May 5, 2005

Mr. R. Anderson
Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
P. O. Box 97, A290
10 Center Road
Perry, OH 44081

SUBJECT: PERRY NUCLEAR POWER PLANT
NRC INTEGRATED INSPECTION REPORT 05000440/2005002

Dear Mr. Anderson:

On March 31, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Perry Nuclear Power Plant. The enclosed report documents the inspection findings which were discussed on April 5, 2005, with Mr. Fred von Ahn and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. In addition to the routine NRC inspection and assessment activities, Perry performance is being evaluated quarterly as described in the Assessment Follow-up Letter - Perry Nuclear Power Plant, dated August 12, 2004. Consistent with Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," plants in the multiple/repetitive degraded cornerstone column of the Action Matrix are given consideration at each quarterly performance assessment review for (1) declaring plant performance to be unacceptable in accordance with the guidance in IMC 0305; (2) transferring to the IMC 0350, "Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems," process; and (3) taking additional regulatory actions, as appropriate. On February 7, 2005, the NRC reviewed Perry operational performance, inspection findings, and performance indicators during the fourth quarter of 2004. Based on this review, we concluded that Perry is operating safely. We determined that no additional regulatory actions, beyond the already increased inspection activities and management oversight, are currently warranted.

Based on the results of this inspection, five NRC-identified findings and six self-revealed findings of very low safety significance, all of which involved violations of NRC requirements, were identified. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of these Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of

Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Perry Nuclear Power Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at **http://www.nrc.gov/reading-rm/adams.html** (the Public Electronic Reading Room).

Sincerely,

/RA/

Steven A. Reynolds
Deputy Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000440/2005002
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	05000440/2005002
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant, Unit 1
Location:	P.O. Box 97 A210 Perry, OH 44081
Dates:	January 1 through March 31, 2005
Inspectors:	R. Powell, Senior Resident Inspector J. Ellegood, Senior Resident Inspector, Palisades M. Franke, Resident Inspector Z. Falevits, Senior Reactor Engineer J. House, Senior Radiation Specialist M. Holmberg, Reactor Inspector C. Roque-Cruz, Reactor Inspector G. Roach, Reactor Engineer R. Smith, Reactor Engineer
Approved by:	C. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000440/2005002; 01/01/2005 - 03/31/2005; Perry Nuclear Power Plant; Evaluations of Changes, Tests, or Experiments; Equipment Alignment; Operator Performance During Non-Routine Evolutions and Events; Post-Maintenance Testing; Refueling and Outage Activities; Surveillance Testing; Other Activities.

This report covers a 3-month period of baseline inspection. The inspection was conducted by resident and regional inspectors. This inspection identified 11 Green issues, all of which involved Non-Cited Violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4, "Procedures" was self-revealed on February 3, 2005. Specifically, while calibrating the containment/drywell purge exhaust radiation monitor 1D17-K660, an error by an instrumentation and control (I&C) technician resulted in an engineered safety feature (ESF) actuation. Specifically, backup hydrogen purge system containment isolation valves M51-F090 and M51-F110 received an isolation signal. The valves functioned as designed and isolated the backup drywell hydrogen purge system. Control room personnel realigned the backup drywell hydrogen purge system in accordance with the system operating instruction. Additional I&C personnel reset the trip signal and completed the calibration procedure successfully. The primary cause of this finding was related to the cross-cutting issue of Human Performance because a personnel error was the primary cause of the event.

  The inspectors determined that an inadvertent ESF actuation due to improper performance of an I&C procedure was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a more significant event. The inspectors determined that the finding was of very low safety significance because the finding: (1) did not contribute to the likelihood of a loss of coolant accident initiator; (2) did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; and (3) did not increase the likelihood of a fire or internal/external flooding. (Section 1R22.3)

Cornerstone: Mitigating Systems

- Green. Inspectors identified a finding of very low safety significance and a violation of Technical Specification 5.4 when, during a walkdown of the high pressure core spray

(HPCS) system, inspectors observed that the scaffolding constructed in the Division 3 emergency diesel generator (EDG) and HPCS pump rooms failed to meet the seismic clearance requirements specified in licensee procedure GCI-0016, "Scaffolding Erection, Modification or Dismantling Guidelines," Revision 4. The inspectors observed that the procedural deviations were not evaluated by engineering to ensure that the safety-related HPCS system would not be adversely impacted during a seismic event. Additionally, inspectors noted that the scaffolding constructions in the Division 3 EDG and HPCS pump rooms were not tracked as a temporary alteration as required by Perry Administrative Procedure (PAP)-0204, "Housekeeping/Cleanliness Control Program," Revision 14. The primary cause of this finding was the failure to implement appropriate procedures for construction of scaffolding that could affect safety-related equipment. The primary cause was related to the cross-cutting area of Human Performance in that the licensee failed to follow both procedures, GCI-0016 and PAP-0204.

The finding was more than minor because, if left uncorrected, the failure to follow procedures for scaffold construction in safety-related areas would become a more significant safety concern. Additionally, the failure to follow procedures designed to protect safety-related equipment from scaffold construction adversely affects the mitigating system cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was determined to be of very low safety significance because, assuming HPCS was rendered inoperable following a seismic event due to non-seismic scaffolding, Significance Determination Process Phase 3 analysis determined the issue to not be greater than Green due to the low frequency of seismic events and the operability of other mitigating systems. The issue was a Non-Cited Violation of Technical Specification 5.4 which required the implementation of written procedures for performing maintenance on safety-related systems.
(Section 1R04)

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4 was self-revealed on January 13, 2005, when a chemistry technician failed to promptly notify the control room upon discovery of an unexpected fire. The fire was located in the chemistry oil lab room of the control complex building within the protected area. The primary cause of this finding was related to the cross-cutting area of Human Performance. The chemistry technician failed to recognize that, in accordance with the Fire Protection Program, prompt notification to the control room is required when a fire is discovered.

  The finding was more than minor because the failure to promptly report a fire prevents plant operators in the control room and other plant personnel from taking prompt and appropriate action pursuant to Fire Protection Program procedures. The resulting failure to implement the Fire Protection Program procedure on discovery of a fire degrades the facility's ability to meet the cornerstone objective of mitigating systems. Although not suitable for Significance Determination Process review, the finding was determined, by regional management, to be of very low safety significance in that (1) the finding did not affect the operability of the automatic fire detection and suppression systems in the affected fire zone, (2) the fire zone was outside of the vital area of the plant, and (3) the fire zone did not contain safe shutdown systems. Additionally, there was no identified damage to safety-related equipment due to the fire, and the fire was observed to be confined to an oven. (Section 1R14)

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4 was self-revealed during a reactor start-up on January 30, 2005, when the intermediate-range monitor (IRM) 'A' instrument was discovered to be inoperable after reactor criticality had been achieved. Prior to start-up, it had been established that IRM 'C' was inoperable. The inoperability of both IRM 'A' and IRM 'C' resulted in operability of less than the minimum required number of IRM channels per trip system of the reactor protection system (RPS) for Mode 2 operation. The licensee entered the appropriate Technical Specification action statement and, as required by licensee procedure, commenced a normal reactor shutdown. The primary cause of this finding was the failure to implement appropriate procedures during maintenance activities on IRM 'A'. A cable connection between the intermediate-range detector and the intermediate-range instrument was left loosely attached at the conclusion of the maintenance activity. This rendered the IRM 'A' instrument inoperable. Additionally, the maintenance procedure lacked appropriate acceptance criteria for determining that the maintenance had been satisfactorily accomplished. The primary cause of this finding was related to the cross-cutting area of Human Performance in that technicians failed to adequately attach and verify connection of the cable in the IRM 'A' system.

  The finding was more than minor because it resulted in a reactor start-up and operation in Mode 2 with less than the required number of IRM trip function channels per RPS trip system. This degraded the plant’s ability to meet the mitigating system cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, the finding resulted in an unplanned reactor shutdown. The finding was of very low safety significance because RPS trip capability was maintained due to designed redundancy in the system logic. The issue was a Non-Cited Violation of Technical Specification 5.4 which required the implementation of written procedures covering the intermediate-range nuclear instrument system. (Section 1R19)

- Green. Inspectors identified a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions” on January 18, 2005. Specifically, the licensee failed to take prompt corrective action after identifying on January 17, 2005, that erroneous or unexplainable data was recorded during Technical Specification required emergency closed cooling water (ECCW) 'B' pump and valve operability testing. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution. After the inspectors brought the issue to the attention of control room personnel, the licensee initiated action to re-code the surveillance as “no credit” based on suspect data. Action was also initiated to reschedule the surveillance prior to its overdue date of February 4, 2005. The licensee’s subsequent performance of the surveillance test was not properly performed which resulted in a missed Technical Specification 5.5.6 surveillance and an additional 10 CFR 50, Appendix B, Criterion XVI violation was identified by the inspectors. The test was performed correctly, with acceptable results, on February 5, 2005, to satisfy Technical Specification requirements.

The inspectors concluded that the failure of a system engineer, an engineering supervisor, and a senior reactor operator to take action to correct an identified condition adverse to quality was more than minor in that it could reasonably be viewed as a precursor to a significant event and, with respect to the performance of Technical Specification required surveillance testing, was associated with the reactor safety cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring mitigating system availability, reliability, and capability. The inspectors determined that the finding did not involve the loss of safety function in that ECCW 'B' subsequently satisfactorily completed the required quarterly pump and valve operability test. The inspectors therefore concluded that the finding was of very low safety significance. (Section 1R22.1)

- Green. Inspectors identified a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions" on February 7, 2005. Specifically, the licensee failed to identify and correct a condition adverse to quality following the inspectors' identification, on January 18, 2005, of an improperly performed Technical Specification required surveillance. As a result of the licensee's failure to properly evaluate the January 5, 2005, performance deficiency and take appropriate corrective action, the surveillance test was again performed improperly on February 1, 2005. In addition to causing unnecessary safety system unavailability during repetitive performances of the procedure, the inadequate performance of the test on February 1, 2005, resulted in a missed Technical Specification 5.5.6 surveillance. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution. The test was performed correctly, with acceptable results, on February 5, 2005, to satisfy Technical Specification requirements. An apparent cause investigation was initiated to review surveillance performance issues.

  The inspectors concluded that the failure of the licensee to adequately address performance issues with respect to a Technical Specification required surveillance procedure was more than minor in that it could reasonably be viewed as a precursor to a significant event and, in this case, resulted in a second improper performance and a missed Technical Specification surveillance. Additionally, the issue was associated with the reactor safety cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring mitigating system availability, reliability, and capability. The inspectors determined that the finding did not involve the loss of safety function in that emergency closed cooling water 'B' subsequently satisfactorily completed the required quarterly pump and valve operability test. The inspectors therefore concluded that the finding was of very low safety significance. (Section 1R22.2)

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4 was self-revealed on February 27, 2005. Specifically, while performing a local leak rate test (LLRT) for the residual heat removal (RHR) 'A' suppression pool suction valve, 1E12-F004A, the valve was opened with the RHR 'A' system drained and vented. As a result, the suppression pool began draining through an open 8 inch drain valve and then overflowed to the auxiliary building floor. The draining was terminated within minutes when the valve was closed per the next step in the LLRT procedure.

The inspectors determined that inadvertent draining of the suppression pool to the auxiliary building floor was a performance deficiency warranting a significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. The inspectors determined that the finding: (1) did not increase the likelihood of a loss of reactor coolant system (RCS) inventory; (2) did not degrade the licensee's ability to terminate a leak path or add RCS inventory when needed; and (3) did not degrade the licensee's ability to recover decay heat removal if lost. The finding affected the cross-cutting issue of Human Performance because a personnel error resulted in a loss of suppression pool volume. (Section 1R22.4)

- Green. Inspectors identified a finding of very low safety significance for the licensee's failure to adequately implement Technical Specification 3.4.10 requirements for alternate decay heat removal methods as amended to the license during the Technical Specification improvement program to adopt Technical Specifications based on NUREG-1434 (Improved Standard Technical Specifications). The finding was considered to be a Non-Cited Violation of 10 CFR 50.36(c)(2)(I). The licensee has initiated action to install an alternate decay heat removal system.

  The inspectors determined that the licensee's failure to adequately implement Technical Specification 3.4.10 was more than minor because it was directly associated with the mitigating system cornerstone objective of availability of a mitigating system. Although not suited for Significance Determination Process review, the finding was determined to be of very low safety significance in that (1) the Mode 4 conditions were maintained by the inoperable, but running, RHR 'B' system and (2) the licensee maintained vacuum within the condenser to provide a method of decay heat removal had coolant temperature rose sufficiently to produce steam. (Section 4OA5)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Severity Level IV Non-Cited Violation associated with the failure to perform an adequate safety evaluation review as required by 10 CFR 50.59 for changes made to the facility as described in the Updated Final Safety Analysis Report. The licensee initiated a NobleChem™ process, which involved deposition of noble metals on primary plant components, but failed to provide a basis for the determination that this change was acceptable without a license amendment. Specifically, the safety evaluation failed to address the impact of the NobleChem™ process on the fuel peak cladding temperature in a post loss-of-coolant accident environment due to catalytic action involving two exothermic reactions.

  Because the Significance Determination Process is not designed to assess the significance of violations that potentially impact or impede the regulatory process, this issue was dispositioned using the traditional enforcement process in accordance with Section IV of the NRC Enforcement Policy. However, the results of the violation, that is, the failure to fully evaluate the NobleChem™ process, were assessed using the Significance Determination Process.

The inspectors considered this issue of more than minor significance, because the finding could have become a more significant safety concern in that, the licensee failed to demonstrate through a documented analysis that the integrity of fuel cladding was not affected by the NobleChem™ process. Because a subsequent vendor analysis adequately demonstrated the integrity of fuel cladding, it was determined that the licensee's failure to provide an adequate basis for the safety evaluation 01-0007 was an issue of very low safety significance and the violation of 10 CFR 50.59 was classified as a Severity Level IV Non-Cited Violation, consistent with the NRC Enforcement Policy. (Section 1R02)

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4 was self-revealed on February 28, 2005. Specifically, while removing a jet pump plug assembly from the reactor vessel, the plug broke loose from the handling pole and roped L-hook while being lifted over the refuel floor auxiliary platform. As a result, the plug dropped approximately 60 feet, primarily through water, and landed on top of several fuel bundles in the reactor core.

  The inspectors determined that dropping a jet pump plug assembly, weighing approximately 25 pounds, onto the top of the reactor core was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. Further, the finding was associated with the barrier integrity cornerstone attribute of human performance and affected the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. Although not suitable for Significance Determination Process review, regional management determined that the finding was of very low safety significance because the dropped plug was subsequently determined to not have caused damage to the fuel. The finding affected the cross-cutting issue of Human Performance because a personnel error caused the plug to be dropped. (Section 1R20.2(1))

- Green. A finding of very low safety significance and a violation of Technical Specification 5.4 was self-revealed on March 10, 2005. Specifically, while attempting to verify the position of control rod 18-55, a senior reactor operator (SRO) inadvertently withdrew control rod 58-35 from position 00 to position 02. Upon recognition of the condition, the SRO took the Technical Specification required actions and immediately reinserted the control rod.

  The inspectors determined that a personnel error that resulted in the inadvertent withdrawal of a control rod was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. Further, the finding was associated with the barrier integrity cornerstone attribute of human performance and affected the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. Although not suitable for Significance Determination Process review, regional management determined that the finding was of very low safety significance because the rod movement had minimal impact of reactivity as evidenced by the lack of response by source range instrumentation and subsequent licensee shutdown margin assessment. Further, the error was immediately recognized and the control rod was inserted to position 00 in less than 15 seconds. Additionally, the SRO's use of the withdraw pushbutton self-limited the movement to one notch. The finding affected the cross-cutting issue of Human Performance because a personnel error resulted in an inadvertent step withdrawal of a control rod. (Section 1R20.2(2))

B. Licensee-Identified Violations

Two violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

The plant began the inspection period at approximately 65 percent power after starting up from a forced outage on December 26, 2004. After a series of power maneuvers to support control rod adjustments, the plant reached 100 percent power on January 5, 2005. At 1:06 a.m. on January 6, 2005, both reactor recirculation pumps downshifted to slow speed rapidly reducing reactor power. After the ‘A’ reactor recirculation pump subsequently tripped, at 1:12 a.m. the operator at the controls inserted a manual scram. The plant entered Mode 4 at 9:00 a.m. on January 7, 2005. Following forced outage activities, the plant entered Mode 2 at 7:12 a.m. on January 30, 2005. The reactor was declared critical at 2:37 p.m. later that same day. After failing to obtain proper overlap of IRM 'A' and source range monitor (SRM) 'A,’ the licensee conducted a procedurally required shutdown at 3:37 p.m. with all rods in at 4:05 p.m. Following troubleshooting of IRM 'A,' the licensee recommenced reactor startup at 8:48 p.m. on January 30, 2005. The reactor was declared critical at 10:23 p.m. later that same day. The plant entered Mode 1 at 2:31 p.m. on January 31, 2005. The unit synchronized to the grid at 0:57 a.m. on February 1, 2005. After a series of power maneuvers to support control rod adjustments, the plant reached 100 percent power on February 5, 2005.

