UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

October 28, 2011

Mr. T. Preston Gillespie, Jr.
Site Vice President
Duke Energy Carolinas, LLC
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000269/2011004, 05000270/2011004, 05000287/2011004 AND EMERGENCY PREPAREDNESS INSPECTION REPORT 05000269/2011501, 05000270/2011501, 05000287/2011501

Dear Mr. Gillespie:

On September 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oconee Nuclear Station Units 1, 2, and 3. The enclosed inspection report documents the inspection results which were discussed on October 13, 2011, with you and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents three findings of very low safety significance (Green) which were determined to be violations of NRC requirements. Additionally, three licensee-identified violations, which were determined to be of very low safety significance, are listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest these NCVs, 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 20555-001; 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 Oconee. 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 Oconee.

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 NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Jonathan H. Bartley, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-269, 50-270, 50-287, 72-04
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Integrated Inspection Report 05000269/2011004, 05000270/2011004, 05000287/2011004 and Emergency Preparedness Inspection Report 05000269/2011501, 05000270/2011501, 05000287/2011501
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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ADAMS: ☐ Yes ACCESSION NUMBER: ML113010411 X SUNSI REVIEW COMPLETE

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Letter to T. Preston Gillespie, Jr., from Jonathan H. Bartley dated October 28, 2011

SUBJECT: OCONEE NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000269/2011004, 05000270/2011004, 05000287/2011004 AND EMERGENCY PREPAREDNESS INSPECTION REPORT 05000269/2011501, 05000270/2011501, 05000287/2011501

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-269, 50-270, 50-287, 72-40
License Nos.:	DPR-38, DPR-47, DPR-55
Report Nos.:	05000269/2011004, 05000270/2011004, 05000287/2011004 05000269/2011501, 05000270/2011501, 05000287/2011501
Licensee:	Duke Energy Carolinas, LLC
Facility:	Oconee Nuclear Station, Units 1, 2 and 3
Location:	Seneca, SC 29672
Dates:	July 1, 2011, through September 30, 2011
Inspectors:	A. Sabisch, Senior Resident Inspector G. Ottenberg, Resident Inspector K. Ellis, Resident Inspector J. Hamman, Resident Inspector R. Russell, Emergency Preparedness Inspector (Sections 1EP2, 1EP3, 1EP4, 1EP5, 4OA1)
Approved by:	Jonathan H. Bartley, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000269/2011-004, 05000270/2011-004, 05000287/2011-004; 07/01/2011 – 09/30/2011; Oconee Nuclear Station Units 1, 2 and 3; Operability Evaluations, Plant Modifications, Post-Maintenance Testing IR 05000269/2011-501, 05000270/2011-501, 05000287/2011-501, 08/22/2011 – 08/26/2011; Oconee Nuclear Station Units 1, 2 and 3; Routine Inspection Report

The report covered a three-month inspection period by the resident inspectors and a one-week inspection period by an emergency preparedness inspector. Three Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Cross-cutting aspects are determined using IMC 0310, "Components Within The Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Mitigating Systems Cornerstone

- Green. An NRC-identified non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, was identified when the licensee failed to follow NSD 220, Updated Final Safety Analysis Report (UFSAR) Revision Process, and processed a technical change to the UFSAR as a non-technical change. The licensee retracted the UFSAR change and intends to submit a License Amendment Request to correct the discrepancy between the facility and the UFSAR.

  The failure to follow NSD 220 was a performance deficiency (PD). This PD was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective in that the licensee used the non-technical editorial change process to modify the qualification of equipment relied upon to mitigate a seismic-induced turbine building flood when a license amendment was required. The inspectors used IMC 0609, Attachment 4, Phase 1 – Initial Screening and Characterization of Findings, and determined the finding was of very low safety significance (Green) because the finding did not result in loss of operability or functionality. The PD directly involved the cross-cutting aspect of using conservative assumptions in decision making in the Decision-Making component of the Human Performance cross-cutting area in that the licensee relied on insufficient information to process a UFSAR change as a non-technical change. [H.1(b)] (Section 1R19)

Barrier Integrity Cornerstone

- Green. An NRC-identified non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for the licensee's failure to promptly identify and correct a condition adverse to quality. The licensee failed to identify and correct a degraded condition associated with containment isolation valves 1HP-5, 2HP-5 and 3HP-5 following the identification of a degraded condition on valve 1HP-5. The licensee restored closing margin to the Unit 1 valve during its refueling outage which began April 2, 2011, by installing a permanent modification on the valve actuator. An interim modification was installed on June 11, 2011, for Unit 2, and on June 10, 2011, for Unit 3 to restore closing margin to those valves.

The licensee's failure to promptly identify the degraded condition of 2HP-5 and 3HP-5 and adequately correct the condition on 1HP-5 as required by 10 CFR 50, Appendix B, Criterion XVI, was a performance deficiency (PD). The PD was more than minor because it was associated with the Barrier Integrity cornerstone attribute of Design Control and adversely impacted the cornerstone objective because the degraded condition had the potential to result in a containment bypass pathway. The inspectors determined a Phase 3 analysis was required because the finding represented a potential containment bypass pathway that would not be isolable following certain events analyzed in Chapter 15 of the Updated Final Safety Analysis Report. A Phase 3 analysis was performed by a regional Senior Reactor Analyst (SRA) who determined that the finding was of very low safety significance (Green) because the line break Large Early Release Frequency (LERF), and the Station Blackout (SBO)/Standby Shutdown Facility (SSF) core damage frequency (CDF) results were less than $1X10^{-6}$. The finding directly involved the cross-cutting area of Human Performance under the Conservative Assumptions and Safe Actions aspect of the Decision Making component, in that the licensee failed to demonstrate conservative decision making in their evaluation of the operability of the Units 1, 2, and 3 letdown line containment isolation valves. [H.1(b)] (Section 1R15)

- <u>Green</u>. A self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified when the licensee failed to follow their modification process. The licensee did not verify the valve actuator margin to be greater than the margin specified in procedure EDM 601, Engineering Change Manual, following internal changes to the reactor coolant system (RCS) letdown line outboard containment isolation valves (CIVs) on all three units. As a result, the CIVs would not have fully closed as required against all postulated differential pressures (dPs) for events defined in Chapter 15 of the Updated Final Safety Analysis Report. The licensee entered this issue into their Corrective Action Program (CAP) as Problem Investigation Program report (PIP) O-11-0218.

