U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Centerior Service Company
Facility:	Perry Nuclear Power Plant
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EXECUTIVE SUMMARY

Perry Nuclear Power Plant, Unit 1
NRC Inspection Report 50-440/96-05

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of announced inspections by engineering specialists who inspected the licensee's response to Generic Letter 89-10, "Safety-Related Motor-Operated Valve (MOV) Testing and Surveillance" (2515/109).

Operations

- The operators performed well in response to a feedwater transient (Section O1.2).

- Equipment deficiencies identified by the inspectors indicated that appropriate personnel did not always identify readily observable equipment deficiencies or, for those that were identified, had not communicated the deficient plant conditions to appropriate plant personnel. After the inspectors reported the equipment deficiencies, the licensee's reactions and followup actions to the reported conditions were prompt and appropriate (Section O2.1).

- Two events associated with the plant's electrical systems were caused by operators not adequately considering their plans before taking actions. One event resulted in a non-cited violation and could have been avoided if the unit supervisor had heeded questions from operators (Section O4.1).

- Overall, the licensee used a variety of self-assessment techniques to identify issues that required corrective actions. However, the inspectors identified other deficient plant conditions. This indicated that not all personnel utilized the licensee's self-assessment identification techniques (Sections O2.1, O7.1, M2, and F5).

Maintenance

- Activities were conducted in a professional manner, tagouts were appropriately completed, engineering and management involvement was apparent. Licensee personnel aggressively pursued corrective actions for previously identified weaknesses in work planning and timely execution of work (Section M1.1).

- The licensee developed a program implementing the NRC maintenance rule prior to the rule deadline (Section M3.1).

- Failure to promptly communicate potential problems with containment vacuum breaker valve indications resulted in a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" (50-440/96005-02) (Section M4.1).

- A maintenance self-assessment, started late in the inspection period, had potential for identifying specific areas for improvement (Section M7.1).

Engineering

- The licensee identified that a modification had altered the operation of the RCIC system in a way that had not been conveyed to the operators (Section E1.1).

- Regarding the MOV program:

  GL 89-10 program documentation and test data provided an adequate basis to conclude that all GL 89-10 program MOVs would perform their intended safety functions under design-basis conditions (Section E2.1).

  Perry had a capable technical MOV staff with a well organized and well documented GL 89-10 program (Section E2.1).

  The MOV tracking and trending program was considered a strength (Section E2.1.9).

  Self-assessments in the MOV area provided good technical findings and were beneficial in improving the MOV program (Section E7.1).

- The licensee responded conservatively and aggressively to transformer failures (Section E2.2).

Plant Support

- The licensee continued to effectively implement the radiological control program at the station. The licensee's program for radioactive material control was being adequately implemented; however, a lack of understanding of the program requirements existed among the general work force and program improvements had not been implemented (Section R1.1).

- The filtered ventilation program was determined to be effectively implemented. The radiation monitoring program was being adequately implemented; however, licensee identified that reliability problems existed with the radiation monitoring system (Sections R2.1 and R2.2).

- The licensee's response to a bomb report was prompt, thorough, and conservative (Section S4.1).

- The licensee determined that a number of motor operated valves may not be capable of performing their safety function under certain control room fire scenarios. The licensee submitted a Licensee Event Report and was developing methods to further evaluate this problem (Section F2.1).

Report Details

Summary of Plant Status

At the beginning of the inspection period the plant was in a forced outage due to the earlier failure of the auxiliary transformer. The plant was started up on June 10 and the main generator was synchronized to the grid on June 11. Power was increased and the plant operated at full power until July 11, when the "A" Reactor Feedwater Pump Turbine (RFPT) tripped and the plant automatically reduced power to about 78%. Following recovery of the "A" RFPT on July 12 the plant operated near full power for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations continued to be professional and safety-conscious.

O1.2 Reactor Feedwater (FW) Pump Turbine Overspeed Trip

a. Inspection Scope (71707, 92901)

On July 11, 1996, at 5:34 a.m., with the plant at full power, the "A" Reactor Feedwater Pump Turbine (RFPT) tripped on overspeed. The inspectors reviewed records of the transient, inspected plant equipment, observed equipment maintenance, and interviewed plant personnel.

b. Observations and Findings

When reactor water level dropped to level 4, the plant responded as expected by automatically reducing power to about 78% and starting the motor driven feedwater (MDFW) pump. Early in the transient # 4 FW Heater isolated due to water level control problems. Operations personnel promptly restored the FW heater and stabilized the plant without further incident. Reactor water level was restored to normal operating level by the remaining steam driven FW pump and the MDFW pump. A reactor engineer was called to the plant and promptly verified that the reactor power and core flow relationship did not require an immediate power or flow change. He also verified that power could be increased to match the available FW capacity. Maintenance and engineering personnel later determined that the overspeed trip had been caused by an electronic failure in the speed governing circuit.

c. Conclusions

The operators performed well in response to the plant transient. The plant equipment responded well to the significant reduction in feedwater to the reactor vessel. Operations was promptly and appropriately supported by maintenance and engineering personnel.

O2 Operational Status of Facilities and Equipment

O2.1 Equipment Deficiencies not Identified by the Licensee

a. Inspection Scope (71500, 71707, 92901)

During the inspection period the inspector's observed that management had emphasized improved communications related to routine plant inspections and followup. However, the inspectors identified several deficient plant material conditions that had not been effectively communicated to the appropriate licensee personnel.

b. Observations and Findings

On July 11, when the "A" Reactor Feedwater Pump Turbine (RFPT) tripped on overspeed, the MDFW pump started automatically. Both the MDFW pump and RFPT, although not safety-related, were important equipment for protecting the reactor core during some postulated accidents. While the MDFW pump was running, the inspectors noted an oil leak on the motor and brought it to the attention of an engineer in the vicinity and the shift supervisor. The inspectors also identified a high vibration on the lube oil sump cover of the "A" RFPT after it had been restarted. The shift supervisor determined that the main lube oil pump was causing the vibration and the inspectors confirmed that the vibration levels were reduced to normal after the licensee had shifted to the auxiliary lube oil pump. The shift supervisor also informed the inspectors that he planned to discuss the observed conditions with his nonlicensed operators to clarify his expectations for the identification and reporting of abnormal plant conditions.

The next week the inspectors determined that personnel working on the MDFW pump motor had not received a detailed description of the oil leak. The inspectors also encountered a technician who was looking for a lube oil pump to take vibration readings on, but he did not know which pump.

On June 12, the inspectors identified an oil leak that had sprayed from the inlet flange of the Division 1 Emergency Diesel Generator (EDG) lube oil cooler. Following discussions with the shift supervisor and system engineer, it was found to have been only observable and distributed when the high volume room ventilation fan was running. The leak had been previously identified, however the work request had been cancelled for unknown reasons. The inspectors observed the "fix-it-now" team correct the leak by tightening the flange bolts.

On July 11, the inspectors questioned the shift supervisor about a deficiency tag on an annunciator window for one of two local control panels for the safety-related drywell hydrogen control compressors. The deficiency tag indicated that a normally lighted annunciator enclosure had been degraded by heat from the annunciator lamps. In response to the inspectors' questions, the shift supervisor determined that there were additional similar problems with annunciator windows. The inspectors verified later that the annunciators windows had been repaired.

