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

January 30, 2009

Mr. Benjamin C. Waldrep
Vice President
Carolina Power and Light Company
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

SUBJECT: BRUNSWICK STEAM ELECTRIC PLANT - NRC INTEGRATED INSPECTION REPORT NOS.: 05000325/2008005 AND 05000324/2008005

Dear Mr. Waldrep:

On December 31, 2008 the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Brunswick Unit 1 and 2 facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 12, 2009, with you and other members of your staff.

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

This report documents two NRC-identified findings and two self-revealing findings. These findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC's Enforcement Policy. If you contest any NCV in this report, 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 Brunswick Steam Electric Plant.

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/

Randall A. Musser, Chief
Reactor Projects Branch 4
Division of Reactor Projects

Docket Nos.: 50-325, 50-324
License Nos.: DPR-71, DPR-62
Enclosure: Inspection Report 05000325, 324/2008005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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).

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Letter to Benjamin C. Waldrep from Randall A. Musser dated January 30, 2009

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-325, 50-324
License Nos.:	DPR-71, DPR-62
Report Nos.:	05000325/2008005, 05000324/2008005
Licensee:	Carolina Power and Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road, SE Southport, NC 28461
Dates:	October 1, 2008 through December 31, 2008
Inspectors:	P. O'Bryan, Senior Resident Inspector G. Kolcum, Resident Inspector J. Austin, Senior Resident Inspector M. Bates, Senior Operations Engineer (Section 1R11.1) H. Gepford, Senior Health Physicist (Section 4OA5.2) R. Baldwin, Senior Operations Engineer (Section 1R11.3) D. Jones, Senior Reactor Inspector (Section 1R11.3)
Approved by:	Randall A. Musser, Chief Reactor Projects Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000325/2008005, 05000324/2008005; 10/01/08 - 12/31/08; Brunswick Steam Electric Plant, Units 1 & 2; Event Follow-up, Licensed Operator Requalification Program.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two NRC identified and two self revealing findings were identified by the inspectors. The findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

<u>Green.</u> A self-revealing Green NCV of Technical Specification (TS) 5.4.1, Procedures, was identified when the licensee failed to correctly reassemble the pilot valve for the Unit 2 Safety Relief Valve (SRV) H. The plant procedure for assembly of the pilot valve, 0CM-VSR-509, Main Steam Relief Valves Target Rock Model 7567 Air Operators and Pilot Assembly, Disassembly, Inspection, and Reassembly, used in 2006 for the Unit 2 SRV H pilot valve specifies that, during assembly, the pilot spring should be placed inside of the pilot valve spring follower. Contrary to this requirement, the pilot valve was assembled with the pilot spring on the ledge of the pilot valve spring follower. The incorrectly assembled pilot valve was installed in Unit 2 in March, 2007 on SRV 'H'. On November 9, 2008, the spring slipped off the ledge of the spring follower, reducing the SRV set point pressure, and causing the SRV to lift at normal operating pressure. The licensee replaced the failed SRV and initiated a root cause analysis to determine the primary and contributing cause of this event.

The failure to assemble the SRV pilot per procedure was identified as a performance deficiency. The performance deficiency was more than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone, and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was determined to be of very low safety significance because the finding does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding has a cross-cutting aspect of procedural compliance, as described in the Work Practices component of the Human Performance cross-cutting area because the licensee failed to follow the procedure as written (H.4(b)). (Section 4OA3)

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation of 10 CFR Part 55.59(a)(2) for failure to correctly evaluate and grade a written examination during the biennial requalification examination for licensed operators. The licensee operations training staff incorrectly allowed two correct answers for a question, where the answers were diametrically opposed (opposite one another) which is prohibited by the examination guideline NUREG-1021. This resulted in a licensed operator standing shift without passing the required annual written examination.

This finding is more than minor because if left uncorrected, it could become a more significant safety concern in that licensed operators would not be adequately tested to ensure an acceptable knowledge level for performing licensed duties. Using the Licensed Operator Requalification Significance Determination Process, this finding was determined to be of very low safety significance (Green) because the individual that failed was a part of a crew that passed their biennial examinations and no issues resulted during the actual watch standing of this crew. All other operators involved were able to perform assigned licensed duties. The finding was a result of the licensee not being in compliance with the requirements of TAP-403, “Conduct of Examinations,” and TAP-411, “Continuing Training Annual/Biennial Exam Development, Administration and Security.” The finding was related to the cross-cutting aspect of procedural compliance of the work control component of the cross-cutting area of Human Performance (H.4(b)) because the examination writers and the training supervisor did not comply with conduct of examination procedure requirements. The licensee has initiated a root cause analysis to determine the primary and contributing causes of this event. (Section 1R11)

Green. The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action” for failure to assure that a condition adverse to quality was promptly corrected, which resulted in the licensee declaring the 2B residual heat removal service water (RHRSW) booster pump inoperable while responding to the Unit 2 reactor scram on November 9, 2008. The licensee added oil to the bearing, restored the RHRSW to operable and entered the issue into the Corrective Action Program (CAP).

The deficiency associated with this event is not promptly investigating and correcting the low oil level in the 2B RHRSW booster pump bearing. The finding is more than minor because it affects the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). It is also associated with the cornerstone attribute of equipment availability and reliability. Since the finding affects both core damage frequency (CDF) and suppression pool cooling, an evaluation using NRC Inspection Manual Chapter (IMC) 0609, Appendix H, “Containment Integrity Significance Determination Process” was performed. Appendix H table 4.1 lists suppression pool cooling as a contributor to late containment failure, but not large, early release frequency (LERF). Therefore the change in CDF associated with the finding was used to characterize its significance. Using the NRC, pre-solved phase two significance determination process worksheets, the change in core damage frequency was found to be less than 1E-6, therefore this finding is of very low safety significance

(Green). The cause of the finding is related to the cross-cutting aspect of thoroughly evaluating problems as described in the Corrective Action Program component of the Problem Identification and Correction cross-cutting area, since the low oil level was identified, but a thorough investigation of the problem was not promptly performed. (P.1(c)) (Section 4OA3)

Green. A self-revealing Green NCV of TS 5.4.1, "Procedures," was identified for failure to comply with clearance order 180845 and 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 kV Breaker. Specifically, the 2A Core Spray pump breaker was inadvertently racked out instead of the Emergency Diesel Generator #3 output breaker. The licensee racked the 2A core spray breaker back into place and entered the issue into the CAP.

