UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-8931

April 30, 2006

Carolina Power and Light Company
ATTN: Mr. James Scarola
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

SUBJECT: BRUNSWICK STEAM ELECTRIC PLANT - NRC INTEGRATED INSPECTION REPORT NOS. 05000325/2006002 AND 05000324/2006002

Dear Mr. Scarola:

On March 31, 2006, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Brunswick Units 1 and 2 facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed with Mr. T. Cleary and other members of your staff on April 13, 2006.

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.

As an incentive to encourage licensee participation in the International Atomic Energy Agency Operational Safety Review Team (OSART) Missions, the NRC determined that, for those NRC baseline inspections that overlap, either in part or fully, with an OSART review, a one-time regulatory credit (reduction in baseline inspection program), would be granted. Based on a review of the inspection report from an OSART inspection conducted at Brunswick in May, 2005, the NRC determined that Brunswick qualified for a 25% reduction of the inspection effort for two NRC inspection procedures (IPs) documented in the enclosed report. Specifically, credit was given for IP 71111.05Q, Fire Protection, and IP 71111.22, Surveillance Testing. As such, the scope of the inspection of these procedures was reduced by 25%.

This report documents two findings, one self-revealing finding and one NRC-identified, of very low safety significance (Green). The findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they had been entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. In addition, one licensee identified violation which was determined to be of very low safety significance is listed in Section 4OA7 of the enclosed report. If you contest any NCV in the enclosed 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 and its enclosure 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/

Paul E. Fredrickson, Chief
Reactor Projects Branch 4
Division of Reactor Projects

Docket Nos.: 50-325, 50-324
License Nos: DPR-71, DPR-62

Enclosure: Inspection Report 05000325/2006002, 324/2006002
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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 and its enclosure 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).

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T. P. Cleary, Director
Site Operations
Brunswick Steam Electric Plant
Progress Energy Carolinas, Inc.
Electronic Mail Distribution

Benjamin C. Waldrep
Plant Manager
Brunswick Steam Electric Plant
Carolina Power & Light Company
Electronic Mail Distribution

James W. Holt, Manager
Performance Evaluation and
Regulatory Affairs PEB 7
Carolina Power & Light Company
Electronic Mail Distribution

Edward T. O'Neil, Manager
Training
Carolina Power & Light Company
Brunswick Steam Electric Plant
Electronic Mail Distribution

Randy C. Ivey, Manager
Support Services
Carolina Power & Light Company
Brunswick Steam Electric Plant
Electronic Mail Distribution

Garry D. Miller, Manager
License Renewal
Progress Energy
Electronic Mail Distribution

Lenny Beller, Supervisor
Licensing/Regulatory Programs
Carolina Power and Light Company
Electronic Mail Distribution

David T. Conley
Associate General Counsel - Legal Dept.
Progress Energy Service Company, LLC
Electronic Mail Distribution

James Ross
Nuclear Energy Institute
Electronic Mail Distribution

John H. O'Neill, Jr.
Shaw, Pittman, Potts & Trowbridge
2300 N. Street, NW
Washington, DC 20037-1128

Beverly Hall, Acting Director
Division of Radiation Protection
N. C. Department of Environment
and Natural Resources
Electronic Mail Distribution

Chairman of the North Carolina
Utilities Commission
c/o Sam Watson, Staff Attorney
Electronic Mail Distribution

Robert P. Gruber
Executive Director
Public Staff NCUC
4326 Mail Service Center
Raleigh, NC 27699-4326

Public Service Commission
State of South Carolina
P. O. Box 11649
Columbia, SC 29211

David R. Sandifer
Brunswick County Board of
Commissioners
P. O. Box 249
Bolivia, NC 28422

Warren Lee
Emergency Management Director
New Hanover County Department of
Emergency Management
P. O. Box 1525
Wilmington, NC 28402-1525

Distribution w/encl: (See page 4)

Report to Mr. James Scarola from Paul E. Fredrickson dated April 30, 2006.

