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

January 29, 2010

Mr. J. Randy Johnson
Vice President - Farley
Southern Nuclear Operating Company, Inc.
7388 North State Highway 95
Columbia, AL 36319

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2009005 AND 05000364/2009005

Dear Mr. Johnson:

On December 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Joseph M. Farley Nuclear Plant, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on January 29, 2010, with Mr. Randy Johnson and 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 NRC reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents three self-revealing and two NRC identified findings of very low safety significance (Green). Five of these findings were determined to involve violations of NRC requirements. Additionally, two licensee-identified violations (LIVs), which were determined to be of very low safety significance, are listed in this report. However, because the findings were of very low safety significance and because they were entered into your corrective action program (CAP), the NRC is treating these findings as non-cited violations (NCVs), consistent with Section VI.A.1 of the NRC's Enforcement Policy. If you contest any 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 Resident Inspector at the Farley Nuclear Plant. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at the Farley Nuclear Plant. The information you provide will be considered in accordance with the Inspection Manual Chapter (IMC) 0305.

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

Sincerely,

/RA/

Scott M. Shaeffer, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket No.: 50-348, 50-364
License No.: NPF-2, NPF-8

Enclosure: Inspection Report 05000348/20009005, and 05000364/2009005
w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

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Letter to J. Randy Johnson from Scott M. Shaeffer dated January 29, 2010

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2009005 AND 05000364/2009005

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	05000348, 05000364
License Nos.:	NPF-2, NPF-8
Report No.:	05000348/2009005, and 05000364/2009005
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Joseph M. Farley Nuclear Plant, Units 1 and 2
Location:	Columbia, AL
Dates:	October 1, 2009, through December 31, 2009
Inspectors:	E. Crowe, Senior Resident Inspector S. Sandal, Resident Inspector B. Caballero, Senior Operations Engineer (Section 1R11) W. Rogers, Senior Reactor Analysts (Section 1R06, 1R12, 1R15, 4OA5) G. MacDonald, Senior Reactor Analysts (Section 4OA5)
Approved by:	Scott M. Shaeffer, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000348/2009005 and 05000364/2009005; 10/01/2009 – 12/31/2009; Joseph M. Farley Nuclear Plant, Units 1 and 2; Internal Flood Protection, Maintenance Effectiveness, Operability Evaluations, and Other Activities.

The report covered a three-month period of inspection by the resident inspectors and one senior operations engineer. Five Green NCVs were identified. The significance of most findings is indicated 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 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 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems (MS)

- Green. A self-revealing non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified for the licensee's failure to identify a credible source of flooding in their internal flooding evaluation of record (performed in 1999). On March 27, 2009, the licensee performed a flushing evolution of the Unit 2 main feedwater (FW) system involving draining of water into the main steam valve room (MSVR) critical pipe chase. A drain located at the bottom of the chase connects to the floor drain system of the auxiliary building lower equipment room. This evolution resulted in water entering the lower equipment room through the floor drain system. The licensee reviewed design documents and discovered the flooding evaluation failed to identify a credible source of flooding from the floor drain system. The licensee performed a root cause analysis and determined a FW line break in the MSVR concurrent with the open drain path, would result in a worst case maximum flood level in the lower equipment room of 1 foot and 10 inches above the floor. This level was determined to adversely affect the turbine driven auxiliary feedwater pump (TDAFWP) uninterrupted power supply inverter/rectifier and would render the pump inoperable.

  The licensee's failure to identify a credible source of flooding in their internal flooding evaluation of record was a performance deficiency. This finding was more than minor because it adversely affected the equipment reliability attribute of the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, this finding resulted in conditions that could render the TDAFWP inoperable on both units. This finding was assessed using the Phase 1 screening worksheet of the SDP and it was determined a Phase 3 analysis was required. A senior reactor analyst performed a Phase 3 evaluation under the SDP and determined that the finding was of very low safety significance (Green). The analysis used a one year exposure time with the emergency air compressors and the TDAFWP failing without the possibility of recovery due to internal flooding. Two initiating events are a steam line break outside containment and a main feedwater line break. The dominant accident sequence was a steam line break with the normal air compressors failing due to common cause, followed by operators failing to terminate the safety injection. The finding was reviewed against the cross-cutting aspects listed in IMC 0305, Operating Reactor Assessment Program, and determined not to have a cross-cutting aspect reflective of current licensee performance. (Section 1R06)

- Green. A self-revealing NCV of TS 5.4, Procedures, was identified for the failure to implement preventative maintenance inspections on the 1-2L 600 volt load center as specified by FNP-0-EMP-1322.10, Maintenance and Cleaning of Westinghouse Switchgear. The failure to perform the specified inspections on the 1-2L 600 volt load center allowed bus fastener torque to degrade to the point that bus bar damage occurred which rendered the 1-2L 600 volt load center inoperable. The licensee has entered the issue into the CAP as CR 2008103720. The licensee has completed corrective actions to restore operability of the 1-2L 600 volt load center and schedule the specified maintenance inspections.

  The failure to implement preventative maintenance inspections on the 1-2L 600 volt load center as specified by FNP-0-EMP-1322.10 was a performance deficiency. This finding was more than minor because it adversely affected the equipment performance attribute of the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the finding resulted in the potential loss of SW cooling due to 1-2L 600 V load center inoperability. This finding was assessed using the mitigating systems cornerstone column of the Phase 1 screening worksheet of the SDP and determined to require a Phase 3 analysis because the finding represented the actual loss of a safety function of a single train for greater than its allowed TS outage time. A senior reactor analyst performed a Phase 3 evaluation under the SDP and determined that the finding was of very low safety significance (Green). The dominant accident sequence was a failure of train A service water (SW) due to loss of the 4KV F bus, failure of the B train due to loss of the pump cooling sub-system and loss of the 600 VAC load center 1/2L due to the performance deficiency causing a total loss of service water to the unit. Auxiliary feedwater (AFW) provided secondary side cooling, but without SW both reactor coolant pump (RCP) seal cooling sources, component cooling water (CCW) thermal barrier cooling & high head safety injection/charging seal injection, failed. Consequently, a seal loss of coolant accident happened without the ability to makeup to the reactor coolant system resulting in core damage. This finding is associated with a cross-cutting aspect in the work control component of the human performance area in that the repetitive task to perform procedure FNP-0-EMP-1322.10 was never entered into the work control process (H.3(b)). (Section 1R12)

- Green. A NRC-identified NCV of Technical Specification (TS) 3.8.9 was identified for failure to meet the limiting condition for operation (LCO) of maintaining two trains of AC vital bus electrical power distribution subsystems operable. The licensee failed to adequately evaluate plant conditions and identify that the 1-2R 600 volt load center was unable to meet its surveillance requirement of correct breaker position and voltage for longer than the allowed outage time.

The failure to properly evaluate plant conditions and recognize the surveillance requirement of TS 3.8.9 was not met was a performance deficiency. As a result, the LCO of maintaining two trains of AC vital bus electrical power distribution subsystems available was not met for longer than the allowed outage time. During the period of August 5 - August 9, 2009, (85 hours and 6 minutes), the Unit 2 power supply to 1-2R 600 volt load center was not available to meet the Unit 2 portion of TS 3.8.9. This finding was more than minor because it adversely affected the equipment performance attribute of the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences. The condition resulted in the 1-2R 600 volt load center not being able to perform its automatic function during a dual unit loss of off site power (LOSP) with loss-of-coolant accident (LOCA) on the specified unit. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined to require a Phase 2 analysis because the condition existed longer than the allowed outage time for a single train of safety-related equipment. A Senior Reactor Analyst performed a Phase 3 evaluation under the Significance Determination Process and determined that the finding was of very low safety significance (Green). Although only one power source to the 1-2R 600 VAC Load Center was out of service, the analysis assumed the load center was totally out of service. Also, for ease of analysis a 112 hour exposure time was used. The dominant accident sequence was a dual unit loss of offsite power (LOSP) due to severe weather and a loss of emergency diesel generators (EDGs) resulting in a station blackout (SBO). While in the SBO condition, the TDAFW train would have failed and offsite power would not have been restored prior to core damage. This finding was assigned a cross-cutting aspect in the work practices component of the human performance area (H.4(b)) because the licensee failed to execute the sequence required by its restoration tagout procedure controlling plant configuration. (Section 1R15)

- Green. A self-revealing NCV of 10 CFR 50.65(a)(1) was identified for failure to perform monitoring of the service water intake structure (SWIS) seismic rings resulting in the inability of 2A, 2B, 2C, and 2E service water pump (SWP) seismic rings to perform their function. The support function of the seismic ring of these pumps failed due to degradation of the fasteners. The licensee entered the issue into the CAP as CR 2009109700. The licensee completed corrective actions to restore functionality of the 2A, 2B, 2C, and 2E SWP seismic rings.

  The failure to perform monitoring of the SWIS seismic rings resulting in the inability of the 2A, 2B, 2C, and 2E SWP seismic rings to perform their function is a performance deficiency. This finding was more than minor because it adversely affected the equipment reliability attribute of the MS cornerstone objective to ensure the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage). This finding was assessed using the Phase 1 screening worksheet of the SDP and determined to be of very low safety significance (Green) because the safety function of the service water pump was determined to not be degraded. The finding is associated with a cross-cutting aspect in the CAP component for the Problem Identification and Resolution (PI&R) area in that the licensee did not complete actions identified in the corrective action program which included inspections of wet pit fasteners.(P.1(d)). (Section 4OA5.3)

- Green. The NRC identified a Green NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, for failure to translate EDG system design into surveillance test procedures rendering LOSP emergency load sequencers inoperable during performance of those tests. The licensee entered the issue into the CAP as CR 2008105195 and is taking corrective action to modify the EDG LOSP circuit to maintain the operability of the LOSP emergency load sequencers during the performance of EDG surveillance tests.

