UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 26, 2005

Florida Power and Light Company
ATTN: Mr. J. A. Stall, Senior Vice President
Nuclear and Chief Nuclear Officer
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 50-335/04-06 AND 50-389/04-06

Dear Mr. Stall:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on January 4, 2005, with Mr. Jefferson 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 self-revealing finding of very low safety significance (Green) was identified. This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this violation as a non-cited violation (NCV), in accordance with Section VI.A of the NRC's Enforcement Policy. If you contest this NCV, you should provide a response, within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the St. Lucie facility.

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

Sincerely,

/RA/

Joel T. Munday, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos.: 50-335, 50-389
License Nos.: DPR-67, NPF-16

Enclosure: Inspection Report 50-335/04-06, 50-389/04-06
w/Attachment - Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-335, 50-389
License Nos.:	DPR-67, NPF-16
Report Nos.:	05000335/200406, 05000389/200406
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	September 26 - December 31, 2004
Inspectors:	T. Ross, Senior Resident Inspector S. Sanchez, Resident Inspector R. Musser, Senior Resident Inspector - Shearon Harris D. Jones, Resident Inspector - Robinson M. Bates, License Examiner R. Aiello, Senior License Examiner (Section 1R11.2)
Approved by:	Joel Munday, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2004-06, 05000389/2004-06; 09/26/2004 - 12/31/2004; Florida Power & Light; St. Lucie Nuclear Plant, Units 1 & 2; Operator Performance During Nonroutine Plant Evolutions and Events.

The report covered a three month period of inspection by resident inspectors and several other inspectors from Region II. One Green non-cited violation (NCV) was identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation (NCV) was identified for failing to properly implement emergency operating procedure 2-EOP-99, Appendix X, Secondary Post Trip Actions, as prescribed by TS 6.8.1.a and Regulatory Guide 1.33. More specifically, a licensed reactor operator did not ensure the main feedwater regulating valve block valves were in the closed position following the reactor trip on December 25, which then directly contributed to the cause of another manual reactor trip on December 27.

  The finding is greater than minor because it involved the human performance attribute of the Initiating Events Cornerstone and its objective, in that failure to follow and implement a required emergency operating procedure step directly contributed to a subsequent plant transient that resulted in a manual reactor trip. The finding is of very low safety significance because, although it caused a manual reactor trip, it did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment functions, and did not increase the likelihood of a fire or internal/external flood. This finding directly involved cross cutting aspects of human performance. (Section 1R14)

B. Licensee Identified Violations

None.

Report Details

Summary of Plant Status

Unit 1 began the report period in a shutdown condition following Hurricane Jeanne. The unit was restarted on October 2, returned to 100% power on October 4, and operated continuously at full power through remainder of the report period.

Unit 2 began the report period in a shutdown condition following Hurricane Jeanne. The unit was restarted on October 4, returned to 100% power on October 5, and operated continuously at full power until December 25, 2004. On that day, operators manually tripped the reactor due to a loss of the 2B condensate pump that was caused by an electrical fault. The unit was restarted on December 26, but was manually tripped the next day from 10% power due to a loss of main feedwater (MFW) when the 2A MFW pump tripped automatically because of an operator error that resulted in overfeeding the 2A steam generator. Unit 2 remained shutdown through the remainder of the report period.

1. **REACTOR SAFETY**
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity [Reactor-R]

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Walkdowns

The inspectors conducted three partial alignment verifications of the safety-related systems listed below to review the operability of required redundant trains or backup systems while the other trains were inoperable or out of service. These inspections included reviews of applicable Technical Specifications (TS), plant lineup procedures, operating procedures, and/or piping and instrumentation drawings (P&ID) which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system. The inspectors also reviewed applicable reactor control operator (RCO) logs; out of service (OOS) and operator work around (OWA) lists; active temporary system alterations (TSA); and/or any outstanding condition reports (CR) regarding system alignment and operability.