SUBJECT:BRUNSWICK STEAM ELECTRIC PLANT - NRC INTEGRATED INSPECTION REPORT NOS. 05000325/2006002 AND 05000324/2006002

Distribution w/encl:
B. Mozafari, NRR
R. Franovich, NRR (Regulatory Conferences Only)
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L. Slack, RII EICS
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REGION II

Docket Nos:	50-325, 50-324
License Nos:	DPR-71, DPR-62
Report Nos:	05000325/2006002 and 05000324/2006002
Licensee:	Carolina Power and Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	January 1, 2006 - March 31, 2006
Inspectors:	E. DiPaolo, Senior Resident Inspector J. Austin, Resident Inspector T. Nazario, Reactor Inspector (1R17) A. Nielson, Health Physicist [In-Office] (Section 4OA7)
Approved by:	Paul Fredrickson, Chief Reactor Projects Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000325/2006002, 05000324/2006002; 01/01/2006 - 03/31/2006; Brunswick Steam Electric Plant, Units 1 and 2; Surveillance Testing and Problem Identification and Resolution

The report covered a three-month period of inspection by resident inspectors and inspections by a reactor inspector and a health physics inspector. Two Green non-cited violations (NCVs) 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). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. An NRC-identified non-cited violation of Technical Specification 3.5.1, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling System, was identified for failure to appropriately evaluate and take corrective measures for a pre-existing flaw on a Unit 1 core spray loop B pipe weld (in-vessel) in accordance with Boiling Water Reactor Vessel and Internals Project guidelines which was committed to by the licensee. This resulted in the Unit 1 core spray loop B subsystem being inoperable for an indeterminate amount of time. The licensee entered the issue into the corrective action program, reevaluated the flaw and implemented a permanent repair of the pipe weld.

This finding is greater than minor because it is associated with core spray system equipment performance and affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance based on core spray loop B being conservatively assumed to be capable of mitigating all analyzed pipe breaks during the time period assumed, except the large break LOCA core damage sequence (Section 1R22).

Cornerstone: Initiating Events

Green. A self-revealing non-cited violation of Technical Specification 5.4.1, Administrative Controls (Procedures), was identified for failure to properly implement requirements for procedure adherence when rinsing a Unit 1 condensate deep bed demineralizer. Procedure steps for starting a third condensate pump when rinsing a condensate deep bed demineralizer at high power were marked N/A (not applicable) and the procedure was performed prior to obtaining supervisor concurrence. As a result, performance of the rinsing procedure on January 4, 2006, resulted in a reduction in condensate system pressure and a plant transient which challenged control room operators. The licensee entered the issue into the corrective action program for resolution. Operators took immediate actions by entering the appropriate abnormal operating procedure and stabilized the plant. In addition, a root cause investigation was performed and the responsible individuals were coached relative to their performance.

This finding is greater than minor because it is associated with system configuration control and affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Although the event contributed to the likelihood of a reactor trip, the finding is of very low safety significance because it did not contribute to the likelihood that mitigation equipment or functions would be unavailable. The cause of this finding is inadequate use of a condensate system procedure and inadequate adherence to a administrative procedure, and is therefore, identified as a performance aspect of the Human Performance cross-cutting area. (Section 4OA2.2).

B. Licensee Identified Violations

A violation of very low safety significance which was identified by the licensee was reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the Corrective Action Program. The violation and the licensee's corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the report period operating at full power. On January 4 the unit reduced power to approximately 90 percent in response to lowering condensate and feedwater pressures which occurred during rinsing of a condensate deep bed demineralizer (CDD). Full power was achieved later that day. On January 14 an unplanned downpower to 70 percent occurred due to the A recirculation pump running back. The runback was determined to be caused by a voltage transient experienced by the control system when the 230kV Castle Hayne offsite feeder experienced a fault. Full power was achieved later that day. On January 25, Unit 1 implemented final feedwater temperature reduction and commenced final coastdown. On March 3, a unit shutdown was performed to commence Refueling Outage (RFO) B116R1. Mode 5 (Refueling) was achieved on March 5. At the end of the inspection period, Unit 1 was still in Mode 5 after experiencing outage schedule delays due to the necessity to repair an in-vessel core spray line weld flaw.