  The licensee's failure to implement the modification process was a performance deficiency (PD). The PD was determined to be more than minor because it was associated with the Barrier Integrity cornerstone attribute of Design Control and adversely impacted the cornerstone objective in that the RCS letdown line outboard CIVs could not perform their design function to fully close during all postulated events. The inspectors determined that a Phase 3 analysis was required. A Phase 3 was performed by a regional SRA who determined this finding was of very low safety significance (Green) because the line break Large Early Release Frequency, and the Station Blackout/Standby Shutdown Facility core damage frequency results were less than $1X10^{-6}$. No cross cutting aspects were identified based on the issue not being indicative of current licensee performance. (Section 1R18)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at approximately 100 percent rated thermal power (RTP) where it remained for the rest of the inspection period.

Unit 2 began the inspection period at approximately 100 percent RTP where it remained for the rest of the inspection period.

Unit 3 began the inspection period at approximately 100 percent RTP where it remained for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

External Flooding Protection: The inspectors conducted a walkdown of the exterior walls of the Unit 1 and 2 auxiliary building (AB) including the cask decontamination tank rooms for potential water intrusion into the AB through the borated water storage tank (BWST) piping trenches following a period of rain to ensure adequate measures or design features were in place to prevent water from entering the building and impacting plant equipment. The inspectors reviewed the actions being taken to meet administrative requirements while a passive civil design feature was taken out-of-service. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial Walkdown: The inspectors performed the three partial walkdowns listed below to assess the operability of redundant or diverse trains and components when safety-related equipment was inoperable or out-of-service and to identify any discrepancies that could impact the function of the system potentially increasing overall risk. The inspectors reviewed applicable operating procedures and walked down system components, selected breakers, valves, and support equipment to determine if they were correctly aligned to support system operation. The inspectors reviewed protected equipment sheets, maintenance plans, and system drawings to determine if the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP. Documents reviewed are listed in the Attachment.

- 3B reactor building spray (RBS) train and 3A, 3B, and 3C reactor building cooling units during 3A RBS train maintenance
- Verification of compensatory measures during the period the SSF was declared inoperable as a result of the SSF pressurizer heater breaker issue
- Walkdown of protected equipment associated with the SSF while the SSF was inoperable during the annual SSF maintenance outage

b. Findings

No findings were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Area Tours: The inspectors walked down accessible portions of the five plant areas listed below to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. The inspectors observed the fire protection suppression and detection equipment to determine if any conditions or deficiencies existed which could impair the operability of that equipment. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis probabilistic risk assessment and sensitivity studies for fire-related core damage accident sequences. Documents reviewed are listed in the Attachment.

- Equipment room, Unit 1, 2 and 3
- Turbine building operating decks, Unit 1, 2 and 3
- Unit 3 penetration rooms, East and West
- Unit 1 / Unit 2 low pressure injection (LPI) and RBS pump rooms
- SSF

Fire Drill Observation: Inspectors observed two unannounced fire drills to verify the fire brigade's use of protective gear and firefighting equipment; that fire fighting pre-plan procedures and appropriate fire fighting techniques were used; and that the directions of the fire brigade leader were thorough, clear, and effective. The inspectors observed the control room crew's response to the report of the fire and the resulting emergency declaration. The inspectors also reviewed the post-drill critique to assess if it was appropriately critical, included discussions of drill observations, and identified any areas requiring corrective action. Documents reviewed are listed in the Attachment.

- On August 30, 2011, a shift fire drill simulating a fire at the hydrogen purifier in the turbine building which affected safety-related cabling on the Unit 1 TD switchgear resulting in the declaration of an Alert
- On September 9, 2011, a shift fire drill simulating a fire at the hydrogen purifier in the turbine building which did not affect any safety-related equipment resulting in the declaration of a Notice of Unusual Event

b. Findings

No findings were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Submerged or Buried Cable Inspection: The inspectors inspected the condition of the following two cable trenches through direct observation. The inspectors verified the trenches contained no standing water and that the cables were intact and in good condition.

- SSF cable trench (inspected during cable separation inspections)
- Radwaste cable and piping trench

b. Findings

No findings were identified.

1R07 Heat Sink Performance

a. Inspection Scope

Annual Resident Review: The inspectors observed the performance of flow testing for the Unit 1 high pressure injection (HPI) A, B, and C pump motor oil coolers to verify the coolers had not unacceptably degraded and observed the coolers during the test to look for any leakage. The test acceptance criteria were compared to established calculations to determine if the criteria were appropriate. The inspectors compared the results of the performed test to previous results to determine if there were any negative trends in cooler performance. The inspectors also verified the licensee was using the cooler testing method outlined in applicable guidance documents as committed to in response to Generic Letter 89-13. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed one active simulator examination to assess the performance of licensed operators during a simulator training session. The scenario included unit runbacks due to a dropped control rod and a main feedwater (MFW) pump trip and entries into AP-01, Unit Runback. Following the runbacks, a trip of the other MFW pump occurred followed by a main steam line break inside containment. The 1B Low Pressure Injection (LPI) pump also failed to start as required during the engineered safeguards actuation as a result of the main steam line break. The inspection focused on high-risk operator actions performed during implementation of the abnormal and emergency operating procedures and the incorporation of lessons learned from previous plant and industry events. The classification and declaration of the Emergency Plan by the Operations Shift Manager was also observed. The post-scenario critique conducted by the training instructor and the crew was observed. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee’s effectiveness in performing the following three corrective maintenance activities. These reviews included an assessment of the licensee’s practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations. For each activity selected, the inspectors performed a detailed review of the problem history and surrounding circumstances, evaluated the extent of condition reviews as required, and reviewed the generic implications of the equipment and/or work practice problem. For those structures, systems and components (SSCs) scoped in the Maintenance Rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. Documents reviewed are listed in the Attachment.

