April 26, 2004

Mr. William O’Connor, Jr.
Vice President
Nuclear Generation
Detroit Edison Company
6400 North Dixie Highway
Newport, MI 48166

SUBJECT: FERMI POWER PLANT, UNIT 2
NRC INTEGRATED INSPECTION REPORT 05000341/2004002

Dear Mr. O’Connor:

On March 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Fermi Power Plant, Unit 2. The enclosed report documents inspection findings which were discussed on April 2, 2004, with you, Mr. Cobb 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.

Based on the results of this inspection, one NRC-identified and one self-revealed finding of very low safety significance were identified, one of which involved violations of NRC requirements. However, because this violation was of very low safety significance and because the issue was entered into the licensee's corrective program, the NRC is treating this finding and issue as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. Additionally, two licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of a Non-Cited Violation, 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 Fermi Power Plant facility.

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Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

Docket No. 50-341
License No. NPF-43

Enclosure: Inspection Report 05000341/2004002
w/Attachment: Supplemental Information

cc w/encl: N. Peterson, Manager, Nuclear Licensing
D. Pettinari, Corporate Legal Department
Compliance Supervisor
R. Whale, Michigan Public Service Commission
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REGION III

Docket No:	50-341
License No:	DPR-43
Report No:	05000341/2004002
Licensee:	Detroit Edison Company
Facility:	Fermi Power Plant, Unit 2
Location:	6400 N. Dixie Hwy. Newport, MI 48166
Dates:	January 1 through March 31, 2004
Inspectors:	S. Campbell, Senior Resident Inspector T. Steadham, Resident Inspector R. Powell, Senior Resident Inspector - Perry W. Slawinski, Senior Radiation Specialist R. Winter, Reactor Engineer
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000341/2004002; 1/01-3/31/2004; Enrico Fermi, Unit 2 Fermi 2; Nonroutine Plant Evolutions, Operability Evaluations, and Surveillance Testing.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on maintenance effectiveness and radiological protection. The inspection was conducted by Region III inspectors and the resident inspectors. Two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual 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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was self-revealed during an event when the failure of the south main turbine lube oil vapor extractor caused an oil leak from the high pressure turbine bearings. The primary cause of this finding was related to the cross-cutting area of Human Performance. Despite vendor recommendations to periodically lubricate the vapor extractor motor bearings, the licensee did not lubricate the bearings.

  This finding was more than minor because it increased the likelihood of a turbine trip as the large oil leak increased the likelihood of a fire which could have challenged equipment necessary to keep the turbine on-line. The finding was of very low safety significance because the duration of the leak was short and the oil did not come into contact with any equipment hot enough to ignite the oil. No violation of NRC requirements occurred. The licensee entered improvement plans for lubricating the main turbine lube oil vapor extractor motors into the corrective action program under CARD 04-20348. (Section 1R14)

- Green. A finding of very low safety significance was identified by the inspectors for the failure to follow approved corrective action procedures when identified corrective actions were not implemented. The licensee performed an engineering evaluation on November 15, 1999, wherein corrective actions identified in the evaluation were not tracked and therefore not implemented by the licensee. The primary cause of this violation was related to the cross-cutting area of Human Performance.

  This finding was more than minor because of the licensee's failure to complete a required engineering analysis, or take appropriate compensatory actions to support a prompt operability evaluation, would be a more significant safety concern if not corrected. The issue was of very low safety significance because an actual loss of a safety function did not occur. This failure to follow procedures was a violation of 10 CFR 50, Appendix B, Criterion V, and is classified as a Non-Cited Violation. The licensee initiated CARD 04-21296 on March 25, 2004, and entered this issue into their corrective action program. Additionally, the licensee updated CARD 99-17607 by including a corrective action to perform the water hammer analysis if the modification is delayed beyond May 15, 2004. (Section 1R15.3)

B. Licensee-Identified Violations

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 and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Fermi 2 began this inspection period at 100 percent rated power where it remained at or near until January 28, 2004, when operators began lowering reactor power to 55 percent. This reduction in power was performed to facilitate inspections on the main turbine to look for oil leaks resulting from a failure of the main turbine lube oil vapor extractors. All leaks were repaired and power was again restored to 100 percent rated power on January 31. Power remained at or near 100 percent power until March 26 when power was reduced to 65 percent power for rod pattern adjustments. Full power was restored on March 28 where it remained through the end of this inspection period.

1. REACTOR SAFETY

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

1R04 Equipment Alignments (71111.04Q)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed six partial walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors utilized the valve and electric breaker checklists listed in the "List of Documents Reviewed" to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors reviewed outstanding work requests and condition assessment resolution documents (CARDs) associated with the trains to verify that those documents did not reveal issues that could affect train function. The inspectors used the information in the appropriate sections of the Updated Final Safety Analysis Report (UFSAR) to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- High Pressure Coolant Injection (HPCI) System
- Emergency Diesel Generator (EDG) 11
- Division 1 Residual Heat Removal System
- Standby Feedwater System
- Standby Liquid Control System
- Reactor Core Isolation Cooling (RCIC) System

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Fire Protection Walkdowns (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of fire fighting equipment, the control of transient combustibles and ignition sources, and on the condition and operating status of installed fire barriers. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events with later additional insights, and their potential to impact equipment which could initiate a plant transient. Inspectors used the documents in the “List of Documents Reviewed” to verify that fire hoses and extinguishers were in their designated locations and available for immediate use. Inspectors looked to see that fire detectors and sprinklers were unobstructed; transient material loading was within the analyzed limits; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors verified that minor issues identified during the inspection were entered into the licensee’s corrective action program.

The following nine areas were inspected:

- UFSAR Section 9A.4.1.8, “Reactor Building Third Floor, Zone 7, El. 641 ft 6 in”
- UFSAR Section 9A.4.1.4, “HPCI Pump and Control Rod Drive Pump Rooms”
- UFSAR Section 9A.4.3.1, “EDG 11”
- UFSAR Section 9A.4.3.1, “EDG 12”
- UFSAR Section 9A.4.3.1, “EDG 13”
- UFSAR Section 9A.4.3.1, “EDG 14”
- UFSAR Section 9A.4.1.9, “Motor Generator Set Room”
- UFSAR Section 9A.4.1.10, “Refuel Floor”
- UFSAR Section 9A.4.2.4, “Relay Room”

b. Findings

No findings of significance were identified.

.2 Observation of Unannounced Fire Drill (71111.05A)

a. Inspection Scope

The inspectors observed an unannounced drill involving a fire in the new and used oil tank farm room on March 23, 2004. The drill was observed to evaluate the readiness of licensee personnel to fight fires. The inspectors considered licensee performance in donning protective clothing/turnout gear and self-contained breathing apparatus, deploying firefighting equipment and fire hoses to the scene of the fire, entering the fire area in a deliberate and controlled manner, maintaining clear and concise communications, checking for fire victims and propagation of fire and smoke into other plant areas, smoke removal operations, and the use of pre-planned fire fighting strategies in evaluating the effectiveness of the fire fighting brigade. In addition, the inspectors attended the post-drill debriefing to evaluate the licensee's ability to self-critique fire fighting performance.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On March 2, 2004, the inspectors observed an operations support crew during the annual requalification examination in mitigating the consequences of events in Scenario No. SS-OP-904-1010, "Standby feedwater, control rod drive pump trip, turbine trip, anticipated transient without scram and standby liquid control failure," on the simulator. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Ability to take timely actions in the conservative direction
- Prioritization, interpretation, and verification of annunciator alarms
- Correct use and implementation of abnormal and emergency procedures
- Control board manipulations
- Oversight and direction from supervisors
- Ability to identify and implement appropriate Technical Specifications actions and Emergency Plan actions and notifications

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness Periodic Evaluation

.1 Periodic Evaluation (71111.12B)

a. Inspection Scope

The inspectors examined the periodic evaluation report completed for the time period of May 2002 through July 2003. To evaluate the effectiveness of (a)(1) and (a)(2) activities, the inspectors examined a number of Fermi (a)(1) Action Plans, functional failures, and condition reports. These same documents were reviewed to verify that the threshold for identification of problems was at an appropriate level and the associated corrective actions were appropriate. Also, the maintenance rule program documents were reviewed. The inspectors focused the inspection on the following four systems (samples):

- Residual Heat Removal
- Residual Heat Removal Service Water
- Emergency Equipment Cooling Water
- High Pressure Coolant Injection

The inspectors verified that the periodic evaluation was completed within the time restraints defined in 10 CFR 50.65 (once per refueling cycle, not to exceed 2 years). The inspectors also determined that the licensee reviewed its goals, monitored structures, systems, and components (SSCs) performance, reviewed industry operating experience, and made appropriate adjustments to the maintenance rule program as a result of the above activities.

The inspectors verified that the licensee balanced reliability and unavailability of SSCs during the previous refueling cycle, which included safety significant systems.

The inspectors verified that (a)(1) goals were established and corrective actions were appropriate to address the causes for SSCs being in (a)(1) category, including the use of industry operating experience, and that (a)(1) activities and related goals were adjusted as needed.

The inspectors verified that the licensee has established (a)(2) performance criteria, examined any SSCs that failed to meet their performance criteria, and reviewed any SSCs that have suffered repeated maintenance preventable functional failures including a verification that failed SSCs were considered for (a)(1).

In addition, the inspectors reviewed maintenance rule self-assessments that addressed the maintenance rule program implementation.

b. Findings

No findings of significance were identified.

.2 Quarterly Inspection (71111.12Q)

a. Inspection Scope

The inspectors reviewed applicable system health reports, associated CARDs, licensee maintenance rule conduct manual, various surveillance tests, applicable design basis documents, maintenance rule scoping determinations, expert panel meeting notes, monthly monitoring reports, and the control room unit logs for the following systems:

- High Pressure Coolant Injection System (E4100)
- Reactor Recirculation System (B3100)
- Emergency Diesel Generator 11(R3000)
- Residual Heat Removal System (E1100)

The inspectors independently evaluated the licensee's determination of maintenance rule functional failures, reviewed surveillance procedures and operators' logs to assess licensee calculation of system unavailability. The inspectors also reviewed licensee-established performance goals and 'Get Well' programs for systems that do not meet performance goals or (a)(1) status systems.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed selected documents, listed in the "List of Documents Reviewed" section of this report, to determine if the risk associated with the activities listed below agreed with the results provided by the licensee's risk assessment tool. In each case, the inspectors conducted walkdowns to ensure that redundant mitigating systems and/or barrier integrity equipment credited by the licensee's risk assessment remained available. When compensatory actions were required, the inspectors conducted plant inspections to validate that the compensatory actions were appropriately implemented. The inspectors also discussed emergent work activities with the shift manager and work week manager to ensure that these additional activities did not change the risk assessment results. The inspectors assessed the following maintenance activities:

- Maintenance Risk for Down Power to Cleanup Turbine Lube Oil Leaks
- Maintenance Risk for RCIC Safety System Outage

b. Findings

No findings of significance were identified.