After the plant reached 100 percent power, a coastdown to a planned refueling outage began on February 6, 2005. On February 21, 2005, the plant reduced power to approximately 25 percent. Shortly after midnight on February 22, 2005, the main generator output breaker was opened commencing Perry’s tenth refueling outage (RFO10). A manual reactor scram was inserted on February 22, 2005, at 0:55 a.m. The plant reached Mode 4 later that same day. The plant entered Mode 5 on February 24, 2005, at 12:10 p.m. when the first reactor pressure vessel stud was detensioned. The plant remained in Mode 5 for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Emergency Preparedness

1R01 Adverse Weather (71111.01)

a. Inspection Scope

On January 5, 2005, a winter storm warning including potential ice accumulation was issued for northeast Ohio. The inspectors observed the licensee’s preparations and planning for the severe weather potential. The inspectors reviewed licensee procedures and discussed potential compensatory measures with control room and outage command center personnel. Additionally, the inspectors conducted walkdowns of various plant structures and systems to check for maintenance or other apparent deficiencies which could affect system operations during the predicted severe weather. The inspectors’ review constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

.1 Safety Evaluation for Noble Chemical Metal Addition Process

a. Inspection Scope

On January 25 and 26, 2005, the inspectors reviewed licensee corrective actions and analysis related to a safety evaluation (SE) 01-0007, "TXI-321 Noble Chemical Metal Addition," which was the subject of an unresolved item (URI) 05000440/2003002-02 identified during an NRC inspection (IR 50-440/03-02) completed in February of 2003. This URI was associated with an inadequate SE. Specifically, the licensee had failed to assess the affects of the NobleChem™ process on the peak cladding temperature (PCT) following a loss-of-coolant accident (LOCA) due to catalytic action involving two exothermic reactions. The inspectors used the requirements of 10 CFR 50.59 in evaluating this issue and the List of Documents Reviewed is included as an attachment to this report.

The reviews discussed above did not count as a completed inspection sample as described in Inspection Procedure 71111.02, "Evaluations of Changes, Tests, or Experiments," because this review included only a followup of corrective actions for a previous inspection sample which has been completed.

b. Findings

Introduction: The inspectors identified that the licensee failed to perform an adequate SE in accordance with 10 CFR 50.59 to determine that a change to the plant did not constitute an unreviewed safety question. Specifically, the licensee did not evaluate the potential for the NobleChem™ process to affect the fuel PCT in a post-LOCA environment. The issue was considered to be of very low safety significance and was dispositioned as a Severity Level IV NCV.

Description: On February 8, 2001, the licensee completed SE 01-0007, "TXI-321 Noble Chemical Metal Addition." In this SE the licensee evaluated the impact of the NobleChem™ process on plant materials and safety system operations. The Updated Final Safety Analysis Report (UFSAR) Section 4.1.2.1.3.1 "Fuel Rod" discussed the Zircaloy fuel clad material and Table 5.2-5 "Reactor Coolant Pressure Boundary Materials," discusses the specific material composition of RCS components. Neither of these sections described the licensee's proposed material changes involving the addition of noble metals into the oxide layers of these materials. Because this process involved deposition of noble metals on internal surfaces of safety-related components (reactor coolant loops, reactor vessel, fuel, etc.), it constituted a change to these components as described in the UFSAR, and the performance of a safety evaluation was required.

On February 12, 2003, the inspectors identified that the licensee failed to evaluate that the affect of the NobleChem^{TM} process on fuel cladding temperature in a post-LOCA environment in SE 01-0007. Specifically, the inspectors were concerned that the NobleChem^{TM} process would result in increases to fuel PCT in a post-LOCA environment in that, it could serve as a catalyst for two exothermic reactions, the recombination of hydrogen - oxygen and the zirconium - water reaction. The licensee's vendor subsequently confirmed through a new safety analysis (reference GE-NE-P86-0004-00-02-R4, "Noble Metal Chemical Addition Technical Safety Evaluation for Perry Nuclear Plant") that this process would facilitate the hydrogen - oxygen recombination reaction, which could affect PCT, but would not affect the zirconium - water reaction rate. The vendor's subsequent analysis (reference GE-NE-0000-0031-3601-R0, "Effect of Noble Chem on Perry LOCA Peak Cladding Temperature") demonstrated that the impact of the NobleChem^{TM} on these reactions would not significantly increase fuel PCT in a post-LOCA environment.

The inspectors determined that this was a violation of 10 CFR 50.59 in that the licensee did not provide in SE 01-0007 an adequate basis to demonstrate that the NobleChem^{TM} process did not adversely affect the fuel. However, subsequent analysis was performed by the vendor which demonstrated that the NobleChem^{TM} process did not adversely affect fuel PCT.

Analysis: Because violations of 10 CFR 50.59 are considered to be violations that potentially impede or impact the regulatory process, they are dispositioned using the traditional enforcement process instead of the SDP. This finding is more than minor because if left uncorrected, the finding could have become a more significant safety concern in that, the licensee failed to demonstrate through a documented analysis that the integrity of fuel cladding was not affected by the NobleChem^{TM} process. Because a subsequent vendor analysis adequately demonstrated the integrity of fuel cladding, it was determined that the licensee's failure to provide an adequate basis for the 10 CFR 50.59, SE 01-0007 was an issue of very low safety significance.

Enforcement: On January 26, 2005, the inspectors identified that the licensee's failure to perform an adequate SE 01-0007, constituted a violation of 10 CFR 50.59 requirements.

Title 10 CFR 50.59(d)(1) states, in part, that the licensee shall maintain records of changes in the facility, of changes in procedures, and of tests and experiments. These records must include a written evaluation which provides the bases for the determination that the change, test, or experiment does not require a license amendment.

Contrary to the above, in SE 01-0007, dated February 8, 2001, the licensee failed to provide a basis for the determination that the NobleChem^{TM} process which deposited noble metals onto materials and components described in the plant's UFSAR (reference UFSAR Section 4.1.2.1.3.1 "Fuel Rod" and UFSAR Table 5.2-5 "Reactor Coolant Pressure Boundary Materials"), was acceptable with respect to impact on fuel PCT without a license amendment. The results of this violation were determined to be of very low safety significance; therefore, this violation of the requirements in 10 CFR 50.59 was classified as a Severity Level IV Violation. However, because this non-willful violation was non-repetitive, and was captured in the licensee's corrective action program (CR 03-00721), it is considered an NCV **(NCV 05000440/2005002-01)** consistent with VI.A.1 of the NRC Enforcement Policy.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors conducted partial walkdowns of the system trains listed below to determine whether the systems were correctly aligned to perform their designed safety function. The inspectors used licensee valve lineup instructions (VLIs) and system drawings during the walkdowns. The walkdowns included selected switch and valve position checks, and verification of electrical power to critical components. Finally, the inspectors evaluated other elements, such as material condition, housekeeping, and component labeling. The documents used for the walkdowns are listed in the attached List of Documents Reviewed. The inspectors reviewed the following three systems:

- low pressure core spray (LPCS) system during a forced plant outage while LPCS was the designated emergency core cooling system (ECCS) for reactor water inventory, on January 11, 2005;
- HPCS system during a forced plant outage while HPCS was the designated system for reactor water inventory, on January 25, 2005; and
- Division 3 EDG and support systems during a refueling outage while designated a protected train for shutdown safety on March 4, 2005.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and a violation of Technical Specification (TS) 5.4 when, during a walkdown of the HPCS system, inspectors observed that the scaffolding constructed in the Division 3 EDG room and the HPCS pump room failed to meet the seismic clearance requirements specified in licensee procedure GCI-0016, "Scaffolding Erection, Modification or Dismantling Guidelines," Revision 4. The inspectors observed that the procedural deviations were not evaluated by engineering to ensure that the safety-related HPCS system would not be adversely impacted during a seismic event. Additionally, inspectors noted that the scaffolding was not tracked as a temporary alteration as required by licensee procedure PAP-0204, "Housekeeping/Cleanliness Control Program," Revision 14.

Description: On March 4, 2005, inspectors conducted a walkdown of Division 3 HPCS, EDG, and EDG support systems. At the time of the inspection, the HPCS system was designated by the licensee as a protected system for shutdown risk. Inspectors noted that scaffolding had been constructed around the Division 3 EDG such that less than 3 inches clearance existed between the scaffolding and the right bank air start regulator pilot valve piping which is less than ½ inch in diameter. The scaffolding procedure, GCI-0016, step 5.5.4.2, required a minimum clearance of 3 inches between all safety-related items. Actual clearance was measured by inspectors to be less than 2 inches. Step 5.5.4.3 of GCI-0016 stated that the required 3 inch clearance can be reduced to 1 inch provided additional bracing is provided to prevent movement of the scaffolding in the direction of the safety-related items. The inspectors did not observe the required additional bracing. The inspectors also noted that scaffolding was attached to several safety-related supports associated with the air start system. Step 5.5.4.4 of GCI-0016 stated that attachment to safety-related supports and equipment shall only be made per an approved engineering change or, when the scaffolding is not permanent, per a structural engineer request for assistance (RFA) condition report (CR) that is referenced in the scaffolding identification tag. Contrary to requirement, inspectors noted the absence of either an approved engineering change or a structural engineer-approved RFA CR required by procedure to be referenced in the scaffolding identification tag for attachment of scaffolding to safety-related supports. Additionally, inspectors observed two unsecured sections of scaffold in close proximity to the left bank air start regulator pilot valve. The scaffold construction date was posted as February 4, 2005, and as such, this scaffolding was present for both critical and shutdown modes of reactor operation. The inspectors reported the seismic clearance concerns to the shift manager.

Later in the day on March 4, 2005, inspectors spot checked the Division 3 EDG room and noted that the previously unsecured scaffolding had been moved and secured in a position less than 3 inches from the EDG's left bank air regulator pilot. This resulted in an additional seismic and procedural issue. Inspectors again noted the absence of procedurally required additional scaffold bracing to account for the new seismic clearance issue on the left side of the diesel. This resulted in scaffolding not meeting procedural clearance requirements on both the right and left air pilot valves. Additionally, scaffold attachments to air start system supports without engineering evaluation remained in place. The inspectors reported the new seismic issue to the shift manager.

On March 7, 2005, inspectors conducted a routine plant status tour which included the HPCS pump room. Inspectors noted that scaffolding built in this room was in close proximity to system components in several areas and was attached to system supports. Inspectors observed that the scaffolding clearance to the small diameter HPCS keep-fill discharge line piping was less than 1 inch. Inspectors noted that the scaffolding procedure does not provide for clearances of less than 1 inch. The inspectors observed that the scaffolding was attached to the HPCS system supports. Again, the inspectors noted the absence of an engineering evaluation reference on the scaffolding tag. Inspectors noted that the scaffolding tag indicated a construction date of January 11, 2005. As such, this scaffolding was present for both critical and shutdown modes of reactor operation.

The inspectors discussed the observed seismic scaffolding issues with the maintenance services superintendent. The maintenance services superintendent indicated that scaffolding was not required to be built to the seismic requirements because all scaffolds built were modeled and controlled in risk space by the temporary alteration procedure controls found in PAP-0204. Based on these comments by the maintenance superintendent, the inspectors became concerned that scaffolding throughout the plant had not been constructed per seismic requirements in safety-related areas. This was further validated by a spot check of scaffolding on the safety-related emergency service water (ESW) system. Inspection of the ESW scaffold documentation revealed that the scaffolding construction checklist was marked “N/A,” or “not applicable,” under the section relating to seismic requirements. Although the inspectors did not identify any scaffold issue that challenged ESW system operability, the “N/A” markings were consistent with the approach to scaffold construction described by the maintenance services superintendent. The ESW scaffolding tag indicated that it was installed on December 13, 2004.

Inspectors noted that the seismic construction section of procedure GCI-0016 contained a note which stated, “refer to PAP-0204 if any of the requirements of this section cannot be met.” The inspectors also noted that per GCI-0016, “all scaffolding is considered to be a Temporary Alteration to the Plant, implemented consistent with the requirements of PAP-0204.”

However, the inspectors noted that GCI-0016 section 2.1, “Precautions,” stated, “For compliance with the design basis of the Plant, scaffolding in safety related areas as listed in Attachment 3, must be seismically restrained and constructed as required by Section 5.5 of this instruction.” GCI-0016 section 5.5, “Seismic Construction Bracing and Clearance,” clearly stated, “this section provides minimum requirements for all scaffolds in safety related areas... refer to PAP-0204 for additional limits regarding implementation of Temporary Alterations, including scaffolding.” Finally, PAP-0204, Attachment 4, “Temporary Alterations,” section 14, stated that temporary alteration must not affect the ability to meet the requirements of GCI-0016, the scaffolding procedure.

The inspectors examined the licensee’s process for evaluating scaffolding as required by the temporary alterations procedures in PAP-0204. The scaffolding procedure, GCI-0016, defined all scaffolding as a temporary alteration. The temporary alterations procedure in PAP-0204 applied to all temporary alterations installed during Modes 1 and 2 or any alterations installed in Modes 3, 4, and 5 that will remain in Modes 1 or 2. The inspectors noted that the sections of the HPCS scaffolding were installed in and existed in both critical and shutdown modes of plant operation. PAP-0204 section 6.4.7 stated that tracking of temporary alterations in support of maintenance is required. The inspectors reviewed the licensee temporary alterations database and found that it did not include any alterations addressing the HPCS scaffolding. Additionally, the inspectors noted that the temporary alterations database only included one active entry under the scaffolding category for the entire plant.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to follow the scaffolding procedure and the temporary alterations procedure was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” dated June 20, 2003. The failure to implement appropriate procedures to properly construct and seismically qualify scaffold in safety-related areas, if left uncorrected, would become a more significant safety concern. The finding involved the attribute of equipment performance, as well as human performance, and affected the mitigating systems objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, interviews with

maintenance personnel revealed that the failure to follow scaffold procedures was a broad program-wide deficiency with the potential to adversely affect numerous plant systems. The finding affected the cross-cutting area of Human Performance because licensee personnel failed to follow both the scaffolding procedure and the temporary alterations procedure.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated April 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004, and Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. Although the licensee had yet to complete their post operability evaluation, the inspectors bounded the significance of the issue by assuming the HPCS was rendered inoperable by the non-seismic scaffolding constructed less than 1 inch from small diameter system keep-fill piping. Using Appendix A, inspectors determined that the finding screened as potentially risk significant due to a seismic event. The inspectors requested assistance of the regional senior risk analyst (SRA) to determine risk significance per Phase 3 analysis. Perry is categorized as a 0.3g focused-scope plant (per NUREG-1407). The licensee used the Electric Power Research Institute (EPRI) Seismic Margins Assessment methodology, described in EPRI NP-6041-SL, with enhancements as specified in NUREG-1407. Since the seismic margins approach was used, no quantitative estimate was made for the seismic contribution to plant core damage frequency. The SRA evaluated the issue and determined that the low initiating event frequency for a significant seismic event, coupled with the availability of the remaining mitigation systems that were not impacted by the finding, resulted in this finding being of very low safety significance.

<u>Enforcement</u>: Technical Specification 5.4 required implementation of the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33, Appendix A, Part 9, recommended procedures for performing maintenance affecting safety-related equipment. Contrary to this requirement, the licensee failed to implement appropriate procedures for scaffolding construction in the Division 3 EDG and HPCS pump rooms. Specifically, GCI-0016, steps 5.5.2.2 and 5.5.4 were not performed as written. This resulted in an unanalyzed condition where scaffolding failed to meet seismic clearance requirements and thereby degraded the reliability of the HPCS system.

Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-01946), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000440/2005002-02)

1R05 Fire Protection (71111.05Q)

.1 Walkdown of Selected Fire Zones/Areas

a. Inspection Scope

The inspectors walked down the following seven areas to assess the overall readiness of fire protection equipment and barriers:

- Fire Area 1CC-3a, Division 2 Switchgear Room;
- Fire Area 1CC-3b, Division 3 Switchgear Room;
- Fire Area 1CC-3c, Division 1 Switchgear Room;
- Fire Area 1CC-4a, Unit 1, Division 2 Cable Spreading Area;
- Fire Area 1CC-4e, Unit 1, Division 1 Cable Spreading Area;
- Fire Zone 0IB-3, Intermediate Building Elevation 620'-6"; and
- Fire Area 1RB-1B, Unit 1 Containment.

Emphasis was placed on the control of transient combustibles and ignition sources, the material condition of fire protection equipment, and the material condition and operational status of fire barriers used to prevent fire damage or propagation.

The inspectors looked at fire hoses, sprinklers, and portable fire extinguishers to determine whether they were installed at their designated locations, were in satisfactory physical condition, and were unobstructed. The inspectors also evaluated the physical location and condition of fire detection devices. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were inspected to determine whether they were in good physical condition. The documents listed at the end of this report were used by the inspectors during the assessment of this area.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed an inspection of internal flooding vulnerabilities associated with turbine building flooding and precautions taken to preclude this flooding from affecting safety-related buildings and equipment. The inspection consisted of a review of the internal flooding design features described in the Updated Safety Analysis Report (USAR) and in the licensee's internal turbine power complex and turbine building flooding calculations. The inspectors also reviewed surveillance test procedures associated with the design features and alarm response instructions associated with level instrumentation designed to detect, alarm, and actuate circulating water and service water system isolations. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's inservice inspection program for monitoring degradation of the RCS boundary and risk-significant piping system boundaries, based on review of records and in-process observation of nondestructive examinations (NDE).

From March 1 through 4, 2005, the inspectors evaluated several activities involving NDE examinations and welding. Specifically, the inspectors observed the following:

- ultrasonic (UT) examination of two of the top head meridional welds 1B13 DK and 1B13 DP, in the reactor building drywell; and
- magnetic particle examination of the top head to top head flange weld in the reactor building drywell.

The inspectors selected these components in order of risk priority as identified in Section 71111.08-03 of Inspection Procedure 71111.08, "Inservice Inspection Activities," based upon the Inservice Inspection activities available for review during the on-site inspection period. The inspectors evaluated these examinations for compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI and plant TS requirements and to determine if indications and defects (if present) were dispositioned in accordance with the ASME Code.

The inspectors reviewed licensee records related to pressure boundary welding performed in the following components:

- relief valve on the RHR system, valve 1E12F0055A; and
- reactor head to drywell first vent valve, valve 1B21F0002.

The inspectors performed this review to determine if the welding acceptance and pre-service examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with the requirements of the ASME Code, Sections III, V, IX, and XI.

The activities that were not available for the inspectors' review for this inspection are identified in the table below.

Inspection Procedure 71111.08 Section Number	Reason Activity was Unavailable For Inspection	Reduction in Inspection Procedure Samples
Section 02.01c Review of examinations with recordable indications that have been accepted by the licensee for continued service.	The licensee did not have identified relevant indications on Code Class 1 and 2 systems from the past two refueling outages.	This unavailable activity prevented the inspectors from completing one inspection item in the sample required by Section 71111.08-5 of Inspection Procedure 71111.08.

Because one inspection item was not available and could not be completed, the above activities were not counted as a completed inspection sample. However, the sample was completed to the extent possible.

The specific list of documents reviewed by the inspectors in conducting this inspection is listed in the attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On February 10, 2005, the resident inspectors observed licensed operator performance in the plant simulator. The inspectors evaluated crew performance in the areas of:

- clarity and formality of communication;
- ability to take timely action in the safe direction;
- prioritizing, interpreting, and verifying alarms;
- correct use and implementation of procedures, including alarm response procedures;
- timely control board operation and manipulation, including high-risk operator actions; and,
- group dynamics.

The inspectors also observed the licensee’s evaluation of crew performance to determine whether the training staff had observed important performance deficiencies and specified appropriate remedial actions. The inspectors’ review constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule requirements to determine whether component and equipment failures were identified and scoped within the maintenance rule and that select structures, systems, and components (SSCs) were properly categorized and classified as (a)(1) or (a)(2) in accordance with 10 CFR 50.65. The inspectors reviewed station logs, maintenance work orders (WOs), selected surveillance test procedures, and a sample of CRs to determine whether the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. Additionally, the inspectors reviewed the licensee's performance criteria to determine whether the criteria adequately monitored equipment performance and to determine whether licensee changes to performance criteria were reflected in the licensee's probabilistic risk assessment. During this inspection period, the inspectors reviewed the control room emergency recirculation system. The inspectors' review constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities to determine whether scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the licensee's program for conducting maintenance risk assessments to determine whether the licensee's planning, risk management tools, and the assessment and management of on-line and shutdown risk were adequate. The inspectors also reviewed licensee actions to address increased on-line and shutdown risk when equipment was out of service for maintenance, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, to determine whether the actions were accomplished when on-line and shutdown risk were increased due to maintenance on risk-significant SSCs. The following seven assessments and/or activities were reviewed:

- the maintenance risk assessment for the week of January 3, 2005, which included planned unavailability of RHR 'C,' schedule changes due to the onset of adverse winter weather, and emergent work for RPS fuse replacement;

- the licensee's shutdown safety assessment following the January 6, 2005, manual reactor scram during and following transition to Mode 4 on January 7, 2005;
- the licensee's shutdown safety assessment and control of emergent work activities including multiple 13.8 kV and 4160 V breaker inspections during the weeks of January 10, 2005, and January 17, 2005;
- the licensee's shutdown safety assessment and control of emergent work activities after declaring all three EDGs inoperable due to concerns with the testable rupture disks (TRDs) during the weeks of January 17, 2005, and January 24, 2005;
- the licensee's risk management and control of maintenance activities after recovery from an unplanned forced outage during the week of February 6, 2005;
- the licensee's configuration and risk management of the EDG systems for temporary modification removal and electrical outages during the week of March 14, 2005; and
- the licensee's shutdown safety assessment and control of the transition from Division 1 to Division 2 electrical bus outages during the week of March 28, 2005.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

.1 Fire In Chemistry Oil Analysis Room

a. Inspection Scope

The inspectors reviewed the licensee's response to a fire in the chemistry oil analysis room. The inspectors reviewed licensee actions relative to the requirements of procedure PAP-1910, Fire Protection Program, Revision 9.

b. Findings

Introduction: A finding of very low safety significance and a violation of TS 5.4 were self-revealed when the licensee failed to implement plant fire procedures for discovery of a fire. Section 4.2.3 of PAP-1910 requires prompt notification of the control room on discovery of a fire. Contrary to the requirements of PAP-1910, the licensee failed to promptly report a discovered fire to the control room.

Description: On January 13, 2005, at approximately 10:20 a.m., a chemistry technician was performing a diesel fuel analysis procedure in the chemistry oil analysis lab. The technician rinsed a 4-liter glass bottle with petroleum ether, allowed it to drip dry, and then placed it in an oven dryer for further drying. The technician closed the oven door, turned the oven on and then went to an adjacent room for approximately 3 minutes. He then returned to the oil lab and found the oven door unexpectedly ajar and saw a small flame at the mouth of the 4-liter bottle. The technician turned the oven off, left the door open, and watched the oven and bottle for about 7 minutes until the flame burned out. During interviews with the inspector, the technician said that, though the fire was unexpected, he did not think to report the fire since he viewed it as a small fire that was under control. At the time, he did not recognize that this was an event that needed to be reported per the Fire Protection Program procedure.

After the fire in the bottle burned out, the technician contacted the lead chemistry technician and described the event. The technician then informed the chemical permit manager of the event. At approximately 11:50 a.m., the chemical permit manager notified the control room. The control room operators evaluated the incident for required actions, including emergency plan entry requirements, and then informed the facility fire marshal. The licensee determined that no emergency plan entry conditions were met. Inspection of the area by the fire marshal revealed no damage to plant equipment.

The oil analysis lab contains toxic chemicals, ordinary combustibles and flammable liquid including approximately 45 gallons of oil. It is located in a fire zone that houses general offices, radiological count rooms and conference rooms. The zone is located in the control complex building within the protected area. Automatic fire detection and suppression equipment consists of smoke detectors and a sprinkler system. Water hose stations and fire extinguishers are also located in this zone.

<u>Analysis</u>: The inspectors determined that failing to follow plant fire protection procedures was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," dated June 20, 2003. The failure to follow fire protection procedures, if left uncorrected, would become a more significant safety concern. Specifically, in addition to the above hazards associated with a fire, the Perry Emergency Plan contains specific entry criteria including fires within any safe shutdown building. The failure to report a fire to the control room clearly inhibits the licensee's ability to assess, classify and notify. The finding involved the attribute of protection from external factors (fire) as well as human performance and affected the mitigating systems objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The UFSAR analysis takes into consideration manual fire suppression equipment as well as automatic features in determining whether the safety objective is achieved for this fire zone. The finding also affected the cross-cutting area of Human Performance because the chemistry technician failed to report a fire to the control room in accordance with licensee procedures.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated March 21, 2003, Appendix F, "Fire Protection Significance Determination Process," dated February 28, 2005. The Fire Protection SDP focused on risks due to degraded conditions of the fire protection program during full power operation of a nuclear power plant. It did not address the potential risk significance of fire protection inspection findings in the context of other modes of operation. Since the plant was shutdown at the time of the event, the inspectors concluded the finding was not suitable for review under IMC 0609.

Although not suitable for SDP review, the finding was determined, by regional management, to be of very low safety significance in that (1) the finding did not affect the operability of the automatic fire detection and suppression systems in the affected fire zone; (2) the fire zone was outside of the vital area of the plant; and (3) the fire zone did not contain safe shutdown systems.

Enforcement: Technical Specification 5.4 required implementation of the applicable procedures recommended in Regulatory Guide 1.33 Revision 2, Appendix A. Regulatory Guide 1.33 Appendix A, Part 6.v., recommended procedures for plant fires. PAP-1910, "Fire Protection Program," Section 4.2.3, "Fire Discovery Actions," Step 1.a., stated, "Promptly notify the Control Room by the nearest available communications system..." Contrary to this requirement, the control room was not notified until approximately 1 hour and 30 minutes after the discovery of the fire.

The finding was not suitable for SDP evaluation, but has been reviewed by NRC management and was determined to be a Green finding of very low safety significance. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-00300), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2005002-03)**.

.2 Loss of 125VDC Bus Panel D-1-B07

a. Inspection Scope

On February 23, 2005, while in shutdown in Mode 4, the licensee experienced a loss of 125VDC bus D-1-B07 during maintenance. This resulted in the loss of control power to numerous plant systems. Inspectors reviewed the licensee's immediate and supplemental actions. Specifically, the inspectors determined the licensee's actions were consistent with operating instructions, alarm response instructions, and off-normal instructions (ONIs).

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected CRs related to potential operability issues for risk-significant components and systems. These CRs were evaluated to determine whether the operability of the components and systems was justified. The inspectors compared the operability and design criteria in the appropriate sections of the Technical Specifications and USAR to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures were in place, would work as intended, and were properly controlled. The inspectors reviewed the following five issues (samples):

- an operability evaluation of the Division 2 EDG following identification of additional fretting on fuel oil return piping completed on January 11, 2005;
- operability evaluations associated with 5 and 15 kV breakers exceeding the 10 year maximum overhaul period identified in the vendor maintenance manual. The inspectors reviewed Revision 0 of the operability evaluation which was completed January 15, 2005, Revision 1 which was completed January 21, 2005, and Revision 2 which was completed on January 27, 2005;
- an operability evaluation of LPCS injection valve due to improper stem lubrication completed on January 16, 2005;
- an operability evaluation of control power fuses, identified to have broken end clips, with respect to seismic qualification completed on January 27, 2005; and
- the licensee's assessment of a discrepant condition on the ESW 'A' pump, identified on March 2, 2005, with respect to operability of the ESW 'B' pump.

b. Findings

The inspectors' concerns with the licensee's operability evaluation for 5 and 15 kV breakers are discussed in detail in NRC Special Inspection Report 05000440/2005005. The Special Inspection Report documents URI 05000440/2005005-02, "Operability Evaluation of Safety Related Breakers Requires Further Review," and NCV 05000440/2005005-03, "Failure to provide Guidance to Refurbish Breakers Within Vendor-specified Time Frames or to Provide Reasonable Alternative Preventative Maintenance Practices to Ensure That Safety-related Breakers Remained Operable." In response to the issue, the licensee has initiated action to restore compliance with vendor-specified time frames prior to the completion of the current refueling outage.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors assessed the following three operator workaround issues (three samples) to determine the potential effects on the functionality of the corresponding mitigating systems:

- the inability to close the RHR 'B' heat exchanger ESW outlet isolation valve P45-F068B;
- the additional requirements imposed on operations personnel due to operability issues associated with the EDG TRDs including door status verification; and
- the cumulative effect of the loss of several control room annunciators due to the clearance (tagout) associated with the installation of the digital feedwater system.

During these inspections, the inspectors reviewed the technical adequacy of the workaround documentation against the UFSAR and other design information to assess whether the workaround conflicted with any design basis information. The inspectors also compared the information in off-normal or emergency operating procedures to the workaround information to ensure that the operators maintained the ability to implement important procedures when required. Lastly, the inspectors conducted a review of recent CRs to ensure that operator workaround related issues were entered into the corrective action program when required.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

During the week of January 10, 2005, the inspectors reviewed the design change package for oscillation power range monitor (OPRM) design modification. The inspectors reviewed the engineering change package, 10 CFR 59.50 safety evaluation, and the design interface evaluations relative to the licensing basis including License Amendment 118, "Perry Nuclear Power Plant, Unit 1 - Issuance of Amendment RE: Activation of Thermal-Hydraulic Stability Monitoring Instrumentation." Additionally, the inspectors conducted interviews of design engineers and licensed operators. Finally, the inspectors conducted control room panel walkdowns to assess operator interface with respect to available indications.

b. Findings

No findings of significance were identified. The operational impact of the modification was further documented in NRC Special Inspection Report 05000440/2005005.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors evaluated the following post-maintenance testing (PMT) activities for risk-significant systems to assess the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written; and equipment was returned to its operational status following testing. The inspectors evaluated the activities against Technical Specification, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications. In addition, the inspectors reviewed CRs associated with PMT to determine if the licensee was identifying problems and entering them in the corrective action program. The specific procedures and CRs reviewed are listed in the attached List of Documents Reviewed. The following five post-maintenance activities were reviewed:

- testing of the reactor recirculation system circuitry conducted January 17, 2005, following a system modification which replaced existing resistor capacitor suppression with diode suppression;

- testing of the Reactor Core Isolation Cooling (RCIC) system conducted January 31, 2005, following numerous maintenance activities including preventive maintenance on the suppression pool suction isolation valve, preventive maintenance on the minimum flow valve, and piping replacement;
- testing of IRM 'A' conducted on January 15, 2005, before the failure of the instrument on reactor start-up;
- testing of RHR valve 1E12F0004A on March 11, 2005, following valve maintenance; and
- testing of 120VAC safety-related power supply EK-1-A1 following maintenance.

b. Findings

Introduction: A finding of very low safety significance and a violation of TS 5.4 were self-revealed when IRM 'A' failed to respond as expected during reactor start-up and was declared inoperable. Recent maintenance work had been performed on IRM 'A.' The maintenance left IRM 'A' in an inoperable state. The licensee failed to implement appropriate procedures to ensure that the maintenance had been satisfactorily accomplished.

Description: On January 30, 2005, a reactor start-up in Mode 2 was in progress per integrated operating instruction (IOI)-1, “Cold Startup,” and criticality was achieved. As required per IOI, operators performed overlap checks of the IRM 'A' and SRM instruments to demonstrate operability of the IRM instruments. Operators noted that IRM 'A' did not demonstrate expected overlap with the SRM instruments as required; and IRM 'A' was declared inoperable. Channels 'C' and 'F' of the IRM were bypassed due to previously determined inoperability and were incapable of demonstrating overlap. Because IRM 'A' and IRM 'C' were in the same RPS trip system and both were inoperable, the minimum TS required operability of three out of the four channels per trip system was not met and TS Action Statement 3.3.1.1 Condition A was entered. Additionally, a reactor shutdown was conducted as required by plant procedure because two or more IRM channels in the same trip system failed overlap checks.