On July 15, the inspectors notified the shift supervisor and the system engineer of a black oily residue on the drain funnel for the air receiver common drain line in the Division II EDG room, with a similar residue spattered on the surrounding area. Although it had no impact on EDG operability, this abnormal condition was clearly visible and it should have been identified as an equipment deficiency.

On July 22, the inspectors observed water leaking onto the floor from the hotwell pumps. The inspectors notified the duty radiation protection technician, who had not been informed of the leak. The licensee determined that the water was not radioactively contaminated.

Throughout the inspection period, the inspectors observed numerous other deficiencies that had been identified by licensee personnel from various organizations. The inspectors also noted that maintenance activities were slowly improving plant materiel condition.

c. Conclusions

Although the conditions observed did not have any impact on equipment operability, the fact that they were identified by the inspectors indicated that plant personnel, including non-licensed operators, health physics technicians, fire watches, and managers who perform housekeeping inspections had not always identified the conditions or kept appropriate personnel fully appraised of deficient plant conditions. Many other deficiencies identified and addressed by the licensee from various organizations indicated that this problem was limited. Communications through the organization to personnel who followed up on the MDFW pump oil leak and the RFPT vibration were weak. The deficiency tag on the hydrogen control compressor control panel did not address the extent of the deficient conditions. The licensee's reactions to the reported conditions were prompt and appropriate, as were their follow up actions.

04 Operator Knowledge and Performance

04.1 Operator Errors Affected Operation of the Electrical System

a. Inspection Scope (71707, 92901, 93702)

On July 3, a nonlicensed operator inadvertently tripped open a motor control center (MCC) feeder breaker while instructing an operator

trainee. Later the same day a safety-related direct current (DC) system was incorrectly configured. In both cases, the inspectors responded to the control room and/or associated spaces to verify that the operators had taken appropriate actions. In addition, the inspectors reviewed related procedures, maintenance history, and evaluations; and interviewed the operations manager, superintendent and individuals involved.

O4.1.1 Inadvertent Trip of an MCC Feeder Breaker

b. Observations and Findings:

The nonlicensed operator and the trainee stated that the operator had placed his hand on the face of the breaker over the trip button, but had not pushed it in, and that they were surprised that the breaker had tripped. This had occurred while the operator was showing the trainee how a breaker would be tagged out. The nonlicensed operator was experienced and the trainee was an experienced engineer who was in the SRO license training program. The inspectors independent review of this event did not reveal any equipment conditions or configurations, such as the trip button protruding from the face of the breaker, that could have caused the trip to occur. The breaker that had tripped was reset and tripped several times after the event with no problems. The licensee indicated that on rare occasions that this type of breaker would trip without the button being depressed and that the only postulated explanation was that it may not have been fully reset. The licensee considered such breaker trips to be isolated random occurrences with no available corrective actions because of the rarity of the occurrences and the fact that once a breaker had tripped with minimal or no known force it had not been possible to identify the trip mechanism's prior configuration.

O4.1.2 Electrical System Placed in Incorrect Configuration

b. Observations and Findings:

On the evening of July 3 the unit supervisor (US) directed the operating crew to cross tie the Unit 1 and Unit 2 direct current (DC) electric supply busses for Division 2. The US had misread the system operating instruction (SOI) and did not declare the Unit 1 bus (ED-1-B) inoperable as required by the SOI. Three other operators had asked the US about the appropriate status of Bus ED-1-B, but he assured them that he had checked the procedure and that there was no problem. The other operators did not review the procedure or ask the US to further explain his conclusion, and the US did not recognize the questions as indications that he might have misread the procedure. The more experienced shift supervisor (SS) was aware that his US had directed the bus lineup change, but did not review the details with him. The US who misread the SOI had been a US for about 3 months and before that he had been a licensed reactor operator and a nonlicensed operator.

SOI-R42 (Div 2), "DIV 2 DC DISTRIBUTION, BUSSES ED-1-B AND ED-2-B: BATTERIES, CHARGERS, AND SWITCHGEAR," Revision 0, Subsection 7.2.2, Step 2, directed Bus ED-1-B be declared inoperable. The US stated that he thought that the SOI required Bus ED-2-B be declared inoperable instead of Bus ED-1-B. Declaring Bus ED-2-B inoperable had no impact on plant operation since it was a Unit 2 bus and all its loads had been isolated for MCC cleaning. The US's failure to declare Bus ED-1-B inoperable was a failure to follow procedure. This was a violation (50-440/96005-01) of Technical Specification 6.8.1 which required that written instructions be implemented for changing modes of operation of the DC system. The potential safety consequences of this violation were minor because the licensee had already fortuitously isolated the loads from Bus ED-2-B and the indication that had not been isolated had not threatened the operability of Bus ED-1-B.

As corrective actions the licensee provided the US and SS with formal coaching and counseling. The licensee also promptly trained each operating shift on initial lessons learned from the event. The inspectors reviewed the training with the operations manager and verified that the importance of communications follow through and feedback had been emphasized and that expectations had been reinforced for responding in appropriate detail to questions. The operations manager also recognized that he needed to continue to insure that the organizational hierarchy did not become a barrier to questioning attitudes, requests for detailed explanations, and appropriate feedback. The inspectors initially reviewed this event on July 5 and verified that the DC busses had been properly restored. The inspectors reviewed the licensee's draft Human Performance Enhancement Systems (HPES) evaluation of the event. The final report had not been completed at the end of the inspection period. The licensee also planned to review the completed HPES evaluation for any additional corrective actions. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.8.1 of the NRC Enforcement Policy (60 FR 34380, June 30, 1995).

c. Conclusions

The operators who caused both events did not adequately consider their actions before taking them. The operators who questioned the US displayed an appropriate questioning attitude but did not follow through on their questions. The licensee's initial response to the events was prompt and appropriate.

07 Quality Assurance in Operations

07.1 Licensee Self-Assessment Activities (40500)

a. Inspection Scope

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

- Routine Plant Operations Review Committee (PORC) Meeting
- Special PORC Meeting prior to startup from the forced outage caused by the failure of the auxiliary transformer
- "Mini Integrated Performance Assessment Process (IPAP)" exit meeting
- Potential Issue Forms (PIF)

b. Observations and Findings

The meetings were attended by appropriate personnel and there was substantive discussion of the topics covered. More than 300 PIFs were written by a variety of personnel who represented a wide cross section of plant organizations. Many of the PIFs demonstrated a good questioning attitude, provided valuable insights into methods of improving performance, or challenged accepted practices. For example:

- QA review of implementation of the operations fuse policy (PIF 96-2475)
- An engineer questioned a part of the recently implemented improved technical specifications (PIF 96-2540)
- A shift supervisor questioned the material condition of a Unit 2 electrical cubicle, even though the condition had been accepted for years (PIF 96-2522)

Contract assessment specialists and licensee personnel used the NRC IPAP inspection module as a basis for a self-assessment of plant activities that was primarily focused on operations, maintenance, and corrective actions. Important issues, such as a reluctance by some individuals to write a PIF, were developed for corrective actions.

c. Conclusions

The licensee used a variety of self-assessment techniques to identify issues that required corrective actions. However, the inspectors observed other deficient plant conditions (Sections O2.1, M2, and F5) that had not been identified. This indicated that not all personnel consistently utilized the licensee's self-assessment techniques.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703, 61726, 92902)

The inspectors observed the conduct of maintenance and surveillance testing during routine plant operation and forced outage activities.