  The failure to translate system design into procedures and instructions for performing EDG surveillance tests that rendered the LOSP emergency load sequencers inoperable was a performance deficiency. This performance deficiency was more than minor because required surveillance test procedures did not alert operators to the fact that the performance of those tests rendered the LOSP load sequencers inoperable and tests were performed that exceeded the allowed outage time for an inoperable sequencer. SDP phase 1 screening determined that core decay heat removal was affected within the mitigating systems cornerstone when the performance deficiency represented loss of a train of a safety function for greater than its technical specification allowed outage time. A phase 3 SDP was required because the phase 2 worksheets do not provide sufficient detail. The phase 3 analysis was performed by a regional SRA. The phase 3 result was <1E-6 for core damage frequency (CDF) and did not involve steam generator tube rupture or intersystem loss of coolant accident (LOCA) sequences and therefore was not a significant large early release frequency (LERF) risk contributor. The dominant sequences involved an LOSP with a failure of the LOSP sequencer while an EDG was in surveillance paralleled with the grid, failure of the operator to load the EDG, combined with failure of the opposite train EDG. With no emergency or offsite power provided, no RCP seal makeup, RCP seal cooling or service water would be available and a seal LOCA would result in core damage. No recovery credit was assumed in the analysis although the EDG themselves and the switchgear to the safety equipment would not have been affected. Factors which reduced the risk included the low exposure time and the availability of other mitigating equipment. The EDGs themselves would not be affected by the performance deficiency only the automatic loading subsequent to an LOSP. The ESF sequencers were not affected by the performance deficiency. The SDP result was Green, a finding of very low safety significance. No cross-cutting aspect was identified because the finding was not indicative of current plant performance. (Section 4OA5.4).

B. Licensee-identified Violations

Violations of very low safety significance, identified by the licensee, have been reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's CAP. These violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 started the report period at 100 percent Rated Thermal Power (RTP). On November 29, the unit experienced a trip of the main generator terminal cooling unit. The unit was ramped to 53 percent RTP as required by station procedures. The main generator terminal cooling unit was repaired and the unit returned to 100 percent RTP on November 30. The unit remained at or near 100 percent RTP for the remainder of the inspection period.

Unit 2 started the report period at 100 percent RTP. On November 5, the unit experienced an oil leak on the Phase 2 main power transformer and was shutdown. The unit was made critical on November 8 and achieved 100 percent RTP on November 10. The unit remained at or near 100 percent RTP for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Seasonal Readiness Review. The inspectors evaluated implementation of the licensee's Severe Weather procedure, FNP-0-AOP-21.0, during the licensee's preparation for potential high winds and rainfall due to tropical storm Ida. The inspectors examined outside areas of the protected area, building rooftops, and missile barriers to verify material was not loose and potential missiles were secured. The inspectors monitored licensee control of the high voltage switchyard and locking of the Spent Fuel Cask Crane. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial Walk-Down: The inspectors performed partial walk-downs of the following two systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors attempted to identify discrepancies impacting the function of the system, and therefore potentially increasing risk. The walk-downs were performed using the criteria in licensee procedures NMP-OS-007, Conduct of Operations, and FNP-0-SOP-0, General Instructions to Operations Personnel. The walk-downs included reviewing the Updated Final Safety Analysis Report (UFSAR), plant procedures and drawings, checks of control room and plant valves, switches, components, electrical power, support equipment, and instrumentation. Documents reviewed are listed in the Attachment.

- Unit 1 Component Cooling Water (CCW) System during repair activities to the 1A Charging Pump suction vent valve
- Unit 2 station Service Water (SW) system train 'A' during repair activities to 2B and 2C SW pumps

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Protection Area Tours: The inspectors conducted a tour of the four fire areas listed below to assess material condition and operation status of the fire protection equipment. The inspectors verified combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; fire detection and suppression equipment was available for use; passive fire barriers were maintained in good material condition, and compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the requirements of licensee procedures FNP-0-AP-36, Fire Surveillance and Inspection; FNP-0-AP-38, Use of Open Flame; FNP-0-AP-39, Fire Patrols and Watches; and the associated Fire Zone Data sheets. Documents reviewed are listed in the Attachment.

- Unit 1/2, Fire Pump House
- Unit 2, CCW Heat Exchanger Room, Fire Zone 6
- Unit 2, Motor Driven Auxiliary Feedwater (MDAFW) Pump B Room, Fire Zone 6
- Unit 2, Non-Radwaste Ventilation Equipment Room, Safety Parameter Display System (SPDS)/Computer UPS Room, and CCW Surge Tank Room, Fire Zone 43

b. Findings

No findings of significance were identified.

1R06 Internal Flood Protection

.1 Review of Areas Susceptible to Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analysis and design documents, including the UFSAR, engineering calculations and abnormal operating procedures for licensee commitments. The inspectors walked-down the area listed below to verify plant design features and plant procedures for flood mitigation were consistent with design requirements and internal flooding analysis assumptions. The inspectors reviewed flood protection barriers, which included plant floor drains, condition of room penetrations, condition of the sumps in the rooms, and condition of water-tight doors. The inspectors also reviewed CRs to verify the licensee was identifying and resolving problems. Documents reviewed are listed in the Attachment.

- Unit 2 Lower Equipment Room

b. Findings

Introduction. A Green, self-revealing NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified for the licensee's failure to identify a credible source of flooding in their internal flooding evaluation of record.

Description. On March 27, 2009, the licensee performed a flushing evolution of the Unit 2 main FW system involving draining water into the MSVR critical pipe chase. A drain located at the bottom of the chase connects to the floor drain system of the auxiliary building lower equipment room. This floor drain system drains into a sump in the lower equipment room, which is processed by the floor drain waste processing system. During the main FW flushing evolution, water backed up into the lower equipment room drain system. Water level also increased in the critical pipe chase in the MSVR, resulting in leakage through a water-tight seal in the wall of the lower equipment room. This leakage resulted in water traversing across the top of the 2A MDAFWP Pump Room and spilling onto three electrical panels and the TDAFWP uninterrupted power supply inverter/rectifier.

The licensee reviewed their design documents and discovered their flooding evaluation of record (performed in 1999) failed to identify a flooding source from the floor drain system. The licensee performed a root cause analysis and determined a FW line break in the MSVR concurrent with this open drain path would result in a worst case maximum flood level in the lower equipment room of 1 foot and 10 inches above the floor. This level was determined to adversely affect the TDAFWP uninterrupted power supply inverter/rectifier rendering the pump inoperable. The licensee also determined this condition could occur on Unit 1. The inspectors concluded the licensee's failure to incorporate plant design into the flooding calculation of record resulted in no action being taken to mitigate a credible source of flooding in the lower equipment room and adversely affected the operability of the TDAFW pump. On March 28, 2009, the licensee installed Thaxton plugs in the critical pipe chase drains of each unit to eliminate this unevaluated source of flooding.

Analysis. The failure to identify a credible source of flooding in the internal flooding evaluation of record was a performance deficiency. This finding was more than minor because it adversely affected the equipment reliability attribute of the MS cornerstone objective to ensure the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, this finding resulted in conditions that could render the TDAFWP inoperable on both units. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined a Phase 3 analysis was required. A senior reactor analyst performed a Phase 3 evaluation under the SDP and determined that the finding was of very low safety significance (Green). The analysis used a one year exposure time with the emergency air compressors and the TDAFWP failing without the possibility of recovery due to internal flooding. Two initiating events, steam line break outside containment and main feedwater break, were considered capable of causing the internal flood failing this equipment. The dominant accident sequence was a steam line break with the normal air compressors failing due to common cause followed by operators failing to terminate the Safety Injection. The finding was reviewed against the cross-cutting aspects listed in IMC 0305, Operating Reactor Assessment Program, and determined not to have a cross-cutting aspect reflective of current licensee performance.

Enforcement. 10 CFR 50, Appendix B, Criterion III states in part that measures shall be established to assure design bases are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, the licensee failed to identify a credible source of flooding in their internal flooding evaluation of record. This failure resulted in conditions that rendered the TDAFW Pumps on both units inoperable during a design basis accident in the MSVR. Because this finding is of very low safety significance and has been entered into the CAP as CR 2009103286, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000348,364/2009005-01, Failure to Identify A Credible Source of Flooding in the Internal Flooding Evaluation of Record.

.2 Annual Review of Cables Located in Underground Bunkers/Manholes

a. Inspection Scope

The inspectors conducted an inspection of the following four underground bunkers/manholes subject to flooding, containing cables whose failure could disable risk-significant equipment. The inspectors performed walk-downs of risk-significant areas to verify the cables were not submerged in water, cables and/or splices appeared intact and observed the condition of cable support structures. When applicable, the inspectors verified proper dewatering device (sump pump) operation and verified level alarm circuits were set appropriately, ensuring the cables would not be submerged. Where dewatering devices were not installed; the inspectors ensured drainage was provided and functioning properly.

- Cable Vault 110
- Cable Vault 114
- Unit 1 Train ‘A’ Diesel Building to Auxiliary Building Cable Tunnel
- Unit 1 Train ‘B’ Diesel Building to Auxiliary Building Cable Tunnel

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

Resident Inspector Quarterly Review: On November 12, the inspectors observed portions of the licensed operator training and testing program to verify implementation of procedures FNP-0-AP-45, Farley Nuclear Plant Training Plan; FNP-0-TCP-17.6, Simulator Training Evaluation/Documentation and FNP-0-TCP-17.3, Licensed Operator Continuing Training Program Administration. The inspectors observed operations simulator scenario 09-S807, conducted in the licensee's simulator for a trip of the 1A CCW pump and HV-8152 fails closed. Additional failures included PT-455 fails high, LT-115 fails high, and TE-412D fails high. The inspectors observed high-risk operator actions, overall crew performance, self-critiques, training feedback and management oversight to verify operator performance was evaluated against the performance standards of the licensee's scenario. Documents reviewed are listed in the Attachment.

Annual Review of Licensee Requalification Examination Results. On December 31, 2009, the licensee completed administering the requalification annual operating tests required to be given to all licensed operators by 10 CFR 55.59(a) (2). The inspector performed an in-office review of the overall pass/fail results of the operating tests, as well as 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 Rule Effectiveness

a. Inspection Scope

The inspectors reviewed the following two activities for: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the MR; (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1). In addition, the NRC specifically reviewed events where ineffective equipment maintenance resulted in invalid automatic actuations of Engineered Safeguards Systems affecting the operating units. Documents reviewed are listed in the Attachment.

- CR 2009103283, Accumulator air leak on actuator for the Unit 1 TDAFWP steam supply valve from the ‘C’ SG – Q1N12HV3235B
- CR 2008103720, Degraded Bus Bar on 1-2L 600 Volt Load Center

b. Findings

CR 2009103283 – Accumulator air leak on actuator for the Unit 1 TDAFWP steam supply valve from the 'C' SG – Q1N12HV3235B

One LIV was identified and is documented in section 4OA7 of this report.

