U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/92002(DRP)

Docket No. 50-440 License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant

Inspection At: Perry Site, Perry, Ohio

Inspection Conducted: January 13 through February 27, 1992

Inspectors: A. Vegel
P. Hiland

Approved By: R. D. Lanksbury, Chief 3/12/92
Reactor Projects
Section 3B

Inspection Summary

Inspection on January 13 through February 27, 1992 (Report No. 50-440/92002(DRP))

Areas Inspected: Routine unannounced safety inspection by resident inspectors of previously identified items; licensee event report followup; surveillance observations; maintenance observations; operational safety verification; event followup; and management meeting.

Results: Of the seven areas inspected, one violation consisting of two examples (Paragraph 6.d and 7.b.1) of failure to properly implement existing instructions was identified. That violation met the test for not issuing a Notice of Violation; however, enforcement discretion was not exercised because of the repetitive nature and potential significance of the two examples. In addition, two non-cited violations (NCVs) were identified in the area of licensee event report followup (Paragraph 3.c and 3.e). Those two NCVs met the test of Section V.G of the Enforcement Policy. At the conclusion of the inspection period, licensee management was aware of and investigating the cause for the cited violations.

The following is a summary of the licensee's performance during this inspection period:

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Plant Operations

Response by plant operators to events was considered good. However, nonlicensed operators were involved in two events that were preventable by proper implementation of existing instructions.

Maintenance/Surveillance

The quality of observed maintenance and surveillance activities was good.

Engineering and Technical Support

Based on routine observations of engineering support to plant operations, this area was considered good. Of note was support provided for equipment leaks and electrical system failures.

Safety Assessment and Quality Verification

The quality of reviewed event reports was acceptable. Observed on-site review committee activities were adequate. A recent Quality Assurance Audit of Generic Letter 89-10 was good.

Emergency Planning

Response to an Emergency Operations Facility fire was adequate. However, some weaknesses were identified by the licensee subsequent to the event.

Security

Security performance remained good with the exception of an isolated incident involving a security guard reading nonwork related material while on station.

DETAILS

1. Persons Contacted

   a. Cleveland Electric Illuminating Company

      # M. Lyster, Vice President - Nuclear
      #*R. Stratman, General Manager, Perry Nuclear Power Plant (PNPP)
      #*K. Donovan, Manager, Licensing and Compliance
      M. Gmyrek, Operations Manager, PNPP
      S. Kensicki, Director, Perry Nuclear Engineering Department (PNED)
      #*F. Stead, Director, Perry Nuclear Support Department (PNSD)
      H. Hegrat, Compliance Engineer, PNSD
      # E. Riley, Director, Perry Nuclear Assurance Department (PNAD)
      *V. Concel, Manager Technical Section, PNED
      *D. Conran, Compliance Engineer, PNSD
      #*W. Coleman, Manager, Quality Assurance Section
      *P. Volza, Manager, Radiation Protection Section
      *D. Cobb, Superintendent, Plant Operations, PNPP
      # K. Peck, Outage Planning
      # B. Walrath, Manager, Engineering Support Section
      # A. Silakowski, Manager, Independent Safety Engineering Group
      # L. Kellythorne, Environmental Monitor

   b. U. S. Nuclear Regulatory Commission

      # A. Davis, Regional Administrator, RIII
      # C. Paperiello, Deputy Regional Administrator, RIII
      # J. Hannon, Director, Project Directorate III-3, Office of Nuclear Reactor Regulation (NRR)
      # R. Knop, Chief, Branch 3, Division of Reactor Project, RIII
      # R. Lanksbury, Chief, Division of Reactor Project, Section 3B, RIII
      # J. Hall, Senior Project Manager, NRR
      #*P. Hiland, Senior Resident Inspector, RIII
      A. Vegel, Resident Inspector, RIII
      *M. Khanna, Intern, RIII

   * Denotes those attending the exit meeting held on February 27, 1992.
   # Denotes those attending the management meeting on February 25, 1992.

2. Licensee Action on Previous Inspection Findings (92702)

   (Closed) Violation (440/90014-07(DRP)): Licensee followup to test failure identified a lack of prompt and adequate corrective actions to the flux spike described in Licensee

Event Report (LER) 440/90015. The corrective actions to this item were reviewed concurrent with the inspectors review of the associated LER described below in Paragraph 3.d. Based on completion of those corrective actions, this item is closed.

No violations or deviations were identified.