Unit 2 began the report period operating at 96 percent power and increasing power following a planned downpower for fuel leak suppression testing, a drywell entry to add oil to the B recirculation pump motor, and to manually backseat the B recirculation pump discharge isolation valve which was exhibiting packing leakage. Full power was achieved on January 2. On March 10, the unit sustained an unplanned downpower to approximately 79 percent in response to lowering reactor vessel level due to the B reactor feedpump minimum flow failing open. Operators isolated the valve and returned the unit to full power on March 11. Another unplanned downpower to approximately 55 percent occurred on March 13 when the A reactor feed pump tripped on low lubricating oil pressure. The cause was due to the standby lubricating oil pump not starting when the operating pump failed. Following repairs to the failed pump and compensatory measures, to operate both lubricating oil pumps, the reactor feed pump was returned to operation. Full power was achieved on March 18. On March 31, the unit performed a planned downpower to approximately 52 percent for control rod scram time testing, and main turbine and main steam valve testing. The unit remained at approximately 52 percent for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns

The inspectors performed three partial walkdowns of the below listed systems to verify that the systems were correctly aligned while the redundant train or system was inoperable or out-of-service (OOS) or, for single train risk significant systems, while the system was available in a standby condition. The inspectors assessed conditions such as equipment alignment (i.e., valve positions, damper positions, and breaker alignment) and system operational readiness (i.e., control power and permissive status) that could - affect operability. The inspectors verified that the licensee identified and resolved equipment alignment problems that could cause initiating events or impact mitigating system availability. The inspectors reviewed Administrative Procedure ADM-NGGC-0106, Configuration Management Program Implementation, to verify that available structures, systems or components (SSCs) met the requirements of the configuration control program. Documents reviewed are listed in the Attachment.

- Unit 1 residual heat removal system loop B when loop A was OOS on February 23, 2006
- Emergency diesel generator (EDG) #1 when emergency bus E6 was OOS and affecting EDG #2 availability on March 24, 2006
- Unit 1 source range monitoring instrumentation operation verification in preparation for and during core alterations

To assess the licensee's ability to identify and correct problems, the inspectors reviewed the following action requests (ARs):

- AR 186830, Incorrect fuses found installed on Unit 1 A recirculation motor-generator set
- AR 186977, EDG #1 Reverse Power Alarm Relay
- AR 182771, Water leakage into turbine building breezeway around Unit 1 a reactor feed pump turbine control cabinet

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Area Walkdowns

The inspectors reviewed ARs and work orders (WOs) associated with the fire suppression system to confirm that their disposition was in accordance with Procedure OAP-033, Fire Protection Program Manual. The inspectors reviewed the status of ongoing surveillance activities to verify that they were current to support the operability of the fire protection system. In addition, the inspectors observed the fire suppression and detection equipment to determine whether any conditions or deficiencies existed which would impair the operability of that equipment. The inspectors toured the following seven areas important to reactor safety and reviewed the associated prefire plans to verify that the requirements for fire protection design features, fire area boundaries, and combustible loading were met. Documents reviewed are listed in the Attachment.

- Unit 1 Reactor Building East and West 80' Elevation (2 areas)
- Unit 2 Reactor Building East and West 80' Elevation (2 areas)
- Unit 1 Reactor Building North and South 20' Elevation (2 areas)
- Unit 1 Drywell (1 area)

To assess the licensee's ability to identify and correct problems, the inspectors reviewed AR 181821 which documented that the Unit 1 cable vault door (fire door #218) was found unlatched.

b. Findings

No findings of significance were identified.