1R14 Nonroutine Plant Evolutions (71111.14)

a. Inspection Scope

The inspectors reviewed CARDs, work orders, industry events and procedures and interviewed engineering, maintenance, operations and work control personnel to follow up on the circumstance surrounding an extensive lube oil leak of the high pressure turbine upon the loss of both turbine lube oil vapor extractors on January 26, 2004. The oil leak caused plant operators to decrease reactor power to 55 percent to access high radiation areas for oil cleanup.

b. Findings

Introduction: An operator wrote CARD 03-01625 to document an abnormal noise from within the motor for the south turbine lube oil vapor extractor (D3014D003). On October 20, 2003, the north turbine lube oil vapor extractor (D3014D002) failed due to a ground fault (CARD 03-02522) and was removed from service and the south extractor was placed in service.

Vapor extractors are redundant 100 percent motor/fan units. The extractors draw off oil fumes from above the surface of the oil in the loop seal and main lube oil reservoir. The loop seal vapor extractor maintains a slight vacuum in the tank and drain piping to remove entrained hydrogen and vent the gas to the turbine building roof. The slight vacuum in the vapor extractors helps prevent oil from leaking from the turbine bearings.

The work screening committee did not fully understand the consequences of the failure of the redundant south vapor extractor and scheduled the north vapor extractor repairs as a plant cold work activity. The licensee received industry operating events on March 10, June 23 and October 21, 2003, regarding lube oil fires due to loss of vapor extractors at Tsurga, Unit 2, Indian Point Unit 3, and Cooper, respectively. Subsequently, operations personnel recognized that the extractors could be replaced while the unit was online and planning began on January 23, 2004, to repair the extractors under Work Request 000Z034279.

On January 26, 2004, the south main turbine lube oil vapor extractor tripped. Initial assessment by a system engineer determined that continued power operations was acceptable with both extractors inoperable. By 5:15 a.m., on January 27, 2004, a radwaste operator reported waste oil tank level increased by about 500 gallons since beginning of shift. At 7:20 a.m., the licensee completed a turbine deck inspection and found varying amounts of oil spraying from the high pressure turbine bearings No. 2 and No. 7. No oil was reported spraying on lagging or hot surfaces. Based on input to the waste oil tank, leakage was estimated to be 1 gpm. No immediate fire concerns existed due to no odor nor obvious oil soaked lagging. As the plant continued operating, the oil drains to the waste oil tank began to overflow and oil collected in the turbine building basement. A large amount of standing oil (covering 75 percent of the area) from the north to south water boxes was under the condenser. Oil was contained to areas under the high pressure turbine, mainly under the hotwell near the condenser pumps and in the north main steam tunnel. By 9:24 p.m., the south vapor extractor was returned to service.

On January 28, 2004, the licensee completed a walk down at 12:30 a.m. of the turbine deck after the south turbine lube oil vapor extractor was restored and found several steam and water leaks. By 5:36 a.m., the north lube oil vapor extractor was returned to service. At 12:15 p.m., operators commenced plant down power to 55 percent to access high radiation areas for oil cleanup. The inspectors had completed a tour of the turbine building basement to assess leakage areas and the progress in cleanup activities. CARD 04-20348 was written to document the loss of the south main turbine lube oil vapor extractor and subsequent plant power reduction.

During the CARD investigation, the licensee reviewed the maintenance history of the vapor extractor motors. Recent preventative maintenance events N946940125 and N946940126 indicated that sealed bearings were installed on both ends of the motor, so no grease fittings were installed. Stock codes indicated that the double shielded bearings were misidentified as sealed bearings. Consequently, the drive end of the motor bearings were not adequately lubricated on a periodic basis. The vendor recommended that the drive end motor bearings be lubricated annually.

Both motors were sent to the vendor for a failure analysis. The vendor reported that the drive end on each motor had metal from the balls worn down to the point that the rotor touched the stator, causing a ground. Grease had dripped out of the bearings, probably caused by overheating due to inadequate lubrication.

<u>Analysis:</u> The inspectors determined that the failure to properly lubricate the vapor extractor motor bearings was a performance deficiency warranting a significance evaluation. Without vapor extractors, an insufficient vacuum existed and caused the bearing oil to leak from the high pressure turbine. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on April 29, 2002. Based on the transient combustible loading from the lube oil leak, the inspectors asked the Region III senior reactor analysts to evaluate any impact of the lube oil leak on the increase in overall plant risk.

The initial Phase 2 risk assessment characterized this finding as potentially risk significant using the benchmarked site specific Risk-Informed Inspection Notebook. However, a Phase 3 analysis performed by the senior reactor analyst determined the issue was a Green finding, after providing additional consideration for duration. The analyst concluded the safety significance of the inspection finding based on the change in core damage frequency and large early release frequency to be Green. A Green finding represents a finding of very low safety significance.

<u>Enforcement:</u> The main turbine lube oil vapor extractors are a non-Technical Specifications system and not required by 10 CFR Part 50, Appendix B. Therefore, no violation of regulatory requirements occurred. This issue was considered a Green finding of very low safety significance **(FIN 05000341/2004002-01)**. The licensee entered improvement plans for lubricating the main turbine lube oil vapor extractor motors into the corrective action program under CARD 04-20348.

1R15 <u>Operability Evaluations</u> (71111.15)

.1 <u>Routine Operability Evaluation Reviews</u>

a. <u>Inspection Scope</u>

The inspectors assessed the following engineering functional analyses (EFA) to ensure that operability was properly justified and the component or system remained available such that no unrecognized increase in risk occurred:

- Steam leak on N30F015C&D, first stage main turbine pressure root valves
- Reportability/operability determination for both control center heating ventilation and air conditioning (CCHVAC) trains being inoperable
- Incorrect sized N2 bottles for D2 emergency equipment circulating water (EECW), CARD 04-21027

b. Findings

No findings of significance were identified.

.2 Motor Control Center Bucket Failures, CARD 02-13627

a. Inspection Scope

The inspectors assessed the following issue to determine if operability was properly justified:

- Trip of Division 2 CCHVAC Supply Fan (CARD 03-21636)

The inspectors reviewed the technical adequacy of the evaluation against Technical Specifications, UFSAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with the requirements of MES-27, "Verification of System Operability," Revision 10.

b. Findings

On October 13, 2003, the Division 2 CCHVAC supply fan tripped due to two blown fuses in Motor Control Center (MCC) 72F-5A, Pos. 1A-R. This failure caused a loss of CCHVAC, a safety-related system. Condition Assessment Resolution Document 03-21636 was written to document this issue. The inspectors discovered that this issue was related to CARD 02-13627 wherein it was identified that certain safety-related MCC buckets manufactured by Spectrum were susceptible to hot spots for, at the time, unknown reasons. The licensee closed out CARD 03-21636 to CARD 02-13627 because 02-13627 was a higher level CARD.

Condition Assessment Resolution Document 02-13627 was written on March 26, 2002, to document an issue where during the removal of a fuse from MCC 72C-2A, Pos. 1A-R, the connector on the fused disconnect switch, the wire from the switch to the fuse block, and the upper fuse block connector came out with the fuse. The licensee's investigation identified evidence of severe overheating in the vicinity of the fuse block and identified the most probable cause to be from loose electrical connections. The licensee then sent the pertinent components to an outside vendor for a failure analysis. In addition, the licensee identified 15 additional MCC buckets that were within the extent of condition and implemented increased frequency of thermography and visual inspections for all 16 buckets.

Thermography and visual inspections for all 16 identified buckets was completed on June 11, 2002. On January 13, 2003, the failure analysis concluded that the cause of the overheating was due to loose connections and that no material compatibilities existed. At the time, the licensee believed the failure to be an isolated occurrence but decided to continue monitoring the 16 identified buckets. These inspections identified a hot spot of "moderate severity" in MCC 72B-3A, Pos. 1A-R on August 7, 2003 and in MCC 72F-5A, Pos. 1A-R on September 15, 2003. 72B-3A, Pos. 1A-R was repaired without incident but 72F-5A, Pos. 1A-R blew two fuses 15 days before scheduled corrective maintenance.

At this point, the licensee assumed that issues found with all three MCC buckets were not isolated occurrences. The licensee then began to look for a root cause for these three issues and determined that the overheating could have been caused by the tinning of the conductor leads in the buckets; however, the root cause evaluation remained open at the conclusion of this inspection period. In addition, the inspectors determined that a review of the vendor's qualification and testing documentation for the affected MCCs was necessary to ensure that the MCCs with the tinned leads were properly qualified by the vendor; however, the inspectors' review of this documentation was not complete at the conclusion of this inspection period.

Pending completion of the root cause evaluation and associated completion of corrective actions, the licensee is performing the thermography and visual inspections on the 16 buckets on a monthly basis and has initiated a review of the method used to prioritize the severity of a hot spot.

This is an Unresolved Item pending the inspectors review of the final root cause, corrective actions, qualification and testing documentation, and the inspectors' determination whether a performance deficiency contributed to the overheating. **(URI 05000341/2004002-02).**

.3 Emergency Equipment Cooling Water (EECW) Voiding Due to Insufficient EECW Makeup Tank Nitrogen Pressure

a. Inspection Scope

The inspectors assessed the following operability evaluation:

- EECW voiding due to insufficient EECW makeup tank nitrogen pressure (CARD 99-17607 and Engineering Functional Analysis (EFA) EFA-P44-04-001)

The inspectors reviewed the technical adequacy of the evaluation against Technical Specifications, UFSAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with the requirements of MES-27, "Verification of System Operability," Revisions 5 and 10 and MQA-11, "Quality Assurance Conduct Manual," Revisions 6 and 9.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion V having very low safety significance (Green) for failure to follow corrective action procedures. The licensee failed to complete effective corrective actions identified in the EFA, specifically the need to perform a more rigorous evaluation of the water hammer scenario or take other prudent compensatory actions. This issue was considered to be NRC-identified because the licensee had failed to take effective corrective actions for over 4 years and did not identify it without the inspectors' questions.

Description: On October 4, 1999, a condition was discovered that had the potential for a water hammer event in the EECW system, which is safety-related, due to insufficient EECW makeup tank pressures. Specifically, if EECW were operating concurrent with a power disruption to the pumps, the pressure in the makeup tank would not be sufficient to ensure that the EECW piping remained solid at the higher piping elevations. This condition was documented in CARD 99-17607 and a prompt operability determination was conducted via an Engineering Functional Analysis (EFA).