3. Licensee Event Report Followup (90712, 92700)

Through review of records, the following event reports were reviewed to determine if reportability requirements were fulfilled, immediate corrective actions were accomplished in accordance with Technical Specifications, and corrective action to prevent recurrence had been established:

a. (Closed) LER 50-440/88004-00: On January 6, 1988, local leak rate testing identified excess secondary containment bypass leakage. The leakage path was through the post accident sampling system (PASS) instrument line containment isolation valves.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

As discussed in the subject LER, the PASS containment isolation valves (1P87-F049 and F055) were inspected to evaluate the cause for excessive leakage. Degradation and discoloration of the valves was noted and believed to be the result of electrical arcing. In addition, small amounts of foreign material ("watery sludge") were found in the valves. The cause for the electrical arcing was not determined; however, the licensee believed it could have been caused during welding activities. The foreign material was believed to be from the water quality during initial operation of the reactor water cleanup system.

Corrective Actions:

As immediate corrective action, the subject valves were replaced and a satisfactory leak rate test was performed on January 13, 1988. Long term corrective action had been under review by the licensee from a similar failed leak rate test reported in LER 50-440/86007. Planned corrective action was to revise the valves design from normally closed to normally open with an automatic isolation signal. The reduced cycling of the PASS isolation valves and adherence to manufacturer's installation requirements was considered adequate to prevent recurrence.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and concluded that corrective action for the subject LER appeared reasonable. However, subsequent leakage problems with the PASS isolation valves (P87-F049 and F055) were noted in Inspection Reports 50-440/90005, Paragraph 11.b.(1) and 50-440/90020, Paragraph 4. LER 50-440/90026-01 dated July 3, 1991, was submitted by the licensee detailing further corrective actions which limited valve cycling and continued to evaluate the adequacy of the subject valves for use in the PASS. Planned leak rate testing was scheduled for the third refueling outage (Spring '92). Based on the completion of corrective actions stated in the subject LER, this item is closed. The inspectors will review the results of scheduled leak rate testing and further corrective actions tracked under open LER 50-440/90026-01.

b. (Closed) LER 50-440/90002-00: On January 7, 1990, the reactor core isolation cooling (RCIC) system isolated due to a high differential temperature (delta-T) signal detected across the RCIC room cooler following a reactor scram from full power. Further evaluation determined the RCIC system was considered to be inoperable during cold weather operations during the second fuel cycle (non-cited violation 440/90002-03 was documented in inspection report 50-440/90002 with respect to this issue).

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined the root cause of the RCIC isolation was a design deficiency involving the delta-T isolation instrument setpoint. The RCIC room delta-T instrumentation did not have enough setpoint margin during the winter mode of operation due to increased capacity of heat removal systems during the winter months. Colder cooling water flow resulted in colder air temperatures at the exhaust of the room cooler. A secondary cause was the inaccuracy in cooling water flow rate associated with the throttling of the room cooler outlet valve. Also contributing to the high differential temperature was the additional heat loading from the RCIC turbine, due to insulation not being installed properly.

Corrective Actions:

To prevent recurrence, the licensee submitted an emergency Technical Specification change request on January 19, 1990, to delete the RCIC differential temperature isolation actuation instrumentation. Following discussions with NRC staff, the licensee submitted an additional emergency Technical Specification change request on January 26, 1990, to revise the RCIC differential temperature "high" isolation setpoint from 37.25 to 70.9 degrees Fahrenheit. In the latter request, to prevent valve manipulation errors, the licensee factored into the supporting calculations the stipulation that the room cooler outlet valves be left in their normal position of 15 gallons per minute, thereby maintaining cooler flow rate constant year round. On January 31, 1990, the NRC approved the licensee's setpoint change request as Amendment 26 to the facility operating license. The NRC staff noted that the setpoint change was approved on an emergency, temporary basis for the winter months until Lake Erie temperature reached 55 degrees Fahrenheit. Subsequently, on March 16, 1990, the licensee submitted another Technical Specification change request to revise the RCIC differential temperature high isolation setpoint and allowable value to 95.9 and 97.2 degrees Fahrenheit respectively, which could be used throughout the range of expected Lake Erie water temperatures. On May 4, 1990, the NRC approved the setpoint and allowable value change as Amendment 28 to the facility operating license.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and concluded that the licensee's corrective actions appeared reasonable and adequate to prevent recurrence. With respect to the misplaced insulation on the RCIC turbine, which contributed to the event, the inspectors observed during a routine tour of the RCIC equipment room, that some of the insulation was not properly installed. Though the misplaced insulation was a minor contributor to the event, it was an example of poor material condition and post maintenance cleanup. The inspectors discussed this issue and other housekeeping deficiencies documented in Paragraph 6.b of this report with licensee management. This item is closed.

c. (Closed) LER 50-440/90010-00: On May 21, 1990, plant operators failed to implement Technical Specification action requirements for inoperable control rod scram accumulators. A failure of the rod control and information system (RC&IS) resulted in the inability to receive updated leak detector and pressure detector information required for accumulator operability. With more than one control rod scram accumulator inoperable, Technical Specifications required the associated control rods to be declared inoperable, and immediate verification of control rod drive pump operation.