Subsequent visual inspection by I&C technicians revealed that a cable which connected the IRM 'A' pre-amp to the IRM 'A' instrument was not properly connected. As found, the cable connection appeared farther out from the pre-amp and unusually angled compared to other pre-amp connections. Further inspection revealed that the connector threads were not fully engaged and were cross-threaded. The faulty pre-amp connection impacted the signal from the IRM 'A' detector to the instrument such that there was no indication of inoperability at the instrument until reactor power increase allowed comparison of IRM 'A' to other instruments where IRM 'A' did not respond as expected. The pre-amp connection was repaired. Operators declared IRM 'A' operable and exited TS 3.3.1.1.

Maintenance was conducted on the IRM 'A' system on January 15, 2005. During this maintenance, technicians removed the connecting cable at the detector pre-amp end in order to test the cable in accordance with instrument calibration instruction (ICI)-C51-7, “Neutron Monitoring System Coaxial Cables/Detectors,” section 5.2.3, “IRM Detector/Cable Checks,” step 7, “I/V Curve <B00909>.” The technicians then exited the

ICI-C51-7 procedure upon completion of section 5.2.3. The last two instructions of section 5.2.3 state, "Deenergize HVPS [High Voltage Power Supply] and disconnect all test equipment. Inform RO [reactor operator] detector may be placed in desired position with regard to current plant operational conditions." The ICI-C51-7 procedure omitted steps requiring re-connection of the cable to the pre-amp and otherwise failed to provide appropriate acceptance criteria to ensure the cable was properly attached. Technicians failed to adequately connect the cable upon completion of the ICI-C51-7 procedure. This resulted in an inoperable IRM 'A' channel following the maintenance.

In Mode 2, per design, a minimum of three of the four IRM channels are required to be operable per trip system to ensure that no single instrument failure will preclude a scram on a valid signal. On January 30, 2005, reactor start-up was commenced with IRM 'C' and IRM 'F' instruments in bypass due to previously determined inoperability. Operators were unaware that IRM 'A' was also inoperable until SRM and IRM overlap checks were made after criticality. Channels 'A' and 'C' of the IRM share the same RPS trip system while IRM 'F' inputs into the other RPS trip system. Logic of the RPS requires at least two IRM scram signals to trip a trip system. While IRM 'A' and IRM 'C' were inoperable, RPS trip capability was maintained by the two remaining operable IRM channels in that system. However, because the number of IRM channel inputs into the RPS was reduced, trip capability was not ensured such that no single instrument failure would preclude a scram on a valid signal.

<u>Analysis</u>: The inspectors determined that erroneously leaving the IRM 'A' channel in an inoperable state after maintenance was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," dated June 20, 2003. The failure to implement appropriate procedures to ensure satisfactory maintenance completion, if left uncorrected, would become a more significant safety concern. The finding involved the attribute of equipment performance, as well as human performance, and affected the mitigating systems objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding affected the cross-cutting area of Human Performance because technicians failed to adequately attach and verify satisfactory connection of the cable in the IRM 'A' system.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated March 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004. Inspectors determined that the mitigating systems cornerstone was affected because reactivity control was degraded due to the loss of an IRM channel input to the RPS. Because RPS maintained its trip capability, the finding did not represent a loss of system safety function and inspectors assessed the finding as Green.

<u>Enforcement</u>: Technical Specification 5.4 required implementation of the applicable procedures recommended in Regulatory Guide 1.33 Revision 2, Appendix A. Regulatory Guide 1.33 Appendix A, Part 9, recommended maintenance procedures for maintenance that can affect the performance of safety-related equipment. Contrary to

this requirement, the licensee failed to implement appropriate procedures during maintenance on IRM 'A.' The maintenance rendered IRM 'A' inoperable.

Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-00762), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000440/2005002-04)**.

1R20 Refueling and Outage Activities (71111.20)

.1 Forced Outage

a. Inspection Scope

The inspectors observed activities associated with a forced outage (one sample) initiated on January 6, 2005. The forced outage continued through February 1, 2005, when the plant synchronized to the grid. The inspectors assessed the adequacy of forced outage-related activities, including implementation of risk management, conformance to approved site procedures, and compliance with TS requirements. The following major activities were observed or performed:

- On January 6, 2005, the inspectors observed the licensee's control of reactor pressure and water level while maintaining the plant in Mode 3, cooldown to Mode 4, and maintenance of Mode 4 plant conditions. The inspectors observed shift briefings, operator performance, shift management coordination of plant activities, and conformance with TS requirements including cooldown limitations.

- From January 6, 2005, through January 30, 2005, the inspectors reviewed licensee restart readiness activities to determine whether emergent issues were appropriately identified as restart restraints and that restart restraint issues were appropriately resolved prior to mode changes.

- On January 30, 2005, the inspectors observed the licensee's reactor startup and subsequent procedurally shutdown after failing to obtain proper overlap of IRM 'A' and SRM 'A.' The inspectors observed subsequent restart activities on January 31, 2005. The inspectors observed shift briefings, operator performance, shift management coordination of plant activities, and conformance with TS requirements including heat-up limitations and mode change requirements.

b. Findings

A self-revealed finding involving a licensee performance deficiency concerning IRM 'A' is discussed in section 1R19 of this report.

.2 Refueling Outage

a. Inspection Scope

The inspectors observed work activities associated with RFO10 which began on February 22, 2005, and continued through the remainder of the inspection period. This constituted one inspection sample. The inspectors assessed the adequacy of outage-related activities, including implementation of risk management, preparation of contingency plans for loss of key safety functions, conformance to approved site procedures, and compliance with TS requirements. The following major activities were observed or performed:

- On February 21 and 22, 2005, the inspectors observed the licensee's shutdown and cooldown of the reactor. The inspectors observed shift briefings, operator performance, shift management coordination of plant activities, and conformance with TS requirements including cooldown limitations.

- The inspectors observed the licensee's control of reactor vessel level during plant shutdown, cooldown, and subsequent reactor pressure vessel disassembly.

- On February 27, 2005, the inspectors observed the licensee's demonstration of the capacity of an alternate decay heat removal method. The inspectors monitored the performance of the identified primary decay heat method throughout the refueling outage.

- The inspectors reviewed the licensee's installation and use of temporary reactor vessel level instrumentation on March 2, 2005. The inspectors periodically verified agreement of redundant level and temperature indications by direct observation throughout the outage.

- On March 7 and 8, 2005, the inspectors reviewed the licensee's contingency plans for establishing containment and fuel handling building closure and licensee work packages to close the containment upper and lower personnel air locks if required.

- On March 9, 2005, inspectors observed the licensee's core alterations process while fuel was removed from the core. On March 28, 2005, the inspectors observed the licensee's core alteration process during core reload.

- During the week of March 14, 2005, inspectors observed the licensee's control of electrical outage maintenance and clearance activities.

b. Findings

(1) Dropped Jet Pump Plug

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed on February 28, 2005. Specifically, while removing a jet pump plug assembly from the reactor vessel, the plug broke loose from the handling pole and roped L-hook while being lifted over the refuel floor auxiliary platform. As a result, the plug dropped approximately 60 feet, primarily through water, and landed on top of several fuel bundles in the reactor core.

Description: On February 28, 2005, the licensee began installing jet pump plugs to establish an isolation boundary for planned work on the reactor recirculation system pump 'B' discharge valve. Work was performed in accordance with licensee WO 200110754, "Install/Remove Jet Pump Plugs in Loop 'B' of Recirc System," Rev. 0. After installation of a jet pump plug, the refueling technicians determined that the plug failed to seat properly and needed to be removed for repair. The technicians had successfully removed the plug from the jet pump and were in the process of lifting the plug onto the refuel floor auxiliary bridge when the technician bumped the assembly against the platform handrail. The plug detached from the handling pole and roped L-hook, dropped back into the water, and traveled approximately 60 feet before landing on the fuel bundles.

The licensee stopped all work on the refuel floor and developed a recovery plan. The jet pump plug was successfully retrieved on March 1, 2005. Initial visual inspection indicated no damage to the fuel bundles. This was subsequently verified by chemistry sampling and fuel bundle inspection during core alterations.

The inspectors attended the licensee's debrief of the refuel floor technicians. The most significant issue identified during the debrief was the failure to use an independent backup method to the handling pole and rope when attempting to lift the plug over the handrail. Specifically, the lead technician identified that typically a third technician would establish physical contact with the plug, by grabbing it by hand, while the plug is brought over the handrail. It was also noted that the pre-job briefing did not identify the need for such additional foreign material exclusion (FME) controls.

The inspectors noted that WO 200110754 contained direction to "take the necessary precautions to avoid dropping anything into the pool during performance of this work order" and that "steps should be taken to maximize foreign material control." As the plug was dropped, in part, due to less than adequate FME controls, the inspectors concluded that the issue was most appropriately characterized as a failure to follow procedures.

Analysis: The inspectors determined that dropping a jet pump plug assembly, weighing approximately 25 pounds, onto the top of the reactor core was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. Further, the finding was associated with the barrier integrity cornerstone attribute of human performance and affected the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. The finding affected the cross-cutting issue of Human Performance because a personnel error caused the plug to be dropped.

The inspectors determined that the finding was not suitable for SDP review as IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process,” Checklist 7 does not address fuel barriers. Although not suitable for SDP review, regional management determined that the finding was of very low safety significance because the dropped plug was subsequently determined to not have caused damage to the fuel.

Enforcement: The performance deficiency associated with this event is the failure to correctly implement procedures required for plant operation. Technical Specification 5.4 requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, Part 9.a, recommended procedures for maintenance that can affect the performance of safety-related equipment and that maintenance be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the requirements of TS 5.4, WO 200110754 was improperly implemented in that less than adequate FME controls were established for jet pump plug removal. As a result, the plug was dropped onto the reactor core. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 05-01599) it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (**NCV 05000440/2005002-05**).

(2) Inadvertent Control Rod Withdrawal

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed on March 10, 2005. Specifically, while attempting to verify the position of control rod 18-55, an SRO inadvertently withdrew control rod 58-35 from position 00 to position 02. Upon recognition of the condition, the SRO took the TS required actions and immediately reinserted the control rod.

Description: On March 10, 2005, the licensee was conducting core alterations in accordance with the “Fuel Movement Master Checklist,” dated February 25, 2005. Step 513 of the checklist contained a note to verify that control rod 18-55 was fully withdrawn from the core prior to removing the full blade guide from the location in accordance with step 514 of the checklist. The refuel supervisor made several attempts to contact the SRO supervising rod movements in the control room, but was unsuccessful. Since no rod movements were in progress or planned at that moment, the SRO supervising control rod movements had left the at-the-controls area.

The control room unit supervisor, an SRO, heard the communication, answered the call, and asked the refuel supervisor to wait for the information. The control room unit supervisor went to the operators control module with the intention, per his subsequent statement, of pressing the “all rods” pushbutton on the display section of the module. However, instead of depressing the “all rods” pushbutton, the control room unit supervisor depressed the “withdraw” pushbutton. Since control rod 58-35 was selected at that time, the control rod was withdrawn from position 00 to position 02. The “at-the controls” reactor operator (RO) and the control room unit supervisor immediately identified the error due to the unintended rod movement. The control room unit supervisor immediately requested the RO to provide a peer check for rod insertion.

Control rod 58-35 was then inserted to position 00. The control room unit supervisor promptly notified the shift manager of the reactivity event and was relieved as unit supervisor by another qualified SRO.

Licensee computer data showed the rod was out of position 00 for less than 15 seconds. No response on any source range instrumentation was observed. The observation was confirmed by licensee computer data. The licensee's subsequent shutdown margin calculation confirmed that parameter was not significantly challenged.

The inspectors noted the rod movement was not in accordance with multiple licensee procedures, including:

- Licensee IOI-9, "Refueling," Rev.11, Section 2.3.1 stated "during rod movements, except those performed under the 'one-rod-out' interlock, an inadvertent criticality may result from out of position control rods or out of sequence control rods. A second licensed operator, or other technically qualified member of the unit technical staff, shall verify conformance with the applicable Technical Specifications and the test procedure when bypassing control rod sequence restraints." No second licensed operator was involved in the movement of 58-35 nor was any test procedure in place.

- Licensee normal operating procedure (NOP)-OP-1004, "Reactivity Management," Rev. 0, Section 4.6.1.2 stated "operation of reactivity controls and other mechanisms which may affect reactivity or power level of the reactor shall only be accomplished with the knowledge and consent of the Licensed Operator 'at the controls' and with the approval of the On-Duty Unit Supervisor."

- Licensee NOP-OP-1004, Section 4.6.1.5 stated "plant specific procedures will be utilized for the positioning of control rods."

The inspectors also identified numerous examples of noncompliance with the expectations and standards identified in licensee NOP-OP-1002, "Conduct of Operations," Rev.1. Most notably:

- none of the 23 responsibilities of the unit supervisor identified in section 4.1.2 of NOP-OP-1002 included the manipulation of equipment, switches, or pushbuttons on the operators' control module;
- the unit supervisor did not request nor obtain a peer check contrary to the standards stated in section 4.4.2 of NOP-OP-1002; and
- the unit supervisor had not participated in the pre-job briefing for core alterations and thus, per section 4.8.6 of NOP-OP-1002, should not have been involved in the performance of Step 513 of the "Fuel Movement Master Checklist."

<u>Analysis</u>: The inspectors determined that a personnel error that resulted in the inadvertent withdrawal of a control rod was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. Further, the finding was associated with the barrier integrity cornerstone attribute of human

performance and affected the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. The finding affected the cross-cutting issue of Human Performance because a personnel error resulted in an inadvertent withdrawal of a control rod.

Although not suitable for SDP review, regional management determined that the finding was of very low safety significance because the rod movement had minimal impact of reactivity as evidenced by the lack of response by source range instrumentation and subsequent licensee shutdown margin assessment. Further, the error was immediately recognized and the control rod was inserted to position 00 in less than 15 seconds. Additionally, the SRO's use of the withdraw pushbutton self-limited the movement to one notch.

Enforcement: The performance deficiency associated with this event is the failure to correctly implement procedures required for plant operation. Technical Specification 5.4 requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, Part 2.I, recommended procedures for refueling and core alterations. The licensee developed procedure IOI-9, in part, to provide instructions for refueling and fuel movement checklists to perform core alterations. Contrary to the requirements of several licensee procedures, identified above, a unit supervisor withdrew control rod 58-35 from position 00 to position 02 while fuel assemblies were in the cell. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-02063), it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (**NCV 05000440/2005002-06**).

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed surveillance testing or reviewed test data for risk-significant systems or components to assess compliance with Technical Specifications; 10 CFR Part 50, Appendix B; and licensee procedure requirements. The testing was also evaluated for consistency with the USAR. The inspectors determined whether the testing demonstrated that the systems were ready to perform their intended safety functions. The inspectors reviewed whether test control was properly coordinated with the control room and performed in the sequence specified in the surveillance instruction (SVI), and if test equipment was properly calibrated and installed to support the surveillance tests. The procedures reviewed are listed in the attached List of Documents Reviewed. The five surveillance activities assessed were:

- ECCW 'B' pump and valve operability testing conducted January 5, 2005, February 1, 2005, and February 5, 2005;
- containment/drywell purge exhaust radiation monitor calibration performed on February 3, 2005;

- Division 1 and 3 EDG operability tests following a failed test of Division 2 EDG during the week of February 6, 2005;
- the LLRT for the RHR ‘A’ suppression pool suction valve, 1E12-F004A, conducted February 27, 2005; and
- testing of safety relief valve (SRV) actuators performed on March 30, 2005.

b. Findings

.1 January 5, 2005, ECCW 'B' Pump and Valve Operability Test

Introduction: Inspectors identified a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions.” Specifically, the licensee failed to take prompt corrective action after identifying that erroneous or unexplainable data was recorded during TS required ECCW 'B' pump and valve operability testing.