1R11 Quarterly Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator performance and reviewed the associated training documents during simulator training sessions for training cycle 2006-01. The simulator observations and review included evaluations of emergency operating procedure and abnormal operating procedure utilization. The inspectors reviewed Procedure OTPP-200, Licensed Operator Continuing Training Program, to verify that the program ensures safe power plant operation. The inspector observed unit start-up training conducted on February 14, 2006. The scenarios tested the operators' ability to respond to various changing plant conditions and operations associated with plant start-up. The inspectors reviewed the operators activities to verify consistent clarity and formality of communication, conservative decision-making by the crew, appropriate use of procedures, and proper alarm response. Group dynamics and supervisory oversight, including the ability to properly identify and implement appropriate Technical Specification (TS) actions, regulatory reports, and notifications were observed. The inspectors observed instructor critiques and assessed whether appropriate feedback was provided to the licensed operators.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

For the two equipment issues described in the ARs listed below, the inspectors reviewed the licensee's implementation of the Maintenance Rule (10 CFR 50.65) with respect to the characterization of failures, the appropriateness of the associated Maintenance Rule a(1) or a(2) classification, and the appropriateness of the associated a(1) goals and corrective actions. The inspectors also reviewed operations logs and licensee event reports to verify unavailability times of components and systems, if applicable. Licensee performance was evaluated against the requirements of Procedure ADM-NGG-0101, Maintenance Rule Program. The inspectors also reviewed deficiencies related to the work activities documented in the ARs listed below to verify that the licensee had identified and resolved deficiencies in accordance with Procedure CAP-NGGC-0200, Corrective Action.

- AR 183102, High Pressure Coolant Injection (HPCI) system valve 1-E41-F079 failure to stroke during testing
- AR 186854, Failure of Relay 1-C11-K23B, refuel mode, one rod permissive relay

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's implementation of 10 CFR 50.65 (a)(4) requirements during scheduled and emergent maintenance activities, using Procedure OAP-025, BNP Integrated Scheduling and Technical Requirements Manual 5.5.13, Configuration Risk Management Program. The inspectors reviewed the effectiveness of risk assessments performed prior to changes in plant configuration for maintenance activities (planned and emergent). The review was conducted to verify that, upon unforseen situations, the licensee had taken the necessary steps to plan and control the resultant emergent work activities. The inspectors reviewed the applicable plant risk profiles, work week schedules, and maintenance WO's for the following five conditions involving OOS equipment:

- Unit 1 online risk condition Yellow while troubleshooting the B recirculation pump motor-generator on January 13, 2006 (emergent)
- Unit 1 online risk condition Yellow due to HPCI system valve I-E41-F079 failure to stroke on February 13, 2006 (emergent)
- Unit 1 online risk condition Yellow due to A Loop of residual heat removal system/residual heat removal service water system OOS on February 22, 2006 (planned)
- Unit 2 online risk condition Yellow during several work windows (March 19-25, 2006) on Unit 1 B battery and battery charger (planned)
- Unit 2 online risk condition Yellow following the 2A reactor feed pump trip while maintaining reactor power at 65%

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Plant Evolutions and Events

a. Inspection Scope

The inspectors observed and/or reviewed the following three transients and abnormal plant conditions to assess operator performance during non-routine evolutions and events. Operator logs, plant computer data, and associated operator actions were reviewed as well as the procedures listed in the Attachment.