This EFA, which relied almost entirely on engineering judgement, determined that "the engineering judgement presented in this EFA is sufficient as a basis for the current operability of the system in the interim until the acceptability of the system design can be rigorously established." In other words, this EFA identified the necessity to perform detailed water hammer analysis.

During the solution team meeting on February 16, 2000, the team decided to issue a proposal to implement a design modification to correct the condition instead of performing a water hammer analysis. The licensee decided to implement a modification to install a makeup pump which would have increased the makeup tank pressure sufficiently to ensure that the piping would remain solid thus alleviating the possibility of a water hammer. The action to perform a water hammer analysis was therefore not tracked because the licensee was pursuing a more definitive resolution to the issue.

The design modification was delayed and ultimately rescheduled to be implemented during the first quarter of 2004 which was later than initially envisioned. The inspectors determined that a water hammer analysis (or other compensatory actions) should have been performed due to the length of time involved but that one was not performed because the licensee was only tracking one corrective action: completion of the modification. The failure to track the corrective action of completing the water hammer analysis led to the delay in implementing overall effective corrective actions because the modification was neither completed as originally envisioned nor was the prompt operability determination ever "rigorously established."

Lastly, the inspectors determined that the postulated EECW water hammer scenario is only an operability concern when EECW is placed in operation. This is because EECW is normally in standby and run infrequently, such as when performing a surveillance test. As such, other compensatory actions could have been taken when EECW was run, such as declaring the system inoperable, until such time as either the water hammer analysis supported system operability or the modification was complete.

Analysis: The inspectors determined that the failure to perform timely and adequate corrective actions was a performance deficiency warranting a 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," issued on April 29, 2002. Specifically, the lack of effective compensatory actions or the completion of a water hammer analysis to substantiate a 4-year old prompt operability determination would become a more significant safety issue if not corrected. The finding also affected the cross-cutting area of Human Performance because the licensee failed to follow their corrective action procedures.

The inspectors completed a significance determination of this issue using IMC 0609, “Significance Determination Process (SDP),” dated April 30, 2002, Appendix A, Attachment 1, “SDP Phase 1 Screening Worksheet for IE, MS, and B Cornerstones.” The inspectors concluded that this finding affected the mitigating systems cornerstone. Since the inspectors answered “no” to all five questions under the mitigation systems column, this finding was considered to be of very low safety significance (Green).

<u>Enforcement:</u> 10 CFR Part 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. One procedure established to meet this requirement includes MES-27, Rev. 6, “Verification of System Operability.” Step 4.3.10 required that bounding assumptions be included in a “routine process.” The inspectors considered that assuming the completion of a water hammer analysis to establish the validity of the prompt operability determination and to develop a corrective action plan was a bounding assumption in the original EFA that was not included in a routine process such as the corrective action process.

Step 4.3.12 required that recommended plant actions be added to the CARD and, if the EFA was extended, that the bounding assumptions be re-evaluated with all required actions documented in the CARD. The EFA’s recommended plant action was that long term actions would be developed on the basis of the water hammer analysis.

Another procedure established to meet 10 CFR Part 50, Appendix B, Criterion V was MQA-11, Rev. 5, “Condition Assessment Resolution Document.” Step 4.4.3.14 required that the licensee “monitor status of actions until completed.”

Contrary to the above:

- The water hammer analysis was not performed
- The requirement to perform a water hammer analysis was not included in any routine process as a bounding assumption
- The requirement to perform a water hammer analysis was not included, and thus not tracked, in the CARD as a corrective action

Based on the inspectors’ questions, the licensee initiated CARD 04-21296 on March 25, 2004, and entered this issue into their corrective action program. Additionally, the licensee updated CARD 99-17607 by including a corrective action to perform the water hammer analysis if the modification is delayed beyond May 15, 2004.

Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000341/2004002-03).

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope

The inspectors performed a semi-annual review of all operator workarounds and challenges identified as of February 4, 2004. The inspectors compared workaround and information to the normal, abnormal, and emergency operating procedures to ensure that operations personnel maintained the ability to correctly respond to plant transients in a timely manner. The inspectors utilized system knowledge, reviewed plant procedures, and interviewed operations personnel to ensure that the workarounds and challenges previously identified did not adversely impact system reliability and availability, create the potential for system misoperation, or result in a workaround that impacted multiple mitigating equipment. Finally, the inspectors reviewed the equipment safety tagging records, equipment out-of-service logs, temporary modification reports, and open operability determinations for potential operator workarounds and challenges that had not been previously identified or assessed for potential impact on normal plant operation or transient response.

In addition to the above, the inspectors reviewed selected issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed and observed the following post maintenance testing activities involving risk significant equipment in the Mitigating Systems cornerstones:

- Post maintenance testing on turbine building heating ventilation and air conditioning discharge fan
- C238040100, post maintenance testing on standby liquid control tank level instrument and test flowmeter
- 000Z040614, 2-out-of-4 logic module not functioning correctly (reactor protection system voter failure)
- 000Z022442, replace RCIC lube oil cooler valve E51F015 per Engineering Design Package 32161

The inspectors verified that the post-maintenance test was adequate for the scope of the maintenance work performed, acceptance criteria were clear, and operational readiness consistent with design and licensing basis documents was demonstrated. The inspectors also verified that the impact of the testing had been properly characterized in the risk assessment, the test was performed as written, the testing prerequisites were satisfied, and that the test data was complete. Following the completion of the test, the inspectors verified that the system was returned to its normal standby configuration.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Quarterly Inspection

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 50, Appendix B, and licensee procedure requirements and evaluated the consistency of the tests with the UFSAR. The inspectors verified that the testing demonstrated that the systems were ready to perform their intended safety functions. Additionally, the inspectors reviewed whether test control was properly coordinated with the control room and performed in the sequence specified in the surveillance instruction and if test equipment was properly calibrated and installed to support the surveillance tests. The specific surveillance activities assessed were:

- HPCI test Procedure 24.202.01, Section 5.1, “HPCI Pump/Flow Test and Valve Stroke at 1025 psig,” performed during week of January 11, 2004
- Procedure 24.307.16, “EDG 13 slow start surveillance”
- Procedure 24.204.01, “Low Pressure Coolant Injection Pump and Valve Operability”
- Conduct VT-2 ISI of Reactor Pressure Vessel in Refueling Outage 6
- Procedure 24.307.01, “EDG 11 24-hour Run followed by Hot restart”
- Procedure 24.206.01 “RCIC Pump and Valve Operability”

b. Findings

No findings of significance were identified.

.2 Primary Containment Isolation Valve Stroke Time Issues

a. Inspection Scope

The inspectors reviewed several CARDs, deviation event reports, failure analysis reports and interviewed system engineering personnel pertaining to several failures of containment isolation valves to meet inservice inspection (ISI) stroke time acceptance criteria. In particular were two recent failures that occurred on October 27, 2003. The inspectors recognized this condition as a potential repeat condition that has been occurring for over 10 years.

b. Findings

On October 27, 2003, the licensee performed Procedure 24.406.01, "Nitrogen Inerting System Valve Operability Test." Primary containment pneumatic Division 1 supply outboard primary containment valve T4901F465 closed in 26.0 seconds and failed the ISI stroke time acceptance criteria of 4.7 to 13.8 seconds. Operators initiated CARD 03-21626 to document the failure. Likewise, on the same day, CARD 03-21627 was written to document Division 2 supply outboard primary containment valve T4901F468 failed to stroke. Consequently, this did not meet the ISI stroke time acceptance criteria of 4.7 to 14 seconds.

Slow stroke time of T4901F465 and the failure to stroke of T4901F468 was caused by the failure of the corresponding solenoid valves (T49F465 and T49F468) to exhaust air from the operators of these valves at a sufficient rate to meet stroke time criteria. Past failure history documented on previous corrective action documents dating back to 1995 that these solenoid valves were mechanically bound/stuck due to foreign material intrusion. This had occurred on other safety-related containment isolation valves as documented in four deviation event reports and seven CARDs. The use of a pipe sealant compound, which was used on the non-interruptible air system to stop fitting leaks, was one compound that caused this condition.

Valves T4901F465 and F468 were sent offsite for failure analysis and chemical analyses were performed on the existing grease used on these valves and also on a fresh sample of grease. Preliminary chemical results demonstrated the presence of a pipe sealant compound in the existing grease, indicating that corrective actions from the previous corrective action documents may have been ineffective. This issue is an Unresolved Item (**URI 05000341/2004002-04)** pending the licensee's determination of the final root cause and the inspectors' review of the root cause.

The licensee entered Technical Specification 5.5.6 and since 10-year ISI intervals was not specified in the specification, they had to enter Surveillance Requirement 3.0.3. Per the TS, they could complete the ISI within 24 hours or the next available opportunity, which is the next refueling outage, provided they perform a risk evaluation with acceptable results.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the licensee perform the following three simulator-based training evolutions that contributed to the "drill/exercise performance" performance indicator:

- Scenario SS-OP-904-1005, "Loss of Control Rod Drive Flow Control/Loss of Vacuum/Anticipated Transient Without Scram"
- Red team RERP drill on February 18, 2004

- Scenario SS-OP-904-1049, "Feed Water Leak Inside Containment/Loss of 120kV"

The inspectors observed activities in the control room simulator and attended the post evaluation critiques in the simulator immediately following the evaluation. The focus of the inspectors' activities was to note any weaknesses and deficiencies in operator performance, ensure that the licensee evaluators noted the same weaknesses and deficiencies, and entered any weaknesses or deficiencies into the corrective action program, as appropriate. The inspectors placed emphasis on observations regarding event classification, notifications, and protective action recommendations.

b. Findings

No findings of significance were identified.

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 reviewed licensee event reports, corrective action documents, electronic dosimetry transaction data for radiologically restricted area egress, and data reported on the NRC's web site relative to the licensee's occupational exposure control performance indicator to determine whether or not the conditions surrounding any actual or potential performance indicator (PI) occurrences had been evaluated, and identified problems had been entered into the corrective action program for resolution. Performance indicator data collection and analysis methods were evaluated by the inspectors as described in Section 4OA1.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns/Boundary Verifications and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified work areas that existed during the inspection within high and locked high radiation areas of the plant and selectively reviewed radiation work permit (RWP) packages and radiation surveys for these areas. The inspectors evaluated the radiological controls to determine if these controls including postings and access control barriers were adequate.

The inspectors reviewed active and recently closed RWPs and work packages which governed activities in radiologically significant areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and RWP policy. Workers were questioned by the inspectors to verify that they were aware of the actions required when their electronic dosimeters malfunctioned or alarmed.