- 1A Low Pressure Safety Injection (LPSI) per OP 1-0410020, HPSI/LPSI - Normal Operation
- 2B LPSI While 2A LPSI OOS For Critical Maintenance Management (CMM) Work per 2-NOP-03.21, Low Pressure Safety Injection System Initial Alignment
- 2B Containment Spray (CS) per 2-NOP-07.41, Containment Spray System Initial Alignment

b. Findings

No findings of significance were identified.

.2 Complete Equipment Walkdown

a. Inspection Scope

During the week of October 4, the inspectors completed a detailed alignment verification of the 2B High Pressure Safety Injection (HPSI) using P&ID 2998-G-078, Safety Injection System, and applicable training guides to walkdown and verify equipment alignment. The inspectors reviewed relevant portions of the Updated Final Safety Analysis Report (UFSAR) and TS. This detailed walkdown also verified electrical power requirements, labeling, hangers and support installation, and associated support systems status. Operating pumps were examined to ensure that vibration levels were not elevated and pump leakoff was not excessive. The walkdowns also included evaluation of system piping and supports to verify that: 1) piping and pipe supports did not show evidence of water hammer; 2) oil reservoir levels indicated normal; 3) snubbers did not indicate any observable hydraulic fluid leakage; 4) hangers were within the setpoints; and 5) component foundations were not degraded. Furthermore, the inspectors examined OOS and OWA lists; active TSAs and outstanding work orders (WO); the System Health report; and any CRs that could affect system alignment and operability.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Inspections

a. Inspection Scope

The inspectors conducted tours of the following eight fire areas or witnessed associated activities listed below during the inspection period to verify they conformed with Administrative Procedure AP-1800022, Fire Protection Plan. The inspectors specifically examined any transient combustibles in the areas and any ongoing hot work or other potential ignition sources. The inspectors also assessed whether the material condition, operational status, and operational lineup of fire protection systems, equipment and features were in accordance with the Fire Protection Plan. Furthermore, the inspectors evaluated the use of any compensatory measures being performed in accordance with the licensee’s procedures and Fire Protection Plan.

- Unit 1 LPSI (Fire Area M)
- 2B HPSI (Fire Area M)
- Unit 1 Diesel Oil Storage Tank Area (Fire Area T-T)
- City Water Storage Tank & Fire Pumps (Fire Area W-W)
- Unit 2 Component Cooling Water (CCW) Surge Tank Room (Fire Area Q)
- Unit 2 Emergency Core Cooling System (ECCS) Rooms (Fire Area M)
- Unit 1 Refueling Water Storage Tank (RWST) Area (Fire Area V-V)

- Unit 1 Cable Spreading Room (Fire Area B)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Internal Flooding

The inspectors reviewed UFSAR Section 3.4, Water Level (Flood) Design and UFSAR table 3.2-1, Design Classification of Structures, System and Components, and verified specific equipment and components in the Unit 2 ECCS pump room (i.e., HPSI, LPSI, and CS systems) that were susceptible to damage from flooding met the stated requirements. The inspectors also walked down procedure 1-ONP-24.01, RAB Flooding, to ensure actions required to be taken in the plant could be accomplished as stated. Furthermore the inspectors reviewed the ECCS sump level indicators and isolation valves preventative maintenance (PM) schedule. The inspectors also verified the corrective action program was being used to identify equipment issues that could be impacted by potential internal flooding.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

.1 Quarterly Review

a. Inspection Scope

On October 20 and November 3, 2004, an inspector observed and assessed licensed operator actions during simulator evaluations. During these simulator evaluations, the inspector watched two separate operating crews respond to equipment failures, off-normal conditions, and accident events (i.e., Main Feedwater line break inside containment, and Steam Generator Tube Rupture, respectively). The inspector discussed crew performances with the simulator instructors and the senior Operations department management representative. The inspector specifically evaluated the following attributes related to the operating crews' performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms

- Correct use and implementation of Emergency Operating Procedure (EOP)-1, Standard Post Trip Actions; EOP-4, Steam Generator Tube Rupture; EOP-9, Loss of Offsite Power; and EOP-15, Functional Recovery
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedure (EPIP) - 01, Classification of Emergencies
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by Operations supervision, including ability to identify and implement appropriate TS actions, regulatory reporting requirements, and emergency plan actions and notifications
- Effectiveness of the post-evaluation critique