- AR 180913, Unit 1 B recirculation pump motor-generator set speed increase unexpectedly on January 13, 2006
- AR 187526 Unit 2 entered AOP 23 due to unplanned trip of 2A reactor feed pump on 3/13/06
- AR 180041, Unit 1 entered Abnormal Operating Procedure (AOP) 23 Condensate/Feedwater System Failure, due to lowering condensate system pressures on January 4, 2006

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the operability evaluations associated with the following five issues documented in the ARs listed below, which affected risk significant systems or components, to assess, as appropriate: 1) the technical adequacy of the evaluations; 2) the justification of continued system operability; 3) any existing degraded conditions used as compensatory measures; 4) the adequacy of any compensatory measures in place, including their intended use and control; and 5) where continued operability was considered unjustified, the impact on any TS limiting condition for operation and the risk significance. In performing the review, the inspectors reviewed Nuclear Generation Group Standard Procedure, OPS-NGGC-1305, Operability Determinations, Rev. 0. In addition to the reviews, discussions were conducted with the applicable system engineer regarding the ability of the system to perform its intended safety function.

- AR 117143, EDG ductile iron piston potential defects
- Engineering Change (EC) 63335, Degraded condition evaluation of Unit 1 HPCI system valve E41-F079
- AR 182870, Control building inlet tornado damper failure
- AR 184467, Unit 2 Power Load Imbalance Operability Determination
- AR 186389, Unexpected one-half scram due to intermediate range nuclear instrument H noise

To assess the licensee's ability to identify and correct problems, the inspectors reviewed the following ARs:

- AR 181667, EDG power potential transformer pedestal anchor bolt embedment deficiency
- AR 180179, Transverse in-core probe drawer found with no power
- AR 185567, Unit 2 main turbine bypass valve #5 did not stroke properly during testing
- AR 183432, Control room tornado damper design requirements

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed a permanent plant modification documented in Engineering Change 61681, Increase Main Steam Isolation Valve Allowable Leakage. The inspectors reviewed the design adequacy of the modification for material compatibility which included functional properties, environmental qualification, and seismic evaluation. One purpose of the review was to verify that the modification met the design bases and the design assumptions. Another purpose was to verify that modification preparation, staging, and implementation did not impair emergency/abnormal operating procedure actions and key safety functions. The inspectors also reviewed the modification to verify that the post-modification testing would establish operability and that unintended system interactions would not occur, and that testing demonstrated that the modification acceptance criteria were met.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

For the five maintenance activities listed below, the inspectors reviewed the post-maintenance test procedure and witnessed the testing and/or reviewed test records to confirm that the scope of testing adequately verified that the work performed was correctly completed, and that the test demonstrated that the affected equipment was capable of performing its intended function and was operable in accordance with TS requirements. The inspectors reviewed the licensee's actions against the requirements in Procedure 0PLP-20, Post Maintenance Testing Program.

- WO-804707, Unit 1 B recirculation pump motor-generator speed increase
- WO-812268, Control building ventilation tornado damper not closing when tested
- WO-611619, SRM channel “C” Calibration and Functional Test
- WO 635910, 1-E11-F021A, Mechanical Inspection and Lubrication
- WO 825915, Replace Diesel Generator #1 Reverse Power Relay

To assess the licensee’s ability to identify and correct problems, the inspectors reviewed AR 189270 which documented that the Unit 1 reactor core isolation cooling system vacuum breaker check valves not opening as required following maintenance.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

The inspectors evaluated Unit 1 RFO B116R1 activities which commenced on March 3, 2006. At the end of the inspection period, Unit 1 was in Mode 5 after experiencing outage schedule delays due to the necessity to repair an in-vessel core spray line weld flaw. Documents reviewed are listed in the Attachment. The following specific areas were reviewed:

Outage Plan. The inspectors reviewed the Brunswick Nuclear Plant Unit 1 Safe Shutdown Risk Assessment for RFO B116R1. The inspectors verified that the licensee had considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. The inspectors’ review of this report was compared to the requirements in Procedure 0AP-022, BNP Outage Risk Management. The review verified that for identified high risk significant conditions, contingency measures were identified. The inspectors frequently monitored the risk condition during the outage.