Approximately two hours after the RC&IS failure, operators realized that thirty-two control rod scram accumulators were inoperable and implemented the required actions.

Licensee Evaluation of Cause and Corrective Actions:

Root Cause:

The licensee determined that the cause of this event was inadequate procedures. Although equipment malfunction initiated the event, lack of procedural guidance for operator response to this particular type of failure resulted in a Technical Specification violation. Because Off-Normal Instruction (ONI)-C11-1, "Inability to Move Control Rods (Unit 1)," and System Operating Instruction (SOI)-C11, "Rod Control and Information System (Unit 1)," did not address, in the necessary detail, the implications of an RC&IS analyzer lockup, the operators failed to determine operability of the affected accumulators in a timely manner. Additionally, although accumulator information was restored to the unaffected rods by placing the analyzer in the test mode, procedural guidance for this activity was not included in the associated operating instructions.

Corrective Actions:

To prevent recurrence, operations procedures were revised to include more detailed guidance to assist operators in determining control rod and control rod scram accumulator operability. On September 23, 1991, the licensee submitted a Technical Specification change request to allow an alternate method of determining whether a control rod drive pump is operating. Additionally, as part of the established requalification training program, all plant licensed operators were instructed on the lessons learned from this event.

Inspectors Evaluation:

Failure to comply with the Action statement of Technical Specifications within the allotted time is a violation. This violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section V.G of the Enforcement Policy. The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed. The inspectors concluded that the licensee's corrective actions appeared reasonable and adequate to prevent recurrence. This item is closed.

d. (Closed) LER 50-440/90015-00: On June 24, 1990, during surveillance testing on the reactor protection system (RPS) instrumentation, reactor power exceeded 102 percent of the maximum power level authorized in the facility operating license. The event occurred when a main steam isolation valve was closed farther than required for the surveillance activity, resulting in a reactor pressure and power increase. Control room operators temporarily secured from the test, returning to normal full power operation.

Licensee Evaluation of Cause and Corrective Actions:

Root Cause:

Causes of this event involved multiple personnel errors by instrument and control (I&C) technicians and control room personnel, as well as procedural inadequacies. Two portable volt/ohm meters (VOM) were installed in RPS circuitry to monitor the state of relays affected by the test; however, one VOM had a blown fuse and test leads for the other VOM had inadequate contact with the relay terminals. Additionally, personnel performing the test did not adequately consider the potential for the effects of such a malfunction, and did not recognize that it had occurred. Finally, the surveillance instruction did not contain adequate information regarding the expected duration, sequence, and setpoints for expected results.

Corrective Actions:

Corrective actions included modifications to relay terminals to improve test lead contact; counselling the individuals involved in the test; enhancements to the surveillance instruction and administrative procedures governing testing activities; reinforcement of surveillance testing requirements by supervisory personnel; and modifications to training programs. Additionally, this event was discussed with all licensed operators and I&C technicians during continuing training.

Inspectors Evaluation:

As documented in Inspection Report 50-440/90014(DRP), Paragraph 8.b.(2), dated August 16, 1990, the inspectors previously evaluated the licensee's immediate corrective actions and root cause determinations as adequate to prevent recurrence. Notice of Violation item 50-440/90014-07(DRP) was issued. During this inspection period, the inspectors reviewed licensee documentation of the event, specifically the long term corrective actions committed to by the licensee in the subject LER. The inspectors verified that the training, procedure revisions, and plant modifications committed to by the licensee were completed. Based on the above reviews, the inspectors concluded that licensee corrective actions were complete and appeared adequate to prevent recurrence. This item is closed. In addition to the subject LER, the inspectors noted that Notice of Violation item 50-440/90014-07 addressed the same event and is considered closed.

e. (Closed) LER 50-440/90027-00: On September 25, 1990, an air roll test was performed on the Division 1 diesel generator while the Division 2 diesel generator was inoperable. That testing resulted in the inoperability of the Division 1 diesel generator and a facility operating license violation.

Licensee Evaluation of Cause and Corrective Actions:

Root Cause:

The cause of this event was personnel error, failure to follow procedure. The operators who performed the testing did not adhere to the "note", preceding the first step of a section, which prohibited performing that section of the procedure with the opposite division's diesel generator inoperable. Although the operators were aware of the Division 2 diesel generator being inoperable, the procedure was not directly consulted prior to the performance of switch manipulations in preparation for the air roll test. As a result, the facility operating license violation occurred.