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

On December 9, 2004, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors reviewed the overall pass/fail results of the individual operating tests, and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the reliability and problems associated with the component listed below, including associated condition reports. The inspectors verified the licensee's maintenance effectiveness efforts met the requirements of 10 CFR 50.65 and Administrative Procedure ADM-17.08, Implementation of 10 CFR 50.65, The Maintenance Rule. The inspectors' efforts focused on the licensee's functional failure determination, a(1) and a(2) classification determination, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also attended applicable expert panel meetings, and interviewed responsible engineers. Furthermore, the inspectors reviewed the applicable drawing 8770-G-088, Sheet 1 and 2, Unit 1 Flow Diagram Containment Spray and Refueling Water Systems; and the ADM-17.08, Figure 4, Goal Setting and Monitoring, attachment for Unit 1 Containment Spray.

- CR 04-7700, Unit 1 Sodium Hydroxide Tank concentration below minimum due to dilution (caused by back-leakage through check valve V070256)

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the risk assessments for the following six SSCs that were OOS for planned and/or emergent work. The inspectors also walked down and/or reviewed the scope of work to evaluate the effectiveness of licensee scheduling, configuration control, and management of online risk in accordance with 10 CFR 50.65(a)(4) and applicable program procedures such as ADM-17.16, Implementation of the Configuration Risk Management Program. Furthermore, the inspectors interviewed responsible Senior Reactor Operators on-shift, verified actual system configurations, and specifically evaluated results from the online risk monitor (OLRM) for the combinations of OOS risk significant SSCs listed below:

- Unit 2 Mode 4 Conditions with multiple risk significant pieces of equipment OOS
- 2B Boric Acid Makeup (BAM) Tank, 2B Instrument Air (IA), HCV-08-1A and HCV-08-1B OOS
- 2B BAM Tank, 2C Auxiliary Feedwater (AFW) Pump, and 2AA Battery Charger OOS
- 2B ECCS CMM
- 2A ECCS CMM
- 2A CS, 2C AFW, and Steam Supply Valves to 2C AFW OOS For Planned Maintenance

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Nonroutine Plant Evolutions and Events

a. Inspection Scope

For the non-routine events associated with the Unit 2 manual reactor trips of December 25 and 27, 2004 (see Section 4OA3), the inspectors evaluated operator performance by interviews, observations and reviewing available information (e.g.,operator logs, plant computer data, and strip charts) to determine what occurred and how the operators responded, and to verify that the response was in accordance with plant procedures (e.g., normal and abnormal operating procedures, EOPs, etc.). In particular, the inspectors independently evaluated the initiating and contributing cause(s) of the December 27 event as they related to operator performance.

b. Findings

Introduction. A Green self-revealing non-cited violation (NCV) was identified for failing to properly implement emergency operating procedure 2-EOP-99, Appendix X, Secondary Post Trip Actions, as prescribed by TS 6.8.1.a and Regulatory Guide 1.33.

Description. On December 25, 2004, Unit 2 was manually tripped from 95% power due to an electrical fault of the 2B condensate pump (CDP) motor. The 2B CDP motor was subsequently repaired and the unit was restarted the next day. However, on December 27, 2004, Unit 2 was manually tripped from 10% power due to decreasing SG level that was caused by a transient due to a feedwater system misalignment. A plant startup had been in progress per general operating procedure 2-GOP-201, Reactor Plant Startup - Mode 2 to Mode 1, when upon latching the main turbine, the 2A SG was overfed resulting in an automatic trip of the 2A MFW pump which subsequently necessitated a manual reactor trip due to low 2B steam generator water level (SGWL).