Shutdown and Cooldown. The inspectors observed portions of the Unit 1 shutdown to enter the outage to verify that activities were in accordance with General Procedure 0GP-5.0, Unit Shutdown. The inspectors verified that the licensee monitored cooldown restrictions by performing 1PT-01.7, Heatup/cooldown Monitoring, to assure that TS cooldown restrictions were satisfied.

Licensee Control of Outage Activities. The inspectors observed and reviewed several specific activities, evolutions, and plant conditions to verify that the licensee maintained defense-in-depth commensurate with the outage risk control plan. The inspectors reviewed configuration changes due to emergent work and unexpected conditions were controlled in accordance with the outage risk control plan. The inspectors reviewed the following specific items, as specified:

- Decay Heat Removal, Spent Fuel Pool Cooling, and Reactor Coolant System Instrumentation. The inspectors reviewed decay heat removal procedures and observed decay heat removal systems' parameters to verify proper removal of decay heat and that reactor vessel level instruments were configured to provide accurate indication. The inspectors also conducted main control room panel walkdowns and walked down portions of the systems in the plant to verify system availability. The inspectors reviewed operational logs to verify that procedure and TS requirements to monitor and record reactor coolant temperature were met.

- Reactivity Control. The inspectors observed licensee performance during shutdown, outage, and refueling activities to verify that reactivity control was conducted in accordance with procedures and TS requirements. The inspectors conducted a review of outage activities and risk profiles to verify activities that could cause reactivity control problems were identified.

- Inventory Control and Containment Closure. The inspectors observed operator monitoring and control of reactor temperature and level profiles and monitored outage work and configuration control for activities that had the potential to drain the reactor vessel. This was performed to verify that the activities were performed in accordance with the outage risk plan. The inspectors reviewed containment control to confirm that secondary containment was maintained in accordance with TS.

- Electrical Power. The inspectors reviewed the following licensee activities related to electrical power during the refueling outage to verify that they were conducted in accordance with the outage risk plan:

    - Controls over electrical power systems and components to ensure emergency power was available as specified in the outage risk report
    - Controls and monitoring of electrical power systems and components and work activities in the power transmission yard
    - Operator monitoring of electrical power systems and outages to ensure that TS requirements were met

Refueling Activities. The inspectors reviewed refueling activities to verify fuel handling operations were performed in accordance with TS and fuel handling procedures and that controls were in place to track fuel movement. The inspectors reviewed refueling floor and plant controls to verify that the foreign material exclusion controls were established.

Identification and Resolution of Problems. The inspectors reviewed ARs to verify that the licensee was identifying problems related to refueling outage activities at an appropriate threshold and entering them in the corrective action program (CAP). The inspectors attended AR review meetings throughout the refueling outage to verify appropriate prioritization of planned resolution of deficiencies discovered during the outage. The inspectors reviewed the following issues identified during the outage to verify that the appropriate corrective actions were implemented:

- AR 185072, Testing requirements for refuel bridge-over-core limit switch
- AR 186357, Temporary vessel level instrument accuracy issues
- AR 186317, Unexpected mismatch of voltages while transferring in-house loads to startup auxiliary transformer
- AR 188907, Unit 1 B inboard main steam isolation valve stem galling
- AR 188516, Damaged fuel channel discovered while inserting fuel bundle into core location
- AR 186459, Cooldown rate of reactor vessel flange exceeded 100F/hour during floodup of vessel
- AR 188134, Loss of supplemental spent fuel pool cooling tower fans
- AR 187170, High voltages on emergency 480 volt substations

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

.1 Routine Surveillance Testing

a. Inspection Scope

The inspectors either observed surveillance tests or reviewed test data for the five risk significant SSC surveillances listed below, to verify the tests met TS surveillance requirements, Updated Final Safety Analysis Report commitments, in-service testing (IST), 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.