The inspectors walked down and surveyed (using an NRC survey meter) radiologically significant area boundaries and other areas in the Turbine, Reactor and Radwaste Buildings to verify that the prescribed radiological access controls were in place, that licensee postings were complete and accurate, and that physical barricades/barriers were adequate. During the walkdowns, the inspectors challenged access control boundaries to verify that high radiation area, locked high radiation area (LHRA) and very high radiation area (VHRA) access was controlled consistent with the licensee's procedures, Technical Specifications, the requirements of 10 CFR 20.1601 and were consistent with Regulatory Guide 8.38, "Control of Access to High and Very High Radiation Areas in Nuclear Power Plants."

The inspectors reviewed RWP and post job review documents for selected activities completed in 2003 to verify barrier integrity and engineering controls performance (e.g., filtered ventilation system operation) and to determine if there was a potential for individual worker internal exposures of >50 millirem committed effective dose equivalent. The inspectors reviewed the licensee's procedures and evaluated its methods for the assessment of internal dose as required by 10 CFR 20.1204. Specifically, the inspectors selectively reviewed the licensee's internal dose assessments for the most recent intakes which occurred during the April 2003 refueling outage (all less than 50 millirem committed effective dose equivalent), to ensure the doses were calculated correctly and included an assessment of the impact of hard to detect radionuclides such as pure beta and alpha emitters, as applicable.

The inspectors reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within spent fuel or other storage pools. Specifically, radiation protection (RP) procedures were reviewed, RP staff were interviewed, and a walkdown of the refuel floor was conducted. In particular, the radiological controls for non-fuel materials stored in the spent fuel pool were examined to ensure adequate barriers were in-place to reduce the potential for the inadvertent movement of highly irradiated materials.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a licensee audit report, the condition assessment resolution document (CARD) database along with individual CARDs related to the radiological access and exposure control programs to verify that identified problems were entered into the corrective action program for resolution. In particular, the inspectors reviewed recent high radiation area (HRA) radiological incidents (non-PI occurrences identified by the licensee in high and locked high radiation areas) to verify that follow-up activities were conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

1. Initial problem identification, characterization, and tracking;
2. Disposition of operability/reportability issues;
3. Evaluation of safety significance/risk and priority for resolution;
4. Identification of repetitive problems;
5. Identification of contributing causes; and
6. Identification and implementation of corrective actions.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and were being resolved. For repetitive deficiencies, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies, if applicable.

The inspectors reviewed licensee documentation packages for all potential PI events occurring since the last inspection to determine if any of these events involved dose rates >25 Rem/hr at 30 centimeters or >500 Rem/hr at 1 meter or involved unintended exposures >100 millirem total effective dose equivalent (or >5 Rem shallow dose equivalent or >1.5 Rem lens dose equivalent). None were identified.

Additionally, the inspectors reviewed the licensee's collective assessment of recent declining radiation worker performance including two high radiation area incidents that occurred in January 2004. Specifically, the licensee's assessment was discussed with RP staff, the actual and potential radiological impact of the incidents were independently assessed using the NRC's significance determination process for the occupational radiation safety cornerstone, and the adequacy of the licensee's problem identification and corrective actions were evaluated.

These reviews represented four inspection samples. Specifically, the samples pertained to the licensee's self-assessment capabilities, its problem identification and resolution program for HRA incidents, a review of the licensee's ability to identify and address repetitive deficiencies, and a review of those potential PI occurrences of greatest radiological risk.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews and Review of Work Practices in Radiologically Significant Areas

a. Inspection Scope

The inspectors observed entry into the Reactor Water Cleanup (RWCU) Heat Exchanger Room (a LHRA) to perform a surveillance and observed the LHRA access controls that were being established following removal of floor plugs in the Turbine Building. The inspectors reviewed the radiation surveys and associated radiological job requirements for these activities provided in the RWP package. The inspectors also attended the as-low-as-is-reasonably-achievable (ALARA) pre-job briefing for the RWCU room entry and assessed the adequacy of the information exchanged.

Job performance was observed to verify that radiological conditions in the work area were adequately communicated to workers through the pre-job brief and postings. The inspectors also verified the adequacy of the radiological oversight provided by the radiation protection staff including the radiological surveys and radiation protection technician job coverage, stay time dose tracking and the LHRA access control provisions utilized while the work took place in the area.

Previously completed work in high radiation areas that had significant dose rate gradients were reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. This work included areas where the dose rate gradients were subject to significant change (i.e., torus dives performed during a previous outage) which involved use of multiple dosimeters and enhanced job controls.

The inspectors also reviewed the licensee’s procedures and discussed with RP staff its practices for at power drywell entry, initial entry following down power, and for traversing in-core probe (TIP) room access to determine the adequacy of the radiological controls and hazards assessment associated with such entries. Work instructions provided in radiation work permits and in pre-entry briefings were discussed with RP staff to determine their adequacy relative to industry practices and NRC Information Notices. The inspectors also reviewed the licensee’s procedure and generic practices associated with dosimetry placement, the use of multiple whole body dosimetry and for extremity monitoring in high radiation areas having significant dose gradients for compliance with the requirements of 10 CFR 20.1201(c) and applicable industry guidelines.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, LHRA and VHRA Access Controls

a. Inspection Scope

The inspectors reviewed the licensee's procedures, associated Prevent Event Checklists, and evaluated RP practices for the control of access to radiologically significant areas (high, locked high, and very high radiation areas) and assessed compliance with the licensee's Technical Specifications, procedures, the requirements of 10 CFR Part 20, and the guidance contained in Regulatory Guide 8.38. In particular, the inspectors evaluated the RP staff's control of keys to HRAs, LHRAs and VHRAs, practices for dose tracking, stay time determinations, and for access control while work in LHRAs and VHRAs was ongoing. The licensee's methods and practices for independently verifying proper closure and locking of access doors upon area egress was also assessed. The inspectors selectively reviewed high radiation area key issuance/return and inventory records for 2004 to verify the adequacy of accountability practices and documentation. Additionally, the inspectors evaluated the licensee's practices for RP and nuclear shift supervisory approval of access into LHRAs and VHRAs to verify compliance with procedure requirements and those of 10 CFR 20.1602. Moreover, the inspectors discussed with RP staff the methods for the movement of highly radioactive material within the plant to ensure temporary high radiation areas were properly controlled and posted.

The inspectors discussed with RP supervisors the controls that were in place for areas that had the potential to become very high radiation areas during certain plant operations to determine if these plant operations required communication before hand with the RP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

The inspectors conducted plant walkdowns to verify the posting and locking of entrances to numerous LHRAs in the Turbine, Reactor and Radwaste Buildings, and for VHRAs (TIP room and Drywell airlock).

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During performance of the surveillance in the RWCU Heat Exchanger Room, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and to determine whether workers were aware of the radiological conditions, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

The inspectors reviewed radiological problem reports which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this matched the corrective action approach taken by the licensee to resolve the identified problems.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements, conformance with procedures and those requirements specified in the RWP, and to determine if their performance was consistent with the radiological hazards that existed.

The inspectors reviewed selected radiological problem reports generated in 2003 through March 2004 to determine the extent of any specific problems or trends caused by RP technician errors, and to determine if the corrective action approach taken by the licensee to resolve the reported problems, if applicable, was adequate.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

Cornerstones: Mitigating Systems and Occupational Radiation Safety

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensees submittals for performance indicators (PIs) and period listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” to verify the accuracy of the PI data. The following four PIs were reviewed.

- High pressure injection system unavailability

- Safety system functional failures
- Residual heat removal safety system unavailability
- Emergency alternating current power safety system unavailability

The inspectors reviewed selected applicable conditions and data from logs, licensee event reports and condition reports from January 1, 2003 through December 31, 2003, for each PI area specified above. The inspectors independently re-performed calculations where applicable. The inspectors compared that information to the information required for each PI definition in the guideline to ensure that the licensee reported the data correctly.

b. Findings

No findings of significance were identified.

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled licensee submittals for the PI listed below for the period October 2003 through March 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The following PI was reviewed:

- Occupational Exposure Control Effectiveness

For the time period reviewed, no reportable occurrences were identified by the licensee. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with RP staff the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm reports, and the licensee's CARD database along with individual CARDs generated during the period reviewed to verify there were no unrecognized occurrences. Additionally, as discussed in Section 2OS1, the inspectors walked down the boundaries of selected LHRAs and VHRAs to verify the adequacy of postings and access control physical barriers.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.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 verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are included in the list of documents reviewed which are attached to this report. The following issues were followed-up by the inspectors:

- Decreased EDG jacket water pressure;
- Spectrum bucket loose connections; and,
- Primary containment isolation valve repeat failures to stroke.

b. Findings

The review of the decreased EDG jacket water pressure is discussed in Section 4OA7. The review of the Spectrum bucket issue is discussed in Section 1R15, and the review of the primary containment isolation valve repeat failures is discussed in Section 1R22.2. Otherwise, no findings of significance were identified.

.2 Corrective Actions Involving Risk Evaluation for Emergent Work

Prioritization and Evaluations of Issues

a. Inspection Scope

The inspectors reviewed the corrective actions for CARDs 03-19466 and 04-20505. Specifically, the inspectors reviewed these CARDs to ensure that all corrective actions had been completed and implemented effectively regarding notifications to operations and probabilistic safety assessment groups whenever maintenance by outside organization would impact the 120kV or 345kV switchyards as required by MMR 12, "Equipment Out of Service Risk Management."

Issues: On September 3, 2003, the Field Supervisor from Newport Service Center informed maintenance personnel that the Luzon power line, one of three 120kV offsite power lines, was unavailable for overhead transmission work. Maintenance personnel failed to inform personnel in both the operations and probabilistic safety assessment group as required by Step 3.8.2 of MMR 12, "Equipment Out of Service Risk Management." A Level 2 CARD (03-19466) was initiated on September 12, 2003 to document the noncompliance. A Level 2 is a non-significant CARD classification that has a potential or actual effect on safe or reliable operation of the plant or personnel. Typically, 3 and 5 day notices are given to Fermi personnel whenever offsite work is being done on the 345kV and 125kV lines, respectively. This information was communicated by facsimile, which were getting lost.

Corrective action for the CARD included ensuring that corporate representatives understand their current responsibilities relating to the notification of unavailable off-site power and operations. An immediate corrective action included placing notice on the plan of the day for information during Luzon line unavailability. This action was completed October 16, 2003.

Subsequently, the Luzon line was restored. Between November 18, and December 30, 2003, the 120kV Swan Creek line was again unavailable as a source of offsite power due to work between the Berlin and Brownstown Substation. Fermi 2 was notified of this shutdown on November 14, 2003. However, the probabilistic safety assessment group was not notified until November 17, 2003, after the risk memo for the work week risk assessment had been completed. Even though the probabilistic safety assessment group was notified by the shift manager before the line was shutdown, this was considered a similar example to the September 3 event in that MMR 12 was not followed. However, a CARD was not initiated. Since the procedure was not followed during this example, the inspectors determined that a CARD should have been written.