- 1A component cooling water cooler retubing due to the ongoing degradation of the cooler tubes
- Repair of the Keowee air circuit breakers auxiliary contact operating rods
- Replacement of CT-5 bushings after Doble testing

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors evaluated the following attributes for the five activities listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforeseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved. Documents reviewed are listed in the Attachment.

- Assessment of the risk and compensatory measures associated with the SSF pressurizer heater breaker resulting in the SSF being declared inoperable. The assessment included a review of planned work, actions established to reduce the overall risk to the station and field walkdowns to verify the actions were appropriately implemented
- Assessment of risk and actions taken in accordance with NSD 417, Nuclear Facility/Generation Status Communication, in response to projected Orange grid condition, including coordination of activities with other Duke sites
- Assessment of the station’s availability determination of the SSF following declaration of the auxiliary service water subsystem inoperability including the impact on the Electronic Risk Assessment Tool (ERAT) model used for planned and emergent work scheduling
- Review of the Critical Activity Plan associated with the annual SSF outage and corresponding assessment of sequencing of planned and emergent work at the station and across the Duke nuclear grid
- Review of the Critical Activity Plan associated with the Keowee Out of Tolerance testing and resulting Orange ERAT risk condition due to the Keowee underground power path unavailability

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following seven operability evaluations or functionality assessments affecting risk significant systems to assess: (1) the technical adequacy of the evaluations; (2) if continued system operability was warranted; (3) if other existing degraded conditions were considered; (4) if compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on Technical Specifications (TS) limiting condition for operations.

- PIP O-11-0218, Containment isolation valve 1HP-5 unexpectedly went to the ‘throttled’ position during engineered safeguards Channel 2 testing
- PIP O-11-8094, Extent of condition review for SSF pressurizer heaters
- PIP O-11-7973, 1MS-92 relief is releasing steam to atmosphere after turbine-driven emergency feedwater pump testing
- PIP O-11-9925, SSF diesel failed to meet acceptance criteria of PT/0/A/0600/021, SSF Diesel Generator Operation
- PIP O-11-9031, Material taken in Unit 3 reactor building for foreign material exclusion controls was not in compliance with SD 1.3.9 containment material control

- PIP O-11-10959, Information related to the frequency used for HPI pump governor is not clearly outlined
- PIP O-11-7998, Honeycomb area on column 93A at elevation 838 adjacent to Unit 3 BWST

b. Findings

Introduction: An NRC-identified Green NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, was identified for the licensee's failure to promptly identify and correct a condition adverse to quality. The licensee failed to identify and correct a degraded condition associated with containment isolation valves 1HP-5, 2HP-5 and 3HP-5 following the identification of a degraded condition on valve 1HP-5.

Description: As discussed in 1R18, 1HP-5 failed to fully close upon receipt of a closure signal. The licensee conducted an apparent cause evaluation which included an extent of condition determination for the letdown line containment isolation capability on 2HP-5 and 3HP-5. The licensee initially concluded that 2HP-5 and 3HP-5 were not vulnerable to the same condition as 1HP-5 because the failure of 1HP-5 was caused by reduced internal clearances and valve degradation based on 1HP-5 experiencing the greatest number of strokes after the valve seat material had been changed in the 2003-2004 time period. However, on May 31, 2011, the licensee declared these valves inoperable based on information that indicated that the valves would not have fully closed for the same reasons that had caused 1HP-5 to fail. The inspectors determined that there were several missed opportunities to identify the degraded conditions with the 1HP-5, 2HP-5 and 3HP-5 valves including:

- On January 11, 2011, the licensee identified internal damage to 1HP-5 and determined that physical modifications to the valve would be required to restore operability. These included installing components made from a harder metal and increasing clearances to reduce the potential for direct surface contact. Although 2HP-5 and 3HP-5 were identical, no actions were defined to make similar changes to those valves.

- On January 18, 2011, the licensee's post-modification testing did not demonstrate that the modification done to 1HP-5 had addressed the cause of the failure to stroke and that the valve would function at design basis pressure conditions before declaring the valve operable.

- On January 25, 2011, the inspectors independently reviewed historical computer and test data and determined that 1HP-5 had not experienced the greatest number of strokes since the seat material had been modified despite that being part of the licensee's basis for the failure of 1HP-5. The licensee did not re-evaluate their conclusion that 2HP-5 and 3HP-5 were not affected when the discrepancy was identified.

- On multiple occasions between February 16, 2011, and May 28, 2011, the inspectors questioned the licensee's use of a maximum RCS pressure of 1700 psig for calculating closing margin of the valves versus higher design basis pressure conditions that may be seen during an ES actuation due to high reactor building pressure. During this period, the licensee determined that the existing actuator springs on all 3 units were insufficient to ensure the valves would close against normal operating pressure conditions, and corrected this condition on Unit 1 during its refueling outage on April 5, 2011, and declared the valves on Units 2 and 3 Operable but Degraded Nonconforming on May 10, 2011. No actions were taken on Units 2 or 3 due to the licensee's position that the 1700 psig RCS pressure remained bounding. On May 28, 2011, the licensee determined that due to a safety analysis error, the valves would be required to close against higher than assumed differential pressures for certain UFSAR design basis events.

The licensee restored closing margin to the Unit 1 valve during its refueling outage which began April 2, 2011, by installing a permanent modification on the valve actuator. An interim modification was installed on June 11, 2011, for Unit 2, and on June 10, 2011, for Unit 3 to restore closing margin to those valves. The licensee generated PIP O-11-0218 to document the issue for resolution.