During the licensee's review of this event, they discovered that the main feedwater regulating valve (MFRV) block valves had been inadvertently left in the open position. Apparently, following the December 25 trip, a human error was made while performing 2-EOP-99, Appendix X, Secondary Post Trip Actions which has a step that required operators to "ENSURE **BOTH** S/G [Main FRV] Block valves CLOSED." Failing to ensure the MFRV block valves were closed prior to startup, allowed a direct flow path to the SGs once the MFRVs were activated. Thus, when operators latched the turbine during startup, the MFRV control system activated thereby allowing the MFRVs to modulate open as required based on the demand signal from the controller. As it turned out, the A MFRV modulated open but the B MFRV did not because the initial conditions for the A-side did not have the same demand as the B-controller. Consequently, when the 2A MFRV modulated open, with its associated block valve left open, the 2A SGWL increased rapidly in an uncontrolled manner to the high level trip setpoint causing the 2A MFW pump to trip. After which, water level in both SGs began to decrease rapidly due to the loss of MFW flow, until the point when operators manually tripped the reactor before the automatic low level trip setpoint was reached. The reason for the MFRV block valves being open at the time of the turbine latch was attributed to human error for failing to ensure they were closed as required by 2-EOP-99, Appendix X.

Analysis. The inspectors determined that the licensee's failure to follow their EOP during post-trip recovery efforts, which resulted in another unplanned manual reactor trip a couple days later, constituted a human performance deficiency. The inspectors determined that the finding is greater than minor because it involved the human performance attribute of the Initiating Events Cornerstone and its objective, in that a failure to follow and implement the required EOP step directly contributed to causing a plant transient resulting in a manual reactor trip. The finding is of very low safety significance in accordance to the SDP Phase 1 worksheet because, although it caused a manual reactor trip, it did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment functions, and did not increase the likelihood of a fire or internal/external flood. This finding directly involved cross cutting aspects of human performance.

Enforcement. TS 6.8.1.a requires that written procedures shall be established, implemented, and maintained as recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, February 1978. Section 6.u of RG 1.33 specifically identifies “Reactor Trip” as a recommended procedure. 2-EOP-99, Appendix X, Secondary Post Trip Actions required operators to “Ensure Both S/G [Main FRV] Block valves CLOSED.” Contrary to this requirement, on December 25, 2004, Unit 2 operators failed to properly implement this provision of 2-EOP-99, Appendix X, Secondary Post Trip Actions. However, because this violation is of very low safety significance and was addressed by the licensee’s corrective action program (i.e., CR 04-17725), this violation is being treated as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy - NCV 05000389/2004006-01, Improper Implementation of Emergency Operating Procedure Following a Manual Reactor Trip.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six CR interim dispositions and operability determinations to ensure that TS operability was properly supported and the affected SSC remained available to perform its safety function with no unrecognized increase in risk. As applicable, the inspectors reviewed the UFSAR, and associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim CR disposition.

- CR 04-10953, Unit 1 Reactor Cavity Fan HVS-2B
- CR 96-2246, 1A Intake Cooling Water (ICW) Pump Pedestal
- CR 04-14409, Part 21 for Unit 1 ECCS Pump Air Entrainment
- CR 04-14409, Part 21 for Unit 2 ECCS Pump Air Entrainment
- CR 04-16572, Unit 1 Shield Building Ventilation System Inlet Temporary Filters
- CR 04-16139, Unit 2 ECCS Sump Suction Isolation Valve (FCV 07-1A)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

.1 Operator Workaround 2004-16219

a. Inspection Scope

The inspectors reviewed OWA 2004-16219 [associated with seat leakage past valve MV-07-3], in order to verify that this OWA did not affect either the functional capability of the related system in responding to an initiating event, or the operators’ ability to implement abnormal or emergency operating procedures. As part of this inspection the inspectors examined drawings 2998-G-078, Sheet 130A and 130B, Unit 2 Safety Injection System; and 2998-G-088 Sheet 1 and 2, Unit 2 Flow Diagram Containment Spray and Refueling Water Systems. The inspectors also reviewed and discussed implementation of 2-OSP-24.01, RAB Fluid Systems Periodic Leak Test, Revision 7, with regard to the system conditions that caused pressure locking of valve FCV-07-1A due to apparent seat leakage past MV-07-3.

b. Findings

No findings of significance were identified.