Description: On January 5, 2005, the licensee conducted quarterly ECCW 'B' pump and valve operability testing. The unit supervisor noted that calculated pump differential pressure was lower than expected and brought the issue to the attention of the responsible system engineer (RSE). The RSE responded on January 17, 2005, through CR 05-00408. In the CR, the RSE concurred that the recorded value, although still in the acceptable range, was 4 psid lower than historical values which had been relatively constant. Upon further review, the RSE identified that the recorded value for throttled pump discharge pressure was likely erroneous in that it was lower than the recorded value for discharge pressure prior to throttling of the flow. The RSE documented a number of possible causes for the erroneous value including problems with the test gauge or operator error while reading the gauge. The erroneous data was a direct input into a TS required calculated value.

The RSE then documented acceptability of the TS required test data despite the noted erroneous data because “all acceptance criteria were met and all pump vibration values looked good.” The RSE obtained supervisor concurrence. The CR was initially coded as “CC” meaning condition adverse to quality, “close” - no evaluation method required. The CR was then reviewed and approved by a SRO. The SRO’s documented comments were “trending purposes.”

The inspectors reviewed CR 05-00408 as per their daily CR review on January 18, 2005. The inspectors immediately questioned the licensee’s disposition of the issue and brought the issue to the attention of the control room and licensee management. The control room personnel concluded that the disposition was inappropriate and initiated action to re-code the surveillance as “no credit” based on suspect data. Action was also initiated to reschedule the surveillance prior to its overdue date of February 4, 2005. The licensee’s subsequent performance of the surveillance test was not properly performed which resulted in a missed TS 5.5.6 surveillance (as discussed in Section 4OA7 of this report) and an additional 10 CFR Part 50, Appendix B, Criterion XVI violation was identified by the inspectors (as discussed in Section 1R22.2 of this report). The test was performed satisfactorily on February 5, 2005.

Analysis: The inspectors determined that accepting TS required surveillance testing results with identified likely erroneous or otherwise unexplainable data was a performance deficiency warranting significance evaluation. The inspectors noted that the CR had not been through the licensee's management review board process, but concluded that the failure of an RSE, an engineering supervisor, and an SRO to take action to correct an identified condition adverse to quality was more than minor in that it could reasonably be viewed as a precursor to a significant event and, with respect to the performance of TS required surveillance testing, was associated with the reactor safety cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring mitigating system availability, reliability, and capability. The finding affected the cross-cutting issue of Problem Identification and Resolution because a condition adverse to quality was not corrected.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The inspectors determined that the finding did not involve the loss of safety function in that ECCW 'B' subsequently satisfactorily met the acceptance criteria of the required quarterly pump and valve operability test on February 5, 2005. The inspectors therefore concluded that the finding was of very low safety significance.

Enforcement: Appendix B, Criterion XVI of 10 CFR Part 50 stated, in part, that "measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to these requirements, on January 17, 2005, licensee personnel, including an SRO, accepted identified erroneous data in TS required surveillance procedure rather than initiating action to promptly correct the condition. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-00547, CR 05-00898, and CR 05-1772), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy
(NCV 05000440/2005002-07).

.2 February 1, 2005, ECCW 'B' Pump and Valve Operability Test

Introduction: Inspectors identified a finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions." Specifically, the licensee failed to promptly identify and correct a condition adverse to quality following the inspectors' identification on January 18, 2005, of an improperly performed TS required surveillance. As a result of the licensee's failure to properly evaluate the January 5, 2005, performance deficiency and take appropriate corrective action, the surveillance test was again performed improperly on February 1, 2005.

Description: On January 18, 2005, the inspectors identified that an SRO failed to take prompt corrective action when a CR clearly stated that erroneous or otherwise unexplainable data was used in the determination of a TS surveillance value (as discussed in Section 1R22.1 of this report). The licensee responded to the inspectors' immediate concerns by discrediting the surveillance and initiating action to reschedule the test. The inspectors noted, however, that the licensee did not initially document the SRO's inappropriate actions nor the failure of the crew to properly perform the SVI in the corrective action program. After additional questions by the inspectors, the licensee issued CR 05-00547, "Lack of Questioning Attitude," dated January 21, 2005, to address the issue.

The inspectors reviewed CR 05-00547 and determined that most aspects of the document, including description of condition and probable cause, categorization, and assigned corrective actions (none), were inadequate. While the inspectors determined that the SRO review of CR 05-00408, "Emergency Closed Cooling 'B' Pump Test," dated January 17, 2005, was inadequate, the inspectors noted the licensee failed to address numerous additional issues, including, but not limited to:

- a system engineer and his supervisor inappropriately recommended acceptance of test data with an erroneous reading;
- an operating crew failed to identify unexpected system response after component manipulation; and
- initial SRO review identified a change in calculated differential pressure, but failed to identify the erroneous input data to the calculation.

As a result of the licensee's failure to adequately document the performance deficiency, failure to properly categorize the issue, and failure to conduct any evaluation of the issue, no corrective action other than a supervisor comment that "individual performance issues are addressed in FENOC performance management process" were taken.

On February 1, 2005, three days before the surveillance would be outside the TS required periodicity, the licensee reperformed the test. On February 5, 2005, the licensee identified that the procedure had been incorrectly performed and entered TS 3.0.3 for a missed TS surveillance. The inspectors considered the failure to follow procedure and missed TS surveillance issues to be licensee-identified and are documented in Section 4OA7 of this report.

Review of the February 1, 2005, test data shows that the same value, pump differential pressure, was again calculated with erroneous data. In this instance, the test performer used the pump discharge pressure recorded in step 5.1.11 of licensee procedure SVI-P42-T2001-B, "Emergency Closed Cooling System 'B' Pump and Valve Operability Test," Rev. 5 in the calculation for pump differential pressure. This value represented pump discharge pressure prior to throttling a valve to establish procedurally required flow conditions. The discharge pressure value should have been requested by the test performer and provided by the in-field non-licensed operator at step 5.1.15.b.

The inspectors concluded that had the January 5, 2005, event received appropriate management attention and proper disposition in the licensee's corrective action program, the February 1, 2005, performance deficiency could have been prevented.

<u>Analysis</u>: The inspectors determined that the licensee's failure to identify and correct a condition adverse to quality was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor in that it

could reasonably be viewed as a precursor to a significant event and, in this case, resulted in a second improper performance and a missed TS surveillance. Additionally, the issue was associated with the reactor safety cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring mitigating system availability, reliability, and capability. The finding affected the cross-cutting issue of Problem Identification and Resolution because a condition adverse to quality was not corrected.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The inspectors determined that the finding did not involve the loss of safety function in that ECCW 'B' subsequently satisfactorily met the acceptance criteria of the required quarterly pump and valve operability test on February 5, 2005. The inspectors therefore concluded that the finding was of very low safety significance.

Enforcement: Appendix B, Criterion XVI of 10 CFR Part 50 stated, in part, that "measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to these requirements, on January 21, 2005, licensee personnel failed to identify a condition adverse to quality and as a result took no corrective action. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-00898 and CR 05-01772), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2005002-08)**.

.3 I&C Error Results in Inadvertent ESF Actuation

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed on February 3, 2005. Specifically, while calibrating the containment/drywell purge exhaust radiation monitor 1D17-K660, an error by an I&C technician resulted in the isolation of the backup drywell hydrogen purge system. The backup hydrogen purge system had been placed in service to prevent drywell pressurization caused by expansion of the drywell air volume during plant startup.

Description: On February 3, 2005, the licensee was performing a calibration of the containment/drywell purge exhaust radiation monitor 1D17-K660 in accordance with licensee periodic testing instruction (PTI)-D17-P1660, "Containment/Drywell Purge Exhaust Radiation Monitor 1D17-K660 Calibration," Rev. 2. While performing step 5.15.12 of the procedure, the licensee's I&C technician erroneously pressed the 1D17-K676 (drywell atmosphere "gas") trip test pushbutton instead of the 1D17-K667 (containment vessel and drywell purge exhaust "particulate") trip test pushbutton. The drywell atmosphere "gas" channel, 1D17-K676, actuation resulted, by design, in an ESF actuation. Specifically, backup hydrogen purge system containment isolation valves M51-F090 and M51-F110 received an isolation signal. The valves functioned as designed and isolated the backup drywell hydrogen purge system. Control room personnel realigned the backup drywell hydrogen purge system in accordance with the system operating instruction (SOI). Additional I&C personnel reset the trip signal and completed the calibration procedure successfully.

The backup drywell hydrogen purge system is used to prevent drywell pressurization caused by increased drywell temperatures such as those experienced during a plant heatup. The licensee had put the system in service on January 31, 2005, during the plant startup.

Analysis: The inspectors determined that an inadvertent ESF actuation due to improper performance of an I&C procedure was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a more significant event. The finding affected the cross-cutting issue of Human Performance because a personnel error was the primary cause of the event.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Initiating Events Cornerstone. The inspectors determined that the finding: (1) did not contribute to the likelihood of a LOCA initiator; (2) did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; and (3) did not increase the likelihood of a fire or internal/external flood. The inspectors therefore concluded that the finding was of very low safety significance.

Enforcement: The performance deficiency associated with this event was the failure to correctly implement procedures required for plant operation. Technical Specification 5.4 requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, Part 8.b.(2).(aa), recommended procedures for area, portable, and airborne radiation monitor calibrations. The licensee developed PTI-D17-P1660, in part, to provide instructions for the calibration of the containment/drywell purge exhaust radiation monitor. Contrary to the requirements of TS 5.4, PTI-D17-P1660, step 5.15.12 was improperly performed. As a result, two containment isolation valves were actuated. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-00871), it is being treated as an NCV, consistent with Section VI.A of the NRC's Enforcement Policy (**NCV 05000440/2005002-09**).

.4 RHR 'A' Suppression Pool Suction Valve Local Leak Rate Test

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed on February 27, 2005. Specifically, while performing a LLRT for the RHR 'A' suppression pool suction valve, 1E12-F004A, the valve was opened with the RHR 'A' system drained and vented. As a result, the suppression pool began draining through an open 8 inch drain valve to the auxiliary building equipment drain sump.

Description: On February 26, 2005, the licensee drained the RHR 'A' loop in accordance with licensee procedure SOI-E12, "Residual Heat Removal System," Rev. 21, Section 7.14.1, "RHR A Drain." The procedure left the system in a configuration such that the piping was drained and vented downstream of the suppression pool suction valve. Multiple vent and drain valves were, per procedure, left in the open position. Due to a licensee work scheduling deficiency, the LLRT for the RHR 'A' suppression pool suction valve, 1E12-F004A, was scheduled for February 27, 2005, when the train was drained and vented. On February 27, 2005, the licensee attempted to perform the LLRT for valve 1E12-F004A in accordance with licensee procedure SVI-E12-T9102, "Type C Local Leak Rate Test of 1E12 Penetration P102," Rev. 5. The test essentially pressurizes the area between the valve discs and determines the leak rate. The SVI required remote stroking of 1E12-F004A valve to ensure the valve was closed by normal methods thus providing representative leakage data.

When requested by the LLRT group, a licensed operator opened valve 1E12-F004A in accordance with SVI-E12-T9102, step 5.1.3.3. The reference time for the valve opening was 116 seconds. Step 5.1.3.4 of SVI-E12-T9102 required the licensed operator to close valve 1E12-F004A. The reference time for valve closure was also 116 seconds. Thus, a drain path from the suppression pool to the auxiliary building equipment drains through the open suction line drain valve, 1E12-F071A, existed for between 4 and 5 minutes. During the time period, the suppression pool drained to the auxiliary building equipment drain sumps which overflowed to floor drain sumps which overflowed through the floor drains to the auxiliary building 568' hallway. Approximately 1 inch of water accumulated in the hallway prior to the termination of the draining when the 1E12-F004A valve was stroked closed.

The inspectors discussed the event with the involved operators and operations management. During the discussions the licensee identified several potential procedure enhancements such as more clearly defining the term "secured status" and including additional valves in the LLRT procedure pre-test valve alignment. Additionally, the licensee identified additional enhancements for more clearly identifying the status (such as "drained") of systems during outage activities via status boards in the control room and outage control center. Finally, the licensee acknowledged the scheduling error which unnecessarily challenged the licensed operators. The inspectors reviewed the licensee's immediate actions and verified the implementation of the additional status boards.

The inspectors noted that SVI-E12-T9102, step 5.1.2.1 directed the operators to place RHR 'A' in secured status per SOI-E12. The inspectors observed that SOI-E12, Section 6.5 addressed shutdown from standby readiness to secured status for an RHR loop. Since the system was not in a secured status as defined by the SOI, but rather was drained per SOI-E12, Section 7.14.1, the inspectors determined that step 5.1.2.1 was not performed as written. The inspectors acknowledge the licensee's proposed procedure enhancements, but determined that fundamental operator knowledge of safety system status combined with literal procedural compliance would have prevented the event. As such, the inspectors concluded the issue was most appropriately characterized as a failure to follow procedures.

<u>Analysis</u>: The inspectors determined that inadvertent draining of the suppression pool to the auxiliary building floor was a performance deficiency warranting a significance

evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a significant event. The finding affected the cross-cutting issue of Human Performance because a personnel error resulted in a loss of suppression pool volume and undesired flooding in the auxiliary building.

Using IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process,” dated February 28, 2005, the inspectors reviewed the finding per Checklist 7. The inspectors noted that the movement of several thousand gallons of water was indicated by alarms in the control room (high sump levels). The inspectors also noted that the quantity of water lost, estimated to be 8,500 gallons, from the suppression pool was minor relative to the pool volume of over 1.5 million gallons. The inspectors also considered that although RHR 'B' was protected and credited for decay heat removal at the time of the event, the licensee had previously demonstrated, by calculation, the availability of an alternate decay heat removal method and was in the process of physically verifying the capability of a second alternate decay heat removal method. As such, the inspectors determined that the finding: (1) did not increase the likelihood of a loss of RCS inventory; (2) did not degrade the licensee’s ability to terminate a leak path or add RCS inventory when needed; and (3) did not degrade the licensee’s ability to recover decay heat removal if lost. The inspectors therefore concluded that the finding was of very low safety significance.

Enforcement: The performance deficiency associated with this event is the failure to correctly implement procedures required for plant operation. Technical Specification 5.4 requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, Part 8.b.(2).(a), recommended procedures for containment leak-rate and penetration leak-rate tests. The licensee developed procedure SVI-E12-T9102, in part, to provide instructions for the testing of penetration P102. Contrary to the requirements of TS 5.4, SVI-E12-T9102, step 5.1.2.1 was improperly implemented in that the RHR ‘A’ loop was not placed in a secured status, but was drained. As a result, when the RHR ‘A’ suppression pool suction valve was opened, the suppression pool began draining through an open 8 inch drain valve to the auxiliary building equipment drain sump. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 05-01543), it is being treated as an NCV, consistent with Section VI.A of the USNRC Enforcement Policy (**NCV 05000440/2005002-10**).

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed documentation for the following temporary configuration changes constituting three samples:

- a change implemented via Operations Standing Order dated January 18. 2005, to maintain Division 1, 2, and 3 EDG TRDs in the unlatched position during engine standby conditions;
- Division 1, 2, and 3 EDG TRD debris shields; and

- Division 1 and 2 EDG TRD corridor fuel oil tank and lube oil tank vent line heat shields.

The inspectors assessed the acceptability of each temporary configuration change by comparing the 10 CFR 50.59 screening and evaluation information against the design basis, the UFSAR and the Technical Specifications as applicable. The comparisons were performed to ensure that the new configurations remained consistent with design basis information. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. The inspectors also reviewed CRs initiated during or following the temporary modification installation to ensure that problems encountered during the installation were appropriately resolved.

b. Findings

Due to repetitive problems with the TRD performance, the licensee completed a 10 CFR 50.59 screen on January 9, 2005, to place the TRDs in an unlatched position during normal EDG standby conditions. The screen concluded that a 10 CFR 50.59 evaluation was not required. The Division 2 EDG TRD was unlatched on January 7, 2005 and the Division 1 EDG TRD was unlatched on January 8, 2005. On January 12, 2005, the 10 CFR 50.59 screen was revised to include the Division 3 EDG TRD.