<u>Analysis</u>: The licensee's failure to promptly identify the degraded condition of 2HP-5 and 3HP-5 and adequately correct the condition on 1HP-5 as required by 10 CFR 50, Appendix B, Criterion XVI, was a PD. The PD was more than minor because it was associated with the Barrier Integrity cornerstone attribute of Design Control and adversely impacted the cornerstone objective because the degraded condition had the potential to result in a containment bypass pathway if the valves had been called upon to close. Using IMC 0609, Attachment 4, Determining the Significance of Reactor Inspection Findings for At-Power Situations, and IMC 0609, Appendix H, the inspectors determined a Phase 3 analysis was required because the finding represented a potential containment bypass pathway that would not be isolable following certain events analyzed in Chapter 15 of the UFSAR. A Phase 3 analysis was performed by a regional SRA. The risk was dominated by line break initiators, and by initiators that caused SBOs and required the SSF to mitigate. The dominant cutsets involved failure of alternate isolation valves to function and failure of the SSF due to excessive loss of inventory from the primary. The SRA concurred with licensee-performed analyses that demonstrated that the LERF contribution for the SBO sequences was minimal and that CDF should be used. The SRA found both the line break LERF, and the SBO/SSF CDF results to be less than $1X10^{-6}$. Therefore, this finding was of very low safety significance (Green). The finding directly involved the cross-cutting area of Human Performance under the Conservative Assumptions and Safe Actions aspect of the Decision Making component, in that the licensee failed to demonstrate conservative decision making in their evaluation of the operability of the Units 1, 2, and 3 letdown line containment isolation valves. [H.1(b)].

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, deficiencies, and defective material are promptly identified and corrected. Contrary to the above, from January 8, 2011, until April 2, 2011, for Unit 1; January 8,

2011, until June 11, 2011, for Unit 2; and January 8, 2011, until June 10, 2011, for Unit 3, the licensee failed to promptly identify and correct a condition adverse to quality involving a degraded condition associated with the containment isolation valves on the Unit 1, Unit 2, and Unit 3 letdown lines. In this case, after identification of a condition adverse to quality on Unit 1, the licensee failed to correct the condition on Unit 1 and failed to identify and correct a similar condition adverse to quality on Unit 2 and Unit 3. Because the finding is of very low safety significance and the licensee has entered this issue into their CAP as PIP O-11-0218, this violation is being treated as an NCV in accordance with the NRC's Enforcement Policy: NCV 05000269, 270, 287/2011004-01, Failure to Promptly Identify and Correct an Adverse Condition Affecting Operability of Letdown Line Containment Isolation Valves.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following four permanent plant modifications to verify the adequacy of the modification package, as well as 10 CFR 50.59 screenings, and to evaluate the modification for adverse affects on system availability, reliability and functional capability. Documents reviewed are listed in the Attachment.

- EC 105851, Replace 1HP-CV-5 Actuator Spring SR60 with SR100 Spring
- EC 97943, Siding and Girts Installation, Unit 1
- EC 97951, Unit 2 BWST / SSF Trench Protection Super Structure
- OE 17302, OE 17229, OE 17589, Replace Soft Goods in Valves 1HP-5, 2HP-5 and 3HP-5

b. Findings

Introduction: A self-revealing Green NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified when the licensee failed to follow their modification process. The licensee did not verify the valve actuator margin to be greater than the margin specified in procedure EDM 601, Engineering Change Manual, following internal changes to the RCS letdown line outboard CIVs on all three units (1HP-5, 2HP-5, and 3HP-5). As a result, the CIVs would not have fully closed as required against all postulated dPs for events defined in Chapter 15 of the UFSAR.

Description: During the 2003 – 2004 period, the licensee replaced the valve seat material for these air-operated CIV's on all three units with a harder material to address seat leakage issues. Procedure EDM 601, Appendix K, required that the licensee verify a minimum actuator output margin of 15 percent if the change affected an air operated valve in any manner. However, because the modification package identified the new seat material as being a "like-for-like" replacement, no verification of available closing margin was performed. As a result, the properties of the different seat material were not accounted for in the actuator torque requirement calculations during the design development process.

On January 8, 2011, during performance of an engineered safeguards (ES) surveillance test, 1HP-5 failed to fully close upon receipt of a closure signal. Indications both in the main control room and locally showed that the valve remained approximately 25 percent open. The applicable TS was entered for an inoperable CIV and following the inability to perform repairs with the unit at power, the licensee placed the unit in Mode 5 to comply with Technical Specification 3.6.3.

The licensee evaluated the failure of 1HP-5 and determined that the actuator did not have sufficient torque to close the valve at dPs expected for events defined in UFSAR Chapter 15 as a result of replacing the valve seat material with the harder material. Between January 8 to 12, internal modifications were made to the valve which included reducing the diameter of the ball assembly to increase internal clearances and replacing the gland ring with a harder grade of stainless steel to reduce the required closing torque for higher dP conditions. In addition, during the refueling outage that began on April 2, the spring in the actuator on Unit 1 was upgraded which provided additional torque to ensure the valve would close under all postulated dP conditions. These modifications resulted in a calculated closure margin of approximately 28 percent. The licensee made temporary modifications to ensure 2HP-5 and 3HP-5 will close against maximum dP conditions and will implement permanent modifications at the next available opportunity. The licensee generated PIP O-11-0218 to document the issue for resolution.

Analysis: The licensee's failure to implement the modification process was a PD. The PD was determined to be more than minor because it was associated with the Barrier Integrity cornerstone attribute of Design Control and adversely impacted the cornerstone objective in that the RCS letdown line outboard CIVs could not perform their design function during all postulated events that would require the valves to close. The inspectors used IMC 0609, Appendix H, Containment Integrity Significance Determination Process, and determined that a Phase 3 analysis was required based on the need to quantify the delta CDF and LERF components of an at-power event, and the postulated events not being addressed by either the Phase 2 pre-solved tables or the plant-specific worksheets. A Phase 3 analysis was performed by a regional SRA. The risk was dominated by line break initiators, and by initiators that caused SBOs and required the SSF to mitigate. The dominant cutsets involved failure of alternate isolation valves to function and failure of the SSF due to excessive loss of inventory from the primary. The SRA concurred with licensee-performed analyses that demonstrated that the LERF contribution for the SBO sequences was minimal and that CDF should be used. The SRA found both the line break LERF and the SBO/SSF CDF results to be less than $1X10^{-6}$. Therefore, this finding was of very low safety significance (Green). No cross cutting aspects were identified based on the issue not being indicative of current licensee performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, required in part that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, since October 2003 for Unit 1, March 2004 for Unit 2, and May 2004 for Unit 3, the licensee failed to implement design control measures that verified the adequacy of design for modifications to the letdown line outboard CIVs. The licensee failed to follow their design change process to verify that adequate closing margin was maintained and that the valves would fully close at pressures expected during all postulated events. Because the finding is of very low safety significance and the licensee has entered this issue into their CAP as PIP O-11-0218, this violation is being treated as an NCV in accordance with the NRC's Enforcement Policy: NCV 05000269, 270, 287/2011004-02, Failure to Verify Adequate Closure Margin.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following six post-maintenance test procedures and/or test activities to assess if: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. Documents reviewed are listed in the Attachment.