CR 2008103720 – Degraded Bus Bar on 1-2L 600 Volt Load Center

Introduction. A Green, self-revealing non-cited violation of TS 5.4, Procedures, was identified for the failure to implement preventative maintenance inspections on the 1-2L 600 volt load center as specified by FNP-0-EMP-1322.10, Maintenance and Cleaning of Westinghouse Switchgear. The failure to perform the specified inspections on the 1-2L 600 volt load center allowed bus fastener torque to degrade to the point that bus bar damage occurred which rendered the 1-2L 600 volt load center inoperable.

Description. At 6:55 AM on April 15, 2008, control room operators received multiple alarms on the emergency power board and noted indications of fluctuating grounds on the 'B' train DC bus for the SWIS. The control room dispatched personnel to the SWIS to investigate the alarms and determined that the 1-2L 600 volt load center was inoperable due to the inability to maintain minimum required TS voltage. The licensee's initial response to this event and immediate actions take to restore 1-2L load center operability are discussed in Section 4OA3.1 of this report and documented in Licensee Event Report (LER) 05000348/2008-002-00. This issue was entered into the licensee's CAP as CR 2008103720.

The inspections of the 1-2L 600 volt load center revealed damage to the phase 2 horizontal bus bar on the Unit 2 side of the load center tie breaker. The inspectors reviewed the licensee's apparent cause determination and root cause evaluation for the event. The licensee's analyses concluded that the bus bar damage was caused by bus bar fastener torque degradation which created a high electrical resistance contact surface at the location of the bus damage. The licensee's evaluations also concluded that either (1) the bus bar fasteners had not been torqued correctly during initial installation of the 1-2L bus, or (2) the torque had degraded over time due to cyclic thermal stresses associated with normal variation of electrical loads on the bus. On May 16, 2008, the licensee completed final repairs to the 1-2L load center restoring the ability of the load center to be powered from Unit 1 or Unit 2.

The inspectors noted that CR 2004101848 had been entered into the licensee's CAP on August 9, 2004, to track action items generated by the Equipment Reliability Improvement Project. Action item (AI) 2004204246 was created to ensure that bus bar fastener torque checks were added to maintenance inspections of low voltage switch gear. The inspectors noted that the licensee closed AI 2004204246 stating that a new procedure would be written to specify torque checks on low voltage switchgear bus fasteners and that a repetitive task in the licensee's work management program would be created to ensure implementation of the new procedure. The licensee approved electrical maintenance inspection procedure FNP-0-EMP-1322.10 on September 19, 2005 which included steps to verify proper torque of low voltage switchgear fasteners.

After FNP-0-EMP-1322.10 was issued by the licensee, actions were not taken to generate a repetitive task in the work management program. As a result, the specified maintenance inspections were never subsequently scheduled or performed prior to the failure that occurred on April 15, 2008.

Analysis. The failure to implement preventative maintenance inspections on the 1-2L 600 volt load center as specified by FNP-0-EMP-1322.10 was a performance deficiency. The failure to perform inspections on the 1-2L 600 volt load center allowed bus fastener torque to degrade to the point that bus bar damage occurred which rendered the 1-2L 600 volt load center inoperable. This finding was more than minor because it adversely affected the equipment performance attribute of the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to perform inspections on the 1-2L 600 volt load center allowed bus fastener torque to degrade to the point that bus bar damage occurred which rendered the 1-2L 600 volt load center inoperable. This finding was assessed using the mitigating systems cornerstone column of the Phase 1 screening worksheet of the SDP and determined to require a Phase 3 analysis because the finding represented the actual loss of a safety function of a single train for greater than its allowed TS outage time. A senior reactor analyst performed a Phase 3 evaluation under the SDP and determined that the finding was of very low safety significance (Green). For ease of analysis the performance deficiency was modeled as the total failure of the 600 VAC Motor Control Center for both exposure periods. Therefore, a 32 day exposure time was used. Recovery of the motor control center was not considered. The dominant accident sequence was a failure of train A service water (SW) due to loss of the 4KV F bus, failure of the B train due to loss of the pump cooling sub-system and loss of the 600 VAC load center 1-2L due to the performance deficiency causing a total loss of service water to the unit. Auxiliary feedwater (AFW) provided secondary side cooling, but without SW both reactor coolant pump (RCP) seal cooling sources, component cooling water (CCW) thermal barrier cooling and high head safety injection/charging seal injection, failed. Consequently, a seal loss of coolant accident happened without the ability to makeup to the reactor coolant system resulting in core damage.

The inspectors reviewed the licensee's root cause evaluation and noted that recent interviews with the licensee's staff indicated that the engineering department was aware procedure FNP-0-EMP-1322.10 existed and assumed that it was being performed by maintenance to ensure the reliability of the switchgear. However, the inspectors noted that interviews also indicated that the maintenance department was unaware of the existence of FNP-0-EMP-1322.10. The inspectors concluded the interviews indicated that a lack of interdepartmental communication and coordination existed which significantly contributed to the failure to take actions to ensure that switchgear reliability was being maintained through the performance of maintenance inspections specified by FNP-0-EMP-1322.10. This finding is associated with a cross-cutting aspect in the work control component of the human performance area in that the repetitive task to perform procedure FNP-0-EMP-1322.10 was never entered into the work control process (H.3(b)).

Enforcement. TS 5.4.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978. Section 9 of Appendix A to RG 1.33 states that preventative maintenance schedules should be developed to specify inspections of equipment. Contrary to the above, on September 19, 2005, the licensee failed to develop a preventative maintenance schedule, through the creation of a repetitive task in the licensee's work management program, to perform bus bar inspections and bus fastener torque checks as specified by procedure FNP-0-EMP-1322.10. As a result of the licensee's failure to implement inspections specified by FNP-0-EMP-1322.10, the procedure was not performed and unidentified degradation of bus fastener torque occurred which resulted in the inoperability of the 1-2L 600 volt load center on April 15, 2008. The licensee completed final repairs to the damaged 1-2L load center bus bar on May 16, 2008 and completed corrective actions on August 7, 2009 to schedule additional preventative maintenance inspections of safety-related switch gear. Because this failure to schedule and perform inspections of safety-related switchgear is of very low safety significance and has been entered into the CAP as CR 2008103720, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000348,364/2009005-02 Failure to Implement Maintenance Inspections of Safety-Related Switchgear.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following three activities to verify appropriate risk assessments were performed before taking equipment out of service (OOS) for maintenance. The inspectors verified risk assessments were performed as required by 10 CFR 50.65(a)(4), and were accurate and complete. When emergent work was performed, the inspectors verified appropriate use of the licensee's risk assessment and risk categories in accordance with requirements in licensee procedures FNP-0-ACP-52.3, Mode 1, 2, & 3 Risk Assessment; FNP-0-UOP-4.0, General Outage Operations Guidance; NMP-GM-006, Work Management and NMP-OS-007, Conduct of Operations.

- Unit 2, October 15, GREEN risk condition during maintenance on B2G load sequencer and SW FCV-3009A
- Unit 2, October 20, YELLOW risk condition during maintenance on B2G load sequencer, 2A CCW pump, and 2C charging pump
- Unit 1, October 26, YELLOW risk condition during maintenance on A train SW pump seismic rings

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following five operability evaluations to verify they met the requirements of licensee procedures NMP-OS-007, Conduct of Operations and NMP-AD-012, ODs and Functionality Assessments. The scope of this inspection also included a review of the technical adequacy of the evaluations, adequacy of compensatory measures, and impact on continued plant operation.

- CR 2009110033, DH-08-02 Station Service Transformer (SST) 2R supply breaker discovered in “racked out” condition
- CR 2009113132, 2C Containment Cooler SW outlet isolation valve Q2P16MOV3441C failed to open on demand from main control board
- CR 2009101841, Inspection cover missing from Unit 2 spent fuel pool (SFP) penetration room filtration duct
- CR 2009113434, Gas void discovered in the A Train Residual Heat Removal (RHR) Heat Exchanger discharge to the 2A Charging Pump
- CR 2009114181, 1-2A Emergency Diesel Generator lube oil temperature above maximum log specification

b. Findings

CR 2009110033 – DH-08-02 SST 2R supply breaker “racked out”

Introduction. A Green, NRC-identified NCV of TS 3.8.9 was identified for the failure to meet the LCO of maintaining two trains of AC vital bus electrical power distribution subsystems operable. The licensee failed to adequately evaluate plant conditions and identify that the 1-2R 600 volt load center was unable to meet its surveillance requirement of correct breaker position and voltage for longer than the allowed outage time.

Description. On August 5, 2009 at 2:30 pm, the licensee entered TS 3.8.9 due to the Station Transformer 2G supply breaker DH-01-02 being stuck in an intermediate position on the 4160 volt 2H non-safety related bus. The licensee determined this issue would result in the inability of the 2H 4160 volt bus to supply the 1-2R 600 volt load center’s step-down transformer during a seismic event. At 5:03 pm, the licensee successfully transferred the 1-2R 600 volt load center to its Unit 1 power source and exited TS 3.8.9. The inspectors determined the Unit 2 power supply from 2H 4160 volt bus would be unavailable during a seismic event because no repairs occurred to the bus at this time. The inspectors also determined the surveillance requirement for TS 3.8.9 was not met for correct breaker alignment for Unit 2. At 10:02 pm, the licensee de-energized the 2H 4160 volt bus to allow repairs. The licensee’s tagout procedure included tagging the DH-08-02 circuit breaker (Unit 2 1-2R power supply to its step-down transformer) to its “racked out” position. The licensee successfully removed circuit breaker DH-01-02 and re-energized the 2H 4160 volt bus, restoring operability of 2H bus at 3:52am on August 6, 2009. The restoration process directed the licensee to “rack in” DH-08-02, however, the licensee decided to leave circuit breaker DH-08-02 in a “racked out” position to facilitate later expected repairs to the 2H 4160 volt bus. The inspectors concluded the licensee had failed to adequately evaluate plant conditions and recognize that with DH-08-02 in the “racked-out” position, did not meet the applicable surveillance requirement for correct breaker alignment. On August 9, 2009, the licensee unsuccessfully performed surveillance procedure FNP-1-STP-27.2, “On-site Distribution” which verifies the surveillance requirement of TS 3.8.9.1. The unsuccessful performance was due to circuit breaker DH-08-02 not being in its required position. The licensee determined the 1C EDG was inoperable due to lack of support conditions (1-2R 600 volt load center unavailable) and entered TS 3.8.1, “AC Sources – Operating.” At 3:36 am on August 9, 2009, the licensee racked DH-08-02 to its proper position and closed the breaker. The licensee exited TS 3.8.1 after restoring automatic transfer capability for the 1-2R 600 volt load center. The inspectors determined the surveillance requirement of TS 3.8.9.1 of correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems were unmet for 85 hours and 6 minutes for the Unit 2 power supply to 1-2R 600 volt load center.

