Item (IFI 50-440/96003-13(DRP)), opened based on other identified GE core design errors.

E2.3 <u>Inservice Inspection Program Corrective Actions</u>

a. <u>Inspection Scope (37551 and 37001)</u>

Engineers identified four residual heat removal (RHR) check valves (1E12-F0063A, 63B, 63C, and 86) that had not been included in the in-service inspection (ISI) program. The inspectors evaluated engineering activities related to this deficiency.

b. <u>Observations and Findings</u>

These check valves provided isolation of the RHR system from the non-safety related condensate transfer and storage system. Failure to include the valves in the ISI program presented the potential to exceed the limits developed in the UFSAR analysis for compliance with 10 CFR 100.11 offsite radiation dose limits after postulated accidents. After some postulated accidents, the RHR system would contain highly radioactive fluid and the check valves were designed to prevent that fluid from spreading to other systems outside containment. The valves had not been tested since they had been installed during plant construction. The licensee's administrative leakage limit for all potential radioactive leakage outside containment was 5 gallons per hour (gph) and the limit for the analysis was 10 gph. Testing (see Section M1.1) of the valves was completed and when the valve as-found leakage was added to other previously identified leakage, the total as-found leakage was 5.3 gph. Some valves were replaced and the total as-left leakage was less than 5.0 gph.

c. <u>Conclusions</u>

This ISI program deficiency was identified by the licensee during corrective action activities for an earlier violation (50-440/EA 96-367) dated November 6, 1996. Engineering response to the deficiency was prompt and conservative. However there were some delays in completing the corrective actions because of planning weaknesses (Section M1.1 b.). Failure to test these check valves was a violation of Technical Specification 5.5.2, Primary Coolant Sources Outside Containment. This licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV 50-440/96017-08(DRP)) consistent with Section VII.B.1 of the NRC Enforcement Policy, NUREG-1600.

E2.4 <u>Review of Updated Final Safety Analysis Report (UFSAR) Commitments</u>

The inspectors reviewed applicable portions of the UFSAR that related to the areas inspected; no inconsistencies were identified. The inspectors also reviewed items that the licensee had identified during its review of the UFSAR. The licensee included the inconsistencies in its corrective action program. These may be reviewed in a future inspection based on the NRC's recently established policy (61 FR 54461, October 18, 1996) for the review of licensee-identified UFSAR inconsistencies.

The inspectors also reviewed current safety evaluations for some of the identified UFSAR inconsistencies. The safety evaluations were timely and appropriate for the identified issues. It appeared that the licensee had addressed the inconsistencies appropriately in accordance with the safety significance.

E7 Quality Assurance in Engineering Activities

E7.1 Emergency Service Water System Operational Performance Inspection

a. Inspection Scope (37551 and 40500)

The inspectors attended the exit meeting for the licensee's self-assessment inspection and reviewed PIFs developed during the inspection. The inspection was modeled on the NRC's Temporary Instruction for Service Water System Operational Performance Inspections.

b. Observations and Findings

The meeting was attended by appropriate personnel and there was substantive discussion of the issues presented. The issues, initially documented with 57 PIFs, included engineering process weaknesses; response to Generic Letter 89-13 and associated commitments; update weaknesses for the UFSAR; and potential operability concerns for ESW Div. 1 at elevated lake temperatures. The inspection team included Perry personnel, consultants, and personnel from other plants.

c. Conclusions

The inspection identified a number of issues and was an indication of effective self-assessment. The effectiveness of the licensee's corrective action plan was not assessed because corrective actions had not yet been developed for the issues.

IV. Plant Support

P2 Staff Knowledge and Performance in Emergency Preparedness

a. Inspection Scope (71750, 92904, 93702)

On December 19, the shift supervisor (SS) determined that the plant had a significant loss of offsite communications capability and classified the loss as an Unusual Event. The inspectors used Inspection Procedures 71750, 92904, and 93702 to evaluate the licensee's performance.

b. Observations and Findings

At about 1:30 p.m. the inspectors observed that the resident inspector office outside telephone lines were dead. Since the NRC operations center emergency notification system (ENS) phone was part of the same telephone system, an inspector went to the control room to inform the SS. The SS, who was attempting to determine the cause of an associated failure of the plant personal paging system, promptly determined that the ENS and other offsite notification phones were dead. The SS, with the assistance of EP communicators, confirmed that no offsite phones designated for Emergency Plan (EP) use were available. The onsite telephone system was functioning normally. The SS promptly notified operations management and EP personnel of the problem and began reviewing the EP procedure. The inspectors verified that EP support for the SS was prompt and effective.