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

The inspectors observed some examples of weaknesses in communications and work planning situations (see Section M4.1). Similar weaknesses have been identified in the past. Licensee managers emphasized the risk significance of a scheduled reactor core isolation cooling (RCIC) maintenance outage. As a result, the licensee identified problems with a modification that was planned to be completed during the outage. Licensee managers concluded that all required materials would not be available and deleted the work from the outage the week before the outage. The remaining work was planned for completion within 32 hours and was actually completed within 44 hours. The inspectors observed the licensee conduct a thorough critique of the outage with good preparation for the critique by the system engineer and broad participation in the critique, including managers who were present.

The inspectors observed all or portions of the following surveillance tests:

SVI M17-T410A	Containment Vacuum Breaker Functional
SVI C51-T0027	Average Power Range Monitor Trip Functionals
SVI R42-T5221	Division III Quarterly
SVI P53-T6305	Air Lock Seal Test
TXI 248	Control Room Heat Load Train A
TXI 249	Control Room Heat Load Train B

Surveillance procedures were appropriate for testing conditions and correctly identified parameters needed to verify proper equipment performance. Test personnel followed the procedures during the observed testing and equipment problems were promptly identified and resolved.

The inspectors observed the performance of TXI-249, which was the first performance of a new surveillance which was going to be required by the improved technical specifications. The test provided a more detailed verification of the cooling function of the control room emergency ventilation system. The licensee's pre-test briefing was thorough with broad participation in the discussion of the expected equipment performance and potential problems. The responsible system engineer was well prepared for the briefing and actively monitored test performance. The equipment performed as required by the improved technical specifications and the UFSAR.

c. <u>Conclusions</u>

All activities observed were conducted in a professional manner, tagouts were appropriately completed, engineering and management involvement was apparent. Licensee personnel aggressively pursued corrective actions for previously identified weaknesses in work planning and timely execution of work.

M2 Maintenance and Material Condition of Facilities and Equipment

a. Inspection Scope (71707, 92720)

The inspectors conducted plant walkdowns throughout the inspection period that identified plant material condition problems. The inspectors also reviewed other licensee-identified problems.

b. Observations and Findings

During maintenance activities the licensee discovered foreign materials in two nonsafety-related pumps. A piece of a metal file was found in the RCIC water leg pump coupling and an extra set screw was found loose in a control rod drive water pump which had been refurbished off-site. Each case was documented for further evaluation.

A lack of adequate lighting on the refuel floor in containment delayed maintenance activities on a containment vacuum breaker (see Section M4.1). Also, the inspectors identified a rubber scaffolding pad on the containment shell that had been left from the recent refueling outage.

Earlier in the inspection period, during an NRC management inspection of the plant, NRC managers found duct tape on a piping flange associated with a residual heat removal valve in containment and an abnormally high quantity of oil from leaks on the Division I and II EDGs.

The inspectors also identified several equipment deficiencies discussed in Sections O2.1, M2, and F5.

c. Conclusions

The licensee usually identified and corrected materiel condition deficiencies. Personnel were sensitive to the importance of documenting problems with foreign material exclusion. However, some obvious deficiencies identified by the NRC indicated that some personnel had not taken appropriate actions to identify and correct deficiencies.

M3 Maintenance Procedures and Documentation

M3.1 Maintenance Rule Program Implementation

a. Inspection Scope (62703)

On July 3, 1996, the licensee implemented its program for complying with the NRC maintenance rule. The inspectors reviewed various documents associated with the maintenance rule, interviewed personnel, and observed administrative controls of maintenance activities to confirm implementation of the licensees maintenance rule program.

b. Observations and Findings

Revision 2 of procedure PAP-1125, "Monitoring the Effectiveness of the Maintenance Program Plan," became effective on July 3, 1996. The licensee trained personnel on the impact of the maintenance rule and provided informal reference material to familiarize personnel with the maintenance rule requirements. The inspectors observed that corrective actions had been taken as a result of a maintenance rule implementation self assessment. The inspectors verified that the licensee had developed a list of systems subject to the maintenance rule and had evaluated past performance of those systems. The inspectors also verified that licensee managers emphasized the maintenance rule implementation goal of maximizing availability of equipment within the scope of the rule.

c. Conclusions

The licensee developed a program implementing the maintenance rule prior to the deadline established in the rule. A strong effort was made to familiarize personnel with the requirements of the program and managers were sensitive to the risk implications of maintenance activities.

M4 Maintenance Staff Knowledge and Performance

M4.1 Failure to Promptly Identify a Condition Adverse to Quality

a. Inspection Scope (62703, 92902)

The inspectors observed troubleshooting and rework activities to correct dual position indication in the control room for containment vacuum breaker valve 1M17-F010. The inspector later followed up on the completion of the associated Work Order 960002479.

b. Observations and Findings

On July 22, the inspectors observed the work process, including a thorough supervisory briefing and technician review of the package. The briefing took place about 2 hours after the valve had been taken out of service by operations. Additionally, as a result of an earlier job walkdown, the work package stated that the work area was poorly lighted. Even though this was noted in the work package, there was an additional hour delay in starting work due to the need for temporary lighting. Once the vacuum breaker was opened, the inspectors independently verified that the associated containment isolation valve was closed, which isolated the penetration from outside atmosphere.

In troubleshooting the vacuum breaker valve the technicians identified that a linkage arm connecting the position indicator and the valve was bent, preventing accurate position indication. The technicians stated that this condition had occurred before and resulted from local leak rate testing (LLRT) of the vacuum breaker valves during plant refueling outages.

The inspectors discussed the situation with the maintenance technicians and supervisors, operations management, and the system engineer and questioned why a PIF was not written. Licensee personnel acknowledged that communication had not occurred promptly for the problem with the containment vacuum breaker and the potential for similar problems with the other vacuum breakers. Subsequently, two PIFs were written to address the issue. PIF 96-2573 was written on July 24 and taken to the control room the same day. PIF 96-2578 was written on July 23 and taken to the control room on July 25.

c. Conclusions

Based on the information that maintenance personnel had about the problem related to the vacuum breaker indications, a PIF should have been written promptly on July 22 and taken to the control room the same day for review and evaluation. Delaying the initiation of the PIF needlessly delayed the start of the corrective action process. Failure to promptly communicate the potential problems with containment vacuum breaker valve indications resulting from a known deficiency in the performance of the associated LLRT was a violation (50-440/96005-02) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," which requires that measures be established to assure that conditions adverse to quality such as deficiencies are promptly identified and corrected.

M7 Quality Assurance in Maintenance Activities

M7.1 Maintenance Self Assessment

a. Inspection Scope (40500)

While observing maintenance activities associated with a containment vacuum breaker (see Section M4.1), the inspector observed a two person team associated with a maintenance self assessment program. The inspectors also reviewed the reporting of findings associated with the work activities.

b. Observations and Findings

The objective of the self-assessment was to identify specific areas needing improvement in the Maintenance Section. The self-assessment involved seven teams that would observe work activities over a 2 week period. The team observed by the inspector consisted of a maintenance supervisor and a plant helper. Both team members demonstrated understanding of the objective and an inquisitive perspective toward ongoing maintenance activities. The team members had several findings which were reported collectively with the other teams at the end of the work day.

c. Conclusion

This portion of the inspection occurred close to the end of the inspection period. Therefore, overall conclusions would be inappropriate however, the self-assessment efforts had potential for identifying areas for improvement in maintenance activities.