On January 6, 2004, the Swan Creek line was again out of service for maintenance and was expected to be restored by February 27, 2004. Fermi received shutdown request (RSD C08318) on December 22, 2004, and the probabilistic safety assessment group and operations personnel were not informed because the corporate representative was not aware of the shutdown. The licensee initiated CARD 04-20505 to document that the corrective action from CARD 03-19466 was ineffective.

4OA3 Event Followup (71153)

.1 Review of Licensee Event Reports (LER)

(Closed) LER 50-341/03-003-00: Non-Conservative Setpoints for Stability Option III Oscillation Power Range Monitor (OPRM) Period Based Detection Algorithm, Period Confirmation Adjustable Variables.

On October 2, 2003, General Electric Nuclear Energy informed the licensee that the stability Option III period based detection algorithm variables for the period tolerance and conditioning filter cutoff frequency may be non-conservative. General Electric recommended that the average OPRM upscale trip (Technical Specifications Limiting Condition for Operation 3.3.1.1, Function 2.f) be considered inoperable for plants with a period tolerance setpoint less than 100 msec and with a cutoff frequency greater than 1.0 Hz. The licensee had the period tolerance set at 50 msec and a cutoff frequency set at 3.0 Hz so their OPRMs were declared inoperable.

General Electric’s 10 CFR, Part 21 Notification concerning this issue states that absent “justification of another value, the period tolerance should be set to 100 msec or greater and the cutoff frequency should be set to 1.0 Hz.” This notification was a result of General Electric’s investigation of the instability event that occurred at Nine Mile Point Unit 2 on July 24, 2003.

Technical Service Request 32761 was initiated to change the OPRM variables for all four OPRMs. Work requests 000Z034318, 000Z034319, 000Z034317, and 000Z034099 were performed to make the necessary changes. The inspectors verified that the setpoints were changed, as required, on all OPRMs. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented this issue in CARD 03-22220. This LER is closed.

4OA4 Cross-Cutting Findings

Two findings described in Sections 1R14 and 1R15.3 of this report had, as its primary cause, human performance deficiencies. First, the licensee failed to grease both turbine lube oil vapor extractors motor bearings that resulted in motor failures and caused a high pressure turbine oil leak, thereby increasing combustible loading under the turbine and increasing the likelihood of a turbine trip. Also, the licensee performed an engineering evaluation on November 15, 1999, wherein corrective actions identified in the evaluation were not tracked and therefore not implemented by the licensee.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. O'Connor and other members of licensee management at the conclusion of the inspection on April 2, 2004. The inspectors asked the licensee whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Maintenance Effectiveness Periodic Evaluation with Mr. W. O'Connor, Jr., Vice President, on January 30, 2004.
- Radiological Protection with Mr. O'Connor, Jr., Vice President, on April 2, 2004.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating Systems

1. 10 CFR 50.55a(g)(4) requires, in part, that throughout the service life of a boiling water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet requirements of Section XI. Section XI, IWA-5222 "System Hydrostatic Test Boundaries" required that: "(c) Systems designed to operate at different pressures under several modes of plant operation or post-accident conditions shall be subject to a system hydrostatic test within the test boundary defined by the operating mode with the higher pressure." Contrary to these requirements, on October 20, 1998, during the conduct of the ASME Code hydrostatic test, the licensee failed to establish the required test boundary and pressurize portions of the multiple safety and risk significant systems to attain pressures required under the most limiting plant operating modes. The licensee determined that the surveillance could not be completed within 24 hours and determined, through a risk evaluation, that conducting the surveillance during the next outage was acceptable. Conducting this evaluation was specified in the bases section

for the 3.0.3 surveillance requirement. The accompanying operability determination concluded that not conducting inspections of this piping in 1998 was of low safety significance.

2. 10 CFR Part 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Contrary to this requirement, in October of 1998, mechanics failed to follow the vendor manual instructions and improperly installed copper adapter gaskets while installing a cylinder liner adapter. Consequently, the improperly installed gaskets contributed to the carbon monoxide leakage into the jacket water cooling system. The licensee had been tracking a steady decrease in jacket cooling water pressure and replaced all 48 gaskets under Work Request 000Z040729. Corrective action recommendations included evaluating the guidance in Procedure 35.307.008 for improvement in installing the gasket correctly and developing procedural guidance for annealing the gaskets.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
W. O'Connor, Jr., Vice President Nuclear Generation
D. Cobb, Plant Manager
T. Dong, Manager Nuclear Performance Engineering
H. Higgins, Radiation Protection Manager
R. Libra, Director Nuclear Engineering
K. Morris, Emergency Preparedness Supervisor
D. Noetzel, Manager Nuclear System Engineering
N. Peterson, Nuclear Licensing Manager
M. Philippon, Operations Manager
L. Sanders, Nuclear Training Manager
R. Slottke, Supervisor, PSA
J. Tibai, Supervisor, Performance Engineering
R. Zyduck, Manager Nuclear Plant Support Engineering

NRC
P. Hiland, Acting Deputy Director, Division of Reactor Projects
M. Ring, Chief, Division of Reactor Projects, Branch 1

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000341/2004002-01	FIN	Oil Leak Caused by Lube Oil Vapor Extractor Failure
05000341/2004002-02	URI	Spectrum MCC Bucket Loose Connections
05000341/2004002-03	NCV	Failure to Follow Corrective Action Procedures
05000341/2004002-04	URI	Failed ISI Testing on Nitrogen System Isolation Valves

Closed

05000341/2004002-01	FIN	Oil Leak Caused by Lube Oil Vapor Extractor Failure
05000341/2004002-03	NCV	Failure to Follow Corrective Action Procedures
05000341/2003003-00	LER	Non-Conservative Setpoints for Stability Option III (OPRM) Period Based Detection Algorithm

Discussed

None.

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Procedure 23.205, Rev. 83; Residual Heat Removal System

Drawing 6M721-5706-2, Rev. W; Residual Heat Removal Div. 1 Functional Operating Sketch

Drawing 6I721-2105-09, Rev. J; Schematic Diagram Reactor Recirculation System Loop B Annunciator Circuits

Procedure 23.206, Rev. 77; Reactor Core Isolation Cooling System

Drawing 6M721-5709-1, Rev. AD; Reactor Core Isolation Cooling (RCIC) System Sketch Functional Operating Sketch

Drawing 6M721-5709-2, Rev. F; RCIC Turbine Lube Oil/Control Oil Functional Operating Sketch

Drawing 6M721-2044, Rev. AX; Diagram Reactor Core Isolation Cooling System (RCIC)

PDC 9210, Rev. A; SBFW Pump Low Suction Pressure Alarm

ARP 1D69, Rev. 10; SBFW Sys Suction Pressure Low

ARP 1D65, Rev. 9; SBFW Isolation RPV H2O Level L8

Procedure 24.107.03, Rev. 33; SBFW Pump and Valve Operability and Lineup Verification Test

Procedure 20.107.01, Rev. 20; Loss of Feedwater or Feedwater Control

Procedure 23.107.01, Rev. 30; Standby Feedwater System

Drawing 6M721-2006, Rev. BA; Condensate Storage and Transfer System Diagram

Drawing 6M721-3103-1, Rev. U; Piping-Isometric-Feedwater From N & S Heater #6 Discharge Valve Turbine House Unit 2

Drawing 6M721-5083, Rev. R; Piping & Instrument Diagram Standby Feedwater System

Drawing 6M721-5715-3, Rev. L; Standby Feedwater System Functional Operating Sketch

Drawing 6M721-5715-4, Rev. D; Standby Feedwater Lue Oil System Turbine Building Functional Operating Sketch

Procedure 23.207, Rev. 81; Emergency Diesel Generator System

Procedure 23.308, Rev. 44; 120V AC Instrument and Control Power System

Drawing 6M721N-2046, Rev. Z; P&ID Diesel Generator System Division I RHR Complex

Drawing 6M721N-2047, Rev. AD; P&ID Diesel Generator System Division II RHR Complex

Procedure 24.202.03, Rev. 32; HPCI System Piping Filled and Valve Position Verification

Procedure 23.202, Rev. 83; High pressure Coolant Injection System

HPCI System Outage Critique; dated January 31, 2001

EFA 01-13940, Rev. 1; EFA for pressure Transient on HPCI Discharge Pipe

Drawing 6M721-5708-1, Rev. AH; High Pressure Coolant Injection System Functional Operating Sketch

Drawing 6M721-5708-2, Rev. J; HPCI Turbine Lube Oil/Control Oil Functional Operating Sketch

1R05 Fire Protection

UFSAR Section 9A.4.1.9; Fourth Floor, Zone 8, El. 659 Ft 6 In.

Drawing 6A721-2408, Rev. R; Fire protection Evaluation Reactor and Auxiliary Buildings Fourth Floor Plan El. 659’-6"

Drawing 6I721-2868-16, Rev. C1; Installation Fire Detection System Third Floor El. 641’-6" Reactor Building - Zone 15

Work Request FP26031208; Perform 28.501.08 Fire Hose Station Inspection

Drawing 6A721-2407, Rev. R; Fire protection Evaluation Reactor and Auxiliary Buildings Third Floor Plan El. 641’-6" and 643’-6"

UFSAR 9A.4.1.8; Third Floor, Zone 7, El. 641 Ft 6 In

UFSAR Section 9A.4.1.8; Reactor Building Third Floor, Zone 7, El. 641 Ft 6 In

Drawing 6A721-2407; Fire Protection Evaluation Reactor and Auxiliary Buildings Third Floor Plan El 641’-6" and 643’-6"

Procedure 67.000.100, Rev. 11; Posting and De-Posting of Radiological Hazards

Emergency Plan Procedure EP-201-03, Rev. 8

Emergency Plan Procedure EP-220, Rev. 13

UFSAR 9A.4.2.4; Relay Room, Zone 3, El. 613 Ft 6 In

UFSAR Section 9A.4.1.10; Fifth Floor, Zone 9, El. 684 Ft 6 In

Drawing 6A721-2405, Rev. S; Fire Protection Evaluation Reactor and Auxiliary Buildings Second Floor - Plan - El. 613’-6"

Drawing 6A721-2409, Rev. S; Fire Protection Evaluation Reactor and Auxiliary Buildings Fifth Floor - Plan - El. 677’-6" and 684’-6"

UFSAR Figure 9A-14; Fire Protection Evaluation Residual Heat Removal Complex Grade Floor Plan (Elevation 590.0 Ft)

UFSAR Figure 9A-15; Fire Protection Evaluation Residual Heat Removal Complex Upper Floor Plan (Elevation 617.0 Ft)

UFSAR Section 9A.4.3; Residual Heat Removal Complex

UFSAR Section 9A.4.1.4; High Pressure Coolant Injection Pump and Turbine and Control Rod Drive Pump Room, Zone 3, El. 540 Ft 0 In. And 562 Ft 0 In.