<u>Analysis.</u> The failure to properly evaluate plant conditions and recognize the surveillance requirement of TS 3.8.9 was not met is a performance deficiency. As a result, the LCO of maintaining two trains of AC vital bus electrical power distribution subsystems available was not met for longer than the allowed outage time. During the period of August 5 through August 9 (85 hours and 6 minutes), the Unit 2 power supply to 1-2R 600 volt load center was not available to meet the Unit 2 portion of TS 3.8.9. This finding was more than minor because it adversely affected the equipment performance attribute of the mitigating system cornerstone objective ensuring the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences. The condition resulted in the 1-2R 600 volt load center being unable to perform its function during a dual unit LOSP with LOCA on the specified unit. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined to require a Phase 2 analysis because the condition existed longer than the allowed outage time for a single train of safety-related equipment. A senior reactor analyst performed a Phase 3 evaluation under the SDP and determined that the finding was of very low safety significance (Green). Although only one power source to the R1/2 600 VAC Load Center was out of service, the analysis assumed the load center was totally out of service. A conservative 112 hour exposure time was used. The dominant accident sequence was a dual unit loss of offsite power (LOSP) due to severe weather and a loss of emergency diesel generators (EDGs) resulting in a station blackout (SBO). While in the SBO condition, the TDAFW train would have failed and offsite power would not have been restored prior to core damage. This finding was assigned a cross-cutting aspect in the work practices component of the human performance area (H.4(b)) because the licensee failed to execute the sequence required by its restoration tagout procedure controlling plant configuration.

<u>Enforcement</u> TS 3.8.9 requires Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems to be operable in Modes 1, 2, 3, & 4. Condition A states: one or more AC electrical power distribution subsystems inoperable; restore AC electrical power distribution subsystem(s) to OPERABLE status within 8 hours. Condition D states: required action and associated completion time of Condition A, B, or

C not met, be in MODE 3 within 6 hours and MODE 5 within 36 hours. Contrary to the above, the licensee failed to meet the surveillance requirement for TS 3.8.9.1. This resulted in the licensee not meeting the LCO of maintaining two trains of AC vital bus electrical power distribution subsystems available. Because this finding is of very low safety significance and has been entered into the CAP as CR 2009107823, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000348,364/2009005-03, 1-2 R Load Center Inoperability.

CR 2009113434 – Gas void in Train ‘A’ RHR supply to 2A Charging Pump

One LIV was identified and is documented in section 4OA7 of this report.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two plant modifications to ensure safety functions of important safety systems had been unaffected. Also, the inspectors verified the design bases, licensing bases and performance capability of risk-significant SSCs had not been degraded through modifications. The inspectors verified any modifications performed during increased risk-significant configurations, did not place the plant in an unsafe condition. The inspectors evaluated system operability, availability, configuration control, post-installation test activities, documentation updates and operator awareness of the modifications. Documents reviewed are listed in the Attachment.

Temporary Plant Modifications

- TM 1072688503, Disable control room annunciator for main turbine thrust bearing rear face metal temperature indicator
- TM 2080724401, installation of temporary indication of #1 Boron Recycle Holdup Tank due to calibration issues with LT 261

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the criteria contained in licensee procedure FNP-0-PMT-0.0, Post-Maintenance Test Program, to verify post-maintenance test procedures and test activities for the following six systems/components were adequate to verify system operability and functional capability. The inspectors also witnessed the test or reviewed test data to verify test results adequately demonstrated restoration of the affected safety functions. Documents reviewed are listed in the Attachment.

- FNP-0-STP-80.1, DG 1-2A Operability Test following repair of #5 cylinder fuel injector leak
- Work Order 2091575502, testing of safety-related sequencer B2G after the addition of load testing trip circuitry
- FNP-2-STP-21.3, TDAFW Steam Supply Valve HV3226 following repairs to actuator
- FNP-2-STP-124.0A, A-Train Penetration Room Filtration Performance Test following exhaust fan boot replacement
- FNP-0-EMP-1313.20, Enhanced Inspection of Cutler-Hammer 4.16kV Circuit Breakers Type MA-VR350, following replacement of Unit 2 breaker DF-13
- 2-DT-09-E21-00782, Venting of 2A Charging Pump suction to remove gas void and return pump to operable status

b. Findings

One LIV was identified and is documented in section 4OA7 of this report.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the following three surveillance tests and either observed the test or reviewed test results to verify testing adequately demonstrated equipment operability and met TS requirements. The inspectors reviewed the activities to assess preconditioning of equipment, procedure adherence and valve alignment following completion of the surveillance. The inspectors reviewed licensee procedures FNP-0-AP-24, Test Control; FNP-0-M-050, Master List of Surveillance Requirements and NMP-OS-007, Conduct of Operations and attended selected briefings to determine if procedure requirements were met. Documents reviewed are listed in the Attachment.

Containment Isolation Valve
- FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations (Pen 63)

RCS Leakage
- FNP-2-STP-9.0, RCS Leakage Test

In-Service Test (IST)
- FNP-1-STP-11.1, 1A RHR Pump Comprehensive IST & Preservice Test Appendix

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

1EP6 Drill Evaluation

a. Inspection Scope

On November 18, 2009, the inspectors observed the licensee's response to an emergency drill. The inspectors evaluated licensee performance to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspections observed emergency response operation to verify event classification and notifications were performed in accordance with FNP-0-EIP-9.0, Emergency Classification and Actions. The inspectors used procedure NMP-EP-303.0, Drill and Exercise Standards, as the inspection criteria. The inspectors also attended the licensee critique of the drill to compare any inspector-observed weaknesses with those identified by the licensee in order to verify whether the licensee was properly identifying failures.

- November 18, simulated RCS leakage continually degrading to the point that a reactor trip and safety injection actuation was required. The RHR to charging line developed a leak allowing a radioactive release, resulting in an upgrade of the emergency classification to a General Emergency.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee data for the PIs listed below to verify the accuracy of the PI data reported during the period listed. Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Rev. 5, was used to verify the basis in reporting for each data element. Documents reviewed are listed in the Attachment.

Mitigating Systems (MS) Cornerstone

- MS PI, RHR
- MS PI, High Pressure Injection

The inspectors reviewed samples of raw PI data, LERs, and Monthly Operating Reports for the period of October 2008 through September 2009. Data reviewed from LERs and Monthly Operating Reports was compared to graphical representations from the most recent PI report. The inspectors also examined a sampling of operations logs and procedures to verify the PI data was appropriately captured for inclusion into the PI report, as well as ensuring the individual PIs were calculated correctly.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Daily CR Reviews

As required by Inspection Procedure (IP) 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the NRC performed a daily screening of items entered into the licensee's CAP. This review was accomplished by reviewing hard copies of CRs, attending daily screening meetings and accessing the licensee's computerized database.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the issue listed below for a more in-depth review. The inspectors considered the following during review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of CRs and (7) completion of corrective actions in a timely manner.

- CR 2009113434, Gas void discovered in Train A RHR to 2A HHSI suction line

b. Findings

One LIV was identified and is documented in section 4OA7 of this report.

c. Observations

The inspectors' review determined the licensee was timely in entering the condition into the CAP. The inspectors determined the licensee's cause determination was adequate and included consideration of extent of condition, generic implications, common cause and previous occurrences including a similar event occurring in January, 2009. The inspectors performed an independent evaluation of operability/reportability. The inspectors discovered the condition exceeded established guidelines for gas voiding. The inspectors reviewed and questioned the licensee's evaluation of operability related to gas voiding. The licensee cited work performed by Westinghouse and a subject matter expert establishing the volume of the void could be 56 cubic feet (actual void size was approximately 13 cubic feet). The licensee also utilizes acceptance criteria established by Westinghouse based upon a continuous two percent void fraction at the suction of the HHSI pump. Also, the program allows an additional transient criterion of ten percent void fraction for five seconds. The total void volume and overall length of the void identified exceeded this criterion. The licensee's program requires further evaluation when these values are exceeded. The licensee's evaluation included review on an operability determination performed for a gas void of 3.98 cubic feet discovered in 2005 in the same location. This operability determination included information provided by Westinghouse in 1988 related to an evaluation of a gas void of 40 cubic feet. The licensee utilized this information as the basis of operability for the current gas void of 13 cubic feet. The inspectors reviewed the licensee's corrective action plans related to the identified root causes. The planned corrective actions were determined to be appropriate. The inspectors did note corrective actions completed for the January, 2009 event were similar and failed to prevent reoccurrence. The inspectors determined this event was not identified as a significant condition adverse to quality, and reoccurrence was not required to be prevented.

.3 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 CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors reviewed repetitive equipment and corrective maintenance issues and considered the results of daily inspector CAP item screening discussed above. The review also included issues documented outside the normal CAP process, including system health reports, corrective maintenance WOs, component status reports, and MR assessments. The inspectors' review nominally considered the six-month period of June 1 through December 31, 2009, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in the licensee's latest integrated quarterly assessment report. Corrective actions associated with the sample of the issues identified in the licensee's trend report were reviewed for adequacy. Documents reviewed are listed in the Attachment.

b. Assessment and Observations

No findings of significance were identified. The inspectors noticed the continuance of a negative trend in the area of procedure use and adherence. During the six month period from July 1 through December 31, 2009, the inspectors discovered the following occurrences where licensee personnel failed to accomplish steps in station procedures.

- CR 2009110308 documents an over-speed trip of the Unit 1 TDAFW pump during the performance of FNP-1-STP-22.16 on August 15, 2009. The operators failed to open steam admission valves in accordance with the station procedure. This issue is documented as a Green NCV in the third quarter 2009 integrated inspection report (NCV 05000348/2009004-02 Failure to Implement Surveillance Test Instructions to Prevent Over-Speed of the TDAFW Pump).