.2 Cumulative Effects of Operator Work Arounds

a. Inspection Scope

The inspectors performed a semi-annual evaluation of the potential cumulative effects of all outstanding Unit 1 and 2 OWAs. The inspectors discussed these potential effects with control room supervision and operators. The inspectors also reviewed the minutes of the previous quarterly OWA Team meeting, which met to systematically examine individual and cumulative OWA status and repair priority, and assess overall risk. Furthermore, the inspector discussed implementation and effectiveness of the OWA program with Operations Support supervision.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspector reviewed the Plant Change and Modification (PC/M) 03123; the associated NRC Safety Evaluation Report dated August 16, 2004; the applicable TS amendment; and the proposed UFSAR change for installing a new spent fuel storage rack in the cask pit area of the Unit 1 spent fuel pool. The inspector also reviewed the licensee’s proposed procedure change requests (PCR) and implementing schedule. As part of the PCR review, the inspector interviewed responsible individuals and attended meetings used for planning all the required procedure changes. Furthermore, the inspector attended cask pit rack project meetings during the preparation and planning stages; interviewed responsible engineering, construction and project personnel during installation and testing activities; and witnessed and/or reviewed portions of the actual cask pit rack assembly installation and testing. The inspector also conducted a post installation walk down of the installed rack.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

.1 Routine Review of Post-Maintenance Testing

a. Inspection Scope

The inspectors witnessed and reviewed post-maintenance test (PMT) activities of the seven risk significant SSCs listed below. The following aspects were specifically inspected: (1) Effect of testing on the plant recognized and addressed by control room and/or engineering personnel; (2) Testing consistent with maintenance performed; (3) Acceptance criteria demonstrated operational readiness consistent with design and licensing basis documents such as TS, UFSAR, and others; (4) Range, accuracy and calibration of test equipment; (5) Step by step compliance with test procedures, and applicable prerequisites satisfied; (6) Control of installed jumpers or lifted leads; (7) Removal of test equipment; and, (8) Restoration of SSCs to operable status. The inspectors also reviewed problems associated with PMTs that were identified and entered into the corrective action program as condition reports.

- 1C ICW Pump Discharge Check Valve per WO#34012170
- 2B HPSI Pump per OP 2-0410050, HPSI/LPSI Periodic Check
- 2B CS Pump per OP 2-0420050, Containment Spray and Iodine Removal System Periodic Check
- 1A HPSI Pump Motor, Breaker and Valves per ADM-78.01, Post-Maintenance Test, Appendix A, and OP 1-0010125A, Surveillance Data Sheets, Data Sheet 8A
- 2A HPSI Pump per OP 2-0410050, HPSI/LPSI Periodic Check
- 2A CS Pump per OP 2-0420050, Containment Spray and Iodine Removal System Periodic Check
- 1A CS Pump per OP 1-0420050, Containment Spray Periodic Check

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

Following the Unit 2 reactor trip on December 25, and continuing through the reactor trip on December 27, 2004, the licensee entered into a short notice outage (SNO). During this SNO, the inspectors observed shutdown activities and monitored unit status to verify compliance with applicable Mode 3 TS and operating procedures. The inspectors also attended status and planning meetings in the Outage Control Center, and reviewed plant restart schedules. The inspectors observed licensee processes for controlling SNO-related work activities in accordance with their administrative procedures. The inspectors also reviewed applicable CRs prior to restart regarding the post-trip review and resolution of post-trip equipment problems. In particular, the inspectors focused their efforts on reviewing the licensee's resolution of the low power feedwater control equipment problems identified during the startup and subsequent reactor trip of December 27. Lastly, the inspectors monitored portions of the Unit 2 startup on January 3, along with the subsequent power ascension, in accordance with applicable TS and operating procedures. Furthermore, licensee identification and resolution of problems that occurred during the SNO were also examined by the inspectors.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions of the following four surveillance tests and monitored test personnel conduct and equipment performance, to verify that testing was being accomplished in accordance with applicable Operating Procedures (OP). The actual test data was reviewed to verify it met TS, UFSAR, and/or licensee procedure requirements. The inspectors also verified that the testing effectively demonstrated the systems were operationally ready, capable of performing their intended safety functions, and that identified problems were entered into the corrective action program for resolution (e.g, CR 04-7561 and 7565). The tests reviewed included one inservice test (IST) and one reactor coolant system (RCS) leak detection TS surveillance test.