Drawing 6A721-2401, Rev. L; Fire Protection Evaluation Reactor Building Subbasement - Plan - El. 540’-0"

Drawing 6A721-2402, Rev. P; Fire Protection Evaluation Reactor and Auxiliary Buildings Basement Floor - Plan - El. 562’-0"

Drawing 6A721-2400, Rev. N; Fire Protection Evaluation Plot Plan

UFSAR 9.5.1.1.2; Codes and Standards

UFSAR Figure 9A-2; Fire Protection Evaluation Reactor Building Subbasement Plan (Elevation 540.0 Ft)

UFSAR Figure 9A-3; Fire Protection Evaluation Reactor and Auxiliary Buildings Basement Plan (Elevation 562.0 Ft)

Procedure 20.000.18, Rev. 33; Control of the plant From the Dedicated Shutdown Panel

Procedure 20.000.22, Rev. 33; Plant Fires

1R11 Licensed Operator Requal

Scenario No. SS-OP-904-1010, Standby Feedwater, Control Rod Drive Pump Trip, Turbine Trip, Anticipated Transient Without Scram and Standby Liquid Control Failure, February 8, 2004

1R12 Maintenance Rule Implementation

Drawing 6I721-2100-01, Rev. E; Logic Diagram Reactor Recirculation System Part 1

Drawing 6I721-2101-10, Rev. T; Schematic Diagram Recirculation Pump B3101C001A

Drawing 6M721-5702-2, Rev. I; Functional Operating Sketch Reactor Recirculation MG Sets A & B Lube Oil/Control Oil

Drawing 6I721-2104-03, Rev. M; Internal-External Wiring Diagram MG Set Control Panel B31P002A

ARP 3D131, Rev. 6; Recirc Sys A Emerg Lube Oil Pump Auto Start

ARP 3D155, Rev. 8; Recirc Sys B Emerg Lube Oil Pump Auto Start

Reactor Recirculation Maintenance Rule Functional Failure Evaluations from January 1, 2001 through December 31, 2003

Selected Control Room Operator logs from January 1, 2001 through January 1, 2004

CARD 02-13666; DCS trouble during RR pump startup from SLO pump controller shifted to manual at 36% speed; dated April 4, 2002

Maintenance Rule Conduct Manual, Rev. 1

Work Request B064961011; Recal RR MG set “B” pressure Switches

CARD 02-13638; RRMG set “A” generator trip; dated march 30, 2002

Instrument Calibration Specification Sheet for PIS Number B31NA05A; Rev. 0

CARD 01-21289; Pressure switch B31NA04B as found out of spec; dated November 6, 2001

CARD 01-15334; RRMG set “B” scoop tube locked; dated June 9, 2001

Reactor Recird Monthly Maintenance Rule Report from January 1, 2001 through December 31, 2003

Drawing 6I721-2101-08, Rev. K; Schematic Diagram Recirc. Pump MG Set Lube Oil Pump B-1, B3103C001C

Drawing 6I721-2101-12, Rev. K; Schematic Diagram Recirc. MG Set Emerg. Oil Pumps C & D, B3103C002A & C002B

CARD 98-18706; Defective Relay; dated October 6, 1998

MMR01; Fermi 2 Maintenance Rule Conduct Manual - Introduction; Revision 1

MMR02; Fermi 2 Maintenance Rule Conduct Manual - Maintenance Rule Program Description; Revision 0

MMR03; Fermi 2 Maintenance Rule Conduct Manual - Scoping; Revision 0

MMR04; Fermi 2 Maintenance Rule Conduct Manual - Determination of Risk Significance; Revision 0

MMR05; Fermi 2 Maintenance Rule Conduct Manual - Determination of SSC Functions; Revision 0

MMR06; Fermi 2 Maintenance Rule Conduct Manual - Establishing Performance Criteria; Revision 0

MMR07; Fermi 2 Maintenance Rule Conduct Manual - Expert Panel; Revision 0

MMR08; Fermi 2 Maintenance Rule Conduct Manual - SSC Classification; Revision 0

MMR09; Fermi 2 Maintenance Rule Conduct Manual - Establishment of Get Well Plans; Revision 1

MMR10; Fermi 2 Maintenance Rule Conduct Manual - Monitoring; Revision 1

MMR11; Fermi 2 Maintenance Rule Conduct Manual - Periodic Assessment; Revision 0

MMR12; Fermi 2 Maintenance Rule Conduct Manual - Equipment Out of Service Risk Management; Revision 0

MMR13; Fermi 2 Maintenance Rule Conduct Manual - Self Assessment of Practices and Processes Effectiveness; Revision 0

MMR14; Fermi 2 Maintenance Rule Conduct Manual - Structures Monitoring; Revision 0

MMR Appendix A; Fermi 2 Maintenance Rule Conduct Manual - Forms; Revision 0

MMR Appendix B; Fermi 2 Maintenance Rule Conduct Manual - Terms and Definitions; Revision 0

MMR Appendix C; Fermi 2 Maintenance Rule Conduct Manual - Maintenance Rule Scoping Summary Report; Revision 0

MMR Appendix D; Fermi 2 Maintenance Rule Conduct Manual - Guidelines for Determining Functional Failures (FF) and Maintenance Preventable Functional Failure (MPFF); Revision 0

MMR Appendix E; Fermi 2 Maintenance Rule Conduct Manual - Maintenance Rule SSC Specific Functions; Revision 0

MMR Appendix F; Fermi 2 Maintenance Rule Conduct Manual - Maintenance Rule Performance Criteria; Revision 2

MMR Appendix G; Fermi 2 Maintenance Rule Conduct Manual - Risk Significance List; Revision 0

MMR Appendix H; Fermi 2 Maintenance Rule Conduct Manual - On-line Maintenance Risk Matrix; Revision 0

Enrico Fermi 2 Maintenance Rule Periodic Assessment; May 2002 - July 2003; dated January 9, 2004

Enrico Fermi 2 Maintenance Rule Periodic Assessment Report - October 2000 through April 2002; dated July 23, 2002

Program Health Report Fermi 2 - Maintenance Rule Program; 1st - 2nd Quarter 2003

Program Health Report Fermi 2 - Maintenance Rule Program; 3rd Quarter 2003

System Health Fermi 2 - RHR; 3rd Quarter 2003

System Health Fermi 2 - RHRSW; 3rd Quarter 2003

System Health Fermi 2 - EECW/EESW; 3rd Quarter 2003

System Health Fermi 2 - HPCI; 3rd Quarter 2003

PSA Basis for the Maintenance Rule (MR) Performance Criteria for EECW, RHR, RHRSW; dated October 1, 2002

Reactor Feedwater Supply System (N2100) MR (a)(1) Get Well Plan; Revision 0; dated August 30, 2002

Annunciator System Get Well Plan; Revision B

Emergency Diesel Generators (R3000) Get Well Plan; Revision D; dated September 18, 2001

CTG11-1 Get Well Plan; Revision A

Log No. 96-002; Maintenance Rule Program Position - Development of Train and Divisional Level Conditional Probability, Allowed Number of Failures and Out-of-Service Hours and Redundancy Factor Determination; dated October 2, 1998

Self-Assessment of System Engineering Monitoring of Maintenance Rule; dated June 26, 2002

Maintenance Rule Functional Failure Evaluation 05202002-1; System N2100; dated June 5, 2002

Maintenance Rule Functional Failure Evaluation 050602; System T2100; dated May 16, 2002

Maintenance Rule Functional Failure Evaluation 021117-D2-01; System E1100; dated November 27, 2002

Maintenance Rule Functional Failure Evaluation 05202002-1; System N2100; dated June 5, 2002

Maintenance Rule Functional Failure Evaluation 030624-d1-01; System P4400; dated July 9, 2003

TMIS-02-0023; Summary of Expert Panel Meeting 130 Conducted January 8, 2002

TMIS-02-0122; Summary of Expert Panel Meeting 131 Conducted January 22, 2002

TMIS-02-0080; Summary of Expert Panel Meeting 132 Conducted February 5, 2002

TMIS-02-0089; Summary of Expert Panel Meeting 133 Conducted February 19, 2002

TMIS-02-0092; Summary of Expert Panel Meeting 134 Conducted March 19, 2002

TMIS-02-0093; Summary of Expert Panel Meeting 135 Conducted April 16, 2002

TMIS-02-0124; Summary of Expert Panel Meeting 136 Conducted April 30, 2002

TMIS-02-0112; Summary of Expert Panel Meeting 137 Conducted May 28, 2002

TMIS-02-0120; Summary of Expert Panel Meeting 138 Conducted June 25, 2002

TMIS-02-0127; Summary of Expert Panel Meeting 139 Conducted July 9, 2002

TMIS-02-0162; Summary of Expert Panel Meeting 140 Conducted August 6, 2002

TMIS-03-0121; Summary of Expert Panel Meeting 151 Conducted October 14, 2003

TMIS-03-0131; Summary of Expert Panel Meeting 152 Conducted October 28, 2003

Expert Panel Meeting Package 153; dated January 27, 2004

CARD 01-20794; Feedwater and RHR Injection Check Valves Get Well Plan; dated February 26, 2002

CARD 02-16270; Pressure Switch Needs Calibrated; dated October 11, 2002

CARD 02-19995; Barton Switch (E11N0218) Does Not “Snap” and Switch Markings Do Not State VDC Rating; dated November 18, 2002

CARD 03-11128; Moore Controller for Div I EECW Indicates 95.3% Open in MCR vice 100% as Indicated in SOP 23.208; dated January 28, 2003

CARD 03-11354; Failed Initiation Relay Sw Div I EECW - Failed Surveillance 46.207.002; dated April 3, 2003

CARD 03-12804; As Found CST Torque Exceeded Maximum CST Torque Target Value; dated January 15, 2003

CARD 03-17458; Unlanded RTD Lead; dated May 1, 2003

CARD 03-17790; Low EECW Flows Found on EECW Loads, Post RF09 Outage due to Crude Burst; dated May 3, 2003

CARD 03-17960; As Found Flow Rates to Div 2 EECW Throttled Loads low Outside of Required Bands; dated June 18, 2003

EDG-11, 12, 13, & 14 Maintenance Rule Functional Failure Evaluations from January 1, 2001 through December 31, 2003

EDG-11 Maintenance Rule Out of Service Hours from January 1, 2003 through December 31, 2003

Selected Operator Logs from January 1, 2003 through December 21, 2003

CARD 02-14005; R3000F607 Would Not Close During MPM Stroke Test; dated August 8, 2002

CARD 01-14026; EDG14 Output Breaker failed to Close on Manual Start/Synchronization; dated March 29, 2001