- CR 2009113499 documents the failure to correctly perform step 5.13 of FNP-2-UOP-1.2, Startup of Unit from Hot Standby to Minimum Load. The control room staff failed to correctly position the rod control selector switch to its “MANUAL” position and inadvertently withdrew Shutdown Bank B an additional six steps. Shutdown Bank B was originally at 226 steps and the additional six steps had minimal impact on reactivity and control of the core.

- CR 2009113619 documents failure to perform step 5.13 of FNP-1-STP-80.1, 1B D/G Operability Surveillance on November 11, 2009. The step required taking of the second watt hour meter reading and had minimal consequences on the diesel and plant.

- CR 2009113434 documents a gas void that improperly moved from the Train A RHR to 2A charging pump line during repair activities of the pump suction vent (Q2E21V923). Guidance provided in the tagout restoration was inadequate, but provided sufficient information for the operators to discover the guidance in FNP-2-SOP-2.1, Chemical and Volume Control System Plant Start up and Operation and FNP-0-ETP-4574.1, Generic Fill and Vent Guidance for Liquid-Filled Safety-Related Systems. The operators failed to properly follow guidance in the above procedure, resulting in a 13 cubic foot void in the suction piping to the 2A charging pump challenging the operability of this pump. This issue was licensee identified determined to be a violation of T.S. 5.4.1.a and is dispositioned in Section 4OA7 of this report.

The inspectors also identified a negative trend in the performance monitoring of components related to SSCs as required by 10 CFR 50.65. The inspectors have reviewed each of these issues and dispositioned the issue as required by the Reactor Oversight Process (ROP).

- CR 2009101539 documents failure to perform performance monitoring of the emergency air system which was scoped into the station MR program in 1994. The emergency air system provides a mitigating function to prevent core damage and radioactive release by providing back-up air to the Atmospheric Relief Valves and the TDAFWP steam admission valves, allowing cool down of the Reactor Coolant System (RCS). Use of the emergency air system for these purposes was directed by the emergency operating procedures. This issue was determined to be a violation of 10 CFR 50.65(a)(1) and was dispositioned in the third quarter 2009 integrated inspection report as a Green NCV 05000348,364/2009004-05, Failure to Monitor and Maintain the Capability of the Emergency Air System.

- CR 2009109700 documents abnormal noise related to operation of the 2E SWP. The licensee inspected the pump impeller area and discovered degradation of a seismic support for the pump. The licensee and inspectors discovered these seismic supports had not been inspected. The seismic supports were determined to be part of the MR function of providing a structure to house the SWPs and associated equipment. CRs 2009112212, 209112205, 2009112198, and 2009112000 documents similar degradation of seismic supports for the 2A, 2B, 2C, and 2D

SWPs. This issue was determined to be a violation of 10 CFR 50.65(a)(1) and is dispositioned in Section 4OA5 of this report as NCV 05000364/2009005-04 Failure to Implement Performance Monitoring of Service Water Pump Seismic Supports.

- CR 2009106669 documents failure to execute performance monitoring of the water-tight doors associated with both Unit 1 and Unit 2 engineered safeguards feature components. The inspectors evaluated the accessible doors in each unit to determine the integrity of these water-tight doors. Seven doors in Unit 1 and nine doors in Unit 2 were evaluated. In addition to hinge problems, the inspectors discovered two doors in Unit 1 with degraded seals (excessive hardening of the rubber seal with small chunks missing), and one door on Unit 2 in which the seal area had cracks entirely across the sealing area. This issue was determined to be a violation of 10 CFR 50.65(b), and was dispositioned in the second quarter 2009 integrated inspection report as a Green NCV 05000348,364/2009003-03 Failure to Include Water Tight Doors in the Scope of the MR.

- CR 2009103250 documents excessive leakage through piping penetration 06-100-17 in the Lower Equipment Room of Unit 2. This leakage occurred during flushing operations of the Main FW System following a main condenser tube leak. The licensee evaluated this leaking seal and determined its current monitoring program was inadequate to recognize the seal degradation. The licensee repaired the seal, and has implemented corrective actions to inspect additional piping penetration seals in the plant. The inspectors reviewed this issue and determined no equipment was made inoperable, and only a minor challenge existed to flood mitigation equipment in the plant.

4OA3 Event Follow-up

.1 (Closed) LER 05000348,364/2009-002-00: TDAFW Pump Inoperable Due to Internal Flooding Concerns

a. Inspection Scope

On March 27, 2009, the licensee performed a flushing evolution of the Unit 2 Main FW System, which involved draining of water into the MSVR critical pipe chase. A drain located at the bottom of the chase connects to the floor drain system of the Auxiliary Building Lower Equipment Room. This evolution resulted in water backing up into the Lower Equipment Room and the licensee declaring the TDAFW pumps for both units inoperable. The issue was documented in the licensee's CAP as CR 2009103286. The inspectors performed a follow-up inspection of the event to gain understanding of the conditions leading up to the event and actions taken following the event. The inspectors toured the affected areas of the plant and evaluated the condition of penetrations associated with the Lower Equipment Room and its adjacent areas. Additionally, the inspectors reviewed the root cause report to assess the detail and thoroughness of the evaluation and proposed corrective actions. A violation of regulatory requirements was identified and is documented as NCV 05000348,364/2009005-01, Failure to Identify A

Credible Source of Flooding in the Internal Flooding Evaluation of Record. See Section 1R06 for details of the violation.

During the flooding event on March 27, 2009, the licensee identified the critical pipe chase floor drain clogged, causing water to fill this area and start leaking into the 100' elevation of the Auxiliary Building above the 2A MDAFW pump room. This issue is documented in CR 2009103249, which was reviewed by the inspectors. Additionally, the licensee identified leaking pipe penetration in the upper portion of the west wall of the Lower Equipment Room. The issue was documented in the licensee's CAP as CR 2009103250.

The inspectors performed a follow-up inspection of the event to gain understanding of the conditions leading up to the event and actions taken by the licensee following the event. Additionally, the inspectors reviewed the root cause report to assess the detail and thoroughness of the evaluation and proposed corrective actions.

b. Observations

The inspectors reviewed the licensee's basic cause determination for clogging of the critical pipe chase floor drain and determined it was appropriate to the conditions identified in the licensee's CR. The licensee attributed the cause to trash in the critical pipe chase being circulated to the drain by several Tygon hoses lying in the pipe chase. The licensee removed the trash and installed a drain plug in the critical pipe chase floor drain to restore assumptions made in the licensee's internal flooding evaluations for the Lower Equipment Room. The inspectors' review of CR 2009103250 discovered the licensee attributed the cause of leaking foam pipe penetration seal to the seal being installed since plant startup in 1981, with no maintenance other than visual inspections. The licensee stated exposure to external elements over time causes foam cells to loose gas, causing the foam to relax inside the frame of the penetration. The licensee repaired the leaking seal and generated two action items (AI). The first AI was to generate a repetitive maintenance task to repair the foam seal on a 10 year frequency, scheduled for completion on February 19, 2010. The second item was to initiate, schedule, plan and track to completion, a WO to repair all foam-type water penetration seals scheduled for completion on June 25, 2010. The scope of these actions includes 105 seals on Unit 1 and 135 seals on Unit 2. These seals are in the charging pump areas, AFW pump areas, and RHR pump areas. Based upon the significance of the above safety-related components, the inspectors engaged the licensee relating to lack of interim compensatory actions. The inspectors also reviewed the licensee's CR database and did not discover evidence of other degraded seals. Based upon current information, the inspectors determined an immediate safety concern did not exist. No new additional findings were identified in the inspectors' review. This LER is closed.

.2 (Closed) LER 05000364/2009-001-00: Service Water Pump Seismic Supports Degraded

a. Inspection Scope

The inspectors monitored the licensee inspections of the seismic rings and ongoing repair activities. The inspectors reviewed work packages which installed new seismic rings and their supports. Additionally, the inspectors reviewed the root cause report to assess the detail and thoroughness of the evaluation and additional proposed corrective actions. The inspectors reviewed the licensee's MR scoping document. The inspectors reviewed additional licensee documents including work orders, interviewed station personnel and discovered a repetitive task to perform cleaning of the SWIS wet pit every three years. FNP-0-ETP-1007, SW Pit Cleanup accomplishes this task and this document was reviewed by the inspectors. The inspectors reviewed the licensee's database for other related activities and failed to discover any other monitoring the licensee performed related to the seismic supports for the SWPs in either unit. The inspectors reviewed CR 200300761, written by the licensee to track recommendations made by the licensee's diver during the wet pit cleaning activities in 2003 and the associated action items.

b. Findings

The inspectors identified a violation of significance which is documented in Section 4OA5. This LER is closed.

.3 (Closed) LER 05000348/2008-002-00: TS 3.0.3 Entry Due to Inoperability of RHR

a. Inspection Scope

On April 15, 2008 at 6:55 am, control room operators identified several Emergency Power Board alarms associated with the SWIS shared train 'B' 1-2L 600 volt load center. The licensee responded to the alarms and determined the 1-2L 600 volt load center could not maintain the minimum required TS voltage and declared the load center inoperable for both units at 8:49 am on April 15, 2008. The licensee previously removed the Unit 1 train 'A' RHR pump from service for scheduled maintenance. Because the 1-2L load center provides required support conditions for train 'B' RHR, TS 3.0.3 was entered for both trains of RHR inoperable on Unit 1. Unit 1 exited TS LCO 3.0.3 at 10:29 am when train 'A' RHR was returned to service. The licensee exited TS 3.0.3 prior to exceeding the allowed outage time. The licensee submitted LER 05000348/2008-002-00 on June 11, 2008 to report loss of RHR safety function occurring as a result of the event. The inspectors performed a follow-up inspection of the event to gain understanding of conditions leading up to the event, and actions taken by the licensee following the event. Additionally, the inspectors reviewed the apparent cause and root cause reports to assess detail and thoroughness of the evaluations and proposed corrective actions.

b. Findings

This LER is closed with one finding identified in section 1R12 of this report.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours. These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No findings of significance were identified.

.2 Resident Inspector Observation of Helium Leak Rate Testing of Holtec Multi-Purpose Canister (MPC)

a. Inspection Scope

On November 4, 2009, Holtec MPC # 41 was helium leak tested by Leak Testing Specialists, Inc. (LTS) under contract to the canister fabricator, Holtec International. LTS performed the helium leak rate testing using Procedure No. MSLT-MPC-HOLTEC, Helium Mass Spectrometer Leak Test Procedure - Hood Technique, Revision MPC-Field-LT-03.