The failure to comply with clearance order 180845 and 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 kV Breaker was identified as a performance deficiency. The performance deficiency was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone objective to maintain the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be of very low safety significance because the finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time, did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk-significant per 10 CFR 50.65 for greater than 24 hrs, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The finding has a cross-cutting aspect of human error prevention, as described in the Work Practices component of the Human Performance cross-cutting area because the licensee inadvertently racked out the wrong breaker. H.4(a) (Section 4OA3)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at rated thermal power. On November 19, 2008, the unit was shut down for a maintenance outage to repair the 1A recirculation pump seal. Unit 1 was restarted on November 24, 2008. On November 26, 2008, while synchronizing the generator to the grid, the Unit 1 reactor automatically scrammed due to a malfunction in the turbine electro-hydraulic control system. Repairs were made to the turbine electro-hydraulic control system and the Unit 1 reactor was restarted on November 28, 2008. The unit returned to full power on December 4, 2008. Unit 1 operated at or near rated thermal power for the remainder of the inspection period.

Unit 2 began the inspection period at rated thermal power. On November 9, 2008, the reactor was manually scrammed when suppression pool temperatures rose due to an inadvertent lift of the H safety relief valve. On November 15, 2008, after replacing the H safety relief valve, Unit 2 was restarted and returned to full power on November 19, 2008. Unit 2 operated at or near rated thermal power for the remainder of the inspection period.

A. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, were verified to be in operation where applicable. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- Unit 1 and 2 heat tracing system for the condensate storage tanks
- Battery room 1A, 1B, 2A, 2B thermostats

b. Findings

No findings of significance were identified.

.2 Readiness For Impending Adverse Weather Condition

a. Inspection Scope

On December 11, 2008, a tornado warning was issued for the plant area and inspectors reviewed the licensee's overall preparations for impending adverse weather conditions. The inspectors walked down areas of the plant susceptible to high winds, including the licensee's emergency alternating current (AC) power systems. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Specific documents reviewed during this inspection are listed in the attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Emergency diesel generators 2, 3, and 4 with emergency diesel generator 1 out of service for planned maintenance on October 21, 2008;
- Emergency diesel generators 1, 3, and 4 with emergency diesel generator 2 out of service for planned maintenance on October 27, 2008 and
- Emergency diesel generators 1, 2, and 3 with emergency diesel generator 4 out of service for planned maintenance on December 9, 2008.

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, TS requirements, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that 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 corrective action program with the appropriate significance characterization. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Resident Inspector Tours

a. Inspection Scope

The inspectors conducted seven fire protection walkdowns, which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Unit 1 Reactor Building North 20' Elevation 1PFP-RB1-1g N
- Unit 1 Reactor Building South 20' Elevation 1PFP-RB1-1g S
- Unit 2 Reactor Building East 50' Elevation 2PFP-RB2-1h E
- Unit 2 Reactor Building West 50' Elevation 2PFP-RB2-1h W
- Unit 1 Turbine Building Air Compressor Area 20' Elevation 1PFP-TB1-1d
- Unit 1 Instrument Air Dryer Area 20' Elevation 1PFP-TB1-1e
- Unit 1 4KV Switchgear Area 20' Elevation 1PFP-TB1-1f

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee’s fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant’s Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant’s ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

.2 Annual Fire Protection Drill Observation

a. Inspection Scope

On November 11, 2008, the inspectors observed fire brigade performance during an unannounced fire drill. The observation was used to determine the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were: (1) proper wearing of turnout gear and self-contained breathing apparatus; (2) proper use and layout of fire hoses; (3) employment of appropriate fire fighting techniques; (4) sufficient firefighting equipment brought to the scene; (5) effectiveness of fire brigade leader communications, command, and control; (6) search for victims and propagation of the fire into other plant areas; (7) smoke removal operations; (8) utilization of pre planned strategies; (9) adherence to the pre planned drill scenario; and (10) drill objectives.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's testing of the number 2 and number 3 emergency diesel generator intercooler and jack water heat exchangers (2 samples) to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing criteria.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Annual Review of Licensee Requalification Examination Results

a. Inspection Scope

On December 10, 2008, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a) (2). The inspectors performed an in-office review of the overall pass/fail results of the individual operating tests and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

.2 Quarterly Review

a. Inspection Scope

On November 17, 2008**,** the inspectors observed operations crew C licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

b. Findings

No findings of significance were identified.

.3 Licensed Operator Requalification

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the week of November 17 - 21, 2008, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of operating tests associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR Part 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors." The inspectors also evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-1998, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The inspectors observed two crews during the performance of the operating tests (4 Scenarios). Documentation reviewed included written examinations, job performance measures (JPMs), simulator scenarios, licensee procedures, on-shift records, simulator modification request records and performance test records, the feedback process, licensed operator qualification records, remediation plans, watchstanding records, and medical records. The records were inspected using the criteria listed in Inspection Procedure 71111.11. Documents reviewed during the inspection are listed in the List of Documents Reviewed.

b. Findings

Introduction: The inspectors identified a non-cited violation of 10 CFR Part 55.59(a)(2) for failure to correctly evaluate and grade a written examination during the biennial requalification examination for licensed operators. The licensee operations training staff incorrectly allowed two correct answers for a question, where the answers were diametrically opposed (exactly opposite one another; contrary) which is prohibited by the examination guideline NUREG-1021. This resulted in a licensed operator standing shift without passing the required annual written examination.

Description: On November 19, 2008, while reviewing licensed operator written examination grading, the inspectors identified two operators that received credit for an answer to a question, where each answer was diametrically opposed. During the inspectors' review of these two answers it was determined that question number 29 was re-graded to allow two answers (i.e., original correct answer "B" was allowed, as well as, the additional correct answer "C"), however, the question could only have one correct answer. During this review, it was determined that two licensed operators both received credit for their respective answers and both were given credit for this question which allowed both the operators to pass the biennial examination. Written examinations at the Brunswick Steam Electric Plant are written in accordance with TAP-403, "Conduct of Examinations," and TAP-411, "Continuing Training Annual/Biennial Exam Development, Administration and Security." These procedures identify the requirements for developing and approving allowable testing materials. They govern the methods to ensure that each test item is accurate, which has discriminatory value and has only one correct answer. If during post-examination review any discrepancies are noted, then the test item should be reviewed and changed with approval from the appropriate Superintendent/Supervisor, if warranted. Additionally, justification should be included on the master examination key.

The examination was administered on December 12, 2007. During post-examination review, the crew pointed out that there could be two correct answers for question 29. During the post-review process, the licensee determined on December 13, 2007 that two answers ("B" and "C") were going to be allowed as correct answers.