- OP 1-2200050B, 1B Emergency Diesel Generator Perodic Test
- OP 2-0700052, AFAS Actuation Relay Test, of Channels A and B
- OP 1-0700050, Auxiliary Feedwater Periodic Test, for the 1C AFW Pump IST Code Run
- OP-0010125A, Surveillance Data Sheets, Data Sheet 1, RCS Inventory Balance

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors continued to periodically screen active temporary modifications, especially for risk significant systems. The inspectors examined the temporary modification listed below which included a review of the technical evaluation and its associated 10CFR50.59 screening. The temporary modification was compared against the system design basis documentation to ensure that (1) the modification did not adversely affect operability or availability of other systems, (2) the installation was consistent with applicable modification documents, and (3) did not affect TS or warrant prior NRC approval. The inspectors also observed accessible equipment related to the temporary modification to verify configuration control was maintained.

- TSA #2-04-009, Unit 2 Main Feedwater 100% Bypass Valve Pushbutton

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

1EP6 Drill Evaluation

a. Inspection Scope

On October 20 and November 4, 2004, the inspectors observed simulator evaluations of licensed operators as part of the Licensed Operator Continuing Training program. During these simulator evaluations the inspectors assessed operator actions on the simulator to verify whether emergency action level classifications, notifications, and protective action recommendations were made in accordance with licensee Emergency Plan Implementing Procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Initiating Events Cornerstone

a. Inspection Scope

The inspectors assessed the accuracy of the following Performance Indicators (PIs) reported to the NRC in accordance with the criteria specified in NEI 99-02, Regulatory Assessment Performance Indicator Guideline, and ADM-25.02, NRC Performance Indicators. The inspectors reviewed the PI data of both Units 1 and 2 for the previous four quarters (i.e., Fourth Quarter 2003 through Third Quarter 2004). Monthly Operating Reports, Licensee Events Reports, RCO Chronological Logs, and CRs were reviewed to verify the reported PI data was complete and accurate. Furthermore, the inspectors interviewed the responsible Licensing and Operations personnel.

- Unplanned Scrams per 7000 Critical Hours (Unit 1)
- Unplanned Scrams per 7000 Critical Hours (Unit 2)
- Unplanned Scrams With Loss of Normal Heat Removal (Unit 1)
- Unplanned Scrams With Loss of Normal Heat Removal (Unit 2)
- Unplanned Transients per 7000 Critical Hours (Unit 1)

- Unplanned Transients per 7000 Critical Hours (Unit 2)

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Routine Review Of Condition Reports (CRs)

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems", and to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all condition reports as they were entered into the licensee's corrective action program.

b. Findings And Observations

There were no specific findings identified from this overall review of the CRs issued each day.

.2 Semi Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors review included daily screening of individual condition reports (see section 4OA2.1 above), licensee trending efforts, and licensee human performance self-assessments. The inspectors review nominally considered the six month period of July 2004 through December 2004, although some examples expanded beyond those dates when the scope of the trend warranted. This review also specifically examined equipment issues identified in selected System Health Reports, and adverse and negative trends identified by the Cross Functional Trend Coordinator Team Reports. Furthermore, the inspectors verified whether adverse or negative trends and issues identified in the licensee's reports were entered into the corrective action program (CAP).

b. Findings and Observations

No violations of NRC requirements were identified. However, during routine tours of the Unit 1 and 2 intake areas and from the review of daily CAP items, the inspectors were aware that the general material and physical conditions of the Unit 1 and 2 intake cooling water (ICW) systems had deteriorated. After one specific tour of the ICW pump areas, the inspectors identified two Unit 1 ICW discharge line expansion joints whose bolting was not properly coated following maintenance to prevent corrosion. The inspectors were aware that this component was recently worked and returned to service after planned maintenance. Upon further investigation by the inspectors, it was determined that the work package had been closed out without the coatings being applied. The licensee initiated CR 04-13096 to address this issue. In response to the inspectors' additional questions regarding coatings on other recently worked components, the licensee identified other work packages for other components that had been closed out prior to protective coatings being applied. This negative trend was then entered into the CAP as CR 04-13396. Furthermore, after more probing by the inspectors, licensee management became aware that approximately 500 coating deficiencies were being tracked by the Maintenance Services department using an informal process outside of the CAP and formal work control and planning processes. The licensee initiated CR 04-13541 to address the programmatic aspects.