- Periodic Test, 0PT-13.1, Recirculation Jet Pump Operability, performed January 13, 2006 on Unit 1
- Periodic Test, 0PT-23.1.2, Tornado-Pressure Check Damper Test, performed on February 2, 2006
- Periodic Test, 0PT-20.3, Local Leak Rate Testing of A and C main steam lines on March 3, 2006 (containment isolation value)
- Periodic Test, 0PT-90.1, Vessel Internal Component Remote Examinations, perform on Unit 1 during refueling outage B116R1
- Control Operator Daily Surveillance Report, 1 OI-03.1 performed the week of March 5, 2006

To assess the licensee's ability to identify and correct problems, the inspectors reviewed the following ARs:

- AR 188102, Source range monitor channel check documentation
- AR 186771, Unit 1 A outboard main steam isolation valve local leak rate test failure
- AR 186327, Unit 1 C inboard main steam isolation valve slow closure time

b. Findings

.2 Inservice Surveillance Testing

a. Inspection Scope

The inspectors reviewed the performance of Periodic Test, 0PT-09.7, HPCI Valve Operability Test, on Unit 1 February 3, 2006, 2006. The inspectors evaluated the effectiveness of the licensee's American Society of Mechanical Engineers (ASME) Section XI testing program to determine 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. The inspectors also assessed any applicable corrective actions taken.

b. Findings

Introduction. The inspectors identified a failure to appropriately evaluate a flaw on a Unit 1 core spray loop B pipe weld. The flaw was determined to have rendered the core spray loop inoperable longer than the allowed outage time as specified in Technical Specification (TS) 3.5.1, Emergency Core Cooling Systems and Reactor Core Isolation Cooling System. Therefore, this inoperability resulted in a Green NRC-identified non-cited violation (NCV) of TS 3.5.1.

Description.

On March 15, 2006, while performing an in-vessel internal visual inspection on Unit 1 using new video technology, the licensee identified a new flaw in the core spray system B loop header weld (P3C-270) heat-effected zone. The B loop header piping is downstream of the header tee box near the vessel wall side of the pipe, inside the reactor vessel, but outside the core shroud. The location of the new flaw was previously inaccessible for visual inspection due to insufficient clearance between the pipe and the inner vessel wall surface. Weld P3C-270 contained a pre-existing flaw that was discovered during an inspection performed in 1993 and had been routinely monitored for crack growth during subsequent refueling outages. Ultrasonic test results of the weld revealed that, with the two flaws, a total of approximately 81 percent of the weld was flawed and that a repair of the weld was necessary. An operability determination of the as-found condition concluded that core spray B loop had been inoperable for an indeterminate amount of time based on its inability to remain intact and deliver the required injection flow to the loop spargers during a design basis accident. The licensee entered the issue into the CAP and initiated permanent repairs of the pipe weld.

The inspectors reviewed the history of the licensee's actions with respect to the core spray in-vessel pipe inspection and flaw evaluation. In-vessel core spray system cracking in boiling water reactors is a generic issue. In response to industry events, the NRC issued IE Bulletin 80-13, "Cracking in Core Spray Spargers". This bulletin requested detailed visual inspections of accessible vessel internal core spray sparger and header piping. In the event that flaws were identified, an evaluation was to be submitted to the NRC for approval. IE Bulletin 80-13 was closed-out in 1988 by NUREG/CR-4523, Closeout of IE Bulletin 80-13, "Cracking in Core Spray Sparger," based on licensee commitments to continue inspections, using guidance contained in IE Bulletin 80-13, at every refueling outage.

During in-vessel core spray inspections, using the guidance of IE Bulletin 80-13, on Unit 1 in 1993, the licensee identified a flaw on core spray B loop header weld P3C-270. An evaluation of the flaw was performed by General Electric (GE) and concluded that the core spray system was operable. Although portions of weld P3C-270 were uninspectable, the licensee accepted the flaw in the as-found condition and determined that the core spray system was operable for at least one additional cycle. The licensee submitted the results of the inspection and flaw evaluation to the NRC for approval in a letter (BSEP 93-0119) dated July 26, 1993. The NRC found the licensee's evaluation acceptable in an NRC Safety Evaluation (SE), dated January 14, 1994. The SE stated that continued operation beyond the following refueling outage was dependant on the satisfactory evaluation of the inspection results during the next refueling outage. Therefore, the licensee was requested to provide the results of the in-vessel core spray inspections and applicable evaluations to the NRC if permanent repairs were not performed.