III. Engineering

E1 Conduct of Engineering

E1.1 Modification Alters Safety-Related System Response

a. Inspection Scope (37551, 40500)

The inspectors evaluated a self-identifying concern with a modification to the Leakage Control System (LCS) completed during the recent refueling outage (RFO5).

b. Observations and Findings

During a review of simulator operations the licensee observed that the Reactor Core Injection Cooling (RCIC) system isolated during a simulated loss of electrical power to the General Electric (GE) Nuclear Measurement Analysis and Control (NUMAC) steam leak detection monitor equipment. The modification that installed the NUMAC equipment had been submitted by the licensee to the NRC for review and a safety evaluation review had been written. Prior to installation of the NUMAC equipment, RCIC did not isolate on a loss of power accident. The licensee found that a relay which prevented RCIC isolation in the previous design had been removed when the NUMAC design was installed. The licensee concluded that RCIC remained operable and capable of performing its designed function. NRR and Region III independently reviewed the licensee's operability determination and concluded, based on the initial information available, that the licensee was in compliance with the Technical Specifications. The inspectors also determined that the licensee had written a UFSAR request to be submitted as part of the routine update submittal. The licensee had not completed its investigation at the end of the inspection period. The licensee planned to include a review of other plant modifications where similar concerns may exist.

c. Conclusions

The changes introduced by this modification were of concern because the RCIC system, a safety-related system required by technical specifications, would no longer perform in the manner that operators were trained to expect. This is an Unresolved Item (50-440/96005-03) pending the inspectors' review of the licensee's investigation.

E2 Engineering Support of Facilities and Equipment

E2.1 Generic Letter 89-10 Program Implementation

a. Inspection Scope (TI 2515/109)

This inspection evaluated the process for qualifying the design-basis capability of motor-operated valves (MOVs) and closure of GL 89-10 review. The inspection concentrated on MOVs that were tested under static or low differential pressure (dP) conditions. A valve sample that included several program closure methods used by Perry was selected to verify design-basis capability. The inspectors reviewed design-basis documents, thrust calculations, test packages, and engineering evaluations for the MOVs listed below:

1E12-F024A	Residual Heat Removal "A" Test Valve to Suppression Pool
1E12-F0028B	Containment Spray "B" First Shutoff
1E12-F0042B	Low Pressure Core Injection "B" Injection
1G33-F0040	Reactor Water Cleanup Return Header Inboard Isolation
1M51-F0090	Combiner Gas Dry Well Purge Inboard Isolation
1P54-F0340	Containment CO_2 Supply Isolation
0P42-F0295A	Control Complex Chiller "A" Crosstie Isolation
1M17-F0025	Containment Vacuum Relief Isolation

The inspectors also reviewed other Perry documentation used to justify program assumptions, such as stem friction coefficients and load sensitive behavior. Further, the inspectors reviewed documentation related to program issues, such as periodic verification, post-maintenance testing, and program audits.

b. Observations and Findings

E2.1.1 Program Scope Changes

A previous inspection report (50-440/95006) questioned the appropriateness of allowing manual versus automatic operation of certain spent fuel pool cooling system valves that the licensee had previously removed from the program. The NRR staff found that manual operation of the valves after a design-basis accident was acceptable, and therefore the valves do not need to be dynamically flow tested in accordance with GL 89-10.

Since the previous inspection, seven valves were removed from the program. The inspectors determined that two valves, 1P22-F015 (Mixed Bed Water Drywell Supply Isolation) and 1P51-F652 (Drywell Outboard Isolation Valve for Service Air System), were inappropriately removed since surveillance stroke-time testing was performed without declaring the valves inoperable. The NRC staff position is that an MOV placed in a position that prevents the safety-related system (or train) from performing its safety function must be capable of returning to its safety position, or the system (or train) must be declared inoperable.

The licensee opted to keep both valves out of the program and plans to declare the valves inoperable during the surveillance testing.

With the removal of these valves, the program scope consisted of 154 MOVs including; 76 gate, 34 globe, and 44 quarter-turn (butterfly) valves. From this population, the licensee was able to dynamically test 64 MOVs.

E2.1.2 MOV Sizing and Switch Settings

Perry's thrust calculations utilized the industry's standard thrust equation to determine thrust requirements for rising stem gate and globe valves. For rising stem MOVs that had been dynamically tested, measured nominal valve factors were used. Non-dynamically tested gate valves relied on the application of test data that was obtained from in-plant testing, testing performed by EPRI, or other industry sources. The licensee used a 15% bias margin to address MOV load sensitive behavior (see below) for rising stem MOVs that were not dynamically tested. A bias margin of 10% was included to account for potential future valve degradation. Minimum thrust requirements for setting of actuator torque switches were adjusted to account for diagnostic equipment inaccuracy and torque switch repeatability.

E2.1.3 Valve Factors

Measured valve factors (VF) were used for dynamically tested rising stem MOVs. Perry had divided MOVs into groups based on valve manufacturer, valve type, and ANSI pressure class rating. Some groups had been divided into subgroups based on valve size. Perry used in-plant data first, and then data from industry testing for justification of VFs for non-dynamically tested MOVs.

Assumed VFs used in the design thrust calculations were generally adequately justified for the 13 rising stem valve groups, although some weaknesses were noted as discussed below.

- Valve Group 6 - Close Direction (6" Borg Warner 1500# Gate Valves): This sub-group consisted of five MOVs; none were dynamically tested. Perry had applied a 0.50 VF based on EPRI performance prediction methodology (PPM) results performed on two MOVs (1G33-F001 and 1G33-F004) that could potentially experience steam blowdown conditions due to postulated line breaks outside containment. However, the inspectors noted that the identified design-basis conditions for 1G33-F039 and 1G33-F040 varied from the system parameters used by the PPM analysis for 1G33-F001 and 1G33-F004. Therefore, there was some uncertainty that the existing PPM data was applicable to 1G33-F039 and 1G33-F040. The lowest margin valve in this group (1G33-F040) had an available VF of 0.618, after accounting for diagnostic equipment uncertainty, torque switch repeatability, load sensitive behavior, and margin for valve degradation. Perry personnel were evaluating the potential for revising the existing PPM analysis using the

alternate system parameters. Further, this valve was scheduled to be modified during the next scheduled outage as part of Perry's margin improvement program.