- "B" low pressure service water (LPSW) pump test following pump motor test and inspection
- SSF diesel generator testing following annual PMs
- SSF pressurizer heater groups "B" and "C" surveillance following modification
- 2A RBS pump test following train maintenance
- 2A emergency feedwater (EFW) pump test following train maintenance
- "C" LPSW pump test following pump lube, breaker, and relay PMs

b. Findings

Introduction: An NRC-identified Green NCV of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, was identified when the licensee failed to follow NSD 220, UFSAR Revision Process, and processed a technical change to the UFSAR as a non-technical change.

Description: The UFSAR stated that "…all portions of the SSF required for mitigation of a seismic induced Turbine Building flood shall be QA-1." SSF equipment required for mitigation of a seismic induced turbine building flood include a bank of pressurizer heaters, powered and controlled from the SSF. However, as documented in NRC IR 05000269, 270, 287/2011017, the pressurizer heater breakers and associated electrical components powered from the SSF required to mitigate this event were not QA-1. Recognizing that this was a discrepancy between the facility and the UFSAR, the licensee used NSD 220, UFSAR Revision Process, to remove the UFSAR statement, and provide clarification as to which equipment was required to be QA-1. However, the licensee processed this change as a non-technical editorial correction such as typographical errors or omissions, clarifications, or formatting change. The inspectors reviewed this change and determined it could not be implemented as a non-technical editorial correction based on the criteria in NSD 220. The change package did not provide adequate justification that certain portions of the SSF, required to mitigate this event, could be excluded from being QA-1 and conflicted with statements made in the design basis documents and calculations that certain equipment could be excluded. The licensee retracted the UFSAR change and intends to submit a License Amendment Request to correct the discrepancy between the facility and the UFSAR. The licensee generated PIP O-11-8863 to document the issue for resolution.

<u>Analysis</u>: The failure to follow NSD 220 was a PD. This PD was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective in that the licensee used the non-technical editorial change process to modify the qualification of equipment relied upon to mitigate a seismic-induced turbine building flood when a license amendment was required. The inspectors used IMC 0609, Attachment 4, Phase 1 – Initial Screening and Characterization of Findings, and determined the finding was of very low safety significance (Green) because the finding did not result in loss of operability or functionality. The PD directly involved the cross-cutting aspect of using conservative assumptions in decision making in the Decision-Making component of the Human Performance cross-cutting area in that the licensee relied on insufficient information to process a UFSAR change as a non-technical change. [H.1(b)]

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion V, Instruction, Procedures and Drawings, required in part, that activities affecting quality shall be accomplished in accordance with instructions, procedures, or drawings. NSD 220 required that all changes to the UFSAR be processed as technical changes except for editorial corrections. Contrary to the above, on July 26, 2011, the licensee failed to accomplish an activity affecting quality in accordance with procedures. The licensee failed to follow NSD 220 which resulted in a UFSAR change that was incorrectly processed as a non-technical change. The change removed a UFSAR statement that was part of the SSF licensing basis which would have been a technical change. Because this finding is of very low safety significance and because it was entered into the licensee's corrective action program as PIP O-11-8863, this violation is being treated as an NCV, consistent with the NRC Enforcement Policy: NCV 05000269, 270, 287/2011004-03, Failure to correctly process a UFSAR change.

1R22 <u>Surveillance Testing</u>

a. <u>Inspection Scope</u>

The inspectors either witnessed and/or reviewed test data for the six surveillance tests listed below to assess if the SSCs met TS, UFSAR, and licensee procedure requirements. In addition, the inspectors determined if the testing effectively demonstrated that the SSCs were ready and capable of performing their intended safety functions. Documents reviewed are listed in the Attachment.

Routine Surveillances

- PT/1/A/0400/007; SSF RC Makeup Pump Test, Rev. 060
- IP/1/A/0315/020 A, TXS RPS Channel A Manual Setpoints Verification
- PT/1/A/0290/004, Turbine Stop Valve Test, Rev. 14

In-Service Tests

- PT/1/A/2200/022, KHU-1 Control Valve IST Surveillance
- PT/2/A/0204/007; 2B RB Spray pump comprehensive test

Reactor Coolant System Leakage

- PT/2/A/0600/010, Reactor Coolant Leakage

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Testing

a. Inspection Scope

The inspectors evaluated the adequacy of the licensee's operation, maintenance, and periodic testing of the Alert and Notification System (ANS) using NRC Inspection Procedure 71114, Attachment 02, "Alert and Notification System Evaluation." The inspectors gathered information through document reviews and interviews and reviewed monthly trend reports and siren test failure records. Additionally, the inspectors observed a siren silent test conducted by Telecom maintenance personnel to verify the test was conducted in accordance with the approved procedures. The inspectors used the applicable planning standard of 10 CFR 50.47(b)(5) and the related requirements in 10 CFR 50, Appendix E, Section IV.D, as reference criteria. The criteria contained in NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, Revision 1, was also used as a reference. Documents reviewed are listed in the Attachment. The inspection activity satisfied one inspection sample.

b. Findings

No findings were identified.