At the time of the exit meeting on November 21, 2008, the licensee had subsequently determined that the individuals were, in fact, graded incorrectly and that the only acceptable answer would be answer "C." However, only one individual required remediation. The licensee took actions to verify that the Technical Specification minimum shift coverage was met from the original time of the failure (December 2007) until the individual was disqualified (December 2008). The licensee conducted two independent evaluations to verify the shift staffing was never below Technical Specification minimum staff coverage during this period. At the time of the exit, the preliminary root cause was a lack of licensee oversight of the requirements for evaluating changes to the biennial written examination. The licensee stated that a root cause analysis would be performed to determine the primary and contributing causes for allowing more than one answer for this question.

Analysis: The failure to correctly evaluate if two answers for a biennial written examination for licensed operators was a performance deficiency. This finding is more than minor because if left uncorrected, it could become a more significant safety concern that could lead to undetected examination failures that could impact more than one operator and could impact an operator's ability to direct or perform licensed activities. It affects the human performance attribute of the Mitigating Systems cornerstone because licensed operator response to initiating events mitigates undesirable consequences. The significance determination was performed in accordance with Manual Chapter 0609, Significance Determination Process, Appendix I, Licensed Operator Requalification Significance Determination Process (SDP). The finding is of very low safety significance (Green) because the individual that failed was a part of a crew that passed their biennial examinations and no issues resulted during the actual watch standing of this crew. All other operators involved were able to perform assigned licensed duties.

The finding was directly related to the cross-cutting aspect of procedural compliance of the work control component of the cross-cutting area of Human Performance. The examination writers and the training supervisor did not comply with conduct of examination procedure requirements. (H.4(b)).

Enforcement: A biennial written examination is required for licensed operators in accordance with 10 CFR Part 55.59(a)(2) which states that licensees (i.e., operators) are to, "Pass a comprehensive requalification written examination and an annual operating test."

Contrary to the above, the inspectors identified one licensed operator who did not pass his biennial written examination. Therefore, the subject licensed operator did not meet the 10 CFR Part 55.59(a)(2) that required the operator pass a comprehensive written examination. Because this issue is of very low safety significance and has been entered into the licensee's corrective action program, Nuclear Condition Report (NCR) 00307361, the violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000325, 05000324/2008005-04, Failure to correctly perform biennial written examination for a licensed operator.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- Service Air Compressors
- Electrohydraulic Turbine Generator Control

The inspectors reviewed events where ineffective equipment maintenance has resulted in invalid automatic actuations of Engineered Safeguards Systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Unit 1 entered Yellow risk condition for performing OMST-RHR-26Q, RHR and Core Spray low reactor pressure calibration on October 2, 2008;
- WR 353187 and AR 299547 for Unit 2 Suppression Pool Temperature Monitoring Annunciator Shows Division 1 Failure on October 3, 2008;
- WR 353533, AR 299880, AR 300745 for RPS leaking scram solenoid valve on October 6, 2008;
- AR 301344 for Unit 2 HPCI steam supply valve steam leak on October 14, 2008 and
- WO 1347584, AR 300661 for EHC pressure regulator 'A' failure and oscillations on October 18, 2008.

These activities were selected based on their potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that 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 that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- AR 302151, 2-CAC-V160, suppression pool containment atmospheric dilution nitrogen injection inlet valve indicated 94 percent open during performance of 0PT 16.1.1, Containment Atmospheric Control valve operability test
- AR 302524 Lessons learned for the Emergency diesel generator #1 outage relating to fuel oil low/low level switch in the saddle tank.

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that Technical Specifications (TS) operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and Updated Safety Analysis Report (USAR) to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The following engineering design package (temporary modification) was reviewed and selected aspects were discussed with engineering personnel:

- WO 823005, 0SMP-MO003, Soft Electrical Backseating of AC Motor Operated Valves Using the Motor Operator, 1-E41 F002, High Pressure Coolant Injection steam supply turbine inboard isolation valve backseating.

This document and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The modification is intended to allow maintenance personnel to eliminate or prevent stem packing leakage.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance (PM) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- 2OP-18, Core Spray System Operating Procedure, 2A Core Spray unplanned LCO entry when breaker inadvertently racked out
- WO 1152187, EDG #3 planned maintenance outage
- WO 1452939, 1A RCR pump after seal replacement
- 0PT-08.1.4a, RHR Service Water System Operability Test- Loop A, 2A RHR service water booster pump planned loop maintenance

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following: the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing, and test documentation was properly evaluated. The inspectors evaluated the activities against TS and the UFSAR to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities for a scheduled Unit 1 maintenance outage conducted November 19 to November 24, 2008, and an unscheduled Unit 2 forced outage, conducted November 9 to November 15, 2008. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedules.

The inspectors observed or reviewed portions of the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup and heatup activities, and identification and resolution of problems associated with the outage.

The following specific areas were reviewed during the inspection period:

Outage Plan. The inspectors reviewed the outage plans to verify that the licensee has considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth.

Licensee Control of Outage Activities. The inspectors observed and reviewed activities and plant conditions to verify that the licensee maintained defense-in-depth commensurate with the outage risk control plan. The inspectors reviewed the electric power systems to ensure emergency power was available.

Monitoring of Startup Activities. The inspectors verified on a sampling basis, that TS, license conditions, and other requirements, commitments, and administrative procedure prerequisites for mode changes were met prior to changing modes or plant configurations. The inspectors observed and monitored the startup activities.

Identification and Resolution of Problems. The inspectors reviewed ARs to verify that the licensee was identifying problems related to outage activities at an appropriate threshold and entering them in the corrective action program. The inspectors reviewed the issues identified during the outage to verify that the appropriate corrective actions were implemented or planned. Documents reviewed in this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Routine Surveillance Testing

a. Inspection Scope

The inspectors either observed surveillance tests or reviewed the test results for the following activities to verify the tests met TS surveillance requirements, UFSAR commitments, in service testing requirements, and licensee procedural requirements. The inspectors assessed the effectiveness of the tests in demonstrating that the SSCs were operationally capable of performing their intended safety functions.

- Unit 2, 0PT-8.1.4b, RHR Service Water Operability Test Loop B on October 3, 2008
- Unit 1, 0PT-01.1.7, RPS Auto Scram Contacters Test on October 6, 2008
- Unit 1, 0PT-02.3.1b Suppression Pool to Drywell Vacuum Breaker Position Check on October 9, 2008
- Unit 2, 0PT-12.2c, EDG #3 Monthly Load Test on October 15, 2008
- Unit 1, 0PT-16.1.1, Containment Atmospheric Control System Valve Operability on October 19, 2008
- Periodic Test 1OI-03.1, Control Operator Daily Surveillance Report (including drywell leakage rate determination) performed the week of December 8, 2008
- Periodic Test 2OI-03.2, Control Operator Daily Surveillance Report (including drywell leakage rate determination) performed the week of December 8, 2008

b. Findings

No findings of significance were identified.