At 2:00 p.m. the SS declared that the plant was in an Unusual Event and directed the EP communicators to begin making offsite notifications with two cellular phones that had been brought to the control room. These phones had not been prestaged for EP response and there were no plans or procedures for their use. The inspectors observed the EP communicators begin the offsite notifications from the plant lunch room because the cellular phones could not be used in the control room. The communicators were not familiar with the cellular phones, existing procedures had been intended for use with specialized notification phones in the control room or EP facilities, and it was more difficult to make the notifications with only two phones available. The communicators, assisted by EP and engineering personnel, promptly adapted to the unexpected conditions and completed the required notifications within the time limits. The SS also made a conservative decision to activate the technical support center (TSC) and the operations support center (OSC). Minimum staffing was established for the emergency operations facility. These facilities were not needed for the Notification of Unusual Event (NOUE), but were activated because the SS anticipated that if another plant event occurred it would be difficult to activate facilities with only two cellular phones. The inspectors had no capability to communicate with offsite NRC facilities or other government agencies. When the licensee obtained additional cellular phones, the inspectors borrowed one to contact the Region III office and verify that EP communications with the NRC were adequate.

The inspectors verified that the TSC and OSC were activated and assisting the SS in restoring offsite communications. The licensee determined that communications had been lost because a sewage line excavation contractor had severed an underground fiber optic cable about 1 kilometer from the licensee-controlled area. Engineering personnel determined that the telephone company had provided the contractor with incorrect information on the cable location.

Normally this single event would not have caused a significant loss of offsite communications capability. However, on September 22, the site's microwave communications tower had been damaged, eliminating a backup telephone link, and repairs to the tower had not been started. The telephone company dispatched a cable-splicing crew to the site of the severed cable. At about 6:00 p.m. the inspectors verified that plant maintenance personnel had provided the telephone company with portable lighting and heating equipment and had stationed plant personnel to monitor repair progress.

At about 11:30 p.m. the inspectors verified that the offsite phone lines were functioning. At about midnight the inspectors verified that personnel at the excavation site had developed an appropriate plan to protect the phone line until the excavation was completed. At 12:40 a.m. on December 20, the TSC concluded that appropriate communications testing had been completed and terminated the NOUE. At about 8:30 a.m. the onsite EP coordinator provided the inspectors with a copy of the Event Closeout Summary required by Appendix 1 of NUREG-0654. The plant manager later informed the inspectors that he would be retaining some of the company's emergency cellular phones on site for EP use.

c. Conclusions

Overall, emergency response performance was excellent. The shift supervisor made a timely event classification and offsite agencies were notified within the required times. All observed personnel demonstrated teamwork and concise and accurate communications. The prompt decision to activate the TSC and OSC was a strength. A weakness in anticipating equipment needs and procedural direction for a significant loss of offsite communications capability was overcome by personnel promptly adapting to the conditions encountered and functioning effectively as a team. The plant manager recognized the weakness and initiated prompt actions to correct it. The TSC and OSC were promptly activated and provided appropriate support to the plant. Facility personnel were professional and strongly focused on response to the event. The licensee provided excellent support to the telephone company repair crew.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 20, 1996 and on December 27, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. C. Stetz, Senior Vice President
L. W. Myers, Vice President - Nuclear
R. D. Brandt, General Manager Operations
N. L. Bonner, Engineering Director
L. W. Worley, Nuclear Services Director
W. W. Kanda, Nuclear Assurance Director
J. Messina, Operations Manager

INSPECTION PROCEDURES USED

IP 37001:	10 CFR 50.59 Safety Evaluation Program
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71500:	Balance of Plant Inspection
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92720:	Corrective Action
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/96017-01	URI	Inadvertent power change caused by FCV movement
50-440/96017-02	URI	EDG and HPCS test possible preconditioning
50-440/96017-03	EEI	Apparent LCO 3.0.3 violation, breaker inoperable
50-440/96017-04	EEI	Apparent LCO 3.0.4 violation, breaker inoperable
50-440-96017-05	EEI	Apparent LCO 3.8.7 violation, breaker inoperable
50-440/96017-06	EEI	Apparent LCO 3.7.3 violation, breaker inoperable
50-440/96017-07	URI	Improper use of FCR
50-440/96017-08	NCV	TS 5.5.2, RHR check valves not tested