1EP3 Emergency Preparedness Organization Staffing and Augmentation System

a. Inspection Scope

The inspectors reviewed the licensee's Emergency Response Organization (ERO) augmentation staffing requirements and process for notifying the ERO to ensure the readiness of key staff for responding to an event and timely facility activation. The qualification records of key position ERO personnel were reviewed to ensure all ERO qualifications were current. A sample of problems identified from unannounced off-hour augmentation drills or system tests performed since the last inspection were reviewed to assess the effectiveness of corrective actions. The inspectors reviewed the records from the unannounced off-hour recall drill conducted October 2, 2009, December 4, 2010, and December 17, 2010, to verify the ERO members were alerted and mobilized and the response facilities were staffed and activated in a timely manner. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, Emergency Response Organization Staffing and Augmentation System. The inspectors used the applicable planning standard of 10 CFR 50.47(b)(2), and the related requirements in 10 CFR 50, Appendix E, as reference criteria. Documents reviewed are listed in the Attachment. The inspection activity satisfied one inspection sample.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

Since the last NRC inspection, the licensee implemented revision 2001-01 of the Oconee Nuclear Site Emergency Plan, Volume A. The inspectors conducted a review of the emergency action level changes and sampled the revisions to the emergency plan and the implementing procedure made between January 27, 2010, and May 9, 2011, to evaluate the changes identified in the revisions for potential decreases in effectiveness of the emergency plan. The inspection included a review of the 10 CFR 50.54(q) change process documentation. The licensee determined the changes resulted in no decrease in the effectiveness of the emergency plan and that the revised plan continued to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR 50. The NRC review of the revisions does not constitute formal approval of the changes and was not documented in a safety evaluation report; therefore, the emergency action level and emergency plan changes remain subject to future NRC inspection in their entirety. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 04, Emergency Action Level and Emergency Plan Changes. The inspectors used the applicable planning standard of 10 CFR 50.47(b)(4) and the related requirements in 10 CFR 50, Appendix E, as reference criteria. Documents reviewed are listed in the Attachment. The inspection activity satisfied one inspection sample.

b. Findings

No findings were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed the corrective actions identified through the emergency preparedness program to determine the significance of the issues and to evaluate the licensee's efforts to identify, track, and resolve deficiencies. The inspectors reviewed the Independent Nuclear Oversight audits and assessments of the emergency preparedness program to determine if the independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2010 biennial exercise, as well as, various emergency preparedness drills conducted in 2009 through 2011 in order to determine if the licensee fulfilled drill commitments and to assess the completeness and effectiveness of related corrective actions. The inspectors reviewed the events and circumstances and licensee actions associated with the Unusual Event declaration on August 11, 2010, following the Unit 3 unplanned loss of safety system annunciation/indication in the control room. The inspectors reviewed selected procedures, event records and logs, and conducted a phone interview with the individual who was the Operations Shift Manager at the time of the event. The purpose of the inspection was to evaluate the licensee's event response actions for compliance with applicable regulatory requirements and the Oconee Nuclear Station Emergency Plan commitments. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 05, Correction of Emergency Preparedness Weaknesses. The inspectors used the applicable planning standard of 10 CFR 50.47(b)(14) and the related requirements in 10 CFR 50, Appendix E, as reference criteria. Documents reviewed are listed in the Attachment. The inspection activity satisfied one inspection sample.

b. Findings

No findings were identified.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors evaluated an ERO dual site drill involving events at both Oconee Nuclear Station and McGuire Nuclear Station on August 30, 2011, which involved activation of the Oconee Technical Support Center (TSC), Operations Support Center and Emergency Operations Facility in Charlotte. The licensee's response to the simulated event was observed from the Oconee plant control room simulator and the Oconee TSC. The staff's implementation of the Emergency Operating Procedure, Emergency Plan and offsite notifications were also observed. The drill involved a fire at the hydrogen purifier in the turbine building which spread to the Unit 1 safety-related 4kV switchgear cabling resulting in an Alert declaration, followed by a large break loss of coolant accident leading to Site Area Emergency and General Emergency declarations. The drill was terminated following additional Protective Action Recommendations that were made following the loss of all three fission product barriers after the containment barrier was breached due to leaking reactor building purge valves. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee data to confirm the accuracy of reported PI data for the following twelve PIs. To determine the accuracy of the report PI elements, the reviewed data was assessed against PI definitions and guidance contained in Nuclear Energy Institute 99-02, Regulatory Assessment Indicator Guideline, Revision 5. Documents reviewed are listed in the Attachment.

Mitigating Systems Cornerstone
- MSPI, Residual Heat Removal (3 units)
- MSPI, Heat Removal (3 units)

Barrier Integrity Cornerstone
- RCS Leakage (3 units)

For the period of July 1, 2010, through June 30, 2011, the inspectors reviewed Operating Logs, Train Unavailability Data, Maintenance Records, Maintenance Rule Data, PIPs, Consolidated Derivation Entry Reports, and System Health Reports to verify the accuracy of the PI data reported for each PI.

Emergency Preparedness Cornerstone
- Emergency Response Organization Drill/Exercise Performance (DEP)
- Emergency Response Organization Readiness (ERO)
- Alert and Notification System Reliability (ANS)

For the DEP indicator, the inspectors verified the accuracy of the number of reported drill and exercise opportunities and the licensee’s critiques and assessments for timeliness and accuracy of the opportunities. The inspectors reviewed the licensee’s documentation for control room simulator training sessions, the 2010 biennial exercise, and other designated drills to validate the accuracy of the submittals.

For the ERO indicator, the inspectors reviewed the licensee’s records and ERO roster to validate the accuracy of the submittals for the number of ERO members assigned to fill key positions and the percentage of ERO members who had participated in a performance enhancing drill or exercise. The inspectors reviewed selected training records for personnel assigned to key positions in the ERO.

For the ANS indicator, the inspector reviewed of a sample of the licensee's records of periodic system tests. The inspectors reviewed the records of the licensee's reported number of successful siren operability tests as compared to the number of siren tests conducted during the reporting period to validate the accuracy of the PI submittals.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution

.1 Daily Screening of Corrective Action Reports

In accordance with Inspection Procedure 71152, Problem Identification and Resolution, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed daily screening of items entered into the licensee's CAP. This review was accomplished by reviewing copies of PIPs, attending daily screening meetings, and accessing the licensee's computerized database.