.2 In Service Testing (IST) Surveillance

a. Inspection Scope

The inspectors reviewed the performance of 0PT-8.2.2b, LPCI/RHR System Operability Test Loop B for Unit 2 on October 1, 2008, to evaluate the effectiveness of the licensee's American Society of Mechanical Engineers (ASME) Section XI testing program for determining equipment availability and reliability. The inspectors evaluated selected portions of the following areas: 1) testing procedures, 2) acceptance criteria, 3) testing methods, 4) compliance with the licensee's IST program, TS, selected licensee commitments, and code requirements, 5) range and accuracy of test instruments, and 6) required corrective actions.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

To verify the accuracy of the PI data reported to the NRC, the inspectors compared the licensee's basis in reporting each data element to the PI definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, Regulatory Assessment Indicator Guideline.

Mitigating Systems Cornerstone

- Mitigating Systems Performance Index, High Pressure Injection System (HPCI) (Unit 1 & Unit 2)
- Mitigating Systems Performance Index, Heat Removal System (RCIC) (Unit 1 & Unit 2)

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) performance indicators listed above for the period from the fourth quarter of 2007 through the third quarter of 2008. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection reports for the period to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Appendix to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of items Entered Into the Corrective Action Program

a. Scope

To aid in the identification of repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed frequent screenings of items entered into the licensee's corrective action program (CAP). The review was accomplished by reviewing daily action request reports.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Trend Review

a. Scope

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' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of July through December 2008, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

b. Assessments and Observations

No findings of significance were identified. The inspectors noted a continuing trend in the area of work control and work practices; this was exemplified by the following identified issues: 1) emergency diesel generator (EDG) alternate safe shutdown switch modification, which would render the EDGs inoperable during a fire concurrent with an auto start signal (AR292232); 2) Unit 2 scram from a Power Load Unbalance Trip while work was being performed in the switchyard (AR294164); 3) Unit 2 scram after SRV 'H' opened at power as a result of inadequate spring installation (AR305697); 4) Unit 1 scram due to an improperly seated EHC card while synchronizing to the grid (AR308480). The inspectors have determined that the licensee has addressed all immediate operability concerns, and is currently developing long-term improvements.

.3 Annual Sample: Review of Operator Workarounds (OWAs)

a. Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the attachment were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their corrective action program and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an initiating event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

b. Findings

No findings of significance were identified.

4OA3 Follow-up of Events (71153)

.1 Unit 2 Scram

a. Inspection Scope

The inspectors reviewed the plant's response to an unplanned scram on November 9, 2008, when Unit 2 was manually scrammed when suppression pool temperatures rose due to an inadvertent lift of the H safety relief valve. On November 15, 2008, after replacing the H safety relief valve, Unit 2 was restarted. To assess operator performance during the transient, the inspectors reviewed operator logs, plant computer data, associated operator actions and Emergency Operating Procedure 2EOP-01-RSP, Reactor Scram Procedure. The inspectors monitored and reviewed the Scram Investigation Team and the post-trip review. Unit 2 entered Mode 4 (Cold shutdown) following the scram on November 9. Mode 1 (Power Operation) was entered on November 15, 2008. Documents reviewed are listed in the Attachment.

b. Findings

i. Failure to Follow Plant Procedures for Assembly of Safety Relief Valves

Introduction. A self-revealing Green NCV of TS 5.4.1, Procedures, was identified when the licensee failed to correctly reassemble the pilot valve for the Unit 2 Safety Relief Valve (SRV) H. The plant procedure for assembly of the pilot valve, 0CM-VSR-509, Main Steam Relief Valves Target Rock Model 7567 Air Operators and Pilot Assembly, Disassembly, Inspection, and Reassembly, used in 2006 for the Unit 2 SRV H pilot valve specifies that, during assembly, the pilot spring should be placed inside of the pilot valve spring follower. Contrary to this requirement, the pilot valve was assembled with the pilot spring on the ledge of the pilot valve spring follower. The incorrectly assembled pilot valve was installed in Unit 2 in March 2007 on SRV H. On November 9, 2008, the spring slipped off the ledge of the spring follower, reducing the SRV set point pressure, and causing the SRV to lift at normal operating pressure.

Description. On November 9, 2008, while operating Unit 2 at 100 percent power and normal operating pressure (1030 psig), SRV H opened, causing reactor pressure to decrease and suppression pool temperature to increase. Operators took actions to shut the SRV by cycling the SRV switch and removing fuses for the SRV actuator, but the SRV did not shut. When suppression pool temperature reached approximately 100ºF, plant operators manually scrammed the reactor per plant procedures. SRV H reclosed when reactor pressure dropped to approximately 990 psig.

In 2006, licensee personnel rebuilt a pilot valve (ultimately installed on SRV H) using plant operating manual for corrective maintenance, 0CM-VSR-509. Step 2.b of section 7.9.1 of this procedure directs that the pilot spring be placed inside the spring follower. However, upon disassembly, there was evidence that the spring had been placed on the spring follower ledge. This evidence consisted of several scoring marks on the spring, the spring follower, and other pilot valve components. These scoring marks showed that 1) the spring was resting on the ledge of the spring follower; 2) the opposite side of the spring was resting toward the center of the spring follower; and, 3) the resultant side loading forces caused friction between other pilot valve internal components. With the spring on the spring follower ledge, the SRV passed certification testing in 2006. The pilot valve was then installed on SRV H in Unit 2 in March 2007. During normal operations, the SRV is subjected to vibration from the main steam line that it is mounted on. On November 9, 2008, it was postulated that this vibration caused the SRV H pilot valve spring to slip into its proper position inside of the spring follower. After the spring slipped into its proper position it lengthened, changing the amount of force it was applying to the pilot valve disc assembly, and reducing the valve's lift set point. The SRV set point was reduced sufficiently to allow the valve to open at normal operating pressure. The licensee replaced the failed SRV and initiated a root cause analysis to determine the primary and contributing cause of this event.

Analysis. The failure to assemble the SRV pilot per procedure was identified as a performance deficiency. The performance deficiency was more than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone, and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was determined to be of very low safety significance because the finding does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding has a cross-cutting aspect of procedural compliance, as described in the Work Practices component of the Human Performance cross-cutting area because the licensee failed to follow the procedure as written. (H.4(b)).