Closed

50-440/96017-08	NCV	TS 5.5.2, RHR check valves not tested

Discussed

50-440/96003-16	IFI	GE core design errors

LIST OF ACRONYMS USED

APRM	AVERAGE POWER RANGE MONITOR
ATWS	ANTICIPATED TRANSIENT WITHOUT SCRAM
BOP	BALANCE OF PLANT
CFR	CODE OF FEDERAL REGULATIONS
CRER	CONTROL ROOM EMERGENCY RECIRCULATION
CRHVAC	CONTROL ROOM HEATING, VENTILATION, AND AIR CONDITIONING
CST	CONDENSATE STORAGE TANK
CT	CURRENT TRANSFORMER
DIV	DIVISION
ECC	EMERGENCY CLOSED COOLING
ECCS	EMERGENCY CORE COOLING SYSTEM
EDG	EMERGENCY DIESEL GENERATOR
EEI	ESCALATED ENFORCEMENT ITEM
ENS	EMERGENCY NOTIFICATION SYSTEM
EP	EMERGENCY PLAN
ESW	EMERGENCY SERVICE WATER
FCR	FIELD CLARIFICATION REQUEST
FCV	FLOW CONTROL VALVE
FHB	FUEL HANDLING BUILDING
GE	GENERAL ELECTRIC
GEI	GENERAL ELECTRICAL INSTRUCTION
GPH	GALLONS PER HOUR
HPCS	HIGH PRESSURE CORE SPRAY
HPU	HYDRAULIC POWER UNIT
HVAC	HEATING, VENTILATION, AND AIR CONDITIONING
IFI	INSPECTION FOLLOW-UP ITEM
IMI	INSTRUMENT MAINTENANCE INSTRUCTION
ISI	INSERVICE INSPECTION PROGRAM
LCO	LIMITING CONDITIONS FOR OPERATIONS
LER	LICENSEE EVENT REPORT
LOCA	LOSS OF COOLANT ACCIDENT
LOOP	LOSS OF OFF-SITE POWER
LPCI	LOW PRESSURE COOLANT INJECTION
LPCS	LOW PRESSURE CORE SPRAY
LPRM	LOCAL POWER RANGE MONITOR
MAPRAT	MAXIMUM AVERAGE PLANAR HEAT GENERATION RATIO
MCC	MOTOR CONTROL CENTER
MOV	MOTOR-OPERATED VALVE
NOUE	NOTIFICATION OF UNUSUAL EVENT
NPF	NUCLEAR POWER FACILITY
NRC	NUCLEAR REGULATORY COMMISSION
NRR	NUCLEAR REACTOR REGULATION
OOS	OUT OF SERVICE
OSC	OPERATIONS SUPPORT CENTER
PCT	PEAK CLAD TEMPERATURE
PDR	PUBLIC DOCUMENT ROOM
PIF	POTENTIAL ISSUE FORM
PORC	PLANT OPERATIONS REVIEW COMMITTEE
PTI	PERIODIC TEST INSTRUCTION
RCIC	REACTOR CORE ISOLATION COOLING

RFO	REFUELING OUTAGE
RHR	RESIDUAL HEAT REMOVAL
RSE	RESPONSIBLE SYSTEM ENGINEER
SS	SHIFT SUPERVISOR
STA	SHIFT TECHNICAL ADVISOR
SVI	SURVEILLANCE INSTRUCTION
TS	TECHNICAL SPECIFICATION
TSC	TECHNICAL SUPPORT CENTER
UFSAR	UPDATED FINAL SAFETY ANALYSIS REPORT
URI	UNRESOLVED ITEM
US	UNIT SUPERVISOR
VAC	VOLT ALTERNATING CURRENT
VP	VICE PRESIDENT
WO	WORK ORDER