.2 Annual Sample

a. Inspection Scope

Keowee Hydro Station Follow-up to the Sayano-Shuskenskaya Facility Event:
The inspectors reviewed the licensee's actions in response to the Sayano-Shuskenskaya Russian hydro-electric facility event of August 17, 2009, which involved the destruction of multiple hydro-electric generating units. The inspectors reviewed the licensee's response to Centre for Energy Advancement through Technological Innovation (CEATI) recommendations which provided for precautionary checks at hydro stations to prevent the same event. The inspectors reviewed the corrective actions completed and planned documented in PIP O-10-0904, including review of the maintenance activities created to inspect the condition of the Keowee Hydro Units (KHU) head covers and bolting, routine wicket gate inspection results, and the vibration and operating history of the KHUs. The licensee's review of the Keowee air admission valve requirements was also reviewed according to the CEATI recommendation. Documents reviewed are listed in the Attachment.

SFP Loading: The inspectors reviewed the licensee's actions in response to Licensee Event Report (LER) 05000269/2009-01, Several Prior Spent Fuel Pool Configurations Did Not Comply with TS 3.7.13. The LER involved three instances where spent fuel assemblies had not been stored in the spent fuel pool (SFP) in compliance with the loading pattern and boundary conditions specified in Technical Specification (TS) 3.7.13. The inspectors reviewed the root cause and long term corrective actions. The inspectors also reviewed the current loading pattern and boundary conditions associated in the Unit 3 SFP as well as the completed surveillance test for Unit 1/2 pool reconfiguration for maintenance. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

.3 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of deficiencies that constituted operator workarounds to determine whether or not they could: affect the reliability, availability, and potential for misoperation of a mitigating system; affect multiple mitigating systems; or affect the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspectors also assessed whether operator workarounds were being identified and entered into the licensee's corrective action program at an appropriate threshold

b. Findings

No findings were identified.

4OA3 Event Follow-up

.1 (Closed) LER 05000270/2010-01-01, Operation Prohibited by TS Due to Removal of West Penetration Room Brick Wall Support Girts: The inspectors previously reviewed this LER and closed Revision 0 of the LER in Oconee Inspection Report (IR) 2010004. The related enforcement actions were discussed in Section 4OA7 of IR 2010004. The revision to the LER was issued to include the cause and corrective actions that were not available in Revision 0 of the LER. The inspectors reviewed the root cause report and corrective actions associated with the event. No additional findings were identified. The licensee documented the condition in their CAP as PIP O-10-5561. This LER is closed.

.2 (Closed) LER 05000269/2010-03-01, Inoperable Emergency Feedwater Flowpath Results in a Condition Prohibited by Technical Specifications: On October 27, 2010, the licensee discovered the EFW flow path to the 1A steam generator (SG) was inoperable due to the nitrogen supply to 1FDW-315, the 1A EFW flow control valve, being isolated. As a result, the valve would not be able to throttle EFW flow to the 1A SG. Immediate actions were taken to place a train of nitrogen backup supply to valve 1FDW-315 in service which restored operability to the EFW flow path to the 1A SG. The licensee determined that the EFW flow path to the 1A steam generator was inoperable for a total of 54 days. The inspectors verified the adequacy of the immediate corrective actions, reviewed the licensee's root cause evaluation, and reviewed the implementation of additional corrective actions. The enforcement aspects of this issue are discussed in Section 4OA7. The licensee entered this issue into their CAP as PIP O-10-8435.

.3 Earthquake

a. Inspection Scope

On August 23, 2011, operators entered AP-5, Earthquake, when notified by individuals on site that they experienced tremors from an earthquake. The inspectors observed the licensee's actions to verify the actions were consistent with AP-5. In addition, the inspectors walked down the site and verified that the accelerometers did not trip and that no visual damage occurred. Throughout this event all three Oconee units remained at 100 percent RTP.

b. Findings

No findings were identified.

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 that 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 were identified.

.2 Operation of an Independent Spent Fuel Storage Installation (ISFSI)

a. Inspection Scope

Under the guidance of IP 60855.1, Operation of an Independent Spent Fuel Storage Installation at Operating Plants, the inspectors observed operations involving spent fuel storage. The inspectors reviewed documentation related to Dry Shielded Canister (DSC) 122, and verified that parameters and characteristics for each fuel assembly stored in the DSC was recorded, and that the records were maintained as controlled documents. The inspectors verified that the fuel selected for storage was consistent with the ISFSI Certificate of Compliance requirements. The inspectors also observed selected licensee activities related to the loading, vacuum drying and transfer of the DSC into the horizontal storage module, to ensure procedural requirements were met. The inspectors also reviewed selected screening evaluations performed pursuant to 10 CFR 72.48 since the last inspection. There were no 10 CFR 72.48 evaluations performed during this period as all screenings determined no evaluations were required. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

4OA6 Management Meetings (Including Exit Meeting)

Exit Meeting Summary

The resident inspectors presented the inspection results to Mr. T. Preston Gillespie, Jr. and other members of licensee management on October 13, 2011. The inspectors asked the licensee if any of the material examined during the inspection should be considered proprietary and no proprietary information was identified.

4OA7 Licensee Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy for being dispositioned as NCVs.

- TS 3.7.5, Emergency Feedwater System, required the EFW System to be operable in Modes 1, 2 and 3 or to restore operability within seven days. Contrary to the above, between September 5, 2010, and October 28, 2010, the licensee isolated the nitrogen supply from 1FDW-315 flow control valve which rendered the EFW flow path to the 1A SG inoperable. The condition was identified on October 27, 2010, and the backup nitrogen supply to the valve placed in service on October 28, 2010. This condition was not greater than very low safety significance (Green) because the calculated incremental core damage probability increase was 1.73E-07. The licensee entered the finding into their CAP as PIP O-10-8435.

- 10 CFR 50.47(b)(2) required timely augmentation of response capabilities and 10 CFR 50.47(b)(14) required periodic exercises to evaluate response capabilities and drills to develop and maintain key skills. The licensee's emergency plan required activation drills to test the recall response times of the ERO after-hours and once during the calendar year. Contrary to the above, the licensee failed to demonstrate timely augmentation of the ERO in the after-hours drills conducted in 2009 and 2010. The finding was not greater than very low safety significance (Green) because the failure was determined to be a degraded planning standard function. The licensee entered the finding into their CAP as PIP O-11-08554.