The NRC resident inspectors observed the helium leak rate testing and verified:

- the procedure was followed,
- the Mass Spectrometer Leak Detector (MSLD) had a minimum sensitivity of 2.0E-8 atm-cc/second/division, and
- the calibrated leak standard was in the range of 1.0E-6 to 1.0E-9 atm-cc/second

The measured helium leak rate on MPC 41 was "No Detectable Leakage," which was less than the maximum allowable leak rate of 2.0E-7 atm-cc/second. No anomalies were identified.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 05000348,364/2009004-01: Failure to Implement Performance Monitoring of Service Water Pump Seismic Supports

a. Inspection Scope

During the third quarter integrated baseline inspection performed July 1 – September 30, 2009, the inspectors identified a URI related to the licensee's failure to implement performance monitoring of the SWP seismic supports. The URI was documented as 05000348,364/2009004-01 in NRC integrated inspection report 05000348,364/2009004. The item was unresolved pending further inspection and interface with the licensee to determine the extent of condition for this issue, and the degree to which the reliability of plant equipment was adversely impacted as a result of the failure to monitor the seismic supports' condition. The NRC inspectors reviewed Farley Calculation SC-2009109700-001, Seismic Evaluation of Unit 2 SW Pumps Without Seismic Support, Revision 1.0.The inspector reviewed considered the following aspects:

- Comparison between the seismic acceleration in the original design record and the more favorable seismic acceleration generated in 1995 based on the criteria from Seismic Qualification Utility Group (SQUG)
- Using 5% damping value design loads allowed by the licensee FSAR instead of the original 3% design loads
- Yield capacities of materials used to qualify for the operability analysis
- The formula used from American Society of Mechanical Engineers (ASME) code
- Computation contents and methods

b. Findings

Introduction. A Green, self-revealing NCV of 10 CFR 50.65(a)(1) was identified for failure to perform monitoring of the SWIS seismic rings resulting in degradation of 2A, 2B, 2C, and 2E SWP seismic rings ability to perform their intended function due to degradation of the seismic ring fasteners.

Description. On August 2, 2009 during a performance run of the 2E SWP, the licensee noticed abnormal noise in the wet pit area of the SWIS near the 2E SWP. At 5:20 am, the control room operators declared the pump inoperable. The licensee inspected the seismic ring remotely and determined the ring had dropped approximately 5 inches at its most remote point. The seismic ring is a hoop encircling the pump's discharge column allowing approximately 0.200 inch clearance with the discharge column. The hoop is bolted onto a bracket which is bolted to the SWIS vertical wall inside the wet pit. Divers entered the SWIS wet pit on August 14 and confirmed the indications seen on the remote camera. On August 15, the divers torqued the upper bolts of the wall bracket and replaced two bolts connecting the hoop of the seismic ring to the wall bracket. This activity restored the seismic ring to its approximate required location. The divers performed ultra-sonic measurements of the wall bracket and discovered corrosion in multiple locations. The most excessive was located in the lower right portion of the bracket and resulted in the lower right corner of the bracket, corroding so the bolt hole and corner was missing from approximately 35 percent of hole circumference. Other locations did not have sufficient corrosion to adversely affect the structural integrity of the wall bracket. The two lower bolts for the wall bracket were corroded to the point their fasteners and most of the bolt threads were missing. These bolts were not replaced. The licensee performed an immediate operability determination for the as-left condition of the seismic ring and declared the pump operable for this condition on August 15.

During the week of September 29, the licensee performed inspections of all Unit 2 SWP seismic rings. The fasteners on the 2E SWPs seismic ring were found not torqued and the ring had dropped below its previous as-left condition. The seismic ring on the 2B SWP was discovered in a similar condition to the 2E SWP seismic ring. The seismic rings on the 2A and 2C SWP were discovered in their proper location, but their fasteners were found not torqued and sufficiently loose so the licensee subsequently declared those pumps inoperable. The fasteners on the 2D SWP were discovered with less than the 150 ft-lbs of required torque, but were not sufficiently loose to render the pump inoperable. The licensee fabricated new wall brackets and seismic rings. The licensee drilled additional mounting holes in the SWIS, mounted the new seismic rings, and restored all SWP seismic rings to an operable condition.

The inspectors reviewed the licensee's MR scoping document. Function W36 states the SWIS provides a structure to house the SWP and associated equipment. This function includes reinforced concrete protecting the SWPs from missile and wind damage, and flooding. The inspectors reviewed licensee documents, interviewed station personnel and discovered a repetitive task to perform cleaning of the SWIS wet pit every three years. FNP-0-ETP-1007, SW Pit Cleanup accomplishes this task. On January 9, 2007, the above procedure was revised to perform inspection of the concrete in the SWIS wet pit which was not present in previous versions. The inspectors reviewed the licensee's database and discovered the new revision was scheduled for July 13, 2009. No evidence of inspection requirements were discovered for the seismic supports or concrete walls of the SWIS. The inspectors reviewed the licensee's database for other related activities and failed to discover any other monitoring the licensee performed related to the seismic supports for the SWPs in either unit. CR 200300761 was written by the licensee to track recommendations made by the licensee's diver during the wet pit cleaning activities in 2003. AI 2003201083 was generated from the above CR and tracked licensee activities to inspect the underwater sections of the SWIS. This AI was closed to AI 2004201531, which was closed to AI 2004204320. All three AIs were opened to track completion of the inspection of the underwater sections of the intake structure concrete. The last AI had a target date of July 1, 2009.

The licensee performed further analysis of the service water pumps and the need for seismic rings to withstand a design basis earthquake. The licensee determined the vendor had utilized more conservative values for the seismic activity. The licensee refined these values and performed additional analysis related to stresses of the Sulzer SW pumps. The licensee determined from this analysis the pump would not have been adversely affected by the seismic activity and thus the pumps would have remained operable. NRC inspectors reviewed Farley Calculation SC-2009109700-001, Seismic Evaluation of Unit 2 SW Pumps Without Seismic Support, Revision 1.0.
The inspector verified the accuracy of the computation, corrected formula and material yield capacities used from the ASME code, and the seismic acceleration correctly

selected from SQUG seismic qualification record. The inspector also performed an independent calculation of the axial stress generated from the bending moments to verify that the calculation was acceptable. The inspector determined that the calculation was adequate and that the service water pumps were operable; however, the seismic rings degradation could have impacted the reliability of the system.

Analysis. The failure to perform monitoring of the SWIS seismic rings resulting in the degradation of the 2A, 2B, 2C, and 2E SWIS seismic rings is a performance deficiency. This finding was more than minor because it adversely affected the equipment reliability attribute of the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the degraded seismic rings initially challenged operability of the SW pumps, further evaluation of operability was required. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined to be of very low safety significance because although the seismic rings were degraded the safety function of the service water pump was determined to not be impacted. The finding is associated with a cross-cutting aspect in the CAP component for the Problem Identification and Resolution (PI&R) area in that the licensee did not complete actions identified in the corrective action program which included inspections of wet pit fasteners.(P.1(d)).

Enforcement. 10 CFR 50.65(a)(1) states in part that each licensee shall monitor the condition of SSCs, against licensee-established goals, in a manner sufficient to provide reasonable assurance that these SSCs are capable of fulfilling their intended function. Contrary to the above, the inspectors determined the licensee had not established goals and were not monitoring the condition of the SWIS seismic supports in a manner sufficient to provide reasonable assurance that these supports for Unit 1 and Unit 2 SWPs were capable of fulfilling their intended function. The inspectors learned the seismic supports of the 2A, 2B, 2C, and 2E SWPs had degraded sufficiently to result in the licensee initially declaring the pumps inoperable and performing additional analysis. Because this finding is of very low safety significance and has been entered into the CAP as CR 2009109700, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000364/2009005-04 Failure to Implement Performance Monitoring of SWP Seismic Support.

.4 (Closed) URI 05000348,364/2009004-03: Load Sequencer Operability during EDG Surveillance Tests

a. Inspection Scope

During the third quarter integrated baseline inspection performed July 1 – September 30, 2009, the inspectors identified a URI related to the licensee's failure to translate EDG system design into surveillance test procedures rendering LOSP load sequencers inoperable during performance of those tests. The URI was documented as 05000348,364/2009004-03 in NRC integrated inspection report 05000348,364/2009004. The item was unresolved pending further inspection and interface with the licensee to determine if evaluations were completed by the licensee prior to scheduling and performing surveillance tests during modes of plant operation requiring the EDGs and emergency load sequencers to be operable.

b. Findings

Introduction. The NRC identified a Green NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, for failure to translate EDG system design into surveillance test procedures rendering LOSP emergency load sequencers inoperable during the performance of those tests.

Description. On May 16, 2008, the licensee completed a review of an engineering judgement regarding the operation of the LOSP circuits with a DG operating in the test mode. The engineering review was being performed in response to industry operating experience (OE), which identified issues where a diesel undergoing surveillance testing would not respond as desired during an LOSP event. As a result of that analysis, the licensee concluded during a LOSP event, while the diesel is in test mode and paralleled with offsite power (such that the LOSP relays actuate prior to the degraded grid or under-frequency relays), a LOSP load shed would occur and the diesel would remain running with its output breaker closed onto the bus. However, the automatic load sequencer would not start safety-related loads because the logic of LOSP circuit verifies the diesel output breaker is open prior to allowing the load start sequence. For the condition identified above, the diesel would remain running and connected to the bus without emergency loads energized because the sequencer would not load the diesel. The licensee concluded this condition applied to the B1F, B2F, B1G, and B2G LOSP sequencers (associated with the 1-2A, 1B, and 2B EDGs).

In response to the engineering analysis, the licensee entered CR 2008105195 into the CAP on May 24, 2008 and began declaring the EDGs inoperable while applying the 10 day completion time of condition B for TS 3.8.1, AC Sources – Operating, when the diesels were paralleled with the offsite power source during surveillance tests. The NRC inspectors reviewed licensee actions in response to CR 2008105195 and the requirements of TS 3.8.1. The inspectors concluded the licensee identified a condition in which surveillance requirements for the affected load sequencers would not be satisfied in response to a design basis LOSP event. Therefore, the inspectors concluded the 12 hour restoration time for an inoperable automatic load sequencer as specified in condition G of TS 3.8.1 should be applied. The inspectors also concluded previous performances of 24 hour EDG endurance surveillance runs exceeded the TS allowed outage time for an inoperable load sequencer (including the required action to place the unit in Mode 3 within six hours as specified by condition H of TS 3.8.1). As a result of the inspectors' concerns regarding application of TS 3.8.1 condition G restoration time for an inoperable sequencer, the licensee deferred future performance of 24 hour EDG surveillance tests pending implementation of a design change in the EDG LOSP circuit allowing emergency loads to auto-start.