On January 18, 2005, the licensee identified that, contrary to statements in the 10 CFR 50.59 screen, the temperature in the EDG TRD tornado missile enclosure could exceed the limiting temperature for the enclosure's concrete. The licensee also noted that an analysis of the enclosure's ability to meet USAR cited standards did not exist. As a result, on January 19, 2005, the licensee declared all three divisional EDGs inoperable (NRC Event Notification Number 41344). The EDG TRDs were relatched. Temporary modifications for debris shields and heat shields were installed. The three EDGs were declared operable on January 30, 2005.

The licensee has since completed an analysis of the capabilities of the tornado missile enclosure and have concluded that the "concrete enclosure, as originally designed, supported operability of the diesel generators and their support systems." On March 23, 2005, the licensee retracted the event notification. Pending inspector review of the licensee's past operability analysis, this issue, including the characterization of the inadequate 10 CFR 50.59 screen, is considered an Unresolved Item (**URI 05000440/2005002-11**).

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors discussed performance indicators with the radiation protection (RP) staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators in the occupational exposure cornerstone that had not been reviewed and reported. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas (HRAs), and airborne areas in the plant. Selected work packages and radiation work permits (RWP) were reviewed to determine if radiological controls including surveys, postings, air sampling data and barricades were acceptable. Work packages and RWPs included:

- RWP 056414; RFO-10 Under Vessel; Revision 0;
- RWP 056420; RFO-10 Reactor Disassembly; Revision 0; and
- RWP 056405; RFO-10 Decontamination; Revision 0.

This review represented one sample.

The identified radiologically significant work areas were walked down and surveyed to determine if the prescribed RWP, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. This review represented one sample.

The inspectors reviewed selected RWPs and associated radiological controls used to access these and other radiologically significant areas, and evaluated the work control instructions and control barriers that were specified, in order to determine if the controls and requirements provided adequate worker protection. Site technical specification requirements for HRAs and locked high radiation areas (LHRAs) were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors determined whether pre-job briefings emphasized to workers the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one sample.

The inspectors reviewed the licensee's job planning records and interviewed licensee representatives to determine if there were airborne radioactivity areas in the plant with a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance, such as high efficiency particulate filtration ventilation system operation and use of respiratory protection, were evaluated for worker protection. Work areas having a history of, or the potential for, airborne transuranic isotopes were reviewed to determine if the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. This review represented one sample.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was evaluated to ascertain whether affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures were properly assessed in accordance with licensee procedures. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and CRs related to the access control program to determine if identified problems were entered into the corrective action program for resolution. These reviews represented one sample.

Corrective action reports related to access controls and HRA radiological incidents (non-performance indicator occurrences identified by the licensee in HRAs less than 1 Rem/hr) were reviewed. Staff members were interviewed and corrective action documents were reviewed to determine if follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee's process for problem identification, characterization and prioritization in order to determine if problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors determined whether the licensee's self-assessment activities also identified and addressed these deficiencies. This review represented one sample.

The inspectors discussed performance indicators with the RP staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone that had not been reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected three jobs being performed in radiation areas, potential airborne radioactivity areas, and HRAs for observation of work activities that presented the greatest radiological risk to workers and included areas where radiological gradients were present. This involved work that was estimated to result in higher collective doses, and included under-vessel and reactor cavity work, and other selected work areas.

The inspectors reviewed radiological job requirements including RWP and work procedure requirements, and attended as-low-as-is-reasonably-achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to ascertain whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and radiological condition postings. This review represented one sample.

The inspectors also evaluated the adequacy of radiological controls including required radiation, contamination and airborne surveys for system breaches and entry into HRAs. Radiation protection job coverage which included direct visual surveillance by RP technicians along with the remote monitoring and teledosimetry systems, and contamination control processes were reviewed to assess the effectiveness of worker protection from radiological exposure. This review represented one sample.

Work in HRAs having significant dose rate gradients was observed to assess the application of dosimetry to effectively monitor exposure to personnel, and to evaluate the adequacy of licensee controls. The inspectors observed RP coverage of under-vessel work which involved controlling worker locations based on radiation survey data and real time monitoring using teledosimetry in order to maintain personnel radiological exposure ALARA. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspectors reviewed the licensee's performance indicators for high risk, high dose rate and HRAs, and for all very high radiation areas (VHRAs) to determine if workers were adequately protected from radiological overexposure. Discussions were held with RP management concerning high dose rate/HRA and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection. This was done to determine whether any procedure modifications would have substantially reduced the effectiveness and level of worker protection. This review represented one sample.

The inspectors evaluated the controls (including Procedures HPI-D0004, "Surveillance Of High Radiation Area Barricades," Revision 4; and PAP-0123, "Control Of Locked High Radiation Areas," Revision 8) that were in place for special areas that had the potential to become VHRAs during certain plant operations. Discussions were held with RP supervisors to determine how the required communications between the RP group and other involved groups would occur beforehand in order to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one sample.

During plant walkdowns, the posting and locking of entrances to high dose rate HRAs, and VHRAs were reviewed for adequacy. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated RP work requirements. The inspectors also evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated RP technician performance with respect to RP work requirements. This was done to evaluate whether the technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This review represented one sample.

Radiological problem reports, which found that the cause of an event was RP technician error, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends along with ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average collective exposure and comparing radiological exposure on a yearly basis for the previous 4 years in order to establish the effects of the plant's source term on radiological exposure for non-outage years and routine refueling outage years. This review represented one sample.

The inspectors reviewed the outage work scheduled during the inspection period along with associated work activity exposure estimates including the five work activities which were likely to result in the highest personnel collective exposures. This review represented one sample.

Site specific trends in collective exposures and source-term measurements were reviewed. This review represented one sample.

Procedures associated with maintaining occupational exposures ALARA, and processes used to estimate and track work activity specific exposures were reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities, ranked by estimated exposure, that were in progress and selected the five work activities of highest exposure significance. This review represented one sample.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to determine if the licensee had established procedures, along with engineering and work controls, that were based on sound RP principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, or special circumstances. This review represented one sample.

Shielding requests from the RP group were evaluated with respect to dose rate reduction and reduced worker exposure, along with engineering shielding responses follow-up. This review represented one sample.

The inspectors reviewed work activity planning to establish that there was consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components and piping, job scheduling, along with shielding and scaffolding installation and removal activities. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and bases for the current annual collective exposure estimate. Procedures were reviewed in order to evaluate the licensee's methodology for estimating work activity-specific exposures and the intended radiological exposure. Dose rate and man-hour estimates were evaluated for reasonable accuracy. This review represented one sample.

The licensee's process for adjusting exposure estimates or re-planning work when unexpected changes in scope, emergent work, or higher than anticipated radiation levels were encountered was evaluated. This included determining that adjustments to estimated exposure were based on sound RP and ALARA principles and had not been adjusted to account for work control failures. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. This review represented one sample.

The licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. Radiation work permits were reviewed to determine if they covered too many work activities to allow work activity-specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors selected five work activities in radiation areas, potential airborne radioactivity areas, and HRAs for observation, emphasizing work activities that presented the greatest radiological risk to workers. Jobs that were expected to result in significant collective doses and involved potentially changing or deteriorating radiological conditions were observed. These included under-vessel work activities and reactor/cavity work. The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The use of engineering controls to achieve dose reductions was evaluated to determine if procedures and controls were consistent with the ALARA reviews, that sufficient shielding of radiation sources was provided for, and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding. This review represented one sample.

- Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays. This review represented one sample.

- The inspectors attended ALARA pre-job briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included observations that first-line job supervisors ensured that work activities were conducted in a dose efficient manner by minimizing work crew sizes, ensuring that workers were properly trained, and that proper tools and equipment were available when jobs started. This review represented one sample.

- Radiological exposures of individuals from selected work groups were reviewed to evaluate any significant exposure variations which could exist among workers, and to determine whether these significant exposure variations were the result of worker job skill differences or whether certain workers received higher doses because of poor ALARA work practices. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RP technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and HRAs that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101(c). This review represented one sample.

The inspectors determined if identified problems were entered into the corrective action program for resolution, and that they had been properly characterized, prioritized, and resolved. This included dose significant post-job (work activity) reviews and post-outage ALARA report critiques of exposure performance. This review represented one sample.

Corrective action reports related to the ALARA program were reviewed and staff members were interviewed to determine if follow-up activities had been conducted in an effective and timely manner commensurate with their importance to safety and risk using the following criteria:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

The inspectors also determined that the licensee's self-assessment program identified and addressed repetitive deficiencies and significant individual deficiencies that were identified in the licensee's problem identification and resolution process. This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to determine whether they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed.

b. Findings

A finding of very low safety significance was identified as part of this routine review and is documented in section 1R22.1 of this report.

.1.2 Routine Review of Identification and Resolution of Problems - Inservice Inspection

a. Inspection Scope

From March 1, 2005, through March 4, 2005, the inspector performed a review of a sample of inservice inspection related problems that were identified by the licensee and entered into the corrective action program. The inspector reviewed these corrective action program documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The specific corrective action documents that were reviewed by the inspector are listed in the attachment to this report (Section 1R08).

b. Findings

No findings of significance were identified.

.2 Annual Sample Review

m. Inspection Scope

The inspectors selected one CR for detailed annual sample review (CR 05-00781). The CR was associated with the addition of incorrect oil to the RCIC pump which resulted in the inoperability of the RCIC system. The report was reviewed to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the report against the requirements of the licensee's corrective action program as delineated in NOP-LP-2001-01, Condition Report Process, Revision 8, and 10 CFR 50, Appendix B.

n. Findings and Observations

No findings of significance were identified. However, inspectors made the following observations: Licensee NOP-LP-2001-01, Attachment 6: "Apparent Cause Analysis," stated that the evaluation should include a problem statement which should include the organization or job function of the individuals involved. Inspectors noted that, though CR 05-00781 was identified as a human performance issue for tracking, the apparent cause problem statement did not include the relevant organization and job function of individuals involved. The procedure also stated the problem statement should include the extent of the problem in terms of time and location. While the problem statement included the extent of the resultant effect on RCIC, it failed to include the extent of the issue of improper oil addition to plant equipment. A review by inspectors revealed other instances of incorrect oil addition to plant equipment as documented in CRs 04-02217, 04-02504, and 01-3811. In each of these examples, the corrective action addressed narrow aspects of the issue and was otherwise inadequate in that it failed to prevent the recurrence of addition of wrong oil type to plant equipment.

4OA3 Event Followup (71153)

.1 Manual Scram Following Dual Recirculation Pump Downshift and Subsequent Trip of Recirculation Pump 'A'

On January 6, 2005, the inspectors observed licensee response to a manual reactor scram initiated after the trip of the 'A' recirculation pump following the spurious shift of both recirculation pumps from high to low speed while the unit was operating at 100 percent power. The inspectors responded to the control room and observed the licensee's control of reactor vessel water level and pressure. The inspectors reviewed licensee actions to reduce steam loads to maintain compliance with TS cooldown limits. The inspectors determined that the licensee completed notifications as required by 10 CFR Part 72. Finally, the inspectors attended the licensee's debrief of the operating crew. No findings of significance were identified.

.2 (Closed) Licensee Event Report (LER) 05000440/2004-002-00: Unplanned Automatic Oscillation Power Range Monitor [OPRM] SCRAM. On December 23, 2004, both reactor recirculation pumps downshifted from fast to slow speed. The power and flow reduction placed the plant in the immediate exit region of the power-flow map. Approximately 9 minutes after the downshift, the OPRMs detected core oscillations and, per design, initiated a reactor scram. Inspector response associated with this event was documented in NRC Integrated Inspection Report 05000440/2004015. Operator response and procedure adequacy were reviewed and documented in NRC Special Inspection Team Report 05000440/2005005.

.3 (Closed) Licensee Event Report (LER) 05000440/2003-004-02: Emergency Service Water Pump Upper Shaft Coupling Sleeve Failure. On September 1, 2003, the ESW pump 'A' was declared inoperable due to shaft coupling failure. This event resulted in an LER. On August 3, 2004, the licensee issued Revision 2 to the LER to provide updated information on the root cause and corrective actions completed. Inspectors reviewed the revised report during the week of February 19, 2005. Inspector review of the pump failure was documented in NRC Integrated Inspection Report 05000440/2003006. As documented in NRC Inspection Report 05000440/2004005, the NRC concluded that the pump failure was a White finding, that is, an issue with low to moderate increased importance to safety. No new findings of significance were identified during review of the LER supplement.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in section 1R04 of this report had, as its primary cause, a human performance deficiency in that maintenance personnel failed to follow procedures for the construction of scaffolding affecting safety-related equipment.

.2 A finding described in section 1R14.1 of this report had, as its primary cause, a human performance deficiency in that the licensee failed to promptly notify the control room upon discovery of an unexpected fire. Specifically, a licensee chemistry technician failed to recognize that, in accordance with the Fire Protection Program, prompt notification to the control room is required when a fire is discovered.

.3 A finding described in section 1R19 of this report had, as its primary cause, a human performance deficiency in that technicians failed to adequately attach and verify satisfactory connection of a cable in the IRM 'A' system.

.4 A finding described in section 1R20.2(1) of this report had, as its primary cause, a human performance deficiency in that technicians failed to implement adequate FME controls and, as a result, dropped a jet pump plug on the reactor core.

.5 A finding described in section 1R20.2(2) of this report had, as its primary cause, a human performance deficiency in that a personnel error by an SRO resulted in the inadvertent withdrawal of a control rod.

.6 A finding described in section 1R22.1 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to promptly correct a condition adverse to quality. Specifically, an SRO accepted TS required surveillance testing results with identified likely erroneous or otherwise unexplainable data rather than initiating action to re-perform the surveillance test.

.7 A finding described in section 1R22.2 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to identify and promptly correct a condition adverse to quality. Specifically, the licensee failed to enter the improper performance of a TS required surveillance procedure in their corrective action program and thus took no corrective action. As a result of the licensee's failure to properly evaluate the January 5, 2005, performance deficiency and take appropriate corrective action, the surveillance test was again performed improperly on February 1, 2005.

.8 A finding described in section 1R22.3 of this report had, as its primary cause, a human performance deficiency in that a technician error resulted in improper performance of an I&C procedure and caused an inadvertent ESF actuation.

.9 A finding described in section 1R22.4 of this report had, as its primary cause, a human performance deficiency in that an operator error resulted in a loss of suppression pool volume.

4OA5 Other Activities

.1 (Closed) URI 05000440/2003002-02: Increased heat input on PCT from the Zr metal - water and hydrogen - oxygen reactions facilitated by Noble Metals. The inspectors reviewed this URI in Section 1R02. This URI is closed.

.2 (Closed) URI 05000440/2004011-01: Operation in Mode 4 with One Method of Decay Heat Removal.

Introduction: A finding of very low safety significance was identified by the inspectors for the licensee's failure to adequately implement TS 3.4.10 requirements for alternate decay heat removal methods as amended to the license during the TS improvement program to adopt a TS based on NUREG-1434 (Improved Standard Technical Specifications). The finding was considered to be an NCV of 10 CFR 50.36(c)(2)(I).

Description: On May 21, 2004, the ESW 'A' pump failed due to a repeat failure of the uppermost shaft coupling. With the inoperable pump, TS 3.7.1 required the licensee to restore the pump to operable status within 72 hours or be in Mode 3 within 12 hours and Mode 4 within 36 hours. While performing plant shutdown and cooldown as required by Technical Specifications, TS 3.4.10 became applicable. This TS required two operable RHR subsystems for decay heat removal and required the licensee to verify an alternate method of decay heat removal within 1 hour for each inoperable RHR shutdown cooling subsystem. Because of the design of the plant, during high decay heat conditions no alternate means of RHR existed sufficient to keep the plant in Mode 4. With only RHR 'B' available, the licensee could not satisfy this condition of TS 3.4.10. Although the licensee has identified several systems with some RHR capacity, none had enough capacity to prevent a transition from Mode 4 to Mode 3 if called upon to do so.