Enforcement. TS 5.4.1, Administrative Control (Procedures), requires that written procedures shall be established, implemented, and maintained, covering applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972 (Safety Guide 33, November 1972). Section I.1 of Regulatory Guide 1.33, Appendix A, November 1972 (Safety Guide 33, November 1972) states that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, in 2006, the licensee failed to follow a procedure for corrective maintenance, 0CM-VSR-509, Main Steam Relief Valves Target Rock Model 7567 Air Operators and Pilot Assembly Disassembly, Inspection, and Reassembly, to reassemble SRV H pilot valve S/N 1101. Specifically, licensee personnel incorrectly assembled the pilot valve when they placed the pilot spring on the ledge of the pilot valve spring follower instead of on the inside of the pilot valve spring follower per section 7.9.1 step 2.b. of procedure 0CM-VSR-509, Pilot Stage Assembly Reassembly. The incorrectly assembled pilot valve was installed in Unit 2 in March 2007, on SRV H. On November 9, 2008, the spring slipped off the ledge of the spring follower, reducing the SRV set point pressure, and causing the SRV to lift at normal operating pressure. Because the finding is of very low safety significance and has been entered into the CAP (AR 305697), and consistent with Section VI.A.1 of the NRC Enforcement Policy, this violation is being treated as a non-cited violation, and is designated as NCV 05000325/2008005-01, Failure to Follow Plant Procedures for Assembly of Safety Relief Valves.

ii. Failure to Take Prompt Corrective Actions for Low Oil Level in the 2B RHRSW Booster Pump

Introduction. The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action” for failure to assure that a condition adverse to quality was promptly corrected, which resulted in the licensee declaring the 2B RHRSW booster pump inoperable while responding to the Unit 2 reactor scram on November 9, 2008.

Description. On October 3, 2008, the 2B RHRSW booster pump was run for a post maintenance test. After the pump ran, an oil sample was taken and approximately 16 ounces of oil was removed from the pump bearing casing. Due to the direction of rotation of the 2B RHRSW booster pump, after oil is removed from the bearing casing, the oil reservoir (glass bubbler) will lower as oil is transferred from the reservoir side of the casing to the opposite side of the bearing. After replenishing oil to the bearing casing, the 2B RHRSW booster pump may not indicate correctly if the pump is not run. After replenishing the oil after the oil sample on October 3, 2008, however, only the reservoir side of the bearing casing was filled with oil and the 2B RHRSW booster pump was not run. Therefore, the 2B RHRSW booster pump casing was not full.

The 2B RHRSW booster pump was next run on October 18, 2008. After the pump ran, plant operators found the oil reservoir empty. Maintenance personnel added approximately 6 ounces of oil to the reservoir, but the pump was not run after the oil was added to ensure the bearing casing was completely full. Also, a nuclear condition report (NCR) was not written to investigate the cause of the empty oil reservoir. Therefore, no further action was taken.

On November 9, 2008, the 2H safety relief valve inadvertently actuated. The unit 2 reactor was scrammed and suppression pool temperature reached 112º F. After placing the 2B RHRSW booster pump in service for suppression pool cooling, operators again discovered the oil reservoir empty. Main control room operators turned the pump off and declared it inoperable because they could not determine if the pump had sufficient oil to operate safely. Maintenance personnel later found that the oil in the bearing casing was at the minimum level and added more oil, raising the oil level to the visible range of the reservoir.

Analysis. The deficiency associated with this event is not promptly investigating and correcting the low oil level in the 2B RHRSW booster pump bearing. The finding is more than minor because it affects the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). It is also associated with the cornerstone attribute of equipment availability and reliability. Since the finding affects both core damage frequency (CDF) and suppression pool cooling, an evaluation using NRC Inspection Manual Chapter (IMC) 0609, Appendix H, “Containment Integrity Significance Determination Process” was performed. Appendix H table 4.1 lists suppression pool cooling as a contributor to late containment failure, but not large, early release frequency (LERF). Therefore the change in CDF associated with the finding was used to characterize its significance. Using the NRC, pre-solved phase two significance determination process worksheets, the change in core damage frequency was found to be less than 1E-6, therefore this finding is of very low safety significance (Green). The cause of the finding is related to the cross-cutting aspect of thoroughly evaluating problems as described in the Corrective Action Program component of the Problem Identification and Correction cross-cutting area, since the low oil level was identified, but a thorough investigation of the problem was not promptly performed. P.1(c)

Enforcement. 10 CFR 50, Appendix B, Criterion XVI requires, in part, that conditions adverse to quality, such as equipment deficiencies, be promptly identified and corrected. Contrary to the above, the licensee did not implement prompt corrective actions for a condition adverse to quality. Specifically, the licensee did not correct the low oil condition in the 2B RHRSW booster pump bearing cavity on October 18, 2008 when the oil reservoir was found empty. Because this finding is of very low safety significance and has been entered into the licensee’s corrective action program (NCR 305727), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000324/2008005-02 Failure to Take Prompt Corrective Actions for Low Oil Level in the 2B RHRSW Booster Pump.

.2 Unit 1 Scram

a. Inspection Scope

The inspectors reviewed the plant's response to an unplanned scram that occurred on November 26, 2008, while synchronizing the generator to the grid. The Unit 1 reactor automatically scrammed due to a malfunction in the turbine electro-hydraulic control system. Repairs were made to the turbine electro-hydraulic control system and the Unit 1 reactor was restarted on November 28, 2008. To assess operator performance during the transient, the inspectors reviewed operator logs, plant computer data, associated operator actions and Emergency Operating Procedure 2EOP-01-RSP, Reactor Scram Procedure. The inspectors monitored and reviewed the Scram Investigation Team and the post-trip review. Unit 1 entered Mode 4 (Cold shutdown) following the scram on November 26. Mode 1 (Power Operation) was entered on November 28, 2008. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.3 Inoperability of 2A Core Spray Pump Due to Operator Error

a. Inspection Scope

The inspectors reviewed operators' response to an unplanned event which made the 2A Core Spray pump inoperable on November 5, 2008. To assess operator performance, the inspectors reviewed operator logs and plant computer data, and interviewed operations and management personnel.

b. Findings

Introduction: A self-revealing Green NCV of Technical Specification 5.4.1, Procedures, was identified for failure to comply with clearance order 180845 and 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 kV Breaker. Specifically, the 2A Core Spray pump breaker was inadvertently racked out instead of the Emergency Diesel Generator #3 output breaker.

Description: During planned maintenance on November 5, 2008, the Emergency Diesel Generator #3 was placed under clearance order 180845 to support repairs due to an emergent air leak. A pre-job brief was conducted for the clearance order and for 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 KV Breaker. The Auxiliary Operator (AO) assigned to the Operations Center was assigned as the safety observer. A second AO was also assigned to this task and was chosen to rack out breaker. Since the second AO was not qualified to rack out 4kV breakers, he was racking out the breaker for training under the instruction of the first AO. While preparing to rack out the Emergency Diesel Generator #3 output breaker, the first AO provided a peer check that the proper breaker was selected. The first AO then relocated outside the safety boundary and out of the line-of-sight of the second AO. As the second AO prepared to operate the Emergency Diesel Generator #3 output breaker, his flash hood fell forward, and required adjustment. The second AO placed the racking tool on the floor, adjusted his hood, and picked up the racking tool again. The second AO then inserted the racking tool into the 2A Core Spray pump breaker, which is adjacent to Emergency Diesel Generator #3 output breaker. Therefore, the wrong breaker was racked out. The 2A Core Spray pump breaker was racked back into place approximately thirty minutes later.