The inspectors reviewed the licensee's CAP to assess the licensee's evaluation of OE related to issues associated with EDGs not responding as expected to an LOSP event during the performance of surveillance tests. The inspectors identified two documents, CR 2006100701 and AI 2007203472, entered into the licensee's CAP on November 14, 2006 and August 7, 2007 respectively. The CAP documents were written to evaluate applicability of OE related to non-essential trips of EDGs that would not be bypassed should an LOSP event occur during EDG surveillance tests. The licensee's evaluations ultimately concluded the conditions described in the OE were not applicable to Farley Nuclear Plant and no further actions were required. The inspectors concluded the evaluations performed by the licensee prior to the May 2008 engineering analysis did not result in a detailed design basis review of how the EDGs would respond to an LOSP event during a surveillance test. The inspectors determined these evaluations were missed opportunities to discover the LOSP emergency load sequencers would not respond as expected to auto-start emergency loads for a design basis event during surveillance testing of the EDGs.

The inspectors did not identify an immediate safety concern for this finding, following the May 2008 engineering evaluation, because the licensee had taken actions to modify surveillance test procedures providing guidance for the operators to mitigate an LOSP condition during surveillance tests of the EDGs. In addition, the licensee deferred 24 hour EDG surveillance tests exceeding the allowed outage time for an inoperable load sequencer pending implementation of a design change in the EDG LOSP circuit allowing emergency loads to auto-start in response to an LOSP event during surveillance tests.

Analysis. The failure to translate system design into procedures and instructions for performing EDG surveillance tests that rendered the LOSP emergency load sequencers inoperable was a performance deficiency. This performance deficiency was more than minor because required surveillance test procedures did not alert operators to the fact that the performance of those tests rendered the LOSP load sequencers inoperable and tests were performed that exceeded the allowed outage time for an inoperable sequencer. Significance Determination Process (SDP) phase 1 screening determined that core decay heat removal was affected within the mitigating systems cornerstone when the performance deficiency represented loss of a train of a safety function for greater than its technical specification allowed outage time. A phase 3 SDP was required because the phase 2 worksheets do not provide detail below the EDG level. The phase 3 analysis was performed by a SRA in accordance with NRC Inspection Manual Chapter 0609 Appendix A utilizing data from the licensee's full scope model. Only the sequencers for EDG 1/2A, EDG 1B, and EDG2B were affected. The phase 3 result was <1E-6 for CDF and did not involve steam generator tube rupture or intersystem loss of coolant accident (LOCA) sequences and therefore was not a significant large early release frequency (LERF) risk contributor. The dominant sequences involved an LOSP with a failure of the LOSP sequencer while an EDG was in surveillance paralleled with the grid, failure of the operator to load the EDG, combined with failure of the opposite train EDG. With no emergency or offsite power provided, no RCP seal makeup, RCP seal cooling or service water would be available and a seal LOCA would result in core damage. No recovery credit was assumed in the analysis although the EDG themselves and the switchgear to the safety equipment would not have been affected. Factors which reduced the risk included the low exposure time and the availability of other mitigating equipment. The EDGs themselves would not be affected by the performance deficiency only the automatic loading subsequent to an LOSP. The ESF sequencers were not affected by the performance deficiency. The SDP result was Green, a finding of very low safety significance.

The inspectors evaluated the finding for a cross-cutting aspect and concluded although the licensee had opportunities prior to the May, 2008 engineering analysis to recognize the need to perform an evaluation of EDG system design; those opportunities were not recent enough to be indicative of current licensee performance. Additionally, the inspectors concluded previous OE evaluated by the licensee was not specific to the Farley EDG design issue ultimately identified. No cross-cutting aspect was assigned to this finding.

Enforcement. 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that design control measures shall be established to assure system design is correctly translated into station procedures and instructions. Contrary to the above, the NRC determined the licensee failed to implement design control measures to translate EDG system design into surveillance test procedures rendering the LOSP emergency load sequencers inoperable. As a result of the failure to correctly translate EDG system design into surveillance test procedures, the licensee performed 24 hour surveillance tests of the EDGs prior to May 16, 2008, rendering the LOSP load sequencers inoperable for a period of time 12 hours greater than the restoration time allowed by plant TS for each performance of that test. Because this failure to properly implement surveillance procedure test instructions has been entered into the CAP as CR 2008105195, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000348,364/2009005-05 Load Sequencer Operability during EDG Surveillance Tests.

4OA7 Licensee Identified Violations

The following violations of very low safety significance were identified by the licensee and are violations of NRC requirements, which meet the criteria of Section VI.A.1 of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, requires in part that conditions adverse to quality are promptly identified and corrected. Contrary to the above, the licensee identified steam leaks in the vicinity of the ‘C’ SG steam supply valve (Q1N12HV3235B) to the Unit 1 TDAFW pump as early as November 17, 2007 and did not take prompt corrective actions to repair the leaks. As a result of the failure to implement corrective actions to repair the steam leaks, the o-ring for the air accumulator associated with Q1N12HV3235B was subjected to a high temperature environment and degraded to the point that the valve was declared inoperable when it failed to meet surveillance test acceptance criteria on March 27, 2009. This issue was identified in the licensee’s CAP as CR 2009103283. Following the failure of Q1N12HV3235B on March 27, 2009, the licensee completed repairs to the previously identified steam leaks and the failed actuator o-ring. Q1N12HV3235B was retested satisfactorily and returned to service on April 30, 2009. This finding was assessed using IMC 0609, SDP, Phase 1 screening worksheet for the mitigating systems cornerstone column and determined to require a Phase 2 analysis because the finding represented the loss of safety function of a single steam supply to the TDAFW pump for greater than the allowed TS outage time of seven days as given by condition ‘A’ of TS 3.7.5, AFW System. A Regional Senior Reactor Analyst performed a Phase 3 evaluation under the Significance Determination Process and determined that the finding was of very low safety significance (Green). The exposure time for the analysis was 268 days. The analysis assumed the Turbine Driven Auxiliary Feedwater Pump failed but, could be easily recovered. The dominant accident sequence was a dual unit Loss of Offsite Power with loss of the Emergency Diesel Generators. The Turbine Driven Auxiliary Feedwater Pump would continue to operate but, due to the performance deficiency and an independent failure of the other steam supply to the turbine portion of the pump, it failed. Neither offsite power nor an Emergency Diesel Generator was recovered in two 2 hours which led to core damage.

- TS 5.4.1.a, requires written procedures be established, implemented, and maintained covering the activities in Regulatory Guide 1.33 Revision 2, Appendix A. Appendix A, Section 9 states in part, maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriated to the circumstances. Contrary to the above, the licensee failed to properly vent and refill the Unit 2 RHR to the charging line (piggy-back line), resulting in a gas void in excess of calculated values for that portion of piping and rendered the 2A charging pump inoperable. The ECCS system was returned to service, TS 3.5.2 exited, and the gas void was later discovered. The control room staff re-entered TS 3.5.2. The piggy-back line was properly filled and vented (vacuum refill method). At this time, the licensee had been in TS 3.5.2 for 79 hours and 17 minutes elapsed (which was 1 hour and 17 minutes into the requirement to enter MODE 4). This issue was identified in the licensee's CAP as CR 2009113434. This finding was assessed using IMC 0609, SDP, Phase 1 screening worksheet for the mitigating systems cornerstone column and determined to require a Phase 2 analysis because the finding represented the loss of safety function of a single train for greater than its allowed T.S. outage time. A Regional Senior Reactor Analyst performed a Phase 3 evaluation under the Significance Determination Process and determined that the finding was of very low safety significance (Green). The exposure time was 79 hours and 17 minutes. The analysis assumed that Emergency Core Cooling Piggyback Valve, 8706A, function to open failed as the surrogate for the performance deficiency. This function was not recoverable in the analysis. The dominant accident sequence was Main Steam Line Break downstream of the Main Steam Isolation Valves followed by operators failing to terminate Safety Injection. Then, when operators transferred to Emergency Core Cooling recirculation, one train of Low Pressure Injection was in maintenance and the other train failed due to the performance deficiency. Without core cooling, core damage would have occurred.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
K. Armstrong, Emergency Preparedness Supervisor
C. Collins, Plant Manager
B. Griner, Engineering Support Manager
P. Hayes, Engineering Director
L. Hogg, Security Manager
J. Horn, Site Support Manager
J.R. Johnson, Site Vice President
T. Livingston, Chemistry Manager
H. Mahan, Licensing Engineer
R. Martin, Technical Services Manager
B.D. McKinney, Licensing Supervisor
C. Medlock, Site Design Manager
W. Oldfield, Fleet Oversight Supervisor
C. Peters, HP Manager
R. Wells, Outage and Scheduling Manager

NRC personnel
S. Shaeffer, Chief, Branch 2, Division of Reactor Projects
E. Crowe, Senior Resident Inspector
W. Rogers, Senior Reactor Analysts
G. MacDonald, Senior Reactor Analysts

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened

None

Opened and Closed

05000348,364/2009005-01	NCV	Failure to Identify A Credible Source of Flooding in the Internal Flooding Evaluation of Record (Section 1R06)
05000348,364/2009005-02	NCV	Failure to Implement Maintenance Inspections of Safety-Related Switchgear (Section 1R12)
05000348,364/2009005-03	NCV	1-2 R Load Center Inoperability (Section 1R15)
05000364/2009005-04	NCV	Failure to Implement Performance Monitoring of Service Water Pump Seismic Supports (Section 4OA5.3)
05000348,364/2009005-05	NCV	Load Sequencer Operability during EDG Surveillance Tests (Section 4OA5.4)