- Valve Group 3 (4" Anchor Darling 900# flex-wedge gate valves): This group had only two MOVs (1E22-F012 and 1E51-F059). The inspectors noted that only 1E51-F059 was dynamically tested in the closed direction, which yielded a VF of 0.28. The inspectors noted that the closed VF justification for this group did not meet the intent of the GL 89-10 Supplement 6 recommendation to dynamically test 30% of a valve group (no less than two). The VF results from at least two MOVs are needed to have reasonable assurance that MOVs in the group perform in a similar manner. Perry had applied a 0.45 VF for 1E22-F012 and had also determined that, after accounting for diagnostic equipment uncertainty, torque switch repeatability, load sensitive behavior, and a 10% margin for valve degradation; the current settings for 1E22-F012 could support a VF of 0.552. Open stroke dynamic testing of 1E22-F012 had resulted in an open VF of 0.38. While the inspectors did not identify any operability concerns with this valve group, as part of the ongoing periodic verification program, Perry will continue to evaluate applicable VF information to confirm the close VF assumptions used for this group.

- Similarly, the VF justification for some subgroups of Groups 4 and 6 (4" and 12" Borg Warner 300# gates, 4" and 6" Borg Warner 1500# gates, and 12" Borg Warner 1500# gates) relied either on a single dynamic test or a single EPRI test and therefore the subgroup did not meet the recommendations of GL 89-10, Supplement 6. Although these valves were acceptable based on adequate capability margin, the licensee will continue to evaluate applicable VF information, particularly for these valve groups, as part of their periodic verification program.

- The inspectors noted that Perry had not incorporated the tested open VF for 1E12-F028B into the thrust calculation. The inspectors also noted that this higher VF should have been used in the thrust calculations for the three other MOVs in Valve Group 4. Perry personnel agreed and initiated a design change control document to correct these calculations. Because of the small difference in VFs, the change will have little effect on the available thrust margin. The inspectors considered the licensee's actions to correct this issue to be acceptable.

E2.1.4 <u>Load Sensitive Behavior</u>

Rising-stem MOVs that were dynamically tested were evaluated using the measured load sensitive behavior margin. Evaluation of non-dynamically tested MOVs relied on analysis of Perry's load sensitive behavior data that determined the mean and the standard deviation of the test results. Based on Perry's use of FelPro N5000 stem lubricant, a load sensitive behavior margin of 15% was used in the thrust calculations. The

inspectors found the licensee's assumptions for gate valves to be adequate. However, Perry determined that the globe valves had an average load sensitive behavior margin of 15.79%, with a standard deviation of 12.02%. Based on this performance, the inspectors considered the licensee's assumed load sensitive behavior margin of 15% unacceptable for globe valves. Perry personnel pointed out that all globe valves had been dynamically tested with actual load sensitive behavior margins incorporated into the current thrust calculations. However, Perry personnel agreed that the program documents should be revised to include a globe valve load sensitive behavior assumption that better represented existing plant data. Based on implementation of the measured load sensitive behavior test data, the inspectors considered the licensee's globe valve load sensitive behavior margins to be adequate.

E2.1.5 Stem Friction Coefficient

The inspectors found the licensee's open stem friction coefficient (SFC) assumption of 0.20 to be adequate based on test data reviews. The close SFC assumption of 0.15 was acceptable based on available margins but the test data was not as well supported statistically. Perry is expected to continue to review SFC performance under the tracking and trending program and under the periodic verification program to further confirm the SFC assumptions.

E2.1.6 Torque Switch Repeatability

The inspectors considered Perry's methods for addressing torque switch repeatability to be adequate for program review closure. Perry's program documents typically followed the guidance contained in Limitorque's Maintenance Update 92-2; however, in cases where more margin was desired, Perry used values based on 200 diagnostic plant tests. The performance of each actuator size (for a given spring pack and dial setting) was analyzed statistically to determine greater than 97% confidence values for each actuator. The results from this study were applied to only 13 gate and globe valves.

E2.1.7 Butterfly Valve Testing

Design-basis capability for butterfly valves was appropriately based on 27 dynamic diagnostic tests with the untested valves grouped in accordance with GL 89-10, Supplement 6, requirements. Six untested butterfly valves were either in very low dP water conditions (less than 16 psid) or in air systems (less than 1 psid). With the exception of two valves, analytical margins for all butterfly valves were greater than 30%. The remaining two valves had adequate margins of 14% and 27%.

E2.1.8 Periodic Verification of Design-Basis Capability

Perry planned to statically test all MOVs at least once every six fuel cycles with increased frequencies based on valve margin and risk priority. Dynamic testing of valves will also be based on valve margin

and valve risk priority. Eleven valves were scheduled for periodic verification (PV) dynamic testing during fuel cycle 6. Further, as a minimum, Perry intends to dynamically test one gate, one globe, and one butterfly valve each fuel cycle. The same three valves are planned to be tested each fuel cycle to monitor for changes over time.

The NRC staff is preparing a generic letter (GL) on PV of MOV design-basis capability and will review the PV program in greater detail following issuance. As stated in the Generic letter consideration of the benefits (such as identification of decreased thrust output and increased thrust requirements) and potential adverse effects (such as accelerated aging or valve damage) when determining appropriate periodic verification testing for each program valve needs to be considered.

E2.1.9 <u>Tracking and Trending of Failure, Maintenance, and Diagnostics</u>

Perry's tracking and trending program was considered to be a strength to the overall MOV program. The program documented in FTI-0028, "MOV Tracking and Trending," Revision 1, appeared well established with thorough procedural and programmatic required actions. The program was supported by a computer database and the inspectors determined that the licensee's trending program appeared capable of tracking and evaluating data to maintain MOV design-basis capability. The program was capable of analyses of a comprehensive range of parameters (diagnostic, failure, preventive maintenance, and corrective maintenance) by individual valve as well as by group or other subset. Compilation and evaluation of trends was prompted after every maintenance or testing activity and was required via trending reports every 2 years (or after each refueling outage) which described recommended actions and feedback. The licensee's program included the MOV failure codes developed by the MOV Users Group (MUG).

A review of selected MOV-related PIFs generated over the last year indicated that, overall, MOV failures were appropriately reviewed and dispositioned. Direct involvement of the MOV engineering team was evident and was considered instrumental in identifying and correcting problems, and where applicable, in determining root causes and implementing corrective action to preclude repetition.

E2.1.10 <u>Post-Maintenance Verification/Testing (PMT)</u>

Post-maintenance verification/testing requirements as documented in FTI-F0036, "PMT Program Matrix," Revision 2, were found acceptable for program closure. The licensee had appropriately established static and dynamic test requirements and controls for use after MOV maintenance and modifications.

c. <u>Conclusions</u>

All significant issues related to Perry's MOV program have been resolved; therefore, the GL 89-10 program review will be closed. Program documentation, test data and margin improvement plans provided

an adequate basis to conclude that all GL 89-10 program MOVs would perform their intended safety functions under worst-case design-basis conditions. The inspectors noted that Perry had a capable technical MOV staff with a well organized and well documented program.

E2.2 Transformer Failure Evaluations

a. Inspection Scope (37551, 71707, 92901, 92903)

The inspectors interviewed licensee personnel and reviewed documents in order to assess the licensee's evaluations of transformer failures.

b. Observations and Findings

Near the end of the previous inspection period balance-of-plant (BOP) transformer LF1C failed while being energized. The resulting electrical transient contributed to the failure of the Unit 1 Auxiliary Transformer which led to a reactor scram. Two days later another BOP transformer failed while being deenergized. Due to the transformer failures the licensee organized a panel of transformer experts with a variety of related backgrounds. The panel reviewed the recent failures, other industry experience, and current transformer inspection and test results.