During repairs on the ESW 'A' pump, the licensee concluded that sufficient doubt existed regarding the ESW 'B' pump, thus they declared the pump inoperable. As such, RHR 'B' became inoperable. The licensee then designated RHR 'B' as its own alternate system. The inspectors reviewed TS requirements, including basis sections, and concluded that an inoperable system cannot be used to satisfy TS conditions that allow for designation of an alternate system. The inspectors requested review by the Office of Nuclear Reactor Regulation and the staff concluded that "a system which has been declared inoperable cannot be designated its own alternate system for the purposes of complying with TS 3.4.10, Required Action A.1. Clearly, an alternate 'method' of decay heat removal was not provided for the B-ESW shutdown cooling system since the 'method' of providing decay heat removal did not change when the inoperable system was declared to be its own alternate." This closes **URI 05000440/2004011-01.**

Analysis: The inspectors determined that the licensee's failure to adequately implement TS 3.4.10 was more than minor because it was directly associated with the mitigating system cornerstone objective of availability of a mitigating system. Although not suited for SDP review, the finding was determined to be of very low safety significance in that (1) the Mode 4 conditions were maintained by the inoperable, but running, RHR 'B' system and (2) the licensee maintained vacuum within the condenser to provide a method of decay heat removal had coolant temperature rose sufficiently to produce steam.

Enforcement: Per 10 CFR 50.36(c)(2)(I), when a LCO is not met, the licensee shall shutdown the reactor or follow any remedial action permitted by the TS until the condition can be met. Required Action A.1 of Perry TS 3.4.10 required an alternate decay heat removal method be established for each inoperable RHR subsystem. This remedial action must be met until the TS condition can be met in order to be in compliance with Technical Specifications. The TS bases define the alternate method as "re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO." To maintain TS compliance, the licensee must establish an alternate decay heat removal method that meets the mission time requirements of the LCO. Contrary to this requirement, the licensee failed to establish an alternate method of decay heat removal after entering Mode 4 on May 23, 2004, due to the failure of the ESW 'A' pump. Additionally, compliance was not established for the 'B' train by declaring the system to be its own alternate after declaring it inoperable on May 24, 2004. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-01005), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2005002-12)**.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to F. von Ahn, General Manager, and other members of licensee management at the conclusion of the inspection on April 5, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- Safety Evaluation Inspection with Mr. K. Russell on January 26, 2005. The licensee did not identify any potential report input information as proprietary.

- Inservice Inspection for Inspection Procedure 71111.08 with Mr. R. Anderson on March 4, 2005.

- Access control to radiologically significant areas, and ALARA planning and controls program with Mr. R. Anderson on March 3, 2005.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance were identified by the licensee and were violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Mitigating Systems

- Technical Specification 5.4 required implementation of procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 4.g., specified procedures for the RCIC system. Contrary to this requirement, on January 31, 2005, procedures were not implemented in that an improper oil type was added to the RCIC pump. As a result, RCIC was inoperable 3 hours and 29 minutes while the oil was subsequently replaced. This issue was entered in the licensee’s corrective action program as CR 05-00781. Inspectors reviewed the finding in accordance with IMC 0609, “Significance Determination Process,” Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” dated December 1, 2004. Inspectors completed Phase 1 screening and continued to Phase 2 because the finding resulted in a loss of system safety function. Using Phase 2, inspectors determined that the finding was of very low safety significance because of the availability of remaining mitigating systems and because of the short time RCIC was inoperable.

- Technical Specification 5.4 required implementation of procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 8.b., specified that implementing procedures are required for each surveillance test, inspection, or calibration listed in the Technical Specifications. Contrary to this requirement, on February 1, 2005, procedures were not implemented in that step 5.1.15.b of licensee procedure SVI-P42-T2001-B, "Emergency Closed Cooling System 'B' Pump and Valve Operability Test," Rev. 5, was not performed correctly resulting in an erroneous determination that a TS required surveillance had been satisfactorily completed. This issue was entered in the licensee's corrective action program as CR 05-00898. The inspectors determined that the failure to properly perform the surveillance test was more than minor in that the issue was associated with the reactor safety cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring mitigating system availability, reliability, and capability. Specifically, the test had to be performed a third time, resulting in unnecessary safety system unavailability and was not performed within the TS required periodicity. Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The inspectors determined that the finding did not involve the loss of safety function in that ECCW 'B' subsequently satisfactorily completed the required quarterly pump and valve operability test on February 5, 2005. The inspectors therefore concluded that the finding was of very low safety significance.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Anderson, Vice President-Nuclear
F. von Ahn, General Manager, Nuclear Power Plant Department
J. Emley, Regulatory Affairs
F. Kearney, Operations Manager
R. Kidder, Superintendent, Plant Operations
J. Lausberg, Manager, Regulatory Compliance
T. Lentz, Director, Nuclear Engineering
M. Massucci, Welding Engineer
J. Messina, Director, Performance Improvement
W. O'Malley, Maintenance Manager
K. Russell, Regulatory Affairs
S. Thomas, Radiation Protection Manager
C. Wirtz, ISI Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000440/2005002-01	NCV	Inadequate Safety Evaluation for the NobleChem™ Process (Section 1R02)
05000440/2005002-02	NCV	Failure to Follow Procedures for Scaffold Construction in Safety-Related Areas (Section 1R04)
05000440/2005002-03	NCV	Failure to Implement TS 5.4 Required Plant Fire Procedures for Discovery of a Fire (Section 1R14.1)
05000440/2005002-04	NCV	Inadequate Restoration of IRM 'A' (Section 1R19)
05000440/2005002-05	NCV	Dropped Jet Pump Plug (Section 1R20.2(1))
05000440/2005002-06	NCV	Inadvertent Control Rod Withdrawal (Section 1R20.2(2))
05000440/2005002-07	NCV	Failure to Take Prompt Corrective Action After Identifying that Erroneous or Unexplainable Data was Recorded During TS Required Testing (Section 1R22.1)
05000440/2005002-08	NCV	Failure to Identify and Correct Inadequate Crew Performance During ECCW Testing (Section 1R22.2)

05000440/2005002-09	NCV	Instrumentation and Control Technician Error Results in Inadvertent ESF Actuation (Section 1R22.3)
05000440/2005002-10	NCV	Inadvertent Establishment of Flow Path from Suppression Pool to Auxiliary Building Floor Drains During RHR LLRT (Section 1R22.4)
05000440/2005002-12	NCV	Inadequate Implementation of TS 3.4.10 for Alternate Heat Decay Removal (Section 4OA5.2)

Opened

05000440/2005002-11	URI	Effect of EDG Operation with Open TRDs on Enclosed Tornado/Missile Enclosure (Section 1R23)

Closed

05000440/2003002-02	URI	Increased heat input on PCT from the Zr metal-water and hydrogen-oxygen reactions facilitated by Noble Metals (Section 4OA5.1)
05000440/2004011-01	URI	Operation in Mode 4 with One Method of Decay Heat Removal (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

<u>1R01</u> <u>Adverse Weather Protection</u>

ONI-R36-2; Extreme Cold Weather; Rev. 1
PTI-GEN-P0027; Cold Weather Support System Startup; Rev. 6
PTI-GEN-0026; Preparations For Winter Operation; Rev. 1

<u>1R02</u> <u>Evaluations of Changes, Tests, or Experiments</u>

CR 03-00721; Question Concerning Safety Evaluation 01-0007; dated February 12, 2003
GE-NE-P86-0004-00-02-R4; Noble Metal Chemical Addition Technical Safety Evaluation for Perry Nuclear Power Plant; dated July 29, 2004
GE-NE-0000-0031-3601-R0; Effect of Noble Chem on Perry LOCA Peak Cladding Temperature; dated July 29, 2004

<u>1R04</u> <u>Equipment Alignment</u>

SOI-E21; Low Pressure Core Spray System; Rev. 16
VLI-E21; Low Pressure Core Spray System (Unit 1); Rev. 4
CR 03-04764; RHR A/LPCS Water Leg Pump Not Supplying Adequate Pressure; dated August 14, 2003;
CR 04-06284; RFA to Evaluate Torque Requirements for LPCS Water Leg Pump; dated December 1, 2004;
SOI-E22A; High Pressure Core Spray System; Rev 11;
PEI-SPI 4.6; Plant Emergency Instruction, Fast Fire Water Alternate Injection; Rev 1
VLI-E22A; High Pressure Core Spray; Rev 6
CR 04-04948; Evaluate Performance of HPCS Pump During SVI-E22-T2001; dated September 23, 2004
CR 04-04948 Scanned Attachment; Additional Evaluation of Pump Performance
CR 04-04948 Corrective Actions 1 and 2; dated October 8, 2004
CR 04-04948 Corrective Action 3; dated October 12, 2004
CR 04-04948 Corrective Actions 4 and 5; dated October 20, 2004
CR 04-04948 Investigation Summary; dated October 31, 2004
SOI-E22B; Division 3 Diesel Generator; Rev. 13
VLI-R47/E22B; Division 3 Diesel Generator Lube Oil System (Unit 1); Rev.3
SOI-R44/E22B; Division 3 Diesel Generator Starting Air System; Rev. 5
VLI-R45/E22B; Division 3 Diesel Generator Fuel Oil System (Unit 1); Rev. 3

GCI-0016; Scaffolding Erection, Modification or Dismantling Guidelines; Rev. 4
PAP-204; Housekeeping/Cleanliness Control Program; Rev. 14
CR 05-01946; Scaffolding in Div. 3 EDG And HPCS Rooms May Not Be Built Per Approved Procedures; dated March 8, 2005

1R05 Fire Protection

CR 05-00280; Personnel Not Verifying That Fire Doors Are Closed and Latched; dated January 7, 2005
FPI-0CC; Pre-Fire Plan Instruction, Control Complex, Rev 3
FPI-A-I02; Fire Suppression Equipment Inspection Guidelines; Rev. 1
FPI-A-A02; Periodic Fire Inspections; Rev. 3
FPI-0IB; Pre-Fire Plan Instruction, Intermediate Building; Rev. 4
FPI-1RB; Pre-Fire Plan Instruction, Reactor Building; Rev. 3

1R06 Flood Protection Measures

ARI-H13-P870-0003-H1; Turbine Bldg Basement Water Level High; Rev. 6
ARI-H13-P870-0003-H2; Circ Pump Trip TB Basement Water Lvl Hi; Rev. 6
SVI-P41-T2001; Service Water to Cooling Towers Isolation Valve Operability Test; Rev. 5
CR 02-00413; Turbine Building Basement Flood Switch Failed to Change State; dated February 9, 2002
Calc. No. IF-003; IPE-IF Turbine Building Floods Main Bay; Rev. 0
Calc. No. IF-19; TPC Circ Water Break; Rev. 0

1R08 Inservice Inspection Activities

Condition Reports

03-01995; Unusual Crud Build-Up On the Reactor Vessel Interior Walls
03-02831; Shroud Head Stud Assembly Modification Ant-Rotation Pin Wear
03-06705; OE- 17005 and 17392, CRD Return Nozzle (–10) to Cap Weld Failure
04-05800; ISI Program Commitment Discrepancies
04-06342; Regulatory Guide 1.65 Contains Supplemental Requirements for Reactor Closure Studs and is Listed in the USAR. However, it is not Addressed Anywhere in the Inservice Examination Program

Condition Reports Issued As a Result of Inspection Activities

05-01803; Order Records for Orders Involving Welding

Nondestructive Examination Reports

0944-05-E015; Ultrasonic Calibration and Examination Record for a 24" Pipe to Elbow Weld; dated February 21, 2005
0944-05-E112; Ultrasonic Calibration and Examination Record for a 12" Elbow to Pipe Weld; dated February 28, 2005
0944-05-E010; Ultrasonic Calibration and Examination Record for a 18" Pipe to 18" x 12" Reducing Elbow; dated February 21, 2005
0944-05-E010;Ultrasonic Calibration and Examination Record for a 12" Pipe to Penetration P-113 Process Pipe; dated February 21, 2005

Procedures

NQI-0941; Liquid Penetrant Examination; Revision 8
NDE-008; Manual Ultrasonic Examination of Ferritic Piping Welds; Revision 9
NQI-0942; Magnetic Particle Examination; Revision 7
NQI-1042; Visual Examination; Revision 9
GE-UT-300; Procedure for Manual Examination of Reactor Vessel Assembly Welds in Accordance With PDI; Revision 8
GE-UT-311; Procedure for Manual Ultrasonic Examination of Nozzle Inner Radius Bore and Selected Nozzle to Vessel Region; Revision 10
GE-UT-704; Procedure for the Examination of Reactor Pressure Vessel Welds with GERIS 2000 OD in Accordance with Appendix VIII; Revision 7

Miscellaneous Documents

Weld Data Sheet; Weld FW-RHR-1; dated December 16, 1999
Weld Data Sheet; Weld FW-RHR-2; dated December 16, 1999
Weld History Record; Weld 99-7795-01; dated May 24, 2003
Weld History Record; Weld 99-7795-02; dated May 23, 2003
WPS 1.1.2-001; Manual GTAW/SMAW, Revision 8
PQR 002; dated November 4, 1983
PQR 009; dated January 30, 1985
305-006-103; Reactor Vessel Head Circumferential and Meridional Weld Arrangement Drawing; Revision A
305-006-112; Reactor Vessel Flange Ligament Drawing; Revision A
Certifications for NDE Personnel:

1. Todd M. Ginder
2. James Williams
3. Wesley C. Money
4. Steven D. Woodyard

1R11 Licensed Operator Requalification

OTC-3058-2004-06C; Simulator Scenario Guide
CR 05-00948; A Comment on an Exam Question was Not Submitted to the NRC, dated February 7, 2005

1R12 Maintenance Effectiveness

Perry Nuclear Power Plant; Plant Health Report; Second Quarter 2004
Perry Nuclear Power Plant; Plant Health Report; Third Quarter 2004
CR 02-00311; Control Room Ventilation Carbon Filter Testing; dated January 30, 2002
CR 02-00402; RFA - Request for Guidance on Minimum Control Room Temperature; dated February 7, 2002
CR 02-01190; Didn’t Receive Expected Alarm When Shutting Down CR [Control Room] Ventilation to Secured Status; dated April 20, 2002
CR 02-01389; Coupling Grease Plug Torques; dated May 6, 2002
CR 02-02499; Evaluation of Chemistry Sampling During M25/26A Outage; dated July 30, 2002

CR 02-02505; Found Wrong Mounting Bolts Installed for 0M25-F0260A; dated July 30, 2002
CR 02-02555; SVI Discrepancy for Control Room Emergency Fan Recirc Fan Flows; dated August 1, 2002
CR 02-02556; Nuts and Washers Missing Off of Unistrut Brackets for 0M25-F0260A, dated August 1, 2002
CR 02-02781; M25-F0255B Shows Dual Indication After Shifting from ER to Normal; dated August 16, 2002
CR 02-03032; M25-B006B Heater Controller Power Cable Heat Damage; dated September 1, 2002
CR 02-03206; Unmarked Ductwork Access Covers; dated September 11, 2002
CR 02-03687; Broken 0M25 Damper Springs Found During Inspection; dated October 7, 2002
Failure Analysis Report; Response to CR 02-03687; dated May 5, 2003
CR 02-03912; M26C001A/B Runtime Counters Broken an Excessive Amount of Time; dated October 21, 2002
CR 02-04138; USAR Discrepancy, Control Room Boundary Restoration Time; dated October 31, 2002
CR 03-00168; Tornado Damper 0M25F0001A Broken Spring; dated January 14, 2003
CR 03-03908; Control Room Ventilation Train B Damper Lineup; dated June 16, 2003
CR 03-04073; Plugs Removed for Greasing of Coupling; dated June 30, 2003
CR 03–04300; Clarification of Bases Wording for Control Room Damper Surveillance SR 3.7.3.4; dated July 17, 2003
CR 04-00662; Control Room HVAC Supply Fan A Flow Lower Than Design; dated February 9, 2004
Maintenance Rule Failure and Condition Monitoring Form; regarding CR 04-00662; dated April 2, 2004
CR 04-02069; CALC M25-000 Cooling Loads Post Accident Exceeds the M25 Cooling Coil Capacity; dated April 21, 2004
CR 04-03333; M25 Heater Cable Hot and Heat Damaged; dated June 26, 2004
Failure Analysis Report; Response to CR 04-03333; dated August 24, 2004
CR 04-05150; Failed SVI-M26-T1264 Resulting in Shutdown Statement; dated October 2, 2004
PAP-1604; Event Notification; dated October 2, 2004
CR 04-05151; RFA - Engineering to Evaluate CERF 1173; dated October 2, 2004
CR 04-05156; As-Found Data Found Out of Allowable Value - Tech Spec; dated October 2, 2004
NOP-LP-2001-10; Mode Hold Resolution Form; dated October 12, 2004
CR 04-05187; Scheduled SVI-M26-T1264 Required T.S. 3.0.3 Entry; dated October 4, 2004
CR 04-05762; Broken Springs on 0M25F0001A Tornado Damper; dated November 11, 2004
Control Room Operator Logs; dated January 1, 2002, to January 3, 2004
USAR Figure 6.4.1; Control Room HVAC and Emergency Recirculation Systems; Rev 13
VLI-M25/26; Control Room HVAC and Emergency Recirculation System; Rev 7