- 10 CFR 50.47(b)(4) required a standard emergency classification and action level scheme is in use by the nuclear facility licensee. Contrary to the above, the licensee implemented the revised security emergency action levels in RP/0/B/1000/001, Emergency Classification, on March 29, 2010, but did not revise the related emergency action level basis document. The finding was not greater than very low safety significance (Green) because it did not result in a loss or degradation of the RSPS function. The licensee entered the finding into their CAP as PIP O-11-04351.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee</u>
K. Alter, Regulatory Compliance Manager
M. Austin, Fleet Emergency Preparedness Manager
S. Batson, Station Manager
S. Boggs, Emergency Services Coordinator
E. Burchfield, Superintendent of Operations
P. Fisk, Mechanical/Civil Engineering Manager
P. Gillespie, Site Vice President
R. Guy, Organization Effectiveness Manager
R. Hester, IWL Responsible Engineer
T. King, Security Manager
P. Kukeveski, Independent Nuclear Oversight
D. Mayes, Steam Generator Maintenance & Engineering
B. Meixell, Regulatory Compliance Engineer/Emergency Planning Manager
T. Patterson, Safety Assurance Manager
J. Pounds, OMP Tornado/HELB QA Oversight
T. Ray, Engineering Manager
F. Richenbaker, OMP Manager
D. Robinson, Radiation Protection Manager
J. Smith, Regulatory Compliance
M. Stephen, OU Program Manager

<u>NRC</u>
J. Stang, Project Manager, NRR

LIST OF REPORT ITEMS

<u>Opened and Closed</u>

05000269, 270, 287/2011004-01	NCV	Failure to Promptly Identify and Correct an Adverse Condition Affecting Operability of Letdown Line Containment Isolation Valves (Section 1R15)
05000269, 270, 287/2011004-02	NCV	Failure to Verify Adequate Closure Margin (Section 1R18)
05000269, 270, 287/2011004-03	NCV	Failure to correctly process a UFSAR change (Section 1R19)

<u>Closed</u>

05000270/2010-01-01	LER	Operation Prohibited by TS Due to Removal of West Penetration Room Brick Wall Support Girts (Section 4OA3.1)

05000269/2010-03-01	LER	Inoperable Emergency Feedwater Flowpath Results in a Condition Prohibited by Technical Specifications (Section 4OA3.2)

DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PIP O-11-11435, Plate approximately 4” x 10” is missing that covered Aux Building Trench at U2 BWST
SD 3.2.16, Control of Passive Design Features, Rev. 1

Section 1R04: Equipment Alignment

OP/3/A/1104/005, Reactor Building Spray System, Rev. 31
OFD-103A-3.1, Flow Diagram of Reactor Building Spray System (BS), Rev. 21
OFD-102A-3.1, Flow Diagram of Low Pressure Injection System (Borated Water Supply and LPI Pump Suction), Rev. 58
Protected Equipment Log for July 10, 2011 covering equipment to be protected to support the SSF pressurizer heater issue
Protected Equipment Log for work associated with the annual SSF maintenance outage

Section 1R05: Fire Protection

Fire Pre-Plan for Zone 95, Unit 1 Equipment Room, Auxiliary Building, Room 310
Fire Pre-Plan for Zone 92, Unit 2 Equipment Room, Auxiliary Building, Room 311
Fire Pre-Plan for Zone 89, Unit 3 Equipment Room, Auxiliary Building, Room 354 and 354A
Fire Pre-Plan for Zones 42 and 43, Unit 1 Main Turbine Floors Areas, Elevation 822’ and 838’
Fire Pre-Plan for Zones 40 and 41, Unit 2 Main Turbine Floors Areas, Elevation 822’ and 838’
Fire Pre-Plan for Zones 38, 39 and 39A, Unit 2 Main Turbine Floors Areas, Elevation 822’ and 838’
Fire Pre-Plan for Zone 98 and 99, Unit 3 East and West Penetration Rooms, Rooms 452, 455, 562 and 566
Fire Pre-Plan for Zones 52, Unit 2 LPI Pumps 2A and 2C and RBS Pump 2A, Rooms 63 and 65
Fire Pre-Plan for Zones 53, Unit 1 LPI Pumps 1B and 2B and RBS Pump 1B and 2B, Room 62
Fire Pre-Plan for Zones 54, Unit 1 LPI Pumps 1a and 1c and RBS Pump 1A, Rooms 61 and 64
Fire Pre-Plan for the Standby Shutdown Facility (Building 8094), Elevations 754’, 777’, 797’, and 817’
NSD 313, Control of Combustible and Flammable Material, Rev. 9
MP/0/A/1705/032, Fire Protection Equipment Inspection, Rev. 33
PIPs O-11-10636, O-11-10480, O-11-10759, O-11-11610

Section 1R07: Heat Sink Performance

Service Water System Program Manual, Rev. 9
ONTC-1-124B-0020-001, Oconee Nuclear Station Unit 1 LPSW Flow to U1 HPI Pump Motor Coolers Test Acceptance Criteria, Rev. 0
ONTC-1-124B-0020-002, Oconee Nuclear Station Unit 1 LPSW Flow to U1 HPI Pump Motor Coolers Test Acceptance Criteria, Rev. 0
EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines, December 1991

PIP O-11-10724, A, B, and C Motor outlet gauges not indicating correctly
PT/1/A/0230/015, High Pressure Injection Motor Cooler Flow Test, Rev. 34, performed September 7, 2011
PT/1/A/0230/015, High Pressure Injection Motor Cooler Flow Test, Rev. 34, performed May 27, 2011
PT/1/A/0230/015, High Pressure Injection Motor Cooler Flow Test, Rev. 34, performed June 15, 2011
PT/1/A/0230/015, High Pressure Injection Motor Cooler Flow Test, Rev. 33, performed March 22, 2011
PT/1/A/0230/015, High Pressure Injection Motor Cooler Flow Test, Rev. 33, performed December 29, 2011
OFD-124B-1.1, Flow Diagram of Low Pressure Service Water System (Auxiliary Building Services), Rev. 61
OFD-124C-1.3, Flow Diagram of High Pressure Service Water System (Auxiliary Building), Rev. 18
Letter dated January 26, 1990, Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment
Letter dated April 4, 1995, Supplemental Response #3 to GL 89-13
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