Corrective Actions:

To prevent recurrence, the operations personnel who performed the air roll on the Division 1 diesel generator were counseled concerning the event and concerning the importance of procedural compliance. These topics were also discussed between operations shift supervisors and their operating crews. Appropriate surveillance instructions were revised to include a step to prevent the air roll of a Division 1 or Division 2 diesel generator when the opposite division diesel generator was inoperable. As part of the established requalification training program, all plant licensed operators were instructed on the lessons learned from this event.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed. The inspectors concluded that the licensee's corrective actions appeared reasonable and adequate to prevent recurrence. The licensee's performance of the air roll test on the operable diesel generator while the opposite diesel generator was inoperable was a violation of Requirement Number 4 in Attachment 2 of the facility operating license. This violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section V.G of the Enforcement Policy.

f. (Closed) LER 50-440/90035-01: On December 4, 1990, the Perry Nuclear Power Plant Architect Engineer, Gilbert/Commonwealth Inc., informed the licensee that a design deficiency may have existed within the control complex chilled water (CCCW) system. That deficiency could have resulted in the loss of the CCCW system following a seismic event with the resultant loss of chilled water to the control room emergency recirculation (CRER) system. Technical Specification 3.7.2 required that the CRER system be operable in all Operational Conditions.

Licensee Evaluation of Cause and Corrective Actions:

Root Cause:

Following the identification of this discrepancy by Gilbert, the CRER system was declared inoperable and several system operational changes were made to allow interim operation. Further evaluation of the nonsafety-related portion of the CCCW system showed that although the nonsafety-related portion of this system was not specifically qualified seismically, it was built such that it would maintain pressure integrity following a safe shutdown earthquake (SSE). A guillotine break in the piping or at the juncture of the piping and the cooling coils would not occur, as had been originally assumed, and the CRER system would remain operable following an SSE. Thus, the immediate corrective actions taken were no longer needed, and the CCCW system was restored to its original configuration. System restoration was completed on February 27, 1991.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and evaluated licensee disposition of the CCCW design deficiency. The inspectors concluded that the licensee's evaluation of this issue was thorough and appeared reasonable to assure that the CRER system would remain operable following a safe shutdown earthquake. This item is closed.

g. <u>(Closed) LER 50-440/91024-00:</u> On December 4, 1991, a Perry plant operator (PPO) performing a weekly check of the emergency service water (ESW) keepfill system discovered the keepfill system pressure reading approximately 3.5 psig. The keepfill system pressure was required to be $\geq$ 13 psig when the ESW "A" loop was in standby. The PPO checked the position of keepfill isolation valve 1P45-F720A and found it closed. The ESW "A" loop and associated loads were declared inoperable in accordance with the applicable Technical Specification action statements.

<u>Licensee Evaluation of Cause and Corrective Actions:</u>

<u>Root Cause:</u>

The mispositioning of valve 1P45-F720A was attributed to personnel error. The last authorized repositioning of 1P45-F720A occurred on November 21, 1991. Interviews of personnel performing work in the vicinity of the keepfill isolation valve did not reveal the source of the error. It was therefore assumed that the valve mispositioning was an unintentional error by an unidentified person.

<u>Corrective Actions:</u>

To prevent recurrence of a similar incident involving the keepfill isolation valve, the required valve position was changed from normally open to locked open. Additionally, all licensed and nonlicensed plant operators were to receive training on this event as part of requalification training.

<u>Inspectors Evaluation:</u>

The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed, with the exception of plant operator training which was still in progress. While conducting event followup inspection of the ESW system, the inspectors noted that the ESW "A" loop local pressure gage isolation valve was closed. With the isolation valve closed, the gage read approximately 3.0 psig, though actual system pressure was approximately 14 psig. The inspectors questioned why the pressure gage was isolated, since it provided positive local indication of ESW "A" system pressure and since the other loop's gages were not isolated. Based on discussions with the licensee it was determined that the pressure gage was normally isolated in accordance with the ESW sampling procedure and that it was only opened once a week during operator rounds. As a result of this discussion, the licensee reviewed the basis for the valve being closed and determined that it was more appropriate that it be open. Subsequently, the licensee changed the sampling procedure to leave the pressure gage isolation valve open. The inspectors concluded that the practice of leaving the pressure gage normally isolated possibly contributed to the delay in identifying the initial problem. The inspectors had no further questions concerning this event. This item is closed.

h. (Open) LER 50-440/91025-00: On December 12, 1991, the licensee identified a crack in a weld on a 3/4 inch vent line connected at a high point in the high pressure core spray (HPCS) system. As previously documented in Inspection Report 50-440/91025, Paragraph 6.b.(2), dated January 29, 1992, the inspectors previously reviewed the licensee's immediate corrective action to repair the subject cracked weld.

During the licensee's investigation into the cause for the identified weld crack, it was discovered that the weld profile was not constructed in accordance with the intended design. The intended weld profile was to have been incorporated in accordance with Engineering Change Notice (ECN) No. 22137-44-7599 dated December 17, 1984. That ECN required a full weld buildup between the system 3/4 inch socket connection and the first 3/4 inch isolation root valve. The full weld buildup was not performed and the as-built configuration was a standard fillet weld.