Analysis: The failure to comply with clearance order 180845 and 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 kV Breaker, was identified as a performance deficiency. The performance deficiency was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone objective to maintain the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be of very low safety significance because the finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time, did not represent an actual loss of safety function of one or more non-Tech Spec trains of equipment designated as risk-significant per 10 CFR 50.65 for greater than 24 hrs, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The finding has a cross-cutting aspect of human error prevention, as described in the Work Practices component of the Human Performance cross-cutting area because the licensee inadvertently racked out the wrong breaker. (H.4(a))

Enforcement: TS 5.4.1, Administrative Control (Procedures), requires that written procedures shall be established, implemented, and maintained, covering applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972 (Safety Guide 33, November 1972). Section I.1 of Regulatory Guide 1.33, Appendix A, November 1972 (Safety Guide 33, November 1972) states that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on November 11, 2008, the licensee failed to comply with clearance order 180845 and 2OP-50, Plant Electric System Operating Procedure, Section 8.1, Racking Out a 4 kV breaker. Specifically, the 2A Core Spray pump breaker was inadvertently racked out instead of the Emergency Diesel Generator #3 output breaker. Because the finding is of very low safety significance and has been entered into the CAP (AR 305192), and consistent with Section VI.A.1 of the NRC Enforcement Policy, this violation is being treated as a non-cited violation, and is designated as NCV 05000325/2008005-03, Inoperability of 2A Core Spray Pump Due to Operator Error.

.4 (Closed) Licensee Event Report (LER) 05000325/2008005: As-Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowed Tolerance. This LER reported that as-found testing for two of the eleven safety/relief valves removed from Unit 1 during the Spring 2008 outage (i.e., B117R1) were outside the TS allowed set point tolerance. An additional safety/relief valve could not be tested due to excessive pilot valve leakage. The cause of the failure of the valves was due to maintenance practices. The licensee has instituted corrective actions to preclude recurrence, including replacing all of the affected valves and revising maintenance procedures. The failure of these three safety/relief valves to lift within the allowed set point limits constituted a condition prohibited by TS 3.4.3. This finding is similar to example 2a of Manual Chapter 0612 appendix E in that the equipment exceeded technical specification limits and the finding is therefore greater than minor. However, an evaluation of the as-found condition of the safety/relief valves was compared to the current overpressure analysis. The analysis concluded that the overpressure analysis remained bounding. Since the valves' degradation would have had a minimal impact on design basis events, this finding has very low safety significance (Green). The enforcement aspects of this finding are discussed in Section 4OA7 of this report. This LER is closed.

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 of significance were identified.

.2 (Closed) URI 05000325,324/2008002-02, Review the Significance of the Storm Drain Stabilization Pond Evaporation Pathway Dose Compared to Doses from All Other Pathways.

An unresolved item (URI) was identified regarding the significance of the Storm Drain Stabilization Pond (SDSP) evaporation pathway dose in regard to meeting the requirement of the Offsite Dose Calculation Manual (ODCM) that dose assessments are required to be consistent with the methodology provided in Regulatory Guide 1.109, "Calculating of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix I." Specifically, RG 1.109 specifies that exposure pathways that may arise due to unique conditions at a specific site should be considered if they are likely to provide a significant contribution to the total dose. A significant pathway is considered one whose additional dose increment is equal to or greater than ten percent of the total from all pathways. Based on the preliminary assessment of doses to the public in 2007 from the SDSP via the evaporation pathway as compared to the 2006 annual effluent release data, the potential existed that this previously unevaluated pathway exceeded ten percent of the total dose for 2007 and should be included in the ODCM. The item was unresolved pending NRC review and evaluation of the final dose assessment for the SDSP evaporation pathway and the total public dose for 2007 that was to be reported in the 2007 Radiological Effluent Release Report.

Subsequently, as part of the review of the 2007 Radiological Effluent Release Report, the inspectors assessed the doses calculated to members of the public from established ODCM pathways. The inspectors also evaluated the public doses calculated for evaporation and seepage of tritiated water from the SDSP, doses for which calculational methodologies were not specified in the ODCM. The inspectors determined that the dose calculated for the ODCM gaseous pathway for tritium, particulates, and iodines was based on hypothetical individuals. Specifically, the organ doses were calculated/reported for an infant located 4.75 miles from the site, with the maximally exposed organ being the thyroid primarily because of the inclusion of the hypothetical grass-cow-milk ingestion pathway. The doses calculated for the SDSP releases, in contrast, were based on the actual adult member of the public living nearest the site boundary.

Review and discussion of these observations with the Office of Nuclear Reactor Regulation (NRR) determined that evaporation of tritiated water from the SDSP did not comprise a new exposure pathway, as defined in RG 1.109, in that the inhalation pathway for gaseous effluent releases was a defined exposure pathway in the ODCM and evaporation was included in the inhalation pathway. Rather, the evaporation of tritiated water from the SDSP represented a new release source. Consequently, the question raised with respect to whether the SDSP was a significant pathway was not technically accurate, because it is a release source not an exposure pathway.

With respect to the dose assessment, RG 1.109 states that the licensee is allowed to demonstrate compliance with 10 CFR 50, Appendix I "at a location where an exposure pathway and dose receptor actually exist at the time of licensing." Thus the use of the hypothetical grass-cow-milk exposure pathway to demonstrate compliance with the design objectives of 10 CFR 50, Appendix I, as proscribed by the ODCM, was acceptable because the exposure pathway existed at the time of licensing. However, RG 1.109 also states that the licensee "is encouraged to use information and data applicable to a specific region or site when possible." Based on that guidance, the licensee can choose to demonstrate compliance at the actual location of the highest exposed individual, as was the case for the dose calculated for evaporation of tritiated water from the SDSP. For purposes of demonstrating compliance with 10 CFR 50, Appendix I and reporting in the annual effluent report, it would be appropriate to either use the pathways and receptors that existed at the time of licensing or the actual location of the highest exposed individual rather than a mix of the two approaches. To this end, the inspectors reviewed a subsequent dose calculation from the evaporated tritium to an infant located 4.75 miles from the site. Based on this review, the inspectors determined that the additional dose was only a small contribution to the total dose and that the licensee was in compliance with the design objectives of 10 CFR 50, Appendix I. This URI is closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 12, 2009, the inspector presented the inspection results to Mr. Ben Waldrep, and other members of the licensee staff. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