The licensee sent the two 13.8 kilovolt (kV) to 480 volt alternating current (VAC) BOP transformers that failed to a manufacturer's facility for evaluation. The manufacturer determined that the transformers had failed due to the effects of electrical corona. This determination was supported by the evaluation of an independent consultant. Corona can occur in dry-type transformers operating at greater than 10kV, causing degradation of the insulation. Higher temperatures can accelerate this effect. When the transformers are energized and deenergized during switching operations the electrical transients can cause the degraded insulation to fail. Based on this information the licensee instructed operations to minimize switching operations associated with the transformers. They have also energized all available transformer cooling fans to reduce operating temperatures and were planning to purchase equipment which could monitor transformers for corona indications.

The expert panel also determined that the safety-related 4160 VAC to 480 VAC transformers should be considered for replacement even though there had been no failures at Perry. The inspectors observed an inspection of a Unit 1 safety-related transformer by members of the expert panel. They confirmed that the transformer, which operated at lower temperatures than the failed transformers, had not been degraded by the corona effect. One energized Unit 2 transformer identical to the safety-related transformers was deenergized and shipped off site for additional evaluation because it was observed to be making a louder noise than the others.

The licensee had the failed auxiliary transformer disassembled and inspected on site by a consultant. The consultant concluded that the transformer had failed due to design weaknesses, material deficiencies, and poor craftsmanship. The Unit 2 Auxiliary Transformer, which had been installed in place of the failed transformer, was also manufactured by McGraw Edison about 14 months later than the Unit 1 transformer. However, the licensee could find no evidence of improvements in identified weaknesses during that time. Since there was no known testing method that would identify the defects observed in the Unit 1 Auxiliary Transformer the licensee could not tell if the Unit 2 transformer had similar defects. Therefore, they had begun a search for a replacement transformer.

The Unit 1 Startup Transformer, which had failed on February 5, 1996, as a result of a spurious fire protection system deluge actuation, had been sent offsite for repairs. Once initial repairs were completed, the transformer failed its post repair testing and had to be rewound. The licensee estimated that the transformer would not be returned to the site until February 1997.

The licensee planned to begin replacement of 13.8 kV to 480 VAC transformers in October 1996. The manufacturer claimed that the new transformers will be less susceptible to the corona effect.

c. Conclusions

Although several transformer failures occurred over the last 6 months, the availability of replacements from the abandoned Unit 2 allowed continued operation with no reduction in electrical system redundancy. Inspections of the current safety-related transformers indicated no duplication of the problems experienced with the BOP transformers. The licensee responded conservatively and aggressively to the failures.

E2.3 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

a. Inspection Scope

While performing the inspections discussed in this report, the inspectors reviewed applicable portions of the UFSAR that related to the areas inspected. Several inconsistencies were noted between wording of the UFSAR and the plant practices, procedures, and parameters observed by the inspectors.

b. Observations and Finding

E2.3.1 UFSAR Table 5.4-2, "Design Parameters for RCIC Components," listed the valve operation dP requirements for the RCIC pump discharge valve 1E51-F013 as 1400 psi for opening or closing strokes. This contradicted the GL 89-10 maximum expected design basis dP of 1247 psid with an active design safety function to open only. Similar discrepancies were noted for other valves listed in UFSAR Section 5.4, "Reactor Coolant System and Connected Systems" (Component and Subsystem Design). Perry

contended that the higher dPs in the UFSAR for program valves were considered "design parameters" used as original design sizing values by the nuclear steam supply system vendor and the architect/engineer and were distinct from GL 89-10 criteria. Based on a sample review of GL 89-10 dPs the inspectors were satisfied that the dPs for the program valves were adequately determined to be the maximum expected design basis dPs. However, as worded, the UFSAR values may be misleading and without clarification, questions as to whether the facility or procedures as described in the UFSAR had been changed would continue. This issue will be reconsidered in the future and is an unresolved item URI (50-440/96005-04).

E2.3.2 UFSAR Section 8.3.2.1.2.1 discussed safety-related DC electrical systems. It stated that "Batteries, battery chargers and distribution equipment for the Class 1E, Division 1 and Division 2, 125-volt dc systems are located in separate, locked rooms...". The inspectors observed that the doors for the battery chargers and distribution equipment are not locked. There was no discussion in this UFSAR section about benefits of locking the doors. Therefore the discrepancy did not appear to have any potential safety consequence. There was no evidence of a safety evaluation being performed for this change. This issue is an an unresolved item URI (50-440/96005-05).

E2.3.3 UFSAR Section 9.1.4.2.3.5, "Fuel Pool Sipper" briefly discussed the use of the fuel pool sipper to concentrate fission gasses as an evolution that would be accomplished in the fuel handling building. The inspectors observed that during the last refueling outage a new method of fuel sipping was used that allowed the fuel to be sipped while it was still in the reactor vessel in the containment. There was no evidence of a safety evaluation being performed for this change. This issue is an unresolved item URI (50-440/96005-06).

E2.3.4 UFSAR Section 9.3.3.3 discussed flooding of the emergency core cooling system (ECCS) rooms. It stated that "Each ECCS pump compartment is provided with watertight locked doors...". The inspectors observed that the watertight doors were not locked. There was no discussion in this UFSAR section about benefits of locking the doors. Therefore the discrepancy did not appear to have any potential safety consequence. There was no evidence of a safety evaluation being performed for this change. This issue is an unresolved item URI (50-440/96005-07).

E2.3.5 UFSAR Section 15A.5.3, "Repair Time Rule" discussed restrictions that must be observed to maintain the validity of assumptions used to establish the "repair time rule". The licensee could not verify that it had observed the restrictions. The potential safety consequence of this issue was not clear at the end of the inspection period. There was no evidence of a safety evaluation being performed for this change. This issue is an unresolved item URI (50-440/96005-08).

c. Conclusion

The inspectors will evaluate the findings and determine whether a violation of NRC requirements has occurred.

E7 Quality Assurance in Engineering Activities

E7.1 Licensee Self-Assessment Activities (40500)

The inspectors reviewed a recent MOV self-assessment along with earlier documented QA MOV activities. The recent self-assessment was completed by consultants knowledgeable in MOV program requirements. Both the self-assessment and the QA audits provided good technical findings and were beneficial in improving the MOV program.

E8 Miscellaneous Engineering Issues (92720, 92903)

E8.1 Simulator Computer Interaction With Control Room

On July 8 while testing a program revision for the simulator computer, a scenario file was inadvertently started that affected computer screen indications in the control room such as control rod positions and core thermal power averages. The operators determined the information to be inaccurate based on control panel indications and plant performance. The condition was corrected and a PIF was initiated. The simulator computer performed two basic functions: 1) operate the simulator and 2) provide plant status information during an emergency from the plant computer to the Emergency Operating Facility computer. Evaluation of how the simulator computer altered computer indications in the control room is an IFI (50-440/96005-09).