CARD 01-17276; Broken Studs on Vertical Drive Compartment; dated August 7, 2001

CARD 01-13638; Incorrect Setpoint & Tolerance Used for “QA1" Tech Spec Relays “OTH” and “CTH” for EDG#13; dated March 14, 2001

CARD 01-19626; EDG11 Output Breaker Tripped When Restoring Offsite Power During 24.307.01; Dated November 20, 2001

CARD 01-15776; Temperature Switch Found Inoperable; dated August 13, 2001

CARD 03-10635; AFCC3 for R30NA04C As Found Out of Spec Low During PM S004030100; dated June 2, 2003

EDG System Health Report - Second Quarter 2003

EDG System Health Report - Third Quarter 2002

EDG System Health Report - Second Quarter 2003

Selected Operator Logs from January 1, 2001 through December 31, 2003

HPCI MR Out of Service Hours from January 1, 2001 through December 31, 2003

HPCI Monthly Monitoring Report from January 1, 2001 through December 31, 2003

CARD 00-15218; Missing Bolt From Inside the HPCI Turbine Casing; dated April 13, 2000

CARD 00-11142; Valve Tried to Auto Close During PMT

CARD 00-11152; HPCI Aux Oil Pump Did Not Start During Shutdown of HPCI

CARD 00-11153; HPCI Aux Oil Pump Discharge Pressure Gauge Reads Low

CARD 00-12134; OOS hours Not Tracked For Several Risk Significant Containment Isolation Valves

CARD 00-12439; HPCI System Performance Monitoring

CARD 00-13051; Maintenance Rule Monthly Reporting Errors

CARD 00-16762; 27.202.01 Step Caused Blown Fuse to E41F029

CARD 00-17175; HPCI Pump Flow Controller Output Failed Low

CARD 01-00776; Loose Anchor Bolt Found After Pressure Transient of HPCI System

CARD 01-10802; Pressure Transient During HPCI System Startup

CARD 01-10803; HPCI Valve Lineup Location Incorrect

CARD 01-13940; Pressure Transient on HPCI Discharge Pipe

CARD 01-19397; 24.202.01 Failed Acceptance Criteria

CARD 01-20890; HPCI Fluid Transient During Performance of 24.202.02

CARD 02-10802; HPCI Surveillance 24.202.01 Section 5.3 Response Time Failure

CARD 02-13985; Broken Terminal Strip in MOV

CARD 02-16367; E41F401 Failed Stroke Time During 24.408.03

CARD 03-10961; HPCI Drain Pot Level Switch Will Not Reset

CARD 03-21738; All 3 Vent Valves Found Open

CARD 03-21926; E41F402 Will Not Stroke Properly

CARD 02-16271; Is HPCI Unavailable if an Operator is Performing 24.202.01

CARD 03-10957; E41F003 Not Stroking Closed

CARD 03-12858; Measured Leakage During PIV Testing of E4150F006 is 0.126 GPM, This Exceeds DC-5576

CARD 03-12916; As Fond Thrust Test Results Below Minimum Target Values

CARD 03-12917; VOTES and MPM Tests Indicate Limit Switch Settings Need Adjusted

CARD 03-16014; Charred Field Wires in MOC

CARD 03-16114; As Left Torque Switch Settings (TSS) greater than CECO Max Allowable

CARD 03-16905; Missing Insulation

Maintenance Rule Scoping Determination for HPCI

HPCI System Performance Monitoring Plan

System Health Report - Second Quarter 2003

System Health Report - Forth Quarter 2002

System Health Report - Third Quarter 2002

1R13 Maintenance Risk Assessment and Emergent Work

CARD 04-20505; Ineffective corrective action for a level 2 CARD; dated February 10, 2004

CARD 03-19466; Operations department & PSA group not notified of Luzon line shutdown as required by MMR12

CARD 04-20348; Loss of main turbine lube oil reservoir vapor extractor; dated January 30, 2004

Drawing 6E721-2811-12, Rev. F; Cable Tray Identification - Turbine Bldg. First Floor EL. 583'-6" Div. I, Div. II, & BOP - Instrumentation

Drawing 6A721-2015, Rev. AB; Turbine House First Floor Plan El. 583' - 6"

Drawing 6E721-2811-11, Rev. M; Cable Tray Identification - Turbine Bldg. First Floor EL. 583'-6" Div. I, Div. II, & BOP - Control

Drawing 6E721-2811-10, Rev. J; Cable Tray Identification - Turbine Bldg. First Floor EL. 583’-6" Div. I, Div. II, & BOP - Power

CARD 04-20389; North turbine lube oil vapor extractor failure not prioritized correctly; dated February 3, 2004

CARD 03-01625; Abnormal noise from TLO south vapor extractor motor; dated August 12, 2003

UFSAR Section 9A.3.1; Shutdown Sequence

UFSAR Section 9A.3.2; Shutdown Systems

UFSAR Section 9A.3.3; Method of Safe-Shutdown Analysis

UFSAR Section 9A.4.5.1; General Description

High Priority Forced Outage Activities; dated January 28, 2004

<u>1R15</u> <u>operability Evaluations</u>

Proprietary Qualification Test Report QTR97P1430/EQ

CARD 02-13627; Line Side Power Lead Failed in MCC 72C-2A, Pos. 1A-R; dated March 26, 2002.

CARD 03-21636; Trip of Div. 2 CCHVAC Supply fan; dated October 30, 2003.

CARD 04-21296; Timeliness of EFA Closure; dated March 25, 2004. (NRC-Identified issue)

CARD 99-17607; Potential for Water Hammer Due to Insufficient EECW makeup Tank Normal and Emergency Setpoint pressures; dated October 4, 1999.

MQA-11, Rev. 5; Condition Assessment Resolution Document; dated November 8, 2000.

MQA-11, Rev. 9; Condition Assessment Resolution Document; dated January 1, 2004.

MES-27, Rev. 6; Verification of System Operability; dated November 4, 1999.

MES-27, Rev. 10; Verification of System Operability; dated September 9, 2003.

EFA-P44-04-001, Rev. 0; dated February 25, 2004.

Procedure 20.000.18, Rev. 27; Control of the Plant From the Dedicated Shutdown Panel.

Procedure 20.000.18, Rev. 33; Control of the Plant From the Dedicated Shutdown Panel.

Design Calculation DC-6024, Rev. 0; EECW Division I Hydraulic Transient Analysis.

UFSAR Section 3.7; Seismic Design

UFSAR Section 7.7.1.4.3.5; Turbine Generator to Reactor Protection System Interface

UFSAR Section 7.2; Reactor Protection System

Design Basis Document C71-00; Reactor protection System; dated March 16, 1992

1R19 Post Maintenance Testing

Work Request 000Z040614; 2-out-of-4 Logic Module Not Functioning Correctly

Drawing 6I721-2145-18, Rev. H; Schematic Diagram Power Range Neutron Monitoring Reactor Protection System Outputs

Drawing 6I721-2155-06, Rev. R; Schematic Diagram Reactor Protection System Trip System “A” System Relays

Drawing 6I721-2045-12, Rev. N; Wiring Diagram Power Range Neutron Monitoring Cabinet H11P608 Bay 4

Work Request 0731040807; Two-out-of-Four Logic Module RPS A2 Response Time Test

Work Request 1402040224; Perform 44.010.142 Div. I RPS Two Out of Four Logic Modules Functional

CARD 04-20732; 2-out-of-4 logic module not functioning correctly; dated February 24, 2004

Job ID 1402040223; Perform 44.010.142 Div. I RPS Two Out of Four Logic Modules Functional

Selected Control Room Operator logs from February 23, 2004 through February 25, 2004

Vendor Manual VMR1-82.3, Rev. A; Two-Out-of-Four Logic Module

Work Request 000Z033843; Investigate/Troubleshoot the cause of U4100C006 tripping

Work Request 000Z033843, Part 7: PMT Activity, “Turbine Building South Exhaust Fan”

Work Request 000Z022442; Replace Valve E51F015

CARD 01-14752; Loss of NIAS Response of HPCI and RCIC System; dated May 11, 2001

Selected Operator Logs From march 3, 2004 through March 4, 2004

MMA-09, Rev. 5; Welding/Brazing; dated September 3, 2003

MMA-11, Rev. 14; Post Maintenance Testing Guidelines; dated September 17, 2003

Procedure 43.206.001, Rev. 26; RCIC Leakage Monitoring Test

Work Request C238040100; Clean, Inspect and Calibrate C41R400

Work Request 0174040121; Perform 24.139.02 SLC Pump and Check Valve Operability Test

Procedure 24.139.02, Rev. 37; SLC Pump and Check Valve Operability Test

1R22 Surveillance Testing

Work Request 0249040113; Perform 24.202.01 Section 5.1 HPCI Pump/Flow Test & Valve Stroke at 1025 psig

Work Request 0298040226; Perform 24.307.30 EDG No. 1 24 Hour Run Followed by Hot Fast Restart

CARD 03-21632; Technical specification requirements table does not support bases and plant design; dated October 20, 2003

Procedure 24.202.01, Section 5.1, "HPCI Pump/Flow Test & Valve Stroke at 1025 psig," Revision 79

Work Request 0268040302; Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig

Work Request 0268031202; Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig

Work Request 0268030902; Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig

Work Request 0268030624; RCIC System Pump and valve Operability Test Partial for PMT on E5150F007

Work Request 0268030603; Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig

Work Request 0268030506; Partial to Stroke Time Test Valves E5150F001, F084, and F019

Work Request 0268030304; Perform 24.206.01 RCIC System Pump Operability and Valve Test @ 1000 psig

Selected Control Room Operator logs from January 1, 2003 through March 10, 2004

Evaluation of ASCO solenoid Valve, Framatome PO #140254, RDR #03-226/ASCO RMA #10377, November 25, 2003

Evaluation of ASCO solenoid Valve, Framatome PO #140254, RDR #04-007/226/ASCO RMA #11142, January 30, 2004

Examination of an ASCO Solenoid Valve Submitted on Fermi-2 Requisition 9072096, January 21, 2004

Examination of an ASCO Solenoid Valve Submitted on Fermi-2 Requisition 9072096, December 10, 2003

Examination of Dow Corning 550® Fluid Received on Fermi-2 Requisition 9072893, March 30, 2004

CARD 03-21626, T4901F465 Did Not Meet Stroke Time During 24.406.01, October 27, 2003

CARD 97-05194, ASCO Solenoid Valve Failure History, September 27, 1997,

CARD 01-17033, T4901F465 Div 1 DW Pneumatics Supply Outboard Isolation Valve Did Not Stroke Closed in Allowable Time, July 29, 2001

DER 97-1311, Potential Conflict with Vendor Installation Instructions for ASCO Solenoid Valves, August 27, 1997