As documented in Inspection Report 50-440/91004, Paragraph 8.b.(5), dated May 7, 1991, the lack of a full weld buildup had been previously identified by the licensee and reported in LER 50-440/91010, dated May 2, 1991. At the time of that discovery the licensee's investigation concluded that the "full weld buildup" detail was unique to fourteen vents and drains in the reactor recirculation system. During this report period, the inspectors discussed with cognizant licensee personnel the failure of past investigations to identify the required full weld buildup on the subject HPCS vent line. Based on those discussions, the inspectors concluded that the past reviews had been performed using a reasonable data base (engineering calculation file) to ascertain the application of the "full weld buildup."

In addition to the above, the inspectors discussed with cognizant licensee personnel the planned followup corrective action discussed in the subject LER. Licensee memorandum C. Angstadt to J. Eppich, dated January 23, 1992, detailed the scope of review to assure that all "unique" double root valve weld configurations were identified. Based on the review of corrective actions completed and planned, the inspectors concluded that adequate resources were being utilized to investigate the potential for similar weld profile discrepancies. The inspectors will review the results of the licensee's investigation currently scheduled to be completed by the end of the first scheduled quarterly system outage following the Spring '92 refueling outage This item remains open.

No deviations were identified; however, two non-cited violations (NCVs) were identified.

4. Monthly Surveillance Observation (61726)

For the surveillance activities listed below, the inspectors verified one or more of the following: testing was performed in accordance with procedures; test instrumentation was calibrated; limiting conditions for operation were met; removal and restoration of the affected components were properly accomplished; test results conformed with technical specifications, procedure requirements, and were reviewed by personnel other than the individual directing the test; and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Surveillance Test No.	Activity
PTI-E22-P006	Division 3 HPCS Diesel Generator Auxiliary System Monitoring
SVI-E12-T5361-B	ECCS/LPCI B Discharge Pressure High Channel Calibration for 1E12N056B
SVI-R85-O1477	Division II Diesel Generator Calibrate Engine Temperature Recorder
SVI-R42-T5218	Performance Test of Battery Capacity Division II (Unit 2)

No violations or deviations were identified.

5. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed and/or reviewed to ascertain that activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

Specific Maintenance Activities Observed:

Work Order	Subject
92-0664	Division II Diesel Generator Starting Air Pressure Switch (Left Bank Calibration)
92-0212	PSI Muffin Fan Squealing/Stalling
91-5635	Division II Diesel Generator Camshaft Side Cover Gasket Replacement
91-4211	Emergency Service Water Pump-B Bolt Repair

No violations or deviations were identified.

6. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during this inspection period. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified tracking of Limiting Conditions for Operation associated with affected components. Tours of the pump houses, control complex, the intermediate, auxiliary, reactor, radwaste, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for certain pieces of equipment in need of maintenance. The inspectors by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping, general plant cleanliness conditions, and verified implementation of radiation protection controls.

a. Remote Shutdown Panel Walkdown

During the report period, the inspectors noted that the control switch for shutdown cooling suction valve 1E12-F006B did not have an information tag at the remote shutdown panel corresponding to the main control room panel. The F006B suction valve was danger tagged closed at the main control room switch and the local breaker was danger tagged open. The practice at Perry was to provide an information tag at the remote shutdown panel switch location to remind operators of actual plant configuration. The inspectors noted that the information tag was removed during the December 1991 forced outage, apparently while using the "B" loop of residual heat removal for shutdown cooling. Following return to full power operation, the F006B was danger tagged closed. The inspectors notified the on-shift unit supervisor of the missing information tag. The unit supervisor confirmed the need for an information tag and one was properly installed. The inspectors had no further concerns regarding the remote shutdown panel.

b. Decline in Plant Housekeeping/Cleanliness

During the course of routine plant tours, the inspectors noted a decline in plant cleanliness and housekeeping. Examples of some of the discrepancies noted are listed below:

PLANT AREA		DISCREPANCIES
Heater Bay	-	Tools, anti-contamination clothing, and oil soaked rags left adrift after maintenance on turbine driven feed pumps.
Rad Waste Bldg.	-	Pigeons nesting in overhead, droppings on floor.
	-	Floor drain screens blocked with debris.
Auxiliary Bldg.	-	RCIC room - plastic bag and oil on floor below grating, turbine insulation not properly installed, access plug for turbine not installed.