.3 Post Maintenance Test Procedure ADM-78.01 Does Not Require Diagnostic Testing of Risk Significant Air Operated Valves (AOV)

a. Inspection Scope

The inspectors selected Condition Report 04-6916 for detailed review. This Condition Report was associated with the post maintenance testing program not requiring diagnostic testing of risk significant air operated valves. The inspectors reviewed this report to verify that the licensee identified the full extent of the issue, performed an appropriate evaluation, and specified and prioritized appropriate corrective actions. Additionally, this matter was reviewed with the plant AOV engineer.

b. Findings and Observations

No violations of NRC requirements were identified. However, the inspectors noted that the licensee's corrective action, which consisted of revising the post maintenance testing procedure (Procedure Change Request 04-3029) to require AOV diagnostic testing following certain maintenance activities, was not to be implemented in a timely manner. Specifically, for the scheduled January 5, 2005, Unit 2 refueling outage, a hold was placed on the revision to procedure ADM-78.01, "Post Maintenance Testing Procedure," such that its requirements would not be implemented until completion of the scheduled refueling outage. Because a substantial portion of the AOV maintenance is completed during refueling outages, the inspectors questioned the prudence of delaying implementation of this corrective action. This matter was brought to the attention of licensee management, whereupon they reviewed the scope of PMTs planned for Category 1 AOVs during the upcoming Unit 2 refueling outage. Based on this review, the licensee revised the applicable work orders to ensure the required PMT would be accomplished during the outage.

.4 Unit 1 and 2 Battery Charger Failures

a. Inspection Scope

The inspectors examined the licensee's response and corrective actions to address recent failures of the 2AA and 1BB Battery Chargers as documented in CRs 03-2753 and 04-11049, respectively. The inspectors discussed these failures in detail, on several occasions, with the responsible system engineer and engineering supervision/management. The inspectors also reviewed the completed CRs, along with the associated maintenance rule documents (i.e., expert panel minutes; the revised Figure 4, Goal Setting and Monitoring), and the “Battery Charger 10 year Parts Replacement Schedule” developed as part of the long term corrective actions. Furthermore, the inspectors witnessed portions of the battery charger rectifier output measurement checks conducted by electrical maintenance in December 2004 as part of the interim corrective actions to verify charger operability and extent of condition. The inspector reviewed the rectifier output results from all of the battery chargers and discussed them with the responsible system engineer and supervisor. Lastly, the inspector discussed the functional failure determinations with the maintenance rule coordinator.

b. Findings and Observations

No violations of NRC requirements were identified. However, the inspectors did make several observations related to the licensee’s corrective actions and maintenance rule implementation. First, the PCRs associated with CR 03-2753 to revise the battery charger 18 month maintenance and operability testing procedures were overdue. These procedures have subsequently been revised. Secondly, the licensee failed to establish interim measures to ensure the extent of condition had been adequately addressed regarding potential age-related rectifier board failures of other battery chargers until such time as the 10 year parts replacement preventative maintenance (PM) could be executed. This issue was promptly resolved by the licensee who began implementing battery charger rectifier output measurement checks. And thirdly, although the maintenance rule expert panel did consider the 1BB Battery Charger failure to be a functional failure, it did not consider this failure to be maintenance preventable. The licensee was currently reconsidering their determination based on the inspector’s concern that the need for replacing battery charger parts on a ten year frequency had been previously recognized by the licensee in the very early 1990's. Parts replacement for the existing battery chargers were several years overdue because the ten year PMs were not scheduled when first identified in the 1991 time frame.