1R13 Maintenance Risk Assessments and Emergent Work Control

Perry Work Implementation Schedule; Week 7, Period 8
Probabilistic Safety Assessment; Week 7, Period 8; Rev. 2
Shutdown Safety Status; dated January 7, 2005, through January 29, 2005
PDB-C0011; PSA Pre-Solved Configurations; Rev. 3
PAP-1924; On-Line Safety Assessment; Rev. 3
CR 05-00911; SVI-R43-T1348 Not Performed as Scheduled With SVI-R43-T1318; dated February 6, 2005

1R14 Operator Performance During Non-routine Evolutions and Events

PAP-1910; Fire Protection Program; Rev 9
CR 05-00300; Unexpected Flame Occurred During Chemistry Analysis Preparation; dated January 13, 2005
ONI-P54; Fire; Rev 8
Fire Report No. 05_01; dated January 13, 2005
CHI-0043; Total Particulate Contamination in Diesel Fuel; Rev 3
CR 05-01352; Loss of Power to Deluge Panel, dated February 23, 2005
CR 05-01350; Loss of D1B07, dated February 23, 2005
OM18: PDB-H005, Plant Data Book Entry Supplemental Sheet, 125 VDC Bus D-1-B; Rev. 0
Outage Control Center Log, RFO10, dated February 23, 2005
SOI-R42 (Sys B); Non Divisional DC System B Distribution, Buses D-1-B and D-2-B: Batteries, Chargers, and Switchgear; Rev. 2
ONI R42-5; Loss of DC Bus D-1-B; Rev. 5

1R15 Operability Evaluation

CR 05-00354; MOV Stem Lubrication Issues; dated January 14, 2005
CR 05-00196; Fretting Observed on Div. DG F.O. Piping; dated January 9, 2005
CR 05-00585; Disposition Broken Metal Fingers on Fuse Clips; dated January 23, 2005
Ultrasonic Thickness Report No. 0941-05-0002; dated January 10, 2005
CR 05-00230; 5 & 15 KV Breakers Beyond Their Due Date for 10 Year Overhaul; dated January 11, 2005
CR 05-01676; As-Found Condition of 1P45C0001A; dated March 2, 2005

1R16 Operator Workarounds

Drawing D-302-0792-00000; Emergency Service Water System; Rev. JJ
PEI-SPI 4.2; RHR Loop B Flood Alternate Injection; Rev. 1
Operations Standing Order; P45B-F0068B Interim Actions; dated January 27, 2005
WO 200459466; Install New FW Control System

1R17 Permanent Plant Modifications

Design Change Package 99-5051; OPRM Scram Trip Connection to the RPS System; Rev.1
Safety Evaluation SE01-0014; 10 CFR 50.59 DCP 99-5051; Rev 1

Design Interface Evaluation; DCP 99-5051; Human Factors; Rev 1
Design Interface Evaluation; DCP 99-5051; Simulator Element; Rev 1
Design Interface Evaluation; DCP 99-5051; Operations Impact; Rev 1
Design Interface Evaluation; DCP 99-5051; Operations; Rev 1
Design Interface Evaluation; DCP 89-205; Operation Procedures; Rev. 0
License Amendment 118; Perry Nuclear Power Plant, Unit 1 - Issuance of Amendment RE: Activation of Thermal-Hydraulic Stability Monitoring Instrumentation (TAC No. MA8671); dated February 26, 2001

1R19 Post-Maintenance Testing

WO 2001136750; Replace Optical Isolator Cards; Rev. 1
Drawing 208-0015-00030; Recirculation Pump C001B - Breaker 4B; Rev. AA
SVI-E51-T2001; RCIC Pump and Valve Operability Test; Rev. 20
WO 200101117; Partial PMI-0030 RCIC Pump Supr Pl Suct Isol; Rev.0
WO 200047200; Full PMI-0030 RCIC Pump Min Flow Valve; Rev. 0
WO 200081128; Install Replacement Piping Section; Rev. 1
CR 05-00813; RCIC Turbine Oil Sample not Performed Following Operation per SVI-E51-T2001; dated February 1, 2005
CR 05-00781; Oil Addition to the RCIC Pump; dated January 31, 2005
CR 05-00793; PCR Enhancement Needed for SVI-E51-T2001; dated January 31, 2005
IOI-1; Cold Startup; Rev. 13
CR 05-00247; Unexpected Half Scram During Maintenance; dated January 11, 2005
CR 04-01539; OE17981-Neutron Monitoring Instrumentation Noise Caused by Loose Connectors; dated March 3, 2004
CR 04-01539 dated March 26, 2004; Attachment; OE 17981 - Neutron Monitoring Instrumentation Noise Caused by Loose Coaxial Cable Connector Back Shell Nuts; undated
CR 05-00765; CR to Document Startup 101 Decision; dated January 30, 2005
WO 200138727; Troubleshoot/Rework IRM 'A' Indication; dated January 30, 2005
CR 05-00762; IRM-A Failure to Attain Proper Overlap; dated January 30, 2005
ICI-C-C51-7-2a; IRM Data Sheet; Rev. 6
ICI-C-C51-7; Neutron Monitoring System Coaxial Cables/Detectors; Rev. 6
GEI-0013; Connector Assembly Data Sheet; Rev. 3
WO 200068448; CC I/V Plot IRM 'A' Detector/Check Electronics; dated January 16, 2005
Post Maintenance Checklist for WO 200073576; RHR 1E12F0004A, dated March 11, 2005
CR 05-02131; PCS Enhancement SVI-E12-T2001(TYPO), dated March 11, 2005
PDB-H0021; EK-1-A1 Load List; Rev. 1
CR 05-02510; 1R25S0033 (EFB-1-A2 Feed To EK-1-A1) Failed Load Test, dated March 21, 2005

1R20 Refueling and Outage Activities

IOI-1; Cold Startup; Rev. 14
IOI-3; Power Changes; Rev. 17
IOI-4; Shutdown; Rev. 9
IOI-5; Maintaining Hot Standby or Hot Shutdown; Rev. 6

IOI-8; Shutdown By Manual Scram; Rev. 2
IOI-9; Refueling; Rev. 10
IOI-12; Maintaining Cold Shutdown; Rev. 4
IOI-17; Drywell Entry and Access Control; Rev. 4
SOI-E12; Residual Heat Removal System; Rev. 21
Mode Change Restraint List; updated daily January 7, 2005, through January 30, 2005
Post Scram Report; Scram No. 1-05-01; dated January 12, 2005
NOBP-OM-4010; Restart Readiness for Plant Outages; Rev. 1
CR 05-00765; CR to Document Startup 101 Decision; dated January 30, 2005
RFO10 Pre-Outage Shutdown Safety Review; dated February 21, 2005
IMI-E2-47; Installation of Reactor Refuel Level Instrumentation For IOI-9; Rev. 3
FTI-D0006; Preparation of Fuel Movement Checklist; Rev. 6
FTI-D0009; Use of the Fuel Movement Checklist; Rev. 8
FTI-B0002; Control Rod Movements; Rev. 7
NOP-OP-1004; Reactivity Management; Rev. 0
GE Perry RFO10 Human Performance Improvement Plan; dated March 2, 2005
WO 200110754; Install/Remove Jet Pump Plugs in Loop “B” of Recirc System

1R22 Surveillance Testing

SVI-P42-T2001B; Emergency Closed Cooling System 'B' Pump and Valve Operability Test; Rev. 5
CR 05-00408; Emergency Closed Cooling 'B' Pump Test; dated January 17, 2005
CR 05-00547; Lack of Questioning Attitude; dated January 21, 2005
CR 05-00898; SVI-P42-T2001B Performance Issues; dated February 5, 2005
SVI-R43-T1318; Diesel Generator Start and Load Division 2, Rev.10
CR 05-00944; Determine the Need to Perform SR 3.8.1.2 for the Div 1 and Div 3 EDGs, dated February 8, 2005
CR 05-00936; Div 2 EDG Fail to Quick Restart for SVI-R43-T1348, dated February 7, 2005
SVI-R43-T1348; Division 2 Standby Diesel Generator 24 Hour Run, Rev. 1
SOI-R43; Division 1 and 2 Diesel Generator System, Rev. 21
PTI-D17-P1660; Containment/Drywell Purge Exhaust Radiation Monitor 1D17-K660 Calibration; Rev. 2
CR 05-01543; LLRT Performance Results in Unexpected Water in Aux Bld Floor Drains; dated February 27, 2005
CR 05-01546; Drain Suppression Pool Water to Aux Building During LLRT; dated February 27, 2005
PDB-B0004; Sump Flows and Capacities; Rev. 1
SVI-E12-T9102; Type C Local Leak Rate Test of 1E12 Penetration P102; Rev. 5
GMI-0017; Steam Safety Relief Valve Removal and Reinstallation; Rev. 9
SVI-B21-T2012; SRV Uncoupled Stroke Testing With GMI-0017; Rev. 1
CR 05-02729; SRV B21F041E Actuator Closed With Division 1 Solenoid Energized; dated March 27, 2005
CR 05-02796; SVI-B21-T2012 Requires Repeat Performance; dated March 29, 2005

1R23 Temporary Plant Modifications

Operations Standing Order; Division 1, 2, and 3 TRD Operation; dated January 18, 2005

Regulatory Applicability Determination 05-00143; Division 1, 2, and 3 Emergency Diesel Generator Testable Rupture Disks; Rev. 0
CR 02-04855; Inspection of Concrete Structures at Div 3 Diesel Exhaust Rupture Piping; dated December 19, 2002
CR 05-00463; Post Accident Temperature for DG Bldg. Missile Shield Exceeds Design Spec.; dated January 18, 2005
10 CFR 50.59 Evaluation No. 04-01200; Installation of Improved Testable Rupture Disk Design for Division 1 and 2 Emergency Diesel Generator Combustion Exhaust Systems; Rev. 1
CR 05-00685; Operational Approval for Order Addendum Not Obtained Prior to Start of Work; dated January 27, 2005
CR 05-00597; Div 1 and Div 2 DG Fuel Oil and Lube Oil Vent Lines in DG Missile Shield Enclosure; dated January 24, 2005
Engineering Calculation 23:02-040; Evaluation of the Temporary Framing for Installing FME Plate Above and Around the TRDs; dated January 22, 2005
Temporary Modification 05-0002; Division 1 EDG TRD FME Protection; dated January 26, 2005
Temporary Modification 05-0003; Division 2 EDG TRD FME Protection; dated January 26, 2005
Temporary Modification 05-0004; Division 3 EDG TRD FME Protection; dated January 26, 2005
Operability Evaluation for CR 05-00463; dated January 29, 2005

2OS1 Access Control to Radiologically Significant Areas and

2OS2 ALARA Planning And Controls

HPI-D0004; Surveillance of High Radiation Area Barricades; Revision 4
PAP-0123; Control of Locked High Radiation Areas; Revision 8
HPI-C0006; Posting Radiological Areas; Revision 6
HPI-C0005; Radiation Work Permits Preparation and ALARA Review; Revision 15
HPI-C0008; In-Line Review of Work Orders; Revision 4
PAP-0114; Radiation Protection Program; Revision 8
RWP 056407; RFO-10 ALARA Activities (Shielding); Revision 0
RWP 056420; RFO-10 Reactor Disassembly; Revision 0
RWP 056414; RFO-10 Under-Vessel; Revision 0
RWP 056433; RFO-10 Valve Repair; Revision 0
RWP 056315; RFO-10 Bioshield Annulus Activities; Revision 0
RWP 056405; RFO-10 Cavity Decontamination; Revision 0
688RPS2004; RP Collective Self-assessment; dated July 22, 2004
PY-C-04-03; NQA Quarterly Audit Report; July 1 - September 30, 2004
BRAC Point Survey Results, RFO-9 and RFO-10
CR05-00177; BRAC Point Survey Indicates Increased Dose Rate; dated January 8, 2005
CR05-01354; Increased Radiological Exposure Due to Use of Respirators in Reactor Cavity; dated February 23, 2005
CR05-01365; Unexpected EAD MG Dose Rate Alarm While Testing CRDMs; dated February 24, 2005

CR05-01108; RP Exceeds Dose Set-point, Receives Alarm Covering Work; dated February 6, 2005
CR05-01238; Procedural Guidance Unclear on Removal and Final Disposition of Tools From CA; dated February 21, 2005
CR05-01233; Contamination Issues Not Effectively Addressed; dated February 21, 2005
CR05-01363; Individual on Refuel Floor Without MG; dated February 23, 2005
CR05-01677; Dose Rate Alarm Received During Quarterly Fire Inspection; dated March 2, 2005
CR05-01698; GE Under-vessel Supervisor Alarms Portal Monitor; dated March 2, 2005

4OA2 Identification and Resolution of Problems

CR 05-00813; RCIC Turbine Oil Sample Not Performed Following Operation Per SVI-E51-T2001; dated February 1, 2005
CR 01-3811; Incorrect Oil In Diaphragm Chamber; dated October 31, 2001
CR 04-02504; Wrong Oil Installed In Pump; dated May 17, 2004
CR 05-00781; Oil Addition To The RCIC Pump, dated January 31, 2005
CR 04-02217; Oil Analysis Results Indicate Potential For Wrong Oil, dated April 29, 2004
SOI-E51; Reactor Core Isolation Cooling System; Rev. 16
CR 01-0516; Potential Wrong Oil In Sewage Ejectors; dated February 14, 2001
CR 04-03001; 1N64C0005A/B Regenerator Blowers Contain The Wrong Oil. Also Reference 04-02991; dated May 21, 2004
CR 03-01029; RFA-RCIC Lube Oil Addition Methodology; dated March 3, 2003

4OA3 Event Followup

PEI-B13; Reactor Pressure Vessel Control; Rev. 7
ONI-C71-1; Reactor Scram; Rev. 6
ONI-C51; Unplanned Change in Reactor Power or Reactivity; Rev. 17
IOI-6; Cooldown - Main Condenser Not Available; Rev. 7
IOI-7; Cooldown Following a Reactor Scram Main Condenser Available; Rev. 7

LIST OF ACRONYMS USED

ALARA	as low as is reasonably achievable
ASME	American Society of Mechanical Engineers
CFR	*Code of Federal Regulations*
CR	condition report
ECCS	emergency core cooling system
ECCW	emergency closed cooling water
EDG	emergency diesel generator
EPRI	Electrical Power Research Institute
ESF	engineered safety feature
ESW	emergency service water
FENOC	FirstEnergy Nuclear Operating Company
FME	foreign material exclusion
HPCS	high pressure core spray
HRA	high radiation area
I&C	instrumentation and control
ICI	instrument calibration instruction
IOI	Integrated Operating Instruction
IMC	Inspection Manual Chapter
IRM	intermediate-range monitor
LCO	limiting condition for operation
LER	Licensee Event Report
LHRA	locked high radiation area
LLRT	local leak rate test
LOCA	loss-of-coolant accident
LPCS	low pressure core spray
NCV	non-cited violation
NDE	Nondestructive Examination
NOP	normal operating procedure
NRC	Nuclear Regulatory Commission
ONI	Off-Normal Instruction
OPRM	oscillation power range monitor
PAP	Perry Administrative Procedure
PCT	peak cladding temperature
PMT	post-maintenance testing
PTI	periodic testing instruction
RCIC	reactor core isolation cooling
RCS	reactor coolant system
RFA	request for assistance
RFO10	Refueling Outage 10
RHR	residual heat removal
RO	reactor operator
RP	radiation protection
RPS	reactor protection system
RSE	responsible system engineer
RWP	radiation work permit
SDP	significance determination process
SE	safety evaluation

SOI	system operating instruction
SRA	senior risk analyst
SRM	source range monitor
SRO	senior reactor operator
SSCs	structures, systems, and components
SVI	surveillance instruction
SRV	safety relief valve
TRD	testable rupture disks
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
USAR	Updated Safety Analysis Report
UT	ultrasonic
VHRAs	very high radiation area
VLI	valve lineup instruction
WO	work order