The inspectors noted that the above discrepancies were singularly of relatively little safety significance; however, they were indications of less than adequate performance. Specifically, the deficiencies were the result of inadequate post-maintenance cleanup, inattention to detail and poor housekeeping practices. Once these discrepancies were identified to the licensee, corrective action was taken. Though short term corrective action to clean up the identified discrepancies was adequate, the adequacy of the licensee's long term corrective actions to improve post-maintenance cleanup practices and general housekeeping of the plant will be documented in future inspection reports.

c. Residual Heat Removal (RHR) Train-A Inoperable

On January 18, 1992, while performing a planned surveillance test, RHR-A was declared inoperable when system pressure could not be maintained. Following closure of valve 1E12-F024A (Full Flow Test Return), the system's "keepfill" pump could not maintain adequate pressure. In response to this event, control room operators declared the applicable modes of RHR-A inoperable and complied with the Technical Specification required action statements. The cause for the low system pressure was believed to be leakage past valve 1E12-F024A due to an incomplete valve stroke during the surveillance test. The 1E12-F024A valve was to be closed on "limit switch" contacts by holding the control switch in the closed position throughout valve travel. In accordance with an engineering disposition of a known nonconformance, the 1E12-F024A was being stroked using "limit-switch" contacts instead of the "torque switch" contacts.

Following reclosure of 1E12-F024A using the "limit switch" contacts, adequate system pressure was maintained. The inspectors reviewed the licensee's investigation of the low system pressure and reviewed applicable valve electrical control drawings with the on-duty shift supervisor. Based on that review, the inspectors concluded the licensee's actions were reasonable and in accordance with Technical Specifications.

d. Loss of Offgas System Flow and Radiation Monitors

On January 31, 1992, a nonlicensed operator placed the wrong station battery on equalize charge causing a D.C. electrical system voltage spike. At the time of event occurrence, the Class 1E, Unit 1, Division 1, safety-related Battery ED1A was to be placed on equalize charge utilizing its associated battery charger located in the Control Complex.

Upon being directed to place the Unit 1, Division 1 Battery ED1A on equalize charge, the nonlicensed operator went to the Turbine Power Complex and placed the Unit 1, System A (D1A) battery (nonsafety-related) on equalize. That action resulted in tripping of the supplied nonsafety-related inverters, loss of process radiation monitors, and isolation of the offgas system. In response to the system transient, plant operators restored the Unit 1, System A, Battery D1A to "float," restored supplied inverters, restored the offgas system flow, and restored all affected radiation monitors within about 30 minutes.

As a followup to this event, the inspectors interviewed the nonlicensed operator, reviewed the applicable plant instructions, and performed a field walkdown of the battery charging evolution. Generic Electric Instruction (GEI)-0039, "Full Battery Equalizing Charge For Lead-Calcium Batteries," Revision 3, dated May 29, 1991, was the applicable instruction at the time of this event. That instruction detailed in Section 5.2 the required steps to initiate an equalize charge. The inspectors noted that GEI-0039 was a maintenance instruction which would normally be performed by maintenance personnel. However, the practice at the Perry plant was to require plant operators to perform switch manipulations on plant equipment.

Upon being given verbal direction to place the Unit 1, Division 1 battery on equalize charge, the nonlicensed operator went to the Unit 1, System A battery charger and placed the battery charger's control switch in equalize. The nonlicensed operator performed that evolution without maintenance personnel present. In addition, the applicable procedure (GEI-0039) was not used. GEI-0039 stated in Section 5.2.3 that the charging current for the Unit 1, System A battery was to be below 17.8 amperes before placing the battery charger in equalize. Normal bus load indicated at the Unit 1, System A battery charger was about 200 amperes. Therefore, failure to review and/or use the applicable instruction, while performing the equalize charge evolution, directly bypassed one of the specific administrative barriers. Technical Specification 6.8.1.a required that written instruction shall be implemented for onsite electrical systems (Reg. Guide 1.33, Revision 2, February 1978, Appendix A, Item 4.w). Contrary to the above, on January 31, 1992, Generic Electric Instruction (GEI)-0039 was not properly implemented for an equalizing battery charge on the Unit 1, Division 1 battery. This is a Violation (50-440/92002-01A(DRP)).

e. Inoperable Main Steam Isolation Valve (MSIV) Leakage Control System

On January 28, 1992, a steam leak was identified in the outboard (MSIV) leakage control system (LCS). The steam leak was through LCS isolation valves (E32-F008 and 009) into the Containment annulus (normal discharge point). In order to reduce the steam leakage, the licensee manually torqued closed the isolation valves and declared the outboard LCS inoperable entering the Limiting Condition for Operation (LCO) specified in Technical Specification 3.6.1 (i.e. 30 day LCO).