4OA7 Licensee-Identified Violations

The following finding of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

Technical Specification Limiting Condition for Operation 3.4.3, Safety/Relief Valves, requires 10 safety/relief valves to be operable while in Mode 1 with their lift set points within a specified range. Contrary to this, during surveillance testing on safety/relief valves removed from Unit 1 during the spring 2008 refueling outage (B117R1), three of the eleven valves did not actuate within TS limits. This was identified in the licensee's CAP (AR 287535). This finding is of very low safety significance because the as-found lift set point conditions of the Unit 1 safety/relief valves were analyzed and determined to meet the design basis criteria for an over-pressurization event.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
M. Annacone, Director Site Operations
G. Atkinson, Supervisor - Emergency Preparedness, Licensing/Regulatory Programs
L. Beller, Superintendent, Operations Training
A. Brittain, Manager – Security
B. Davis, Manager – Engineering
J. Fergusen, Manager - ER&C
L. Grzeck, Lead Engineer - Technical Support
S. Howard, Manager - Operations
R. Ivey, Recovery Manager
J. Johnson, Chemistry Manager
P. Mentel, Manager, Support Services
M. Millinor, Environmental
W. Murray, Licensing Specialist
T. Pearson, Supervisor - Operations Training
A. Pope, Manager - Maintenance
E. Rochelle, RC Supervisor
T. Sherrill, Engineer - Technical Support
J. Titrington, Manager - Nuclear Oversight Services
M. Turkal, Lead Engineer - Technical Support
J. Vincelli, RC Manager
B. Waldrep, Site Vice President
M. Williams, Manager - Training Manager
E. Wills, Plant General Manager

NRC Personnel
Harold Christensen, Deputy Division Director, Division of Reactor Safety, Region II
Randall A. Musser, Chief, Reactor Projects Branch 4, Division of Reactor Projects, Region II

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000324/2008005-01	NCV	Failure to Follow Plant Procedures for Assembly of Safety Relief Valves (Section 4OA3)
05000324/2008005-02	NCV	Failure to Take Prompt Corrective Actions for Low Oil Level in the 2B RHRSW Booster Pump (Section 4OA3)
05000324/2008005-03	NCV	Inadvertent Rack Out of the 2A Core Spray Pump Circuit Breaker (Section 4OA3)
05000325,324/2008005-04	NCV	Failure to Correctly Perform Biennial Written Examination for a Licensed Operator (Section 1R11)

Closed

05000325/2008005	LER	As-Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowed Tolerance (Section 4OA3)
05000325,324/2008002	URI	Review the significance of the storm drain stabilization pond evaporation pathway dose compared to doses from all other pathways (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

0AOP-13.0, Operation during Hurricane, Flood Conditions, Tornado, or Earthquake
0AI-68, Brunswick Nuclear Plant Response to Severe Weather Warnings
0PEP-02.6, Severe Weather
0OI-01.03, Non-Routine Activities
0PM-HT001, Preventative Maintenance on Plant Freeze Protection and Heat Tracing System

Section 1R04: Equipment Alignment

0OP-50.1, Diesel Generator Emergency Power System Operating Procedure
Drawing D-02265, sheets 1A and 1B, drawing D-02266, sheets 2A and 2B, Piping Diagram for Diesel Generators Starting Air System Units 1 and 2
Drawing D-02268, sheets 1A and 1B, drawing D-02269, sheets 2A and 2B, Piping Diagram for Diesel Generators Fuel Oil System Units 1 and 2
Drawing D-02270, sheets 1A and 1B, drawing D-02271, sheets 2A and 2B, Piping Diagram for Diesel Generators Lube Oil to Lube Oil System Units 1 and 2
Drawing D-02272, sheets 1A and 1B, drawing D-02273, sheets 2A and 2B, Piping Diagram for Diesel Generators Jacket Water System Units 1 and 2
Drawing D-02272, sheets 1A and 1B, drawing D-02273, sheets 2A and 2B, Piping Diagram for Diesel Generators Jacket Water System Units 1 and 2
Drawing D-02274, sheets 1 and 2, Piping Diagram for Diesel Generators Service and Demineralized Water System Units 1 and 2

Section 1R05: Fire Protection

0PFP-013, General Fire Plan
1PFP-RB, Reactor Building Prefire Plans Unit 1
1PFP-TB, Turbine Building Prefire Plans Unit 1
2PFP-RB, Reactor Building Prefire Plans Unit 2
2PFP-TB, Turbine Building Prefire Plans Unit 2
0AP-13 Plant Equipment Control
0AP-50, Site Command, Control, and Communications Manual
0OP-41, Fire Protection and Well Water System
0PEP-2.1, Initial Emergency Actions
0TPP-219, Fire Protection Training Program
0PFP-MBPA, Miscellaneous Buildings Pre-Fire Plans – Protected Area
OPS-NGGC-1303 Independent Verification
0PT-34.11.2.0, Portable Fire Extinguisher Inspection
SAF-NGGC-2172 Industrial Safety
AR 303381, Failed fire drill
AR 309905, Fire drill response

Section 1R07: Heat Sink Performance

0ENP-2704, Administrative Control of NRC Generic Letter 89-13 Requirements
0MST-DG500R, Emergency Diesel Generators 24 Month Inspection

Section 1R11: Licensed Operator Requalification

0TPP, Licensed Operator Continuing Training Program
TRN-NGGC-0014, NRC Initial Licensed Operator Exam Development and Administration

1EOP-01-LPC, Level/Power Control
0AOP-30.0, Safety/Relief Valve Failures
0PEP-2.1.1, Emergency Control – Notification of Unusual Event, Alert, Site Area Emergency, or General Emergency
0PEP-02.1, Initial Emergency Actions
EOP-01-LEP-02, Alternate Control Rod Insertion
1OP-05, Standby Liquid Control System

Procedures:

SI-216.1, Brunswick Simulator Instruction, Rev. 17
OTPP-206, Simulator Program, Rev. 3
TAP-403, Conduct of Examinations, Rev. 10
TAP-411, Continuing Training Annual/Biennial Exam Development, Administration and Security, Rev. 9
0AI-101, Observation Program, Rev. 21
0OI-01.05, License Activation and Maintenance, Rev. 15

Written Examinations Reviewed:

All 2006/2007 Biennial Written Examinations (5 Reactor Operator/6 Senior Reactor Operator)

Simulator Documents:

TAP-409, Conduct of Simulator Training
TAP-412, Simulator Operations and Maintenance, Rev. 3

Transient Tests (2006 & 2007):