E8.2 (Closed) Unresolved Item 50-440/93023-03: Loss of safety function for Emergency Closed Cooling Water System. Corrective actions taken to ensure proper butterfly valve limit switch set up was accomplished with revised maintenance procedures, training, and butterfly valve testing performed in accordance with the licensee's GL 89-10 program. This item is being tracked with LER 93021.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls (83750)

R1.1 Radioactive Material Control Program

a. Scope

The inspectors reviewed the performance of the licensee's radioactive material (RAM) control program for tools and equipment moved within the Radiologically Restricted Area (RRA). The inspectors interviewed Radiation Protection, Maintenance, and Quality Assurance personnel to determine the level of understanding of the program by the general workforce.

b. Observations and Findings

Several recent Potential Issue Forms (PIFs) had been generated addressing RAM storage within the RRA and the RAM control program in general. The documented occurrences suggested that the program was not fully effective in ensuring that workers had a clear understanding of the RAM control program (e.g. proper methods of returning tools and equipment to storage locations).

Personnel interviews indicated that various interpretations of the "hot tool" return process existed. Some workers believed that all material should be directly returned to the hot tool crib while others indicated that tools should be returned to the decontamination facility. This uncertainty appeared to be a significant contributor to material not being returned to the proper storage locations.

The station had identified several programmatic improvement opportunities; however, these enhancements had not been implemented. The inspectors will monitor the licensee's effectiveness in implementing radioactive material control program improvements IFI (50-440/96005-10).

c. Conclusions

The plant's RAM control program was being adequately implemented; however, a lack of understanding of the program requirements existed among the general work force and identified program improvements had not yet been implemented.

R1.2 Review of 1995 Annual Radioactive Effluent Report

The inspectors reviewed the licensee's Annual Environmental and Effluent Release Report for 1995 submitted to the NRC in April 1996. The report appropriately detailed environmental monitoring and radioactive effluent releases for 1995 and demonstrated that plant operations did not result in any significant environmental impact. Effluent releases for 1995 were well below Technical Specification limits. The inspectors noted that the licensee had continued to effectively implement the environmental monitoring and effluent release programs.

R2 Status of RP&C Facilities and Equipment (84750)

R2.1 Review of Filtered Ventilation Systems

The inspectors reviewed procedures and performance test results for selected filtered ventilation trains. The review also included inspections of the control room, fuel handling building, and annulus exhaust gas ventilation systems. The charcoal and freon filter testing was performed by individuals from the company's BETA Laboratory. The procedures reviewed were technically sound and performance test results verified filter train integrity and were performed at the Technical Specification required frequency. The systems inspected were well

maintained. The inspectors concluded that the licensee had an effective ventilation filter testing program.

R2.2 Review of Process and Area Radiation Monitor Program

a. Scope

The inspectors reviewed procedures, alarm setpoint calculations, and performance data regarding the licensee's process, effluent, and area radiation monitoring system. The inspectors also observed the material condition of selected monitors.

b. Findings and Observations

Based on reviews of licensee monitor setpoint methodology and discussions with the Chemistry department staff, the inspectors determined that a sound basis existed for the determination of radiation monitor alarm setpoints. The Chemistry department was in the process of revising procedures governing the radiation monitoring program to more clearly define technical bases for alarm setpoint methodologies and streamline the process for establishing setpoints in the field by chemistry technicians.

A recently performed licensee review of system applicability to the Maintenance Rule indicated that the Radiation Monitoring System failed to meet the Reliability Performance Criteria and had been classified an A(1) system. The review of system performance by the licensee from June 1, 1992, to June 1, 1996, identified 16 functional failures of various radiation monitors. None of the failures resulted in a reportable event; however, limiting conditions for operation (LCOs) had been frequently entered to satisfy Technical Specification required sampling. The licensee was establishing long term corrective actions to improve the system's performance. One corrective action already accomplished was the hiring of a radiation monitor specialist to provide increased oversight of the program.

c. Conclusions

The inspectors determined that the process, effluent, and area radiation monitoring program was being adequately implemented. Technical bases for alarm set point determinations appeared to be sound; however, reliability performance of the system warranted improvement.

R2.3 Electronic Dosimeter Performance Monitoring

a. Scope

The inspectors reviewed electronic dosimeter (ED) performance problems the plant had recently experienced. This issue had been briefly mentioned in Inspection Report 50-440/95009.

b. Observations and Findings

The Radiation Protection department instituted an aggressive program to monitor the noted problems which ranged from the EDs "turning off" to erroneous displays on the readout. Following extensive communications with the ED vendor, the vendor determined that most of the problems were related to the computer software configuration installed at the station combined with the use of older model dosimeters. The Radiation Protection group promptly implemented additional controls for high radiation area entries to ensure workers were appropriately monitored in the event of an ED failure while within such areas. The performance trending had indicated that the failure rate had significantly been reduced following several software modifications. The inspectors discussed the problem with vendor representatives to determine if there was a generic problem with the ED. The vendor representative indicated that the problems being experienced at Perry were isolated to that site due to their unique configuration of the dosimeter software coupled with the HIS-20 access software and the use of the old model DMC 90 dosimeters.

c. Conclusions

The inspectors determined that the licensee had effectively monitored, evaluated, and applied appropriate corrective actions to the ED performance problems.

R8 Miscellaneous RP&C Issues

R8.1 (Closed) Inspection Followup Item 50-440/96003-02: Radiation Protection department response to the inadvertent creation of high dose rates during Vibration Monitoring Instrumentation Removal (VMIR) activities. The inspectors reviewed corrective actions taken to preclude recurrence of creating high radiation dose rates within the upper drywell during movements of in-vessel components. As discussed in IR 96003, this incident did not result in any regulatory violation. However, several program weaknesses were identified that contributed to the incident. The licensee's review identified several weaknesses within the Radiation Work Permit (RWP) program, Work Planning and Scheduling methodology, and with Operations Manual procedures governing in-vessel component movements. Corrective actions included enhanced training for Radiation Protection Technicians, the inclusion of this and similar events into RWP/ALARA reviews for discussion during planning meetings and pre-job briefings, and improvements to operations procedures addressing the movement of in-vessel components. In addition, improvements were made to the NRC Information Notice review process to ensure applicability reviews would be more broadly focused. These corrective actions appeared to address the root causes of the original problem.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Response to Report of a Bomb

a. Inspection Scope (71750, 92904)

At about 6:00 p.m. on June 28, the inspectors observed the operations shift supervisor receive an offsite telephone report in the control room of a bomb in the plant. The inspectors observed the response of operating and security shift personnel.

b. Observations and Findings

The inspectors verified that the operations shift supervisor promptly documented the information received and notified the security shift supervisor. The inspectors verified that the security shift supervisor promptly assisted the operations shift supervisor in evaluating the report. The inspectors observed the shift supervisors' followup discussions with the person who reported the bomb and with cognizant law enforcement personnel. The licensee concluded that there was not a credible threat to the plant.

c. Conclusions

The licensee's response to the bomb report was prompt, thorough, and conservative. Observed discussions of the report were thorough and professional. Reportability was correctly evaluated and the decision that the bomb report was not credible was appropriate.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Valve Performance During Postulated Appendix R Fire Scenarios

Information Notice (IN) 92-18 identified the potential for loss of remote shutdown capability during a control room fire. Due to potential hot shorts caused by a control room fire, various MOVs subsequently controlled from the remote shutdown panel could go to a stall condition since the control signal would not be available to stop power to the motor. This could cause valve and or operator degradation that could result in the loss of safe shutdown capability.