After evaluating several options, the licensee elected to manually torque the LCS isolation valves to 85 foot-pounds, verify the operability by full stroke cycling with the motor operators, and a final manual torque of 80 foot-pounds. That activity was successful in reducing the steam leak to an acceptable level and the LCS was declared operable. The inspectors reviewed the actions taken by the licensee (documented in Condition Report 92-018) and noted that system operability was demonstrated in accordance with plant administrative procedures.

f. Low Hydrogen Pressure Alarm

On February 8, 1992, a low hydrogen pressure alarm was annunciated in the control room. Shortly (30 minutes) after receipt of the low pressure alarm, hydrogen system pressure stabilized and no further rapid decreases were observed. As documented in licensee Condition Report 92-021, immediate actions included a plant walkdown of the hydrogen supply system in an attempt to identify potential leaks. The hydrogen supply tanks were located outside the Turbine building and provide makeup hydrogen to the main generator cooling system. The initial walkdown did not identify any leaks in the system. The inspectors performed a field walkdown of accessible system piping and components during the report period and no anomalies were identified. The inspectors noted that increased monitoring of the hydrogen supply system was initiated and further evaluations were being performed by the system engineers.

g. Fire Deluge Actuation

On February 13, 1992, a turbine bearing deluge initiation signal was annunciated in the main control room. At the same time the diesel and motor driven fire pumps started. In addition, a "Battery 1A DC System Trouble" annunciator was received. In response to the annunciated conditions, the plant fire brigade was dispatched to investigate the cause for the automatic deluge actuation. Fire brigade personnel identified that the deluge system had pressurized; however, the associated spray nozzle head was intact and no actual fire was present. As documented in licensee Condition Report 92-022, further investigation isolated the cause for the deluge signal to be an electrical fault in the automatic control circuit. Since the individual sensors were not accessible during plant operation, the turbine bearing deluge system was manually isolated. Appropriate compensatory actions were initiated.

h. Post Accident Sampling System

During the report period, the inspectors discussed with cognizant licensee personnel the operability of the post accident sampling system (PASS). The purpose of those discussions was to verify adequate licensee attention was directed to correct known problems. Specifically, the PASS was not capable of sampling the Containment atmosphere. The apparent reason for the inability to obtain a gaseous sample was an equipment malfunction with an eductor. Based on discussions with licensee supervision, the inspectors concluded that reasonable efforts had been underway to return the PASS to a fully operable condition. At the end of the report period, the licensee initiated Condition Report 92-027 to document the continued problems in repairing the PASS. The inspectors will continue to monitor the licensee's efforts to restore PASS to a fully operational condition.

No deviations were identified; however, one Violation was identified.

7. Onsite Followup of Events at Operating Power Reactors (93702)

a. General

The inspectors performed onsite followup activities for events which occurred during the inspection period. Followup inspection included one or more of the following: reviews of operating logs, procedures, and condition reports; direct observation of licensee actions; and interviews of licensee personnel. For each event, the inspectors reviewed one or more of the following: The sequence of actions; the functioning of safety systems required by plant conditions; licensee actions to verify consistency with plant procedures and license conditions; and verification of the nature of the event. Additionally, in some cases, the inspectors verified that licensee investigation had identified root causes of equipment malfunctions and/or personnel errors and were taking or had taken appropriate corrective actions. Details of the events and licensee corrective actions noted during the inspector's followup are provided in Paragraph b. below.

b. Details

(1) Loss of Instrument Air

On January 25, 1992, while operating at 100 percent power, an unexpected loss of instrument air header pressure occurred. At the time of event occurrence, plant operators were shifting the instrument air header "Afterfilters" to isolate a leaking drain valve. Instrument air header pressure dropped below the minimum allowed value of 90 psig for about one minute. Immediate response by plant operators was to restore the Afterfilters to the pre-event configuration which returned instrument air header pressure to normal.

The licensee initially reported this event via the Emergency Notification System (ENS) to the NRC Operations Center on January 25. The basis for the initial notification was the potential loss of the motive force (air) required for operation of both the inboard and outboard main steam isolation valves (MSIVs). However, after further review the licensee concluded that the inboard MSIVs had not been affected by the reduced instrument air header pressure. On January 29 the licensee informed the NRC Operations Center via the ENS that further review determined the subject event was not a reportable occurrence.

For this event, the inspectors reviewed the licensee's actions as documented in Condition Report 92-009, dated January 25, 1992. In addition, the inspectors interviewed the plant nonlicensed operator performing the Afterfilter shift evolution; reviewed applicable system operating instructions and drawings; and performed a field walkdown of the system components involved. The inspectors noted, based on review of system drawings and direct field observations, that the licensee's conclusion that only outboard MSIVs were affected was reasonable. Therefore, the determination that the event was not reportable was appropriate.

The inspectors noted that the cause for the loss of instrument air header pressure was an incorrect valve manipulation performed by the nonlicensed operator. The individual performing the Afterfilter shift evolution neglected to bring the applicable instruction to the work station. When performing the evolution from memory, the instrument air supply to the outboard MSIVs was isolated. System Operating Instruction (SOI)-P51/52, "Service and Instrument Air Systems," Revision 6, Paragraph 5.4 detailed the correct valve manipulation for shifting Afterfilters.