STP-TN-001, Simulator Tests procedure, Simultaneous Trip of Both Recirc. Pumps, Rev.2
STP-TN-004, Simulator Test Procedure, Manual Scram

Malfunction Tests:

- IST-6.12.3, Reactor Coolant Pump Trip, 2002 and 2006
- IST-6.7.1.2, Loss of Normal and Emergency Feedwater, 2001 and 2005
- IST-6.11.5, Pressurizer Pressure Channel Failure, 2002 and 2006
- IST-6.15.1, Inadvertent Turbine Trip, 2003 and 2007
- IST-6.7.8, Feed Line Break Inside Containment, 2000 and 2004

Job Performance Measures (JPMs)

LOT-SIM-JP-050-B01, Manual Transfer of E-Bus from the Normal Feeder to the DG, Rev 6
LOT-SIM-JP-010-A02, Vent the Drywell per OP-10 w/ Stack Rad Monitor Increase >50%, Rev. 4
LOT-SIM-JP-007-A01, Bypass A Control Rod From The RWM Sequence, Rev. 3
LOT-SIM-JP-003-A03, Transfer RPS Bus B From Normal to Alternate Power, Rev. 3
LOT-SIM-JP-002-A05, Recovery From Reactor Recirculation Pump Runback, Rev. 1

LOT-OJT-JP-300-J18, Install Circuit Alterations to Bypass RPS per LEP-02 Section 3, Rev. 1
AOT-OJT-JP-300-K01, SEP-09 CRD Flow Maximization – Reactor Building Accessible, Rev. 1
AOT-OJT-JP-037.3-01, Changing Turbine Building Ventilation System from Once-Through to Recirculation Lineup, Rev. 0

Simulator Scenarios

LORX-007, ESS Cabinet Loss Of Normal Power, Loss of Stator Cooling, Main Turbine Bypass Failure, ATWS, Stuck Open Relief Valve
LORX-046 ECCS Instrument Failure, Loss of Off-Site Power, Small Break LOCA Requiring Emergency Depressurization

Article I - LERs

LER 2-2007-001

Other:

Assessment 215530, Operator Initial Training Programs, 5/14 – 5/18/2007
Assessment 259385, LOCT and NLOCT Training Program, 1/28 – 2/1/2008
Completed Detailed Observation Reports, BNP Plant Observation Program, 2008
Slide Presentation – NCR 227261, Control Rod moved in Quadrant with INOP SRM

Reactivation Records (4)
Medical Records (6)
Completed License Activation/Reactivation Forms, dated 1/2007 – 6/2008

Feedback Comments from Licensed Operator Requal 2006 thru 2007
Remedial Training Plans-Written Exam Failures (3)
Remedial Training Plans-As Found Exam Crew Failure (1)

Section 1R12: Maintenance Effectiveness

ADM-NGGC-0101, Maintenance Rule Program
NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants
AR 300623, 2B air compressor trip
AR 304669, 2D air compressor trip/entry into 0AOP-20.0
AR 306649, 2D air compressor leak after maintenance
AR 320169, Unit 1 service air compressor issue
AR 303073, Multiple ELU failures during 0MST-ELU11Q
AR 310915, U1 EHC pressure regulator bias adjustment

Section 1R13: Maintenance Risk Assessment and Emergent Work Control

0AP-022, BNP Outage Risk Management
ADM-NGCC-0104, Work Management Process
0AI-144, Risk Management

ADM-NGGC-0006, Online EOOS Model

Section 1R15: Operability Evaluations

OPS-NGGC-1305, Operability Determinations
OPS-NGGC-1307, Operational Decision Making

Section 1R18: Plant Modifications

EGR-NGGC-0005, Engineering Change
EGR-NGGC-0011, Engineering Product Quality
0SMP-MO003, Soft Electrical backseating of AC Motor operated Valves Using the Motor Operator

Section 1R19: Post Maintenance Testing

0PLP-20, Post Maintenance Testing Program

Section 1R20: Outage Activities

POM, Volume III, Operating Procedure 1OP17, Residual Heat Removal System Operating Procedure
POM, Volume IV, General Plant Operating Procedure 0GP-01, Prestartup Checklist
POM, Volume IV, General Plant Operating Procedure 0GP-02, Approach to Criticality and Pressurization of the Reactor
POM, Volume IV, General Plant Operating Procedure 0GP-03, Unit Startup and Synchronization
POM, Volume IV, General Plant Operating Procedure 0GP-12, Power Changes

POM, Volume XII, Special Maintenance Procedure 0SMP-RPV502, Reactor Vessel Reassembly
POM, Volume XII, Maintenance Management Manual 0MMM-015, Operation and Inspection of Cranes and Material Handling Equipment

Section 1R22: Surveillance Testing

POM, Volume II, Operating Instruction 1OI-03.1, Control Operator Daily Surveillance Report
POM, Volume II, Operating Instruction 2OI-03.2, Control Operator Daily Surveillance Report

Section 4OA1: Performance Indicator Verification

Procedures
REG-NGGC-0009, NRC Performance Indicators and Monthly Operating Report Data

Records and Data
Monthly PI Reports, December 2007 – November 2008

Section 4OA2: Problem Indentification and Resolution

Drawing D-02525, Reactor Building Residual Heat Removal System Piping Drawing

Section 4OA3: Event Followup

1OP17, Residual Heat Removal System Operating Procedure
2OP17, Residual Heat Removal System Operating Procedure
0GP-01, Prestartup Checklist
0GP-02, Approach to Criticality and Pressurization of the Reactor
0GP-03, Unit Startup and Synchronization
0GP-12, Power Changes
0OI-01.06, Post Scram Review
0MMM-015, Operation and Inspection of Cranes and Material Handling Equipment
AR 89705, Group 1 Isolation Due to EHC Malfunction
AR 305697, Spurious SRV Failing Open Requiring a Manual Reactor Scram
AR 305763, IRM 'H' Declared Inoperable Due To Spiking
AR 305780, IRM 'E' Inoperable Due To Erratic Operation
AR 306041, 2-B21-F010B Body To Bonnet Leak
AR 308480, Unit 1 Reactor Scram While Synchronizing To The Grid
AR 308534, Establish Burn-in Requirements For Critical Circuit Cards
AR 308536, #2 EDG Four Day Tank Level Indicator and Level Alarms Unreliable
AR 308547, Repetitive Rod Speed Adjustments
AR 308882, Unexpected Scoop Tube Lock of 1A Recirc MG Set
AR309192, EHC Card Altered Before As-Found Conditions Photographed
Work Order (WO) 1455676 Trouble-shoot Electro-Hydraulic Control System
Scram Investigation Team Report, November 9, 2008 Unit 2
WO 354955, 2B RHR SW Booster Pump Oil Addition Following Run