Perry's April 1992 response to IN 92-18, concluded that the structural integrity of the valves was considered to be acceptable based on use of stall thrust in the valve seismic qualification reports. In addition, the licensee concluded that the stall thrust effects would still permit valve operation and would not affect the valve's safe shutdown related function. That stall thrust was based on standard methods in effect at that time and the design stem coefficient of friction. Since then, GL 89-10 industry testing has shown that available motor torque is higher and that actual stem coefficients of friction are lower, both of which could result in a high stall thrust being applied to the valve. Therefore, subsequent analyses revealed that the initial evaluations

were incorrect since the actuator capability and weak link data applied was not conservative. Perry re-evaluated IN 92-18 in preparation for the GL 89-10 closeout inspection and due to IN 92-18 concerns raised by other licensees. A screening method using conservative weak link limits identified up to 21 valves that have stall thrust greater than the weak link limits.

The licensee was in the process of further evaluating the use of the more conservative assumptions and the effects of a stall condition on the valve and the potential loss of safe shutdown function. At the end of the inspection period, the licensee had developed a method to further evaluate the weak link limit calculation assumptions, the effects of a stall condition on the valves, and the potential loss of safe shutdown function. LER 96-006 was submitted on August 19, 1996 to document identification of 12 MOVs that could be affected by the postulated fire scenario such that the valves would be damaged to the extent that they cannot be relied upon to perform their safe shutdown related functions. Final review of this issue, including review of the licensee's evaluation, compensatory actions, and any required corrective action, will be tracked as part of the closeout of LER 96-006.

F5 Fire Protection Staff Training and Qualifications

a. Inspection Scope (71750, 92904)

The inspectors routinely observed fire protection equipment and structures during their inspections of the plant.

b. Observations and Findings

On July 5, 1996, the inspectors observed that an electrical breaker maintenance cart permanently stored in the Division II Electrical Switchgear Room had worn a hole through the east firewall about 2 inches above the floor. The inspectors informed the shift supervisor of the condition and a fire impairment was promptly established for this fire barrier deficiency. The hole was smaller than a hole that would require a fire impairment in accordance with the licensee's impairment program. The hourly fire watch required to compensate for the impairment had already been established for another fire impairment. The damage appeared to be the result of repeated movements of the cart against the wall.

c. Conclusions

There had been earlier opportunities for the plant staff to identify this damage, but there was no evidence that it had been identified prior to the inspectors' observation. The prompt use of a fire impairment was conservative.

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 July 26, 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.

X3 Management Meeting Summary

On June 11, 1996, the Director, Division of Reactor Projects-III/IV, ONRR inspected the plant and met with various members of the licensee's staff to discuss current plant issues.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 71500:	Balance of Plant Inspection
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparation
IP 71750:	Plant Support Activities
IP 83750:	Occupational Radiation Exposure
IP 84750:	Radioactive Waste Management - Inspection of Waste Generator Requirements of 10 CFR 20 and 10 CFR 61
IP 90700:	Feedback of Operational Experience Information at Operating Power Reactors
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
TI 2515/109:	Inspection Requirements for Generic Letter 89-10

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/96005-01	NCV	Electrical system placed in incorrect configuration
50-440/96005-02	VIO	Slow identification of condition adverse to quality
50-440/96005-03	URI	Modification affects RCIC operation
50-440/96005-04	URI	UFSAR Table 5.4.2, valve design parameters
50-440-96005-05	URI	UFSAR SEC. 8.3.2.1.2.1, safety related dc electrical
50-440/96005-06	URI	UFSAR SEC. 9.1.4.2.3.5, fuel pool sipper
50-440/96005-07	URI	UFSAR SEC. 3.3.3, Flooding ECCS rooms
50-440/96005-08	URI	UFSAR SEC. 15A.5.3, Repair time rule
50-440/96005-09	IFI	Simulator computer interaction with control room
50-440/96005-10	IFI	Radioactive material control program

Closed

50-440/93023-03	URI	ECCS operability
50-440/95003-02	IFI	Drywell dose rates high due to VMIR activities
50-440/96005-01	NCV	Electrical system placed in incorrect configuration

Discussed

None

LIST OF ACRONYMS USED

ALARA	AS LOW AS REASONABLY ACHIEVABLE
ANSI	AMERICAN NATIONAL STANDARD INSTITUTE
BOP	BALANCE OF PLANT
CFR	CODE OF FEDERAL REGULATIONS
DC	DIRECT CURRENT
DIV	DIVISION
dP	DIFFERENTIAL PRESSURE
ECCS	EMERGENCY CORE COOLING SYSTEM
ED	ELECTRONIC DOSIMETER
EDG	EMERGENCY DIESEL GENERATOR
EPRI	ELECTRICAL POWER RESEARCH INSTITUTE
FR	FEDERAL REGISTER
FTI	TECHNICAL ENGINEERING INSTRUCTION
FW	FEEDWATER
GE	GENERAL ELECTRIC
GL	GENERIC LETTER
HPES	HUMAN PERFORMANCE ENHANCEMENT SYSTEM
IFI	INSPECTION FOLLOW-UP ITEM
IN	INFORMATION NOTICE
INEL	IDAHO NATIONAL ENGINEERING LABORATORY
IPAP	INTEGRATED PERFORMANCE ASSESSMENT PROCESS
LCO	LIMITING CONDITIONS FOR OPERATIONS
LCS	LEAKAGE CONTROL SYSTEM
LLRT	LOCAL LEAK RATE TESTING
MCC	MOTOR CONTROL CENTER
MDFW	MOTOR-DRIVEN FEEDWATER
MOV	MOTOR-OPERATED VALVE
MUG	MOV USERS GROUP
NCV	NON-CITED VIOLATION
NRR	OFFICE OF NUCLEAR REACTOR REGULATION
NUMAC	NUCLEAR MEASUREMENT ANALYSIS AND CONTROL
ONRR	OFFICE OF NUCLEAR REACTOR REGULATION
PAP	PERRY ADMINISTRATIVE PROCEDURE
PDR	PUBLIC DOCUMENT ROOM
PIF	POTENTIAL ISSUE FORM
PMT	POST-MAINTENANCE TESTING
PORC	PLANT OPERATIONS REVIEW COMMITTEE
PPM	PERFORMANCE PREDICTION METHODOLOGY
psid	POUNDS PER SQUARE INCH DIFFERENTIAL
PV	PERIODIC VERIFICATION
QA	QUALITY ASSURANCE
RCIC	REACTOR CORE ISOLATION COOLING
RFO	REFUELING OUTAGE
RFPT	REACTOR FEEDWATER PUMP TURBINE
RI	RESIDENT INSPECTOR
RWP	RADIATION WORK PERMIT
SFC	STEM FRICTION COEFFICIENT
SOI	SYSTEM OPERATING INSTRUCTION
SRI	SENIOR RESIDENT INSPECTOR
SRO	SENIOR REACTOR OPERATOR

SS	SHIFT SUPERVISOR
UFSAR	UPDATED FINAL SAFETY ANALYSIS REPORT
URI	UNRESOLVED ITEM
US	UNIT SUPERVISOR
VAC	VOLT ALTERNATING CURRENT
VF	VALVE FACTOR
VIO	VIOLATION
VMIR	VIBRATION MONITORING INSTRUMENTATION REMOVAL