4OA3 Event Followup

.1 Unit 2 Manual Reactor Trip - December 25, 2004

a. Inspection Scope

On December 25, 2004, Unit 2 was manually tripped from 95% power due to rapidly degrading conditions involving the 2B condensate pump (CDP) motor. The unit had been operating at 100% power when the operators noticed high amperage indication on the main control board for the 2B CDP motor. Preparations for a rapid downpower were made and a field operator was dispatched to the condensate pump area. After the field operator reported back to the control room that the 2B CDP motor power supply connection was overheating, the control room operators manually tripped the unit and entered their emergency operating procedures (EOPs). Subsequent investigation by the licensee determined that the apparent cause of the motor failure was the loss of a single phase in the motor power circuit due to a defect in the electrical termination that caused heating to the point that the “A” phase motor lead failed. An inspector responded to the control room to interview operators, review applicable logs, examine computer data and strip charts, and verify that the unit was stable in Mode 3 and that all safety-related mitigating systems had operated properly. The inspector observed operator and plant response, and discussed the event with Operations personnel. Subsequently, the inspector also discussed the risk significance with Region II personnel, and verified that appropriate notifications were made in accordance with 10 CFR 50.72. Furthermore, the inspector reviewed the post-trip reports and interim dispositions of CR 04-17725.

b. Findings

No findings of significance

.2 Unit 2 Manual Reactor Trip - December 27, 2004

a. Inspection Scope

Following the manual reactor trip described above, the 2B CDP motor was replaced, and Unit 2 was restarted the next day. However, on December 27, 2004, while Unit 2 was at 10% power, operators initiated another manual reactor trip due to decreasing SGWL that was primarily caused by a misalignment of the MFW system (see Section 1R14). An inspector responded to the control room to interview operators, review applicable logs, examine computer data and strip charts, and verify that the unit was stable in Mode 3 and that all safety-related mitigating systems had operated properly. The inspector observed operator and plant response and discussed the event with Operations personnel. Subsequently, the inspector also discussed the risk significance with Region II personnel, and verified that appropriate notifications were made in accordance with 10 CFR 50.72. Furthermore, the inspector reviewed the post-trip reports and interim dispositions of CR 04-17851.

b. Findings

One finding of significance was identified related to operator performance that directly contributed to causing the transient that resulted in a manual reactor trip (see Section 1R14).

4OA4 Cross Cutting Aspects of Findings

A Green self-revealing NCV was identified and documented in Section 1R14 of this report which directly involved cross cutting aspects of Human Performance. Licensed operators failed to follow and implement a required EOP step to close the MFRV block valves during secondary post-trip operator actions. This omission directly contributed to a loss of MFW transient during Unit 2 startup, that ultimately resulted in a manual reactor trip on December 27, 2004.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Bill Jefferson and other members of licensee management on January 4, 2005. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

Supplemental Information

KEY POINTS OF CONTACT

Licensee Personnel

M. Alfonso, Work Control Manager
M. Bruecks, Security Manager
C. Buehrig, Maintenance Rule Coordinator
D. Calabrese, Emergency Planning Supervisor
C. Costanzo, Operations Manager
R. De La Espriella, Site Quality Manager
L. Edwards, Training Manager
K. Frehafer, Licensing Engineer
R. Hughes, Site Engineering Manager
E. Katzman, Performance Improvement Department Manager
G. Johnston, Plant General Manager
W. Jefferson, Site Vice President
J. Martin, Operations Support Supervisor
R. McDaniel, Fire Protection Supervisor
W. Nurberg, Chemistry Manager
W. Parks, Operations Supervisor
T. Patterson, Licensing Manager
J. Porter, Operations Support Engineering Manager
G. Swider, Systems Engineering Manager
J. Tucker, Maintenance Manager
S. Wisla, Health Physics Manager

Other licensee employees contacted include office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC personnel

B. Moroney, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000389/2004006-01	NCV	Improper Implementation of Emergency Operating Procedure Following a Manual Reactor Trip (Section 1R14)