Technical Specification 6.8.1.a required that written instructions shall be implemented for the instrument air systems (Reg. Guide 1.33, Revision 2, February 1978, Appendix A, Item 4.v). Contrary to the above, on January 25, 1992, SOI-P51/52 was not properly implemented for shifting instrument air Afterfilters. This is a Violation (50-440/92002-01B(DRP)).

(2) Loss of Emergency Offsite Facility

On February 18, 1992, at about 2:30 a.m., while operating at 100 percent power, the emergency offsite facility (EOF) was declared inoperable. An electrical fire in a power supply inverter required isolation of both normal and alternate electrical inputs.

With the cause of the fire (limited to a transformer) unknown, the shift supervisor directed that the EOF remain de-energized until an investigation concluded it was safe to energize the EOF from its alternate source. Subsequently, at about 1:00 p.m. EOF electrical power was restored from its alternate source.

The inspectors performed a walkdown at the location of the electrical panels in the EOF. The inspectors noted damage was isolated to the power supply inverter. Further, the inspectors noted the licensee had initiated Condition Report 92-024 to document this event and to document delays in obtaining access to the EOF electrical switchgear room.

The licensee informed the NRC Operations Center of this event via the ENS initially at about 4:00 a.m. on February 18. A followup notification was made by the licensee at about 1:00 p.m. on the same day notifying restoration of EOF electrical power.

(3) Loss of Containment Integrity

On February 26, 1992, at about 10:30 a.m. while operating at 100 percent power, the licensee identified a loss of containment integrity. While performing local leak rate testing of a containment inboard vacuum breaker check valve, concurrent work activities on the associated outboard motor-operated butterfly valve were commenced. Upon review of the work package by a unit supervisor, an initial conclusion was made that the inboard check valve was not defined as a "manual valve." Therefore, the Action statement of Technical Specification 3.6.4 was entered requiring the plant to be in HOT SHUTDOWN within the next 12 hours.

No actual power reduction was made since the work being performed on the outboard containment isolation butterfly valve was suspended and that valve was locked closed. That action complied with the Limiting Condition for Operation of Technical Specification 3.6.4.

The licensee informed the NRC Operations Center of this event via the ENS at about 6:30 p.m. on February 26. At the end of this report period, the licensee was evaluating this event to determine if an actual loss of containment integrity occurred. The results of that evaluation were to be documented in licensee Condition Report 92-031. The inspectors will document their review of the licensee's evaluation in a future inspection report.

No deviations were identified; however, one violation was identified.

8. Evaluation of Licensee Self-Assessment Capability (40500)

a. On-Site Review Committee

During the report period, the inspectors observed on-site review committee meetings to evaluate that organization's effectiveness. For the meeting attended, the inspectors considered the following attributes: degree of plant management involvement and/or domination of discussions; if constructive discussion occurred; if the majority of the committee consistently voted the same as the chairman; if the committee was biased toward operation or safety; and, if the committee used design basis, Updated Safety Analysis Report (USAR), or vendor technical manuals for their determinations in addition to the Technical Specifications.

In preparation for the attended meetings, the inspectors reviewed draft submittals of items that were submitted for the on-site review committee's approval. Items presented to the on-site review committee included safety evaluations, temporary changes to procedures, setpoint change requests, procedural revisions, and design change packages.

During this report period, the following on-site review committee meeting was observed by the inspectors:

Meeting No.	Date
92-013	02/06/92

For the meeting observed, the inspectors concluded that the function of the on-site review committee was effectively implemented.

No violations or deviations were identified.

9. Plant Status Meeting (30702)

NRC management met with licensee management on February 25, 1991, at NRC Region III office in Glen Ellyn, Illinois. Personnel attending that meeting are designated by (#) in Paragraph 1 of this report. The purpose of the meeting was to discuss the licensee's total quality process, the Perry 5-year plan, and an outage overview covering shutdown risk and specific shutdown issues. At the conclusion of the meeting, NRC management acknowledged the licensee's efforts and planned activities.

10. Items For Which A "Notice of Violation" Will Not Be Issued

During this inspection, certain activities, as described above in Paragraphs 3.c and 3.e, appeared to be in violation of NRC requirements. However, because the NRC wants to encourage and support licensee initiatives for self-identification and correction of violations, the violations are not being cited because the criteria specified in Section V.G of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C, (1991)), were satisfied.

11. Exit Interviews

The inspectors met with the licensee representatives denoted in Paragraph 1 throughout the inspection period and on February 27, 1992. The inspectors summarized the scope and results of the inspection and discussed the likely content of the inspection report. The licensee did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.