PARTIAL LIST OF DOCUMENTS REVIEWED DURING THIS INSPECTION

Audit Report PA 96-21 Plant Operations Review Committee, 12/19/96
Communication Record Sheet, Dated 12/19/96 SUBJECT: NRC Notification
Control room standing orders, various dates
Control room computer printouts, various parameters, various dates
Control room daily instructions, various dates
Control room daily instructions, supplemental reading, various dates
Control room safety tag log, various dates
Control room strip charts, various parameters
Control room annunciator status books, revisable format, various dates
Control room LCO log, various dates
Deficiency tags, various locations, various dates
Design Change Package 91-0210 REV. 1
Emergency Service Water - Operational Performance Inspection Summary
December 16, 1996
Fire extinguisher inspection tags, various locations, various dates
GEK-63100, Operation and Maintenance Instructions, Hydraulic Control Unit 4/80
Limiting Access To Specific Areas (undated)
Managers' Meeting Report - 11/4, 6, 8, 13, and 15/96
Managers' Communication & Teamwork Meeting Report, 11/18, 20, 22, 25, & 27/96
Managers' Communication & Teamwork Meeting Report, 12/2, 4, 6, 9, 11, & 13/96
Managers' Communication & Teamwork Meeting Report, 12/16, 18, & 20/96
Monthly Access Level Use Review For October, Dated 11/4/96
Monthly Access Level Use Review For November, Dated 12/5/96
Monthly ALARA Report 12/02/96
Monthly Operations Report - November 1996
NRC Inspection 96017 Debrief Summary - 12/19/96
Operator Training: LOCA ANALYSIS ERROR (J-11; 11/25/96)
Operational Surveillance Report No. 96-057, 11/11/96, Control Rod Drive
Pump
Operational Surveillance Report No. 96-058, 11/05/96
Operations Administrative Control Tags, various locations, various dates
Operations Information Tags, various locations, various dates
PAP 0201, Conduct of Operations, Rev. 9, effective 3/28/95
Perry Daily Report - Tuesdays and Thursdays, except Nov. 28, 1996
Perry News Flash, Results of Enforcement Conference, dated 11/11/96
Perry Plan for Excellence, General Familiarization - Undated.
PIF 96-3186 Issues, 11/20/96
Plan of the Day - 11/04-08/1996
Plan of the Day - 11/12-15/1996
Plan of the Day - 11/18-22/1996
Plan of the Day - 11/25-27 & 29/1996
Plan of the Day - 12/02-06/1996
Plan of the Day - 12/09-13/1996
Plan of the Day - 12/16-20/1996
Plant Log, Vol. 31, Pages 59 and 60, August 5 and 6, 1996
Plant Log, Vol. 31, (11/01/96) Page No. 147 - 150 (11/04/96)
Vol. 32, (11/05/96) Page No. 1 - 46 (12/20/96)
Plant strip charts, various parameters, various dates
Potential Issue Form No. 96-3337 through 96-3768

POS (Perry Operations Section) Performance Indicators - October 1996
POS Performance Indicators - November 1996
Procedure/Instruction Change, Rev. 7 (PAP-1201), Change No. 2,
    TITLE: Control of Measuring and Test Equipment dated 11/14/96
QCS Corrective Action Management Report Week Ending 11/8/96, dated 11/7/96.
Radiation Work Permit 97006
Radiologically Restricted Area Radiation Surveys, various dates
Safety Tags, various locations, various dates
Simple Modification Request Form, No. 96-6043, Rev. 0 - 11/22/96
SURVEILLANCE AREA/ACTIVITY Review the use of Field Clarification Requests, the
    process followed by field generated As-Builts, and the timely updating
    of department/section controlled procedures and drawings 11/5/96
SURVEILLANCE AREA/ACTIVITY Plant Operation/Remote Shutdown 11/12/96
SURVEILLANCE AREA/ACTIVITY Control Rod Drive Pump 11/11/96
SURVEILLANCE AREA/ACTIVITY E12/P11 System Outage for Check valve replacement
Surveillance Testing of the B21-F0067's, 3/21/96
Temporary Modification Tracking Report, November, dated 11/01/1996
Temporary Modification Tracking Report, December, dated 12/01/1996
Unit Log, Unit 1, Vol. 89,(11/01/96) Page No. 136 - 150 (11/07/96)
    Vol. 90,(11/07/96) Page No. 1 - 106 (12/20/96)
Updated Final Safety Analysis Report
Various System Description Manuals
Weekly Effluent and Release Rate Data Report, about November 4, 1996
Weekly Effluent and Release Rate Data Report, about November 11, 1996
Weekly Effluent and Release Rate Data Report, about November 18, 1996
Weekly Effluent and Release Rate Data Report, about November 25, 1996
Weekly Effluent and Release Rate Data Report, about December 12, 1996
Weekly Effluent and Release Rate Data Report, about December 16, 1996