Closed

05000348/2009-002-00	LER	Turbine Driven AFW Pump Inoperable Due to Internal Flooding Concerns (Section 4OA3.1)
05000364/2009-001-00	LER	Service Water Pump Seismic Supports Degraded (Section 4OA3.2)
05000348/2008-002-00	LER	TS 3.0.3 Entry Due to Inoperability of RHR (Section 4OA3.3)
05000348,364/2009004-01	URI	Failure to Implement Performance Monitoring of Service Water Pump Seismic Supports (Section 4OA5.3)
05000348,364/2009004-03	URI	Load Sequencer Operability during EDG Surveillance Tests (Section 4OA5.4)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures:
FNP-0-AOP-21.0, Severe Weather, Version 27

Section 1R04: Equipment Alignment

Condition Reports:
2009113434

Documents:
A-181001, Functional System Description Station Service Water, Version 53.0
A-181009, Functional System Description Chemical Volume and Control System, High Head Safety Injection, Accumulators, and Reactor Water Systems, Version 32.0

Drawings:
D-175039, Sheet 1, Version 24.0
D-175039, Sheet 6, Version 8.0
D-200013, Sheet 2, Version 22.0

<u>Section 1R05: Fire Protection</u>

<u>Drawings:</u>
A-509018, Sheet 12, Version 2.0
A-509018, Sheet 14, Version 2.0
A-509018, Sheet 35, Version 1.0

<u>Procedures</u>:
FNP-0-AP-36.0, Fire Surveillance and Inspection, Version 19.0
FNP-0-AP-38.0, Use of Open Flame, Version 16.0
FNP-0-AP-39.0, Fire Patrols and Watches, Version 16.0

<u>Section 1R06: Internal Flood Protection</u>

<u>Action Item</u>:
209206435

<u>Condition Reports</u>:
2009103286, 2009103249, 2009103250, 2009114086, 2009114087

<u>Documents</u>:
BM-99-1932-001, Internal Flooding Assessment

<u>Procedures</u>:
FNP-0-EMP-1370.02, Installation and Repair of Penetration or Conduit Seals, Version 15.0
FNP-2-FSP-39.0, Visual Inspection of Penetrations (Non Fire Barrier), Version 18.0

<u>Work Orders</u>:
S062425201, S063505701, 1070945601, 1090983501, 1091634701, 2063398301, 2090980901, 2090981201, 2090982601, 2090983401, 2091635101

<u>Section 1R11: Licensed Operator Requalification</u>

<u>Documents</u>:
Licensed Operator Continuing Training Simulator Exercise Guide, OPS-56400A LOCT 08-10 Cycle 8, High Intensity Training, 09-S807, dated August 25, 2009

<u>Procedures</u>:
FNP-1-AOP-9.0, Loss of Component Cooling Water, Version 22.0
FNP-1-AOP-16.0, CVCS Malfunction, Version 14.0
FNP-1-AOP-100.0, Instrumentation Malfunction, Version 9.0
FNP-1-ARP-1.4, Main Control Board Annunciator Panel D, Version 48.0
FNP-1-ARP-1.5, Main Control Board Annunciator Panel E, Version 52.0
FNP-1-ARP-1.8, Main Control Board Annunciator Panel H, Version 33.0

Section 1R12: Maintenance Rule Effectiveness

Action Items:
2008203462, 2008203463, 2008203464, 2008203465, 2008203466, 2008203467, 2008203468, 2008203469, 2008203483, 2008206714, 2008206715, 2008206716, 2008206717, 2008206718, 2008206719, 2008206720, 2008206721, 2008206722, 2008206723, 2008206724, 2008206725, 2008206726, 2008206727, 2008206728, 2008206729, 2008206730, 2008206731, 2008206732, 2008206733, 2008206734, 2008206735, 2008206742, 2008206743, 2008206744, 2008206745, 2008206746, 2008206747, 2008206748, 2009200879, 2009200881, 2009200882, 2009204227, 2009204228, 2009204229, 2009204230, 2009204231, 2009204232, 2009204233, 2009204234, 2009204649

Condition Reports:
2008103720, 2008103741, 2008103905, 2008104055, 2008104119, 2007111882, 2006104174, 2007107575, 2007111134, 2007111785, 2007111980, 2008106504, 2009103283, 2009103380, 2009104820, 2009105901, 2008109838

Documents:
Root Cause Investigation for CR 2008103720, 1-2L 600V Load Center Bus Bar Failure, dated October 17, 2008
Apparent Cause Determination for CR 2009103283, Q1N12HV3235B Accumulator Air Leak, dated June 25, 2009
Apparent Cause Grading Sheet, CR 2009103283, dated September 3, 2009
Selected Unit 1 Control Room Logs, dated April 15, 2008
Selected Unit 1 Control Room Logs, dated March 27 through March 30, 2009
Unit 1 Licensee Event Report 2008-002-00, TS 3.0.3 Entry Due to Inoperability of Residual Heat Removal System, dated June 11, 2008
A506250, Unit 1 Electrical Load List, Version 55.0
A351199, Unit 2 Electrical Load List, Version 50.0

Procedures:
FNP-0-MP-18.3, Kerotest Check Valves Inspection and Rework, Version 1.0
FNP-1-STP-22.20, TDAFW Pump Steam Admission Valves Air Accumulator Test, Version 11.0
FNP-0-IMP-213.02, Cowan Actuator Maintenance Instructions for the Unit 1/Unit 2 Steam Supply Valves to TDAFWP, Version 4.0
FNP-1-STP-21.3, TDAFWP Steam Supply Valves Valve Inservice Test, Version 18.0
FNP-1-STP-22.16, Turbine Driven Auxiliary Feedwater Pump Quarterly Inservice Test (TAVG $\geq$ 547degF) with Preservice Test Appendix, Version 46.0

Work Orders:
1072825201, 1072825202, 1072060401, 1072651901, 1072818001, 1072832201, 1090984001, 1091291401, 1081381701, 1060362201, 1070669701, 1090984301, 1072853501, 1071995301, 1090989801

Section 1R15: Operability Evaluations

Condition Reports:
2009113132, 2009101841, 2009103127, 2009103649, 2009113434, 2009114181

Procedures:
FNP-2-STP-17.0, Containment Cooling System Train A(B) Operability Test, Version 15.0

Work Orders:
2091312801, S090430201

Section 1R18: Plant Modifications

Condition Report:
2008112893

Procedures:
FNP-0-AP-8, Design Modification Control, Version 45.0

Work Orders:
1072688502, 1072688503, 2080724401, 2080724402

Section 1R19: Post Maintenance Testing

Condition Report:
2006110087, 2008113270, 2009100230, 2009106820, 2009110775, 2009111301, 2009112506, 2009111254, 2009113434

Documents:
DCP 2091575501, Diesel Generator 2B Load Test Trip Circuitry From Loss of Offsite Power Sequencer B2G
2-DT-09-E21-00274, 2A Charging Suction Line Vent (tagout)
2-DT-09-E21-00782, 2A Charging Suction Line Vent (tagout)

Drawings:
D-204616, Sheet 1, Version 19.0
E-133337, Sheet 6, Version A8
E-133337, Sheet 7, Version A12

Procedures:
FNP-0-EMP-1549.03, Agastat Series ETR Time Delay Relay Testing and Replacement, Version 9.0
FNP-0-EMP-1313.19, Inspection and Adjustment of Cutler-Hammer 4.16kV Circuit Breakers Type MA-VR350, Version 12.0
FNP-0-EMP-1313.20, Enhanced Inspection of Cutler-Hammer 4.16kV Circuit Breakers Type MA-VR350, Version 12.0
FNP-0-ETP-4574.0, Gas Accumulation Monitoring and Trending, Version 5.0
FNP-0-ETP-4574.1, Generic Fill and Vent Guidance for Liquid-Filled Safety Related Systems, version 1.0
FNP-0-IMP-400.9, Air Operated Valve and Dampers Testing, Version 14.0
FNP-0-STP-80.1, Diesel Generator 1-2A Operability Test, Version 55.0
FNP-2-PMP-1298, Functional Test From DG 2B Breaker Load Trip Circuitry From LOSP Sequencer B2G, Version 1.0

FNP-2-SOP-2.1, Chemical and Volume Control System Plant Startup and Operation, Version 105.0
FNP-2-STP-21.3, TDAFW Steam Supply Valves Valve Inservice Test, Version 19.0
FNP-2-STP-124.0A, A-Train Penetration Room Filtration Performance Test, Version 10.0
NMP-OS-007-002, Generic Fill and Bent Guidance for ECCS, RCIC, and CS Systems, Version 3.0
Work Orders:
2080765501, 2082348301, 2091575502, 2091575510, 2092556701, 2092570201, S090719601, S09231801, 2063218201, 2092364801, 2090977701

Section 1R22: Surveillance Testing

Condition Reports:
2009104034

Documents:
FNP-2-STP-9.0, RCS Leakage Test, Version 44.0, Surveillance Test Record, performed September 23, 2009

Procedures:
FNP-0-MP-18.3, Kerotest Check Valves Inspection and Rework, Version 1.0
FNP-1-STP-11.1, 1A RHR pump Comprehensive Inservice Test & Preservice Test Appendix, Version 54.0
FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations, Version 40.0
FNP-2-STP-9.0, RCS Leakage Test, Version 44.0

Work Orders:
1080391801, 1072672001, 1070743501

Section 1EP6: Drill Evaluation

Procedures:
FNP-0-EIP-9.0, Emergency Actions, Version 60.0
NMP-EP-303, Drill and Exercise Standards, Version 1.0

Section 4OA1: Performance Indicator Verification 71151

Condition Reports:
2008100818, 2007110854, 2007110411, 2009100772, 2007110411

Procedures
FNP-0-AP-54, Preparation and Reporting of NRC PI Data and NRC Operating Data, Rev. 12
FNP-0-SYP-25.0, Mitigating System Performance Index Desktop Guide, Version 2.0

Documents:
Farley Unit 1 and Unit 2 Consolidated Data Entry Unavailability and Unreliability Derivation Reports for Residual Heat removal Systems

Farley Unit 1 and Unit 2 Consolidated Data Entry Unavailability and Unreliability Derivation Reports for High Pressure Injection Systems
Selected Unit 1 and Unit 2 Control Room Logs from October 2008 through September 2009

Section 4OA5: Other

Documents:
Calculation SC-2009109700-001, Seismic Evaluation of Unit 2 SW Pumps Without Seismic Support, Revision 1.0.
Southern Company Services, Inc., Seismic Response Spectra for J.M. Farley Nuclear Plant – Units 1 and 2, Revision 0, Dated 4/1/1987
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