DER 97-1202, Inadvertent Closure of T4901F466, August 5, 1997,

CARD 97-05194, ASCO Solenoid Valve Failure History, September 11, 1997

CARD 98-13799, T49F467 Replacement Interval 40 years and T49F466 had Replacement Interval of 8.87 Years, May 20, 1998

CARD 97-05194, ASCO Solenoid Valve Failure History (transfer of DER 97-1202 to CARD Process), March 12, 1998

CARD 01-15341, T4901F469, Nitrogen Supply Valve E/V, June 13, 2001

Deviation Event Report 95-0396, T49F465 Failed Stroke Test, June 4, 1995

Environmental Qualification Maintenance and Surveillance Requirement for EQ1-EF2-052A For ASCO Solenoid NP Series 8320-Suffix E Solenoid Valves, January 1, 2003

LER 03-004; EDG 12 Lube Oil Pressure Low; dated January 6, 2004

Job ID 0001040212; Perform 24.307.16 Sec-5.1 EDG 13 Start and Load Test - Slow Start; Completed on February 12, 2004

Situational Surveillance 24.000.01, Attachment 28C; Demonstrating Availability of CTG 11-1; Completed February 12, 2004 at 0900 hours

Procedure 24.307.16, Rev. 45; Emergency Diesel Generator 13 - Start and Load Test

CARD 04-20518; Some areas of the ASME Class 1 pressure rating boundary were not pressurized as required by ASME Section XI and Code Case N-498-1 during the 10-year system leakage test performed during RF-06; dated February 11, 2004

Drawing 6M721-4536, Rev. H; Diagram - Primary Systems Hydrostatic Test

Procedure 24.204.01, Rev. 51; Div. 1 LPCI and Suppression Pool Cooling/Spray Pump and Valve Operability Test

Work Request 0261040203; Perform 24.204.01 Div. 1 LPCI and Suppression Pool Cooling/Spray Pump and Valve Operability Test

1EP6 Drill Evaluation

Evaluation Scenario SS-OP-904-1005; Loss of CRD Flow Control/Loss of Vacuum/ATWS; Rev 1

Evaluation Scenario SS-OP-904-1049; Feedwater Leak Inside Containment/Loss of 120kV; Rev. 3

Evaluation Scenario SS-OP-904-1010; Standby Feedwater Surveillance/Control Rod Drive Pump Trip/Main Turbine Trip with East Turbine Bypass Valve Failure/ATWS; Rev. 4

RERP Drill Package for Red Team Drill on February 18, 2004

2OS1 Access Control to Radiologically Significant Areas

Radiation Protection Conduct Manual; Chapter 06; Accessing and Control of High Radiation, Locked High Radiation Area and Very High Radiation Areas; Revision 6

Plant Technical Procedure 63.000.200 w/Attachments; ALARA Reviews; Revision 15

Plant Technical Procedure 23.425.01 w/selected Attachments; Primary Containment Procedures; Revision 49

Plant Technical Procedure 67.00.101 w/selected Attachments & Enclosures; Performing Surveys and Monitoring Work; Revision 16

Plant Technical Procedure 63.000.100 w/selected Enclosures; Radiation Work Permits; Revision 20

MRP 06002; High Radiation Area Key Index; Revision 1

MRP 06003; High Radiation Area Key Issue Logs for 2004 thru March

RWP No. 04-1009 Task 03; LHRA Entry; Revision 0

RWP No. 03-1047 and associated Pre-Job ALARA Review; Replace TIP “A” thru “E” Detectors and Transport to Radwaste for Storage; Revision 1

RWP No. 01-1164 and associated Pre-Job ALARA Review; Torus Diving - Desludge, Inspection, Coating Inspection, Including Support Work; Revision 0

Radiation Protection Tracking CARD Database (for Radiation Protection, Chemistry, Safety and Radwaste Departments); January 2003 thru March 25, 2004

CARD 04-20926; Radiation Worker Declining Performance Trend; dated March 6, 2004

CARD 04-20339; MRP06 Violation; dated January 29, 2004

CARD 04-20275; Procedure Violation of MRP06; dated January 26, 2004

CARD 03-12507; Operator Receives Dose Rate Alarm While Adding Oil to RCIC Turbine; dated December 2, 2003

CARD 03-16937; Evaluate Auditor Comments Regarding Choice of Sample Analysis to Determine Relative Effect of Hard to Detect Radionuclides on Internal Dose; dated April 17, 2003

CARD 03-10344; Tri-Nuke Filter Medium Floating in the Spent Fuel Pool; dated April 1, 2003

CARD 04-20972; Dose Received While Restoring RWCU; dated March 9, 2004

Audit Report 03-0112; Radiation Protection Program; dated December 15, 2003

Plant Technical Procedure 65.000.211; Bioassay Sample Collection and Processing; Revision 8

Plant Technical Procedure 65.000.257; Calculation of Internal Dose to Personnel; Revision 6

Plant Technical Procedure 65.000.262; Operation of the Canberra Fastscan System; Revision 1

Plant Technical Procedure 65.000.265; Maintenance and Operation of the Fermi 2 Whole Body Counters Using Renaissance Software; Revision 3

Radiation Protection Work Instruction WI-RP-002; Failed Fuel Action Plan; Revision 1

4OA1 Performance Indicator Verification

Work Request 000Z020877; Repair Leaks on EDG 12

Work Request 000Z034098; EDG 12 Lube Oil Pressure Continues to Drop

Selected Control Room Operator logs from June 2,2003 through June 3, 2003

Selected Control Room Operator logs from November 8, 2003 through November 9, 2003

CARD 03-12686; Loose connection in lube oil pressure sensing line of EDG 12. EDG 12 SSO Critique; dated November 8, 2003

CARD 03-10847; EDG 12 lube oil pressure slowly trending down; dated July 3, 2003

EDG 12 Maintenance Rule Out of Service Hours from June 2, 2003 through November 8, 2003

LER 03-001; Loss of High Pressure Coolant Injection Safety Function Due to Closure of Steam Supply Valve; dated August 29, 2003

Maintenance Rule Functional Failure Evaluations from January 1, 2003 through December 31, 2003

CARD 04-20666; Missed unavailability hours for 2003 RHR NRC PI; dated February 19, 2004 (NRC-Identified issue)

January 2003 through December 2003 RHR NRC Performance Indicator Summary Reports

Personnel Who have Received > 100 Millirem for a Single Entry and > 1000 Millirem/Hour Dose Rate Alarm (electronic dosimetry transaction records for September 2003 - March 2004)

4OA2 Identification and Resolution of Problems

CARD 04-20772; EDG 11 minor exhaust to coolant leaks; dated February 26, 2004

Selected Control Room Operator Logs from March 3, 2004 through March 8, 2004

CARD 04-11201; EDG 11 jacket coolant pressure trending down; dated January 5, 2004

Procedure 35.307.008, Rev. 22; Emergency Diesel Generator - Engine General Maintenance

Work Request 000Z980134; Replace EDG #12 cylinder liners in RF06

CARD 04-20924; EDG work practice/procedure improvements; dated March 6, 2004

CARD 04-21010; Adapter gaskets installed backwards, work history: as found condition; dated March 11, 2004

Drawing 6I721N-2711-26, Rev. T; Schematic Diagram Diesel Generator #12 Annunciator System Unit 2

Drawing 6M721-5734, Rev. AM; Emergency Diesel Generator System Functional Operating Sketch

Drawing 6I721N-2711-24, Rev. AF; Schematic Diagram Diesel Generator # 12 Control Part 1

Drawing 6I721N-2711-25, Rev. AB; Schematic Diagram Diesel Generator # 12 Control Part 2

Drawing 6I721N-2712-51, Rev. Q; Wiring Diagram Diesel Gen. #12 Terminal Box, Eng. Gauge Panel R30P320 & Miscellaneous

4OA3 Event Followup

Vendor Manual VMR1-51.0, Rev. C; Thermal Hydrogen Recombiner System

CARD 03-22044; Installed fuse too large for application; dated November 3, 2003

EQ1-EF2-143; IEEE 323-1974 Qualification and Test Summary Report for Class 1E Motor Control Centers; dated April 29, 1983

Specification 3071-128-EJ; Standard EJ-2-1; Rev. AQ

Drawing 6I721-2654-08, Rev. F; Combustible Gas Control System Schematic Diagram Div. I & II

Work Request 000Z034480; Fire in Div. 1 TRS Panel in Relay Room

Selected Control Room Operator Logs on October 21, 2003

CARD 03-21658; Fire in Div. 1 TRS panel in relay room; dated October 31, 2003

CARD 03-23006; Failed PMT - WR 000Z034480; dated November 5, 2003

Drawing 6I721-2655-02, Rev. J; Combustible Gas Control System W/D Control Cab. H11-P886 (Div. I) & H11-P887 (Div. II)

ARP 11D43, Rev. 7; 13.2kV Breaker Trip

Drawing 6SD721-2500-02, Rev. M; One Line Diagram 13.8kV

Drawing 6SD721-2500-01, Rev. AB; One Line Diagram Plant 4160V & 480V System Service Unit 2

LER 03-003; Non-Conservative Setpoints for Stability Option III (OPRM) period Based Detection Algorithm, Period Confirmation Adjustable Variables; dated November 26, 2003

CARD 03-22220; OPRM Tunable Parameters (Corner Frequency and period Tolerance) Not Set Correctly Based on GENE Analysis of NMP2 Instability Event; dated October 2, 2003

CARD 03-22962; OTH 03-128 (SC03-022) OPRM Signal Attenuation due to Conditioning Filter; Dated November 10, 2003.

VTM VMR1-59, Rev. G; Low-Voltage Power Circuit Breakers

UFSAR 8.3.1.1.13.1; Auxiliary Electrical Power Systems

CARD 04-20509; Breaker Tripped on Overload; dated February 11, 2004

WR Q167010100; Perform Test on 480V SWGR BKR 72M POS 4C and Test Power Shield Relay

Selected operations logs from October 3, 2003 through February 14, 2004

Procedure 35.318.003, Rev. 32; Power Shield - 480 Volt Circuit breaker Solid State Trip Testing

LIST OF ACRONYMS USED

ALARA	As Low As Is Reasonably Achievable
CARD	Condition Assessment Resolution Document
CCHVAC	Control Center Heating Ventilation and Air Conditioning
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EECW	Emergency Equipment Cooling Water
EDG	Emergency Diesel Generator
EFA	Engineering Functional Analyses
HPCI	High Pressure Coolant Injection
HRA	High Radiation Area
ISI	Inservice Inspection
LER	Licensee Event Report
LHRA	Locked High Radiation Area
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
OPRM	Oscillation Power Range Monitor
PI	Performance Indicator
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RP	Radiation Protection
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SSC	Structures, Systems, and Components
TIP	Traversing In-Core Probe
UFSAR	Updated Final Safety Assessment Report
VHRA	Very High Radiation Area