In 1995, the licensee reinspected the core spray weld P3C-270 flaw and submitted the results of that inspection and evaluation to the NRC (BSEP 95-0216). The evaluation concluded that the core spray piping was acceptable in the as-found condition for the next operating cycle and referred to the previously performed 1993 GE evaluation. No further correspondence between the licensee and NRC was documented related to the flaw. The licensee continued to inspect the known flaw during subsequent outages using the guidance of IE Bulletin 80-13 and did not observe any change in flaw size; therefore, the licensee documented the results of each successive inspection and continued to accept the flaw based on technical justifications that referenced the 1993 GE evaluation.

In 1994, the Boiling Water Reactor Vessel Internals Project (BWRVIP) was formed to address generic issues with BWR vessel internals. In 1997, the BWRVIP issued BWRVIP-18, BWR Vessel and Internals Project BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines (Electric Power Research Institute Technical Report 106740). The inspectors identified that the guidance in IE Bulletin 80-13 was replaced by BWRVIP-18 in 1999. An NRC SE, dated December 2, 1999, documented a review of BWRVIP-18 and determined that it would provide acceptable levels of quality for inspection and flaw evaluation of core spray reactor pressure vessel internal components. The SE stated that the intent of BWRVIP-18 was to replace the inspection guidance contained in IE Bulletin 80-13. BWRVIP-18 contains guidance on assumptions to be used when evaluating flaws on piping welds that have uninspectable areas. The SE clarified that the “baseline” inspection described in BWRVIP-18 is the first inspection that satisfies the guidelines in BWRVIP-18. This inspection includes all accessible piping, sparger and attachment welds.

The inspectors found that, by at least 1997, the licensee was committed to implement the BWRVIP guidelines at Brunswick. A BWRVIP letter “BWR Utility Commitments to the BWRVIP”, dated May 30, 1997, to the NRC, stated that “all U.S. BWR/2-6 utilities identified in Attachment 1 have been active members of the BWRVIP since its inception in 1994". Attachment 1 listed Carolina Power and Light as a U.S. BWRVIP utility member. The letter further states, in part, that BWRVIP products would be implemented at utility member plants and if a plant does not implement the BWRVIP products, the plant will provide timely notification to the NRC staff. Additionally, in accordance with Engineering Procedure 0ENP-15, Reactor Vessel and Internals Structural Integrity Program, the licensee is required to implement new or revised BWRVIP guidelines as they are approved by the NRC. 0ENP-15 was originally issued in 2003. Periodic Test 0PT 90.1, Vessel Internal Component Remote Examinations, states that BWRVIP inspections were officially implemented, where possible, in the Spring 1998 refueling outage for Unit 1. The inspectors determined that after the licensee’s commitment to the BWRVIP guidelines, assumed to be no earlier than 1997, the licensee continued to evaluate the core spray weld P3C-270 flaw referring to the 1993 GE evaluation. The flaw was not “baselined” as described in the SE nor were assumptions from the BWRVIP guidelines used when evaluating the flaw for operability.

The BWRVIP guidelines uses a ‘2x’ approach for uninspectable areas, such as the core spray weld P3C-270 flaw . If the measured flaw was ‘x’ percent of the inspected length, then it must be assumed that ‘2x’ percent of the uninspected length is cracked. Subsequent to issuance of the SE, the licensee did not evaluate the pre-existing flaw on weld P3C-270 using this assumption. Through discussions with the licensee, the inspectors determined that weld P3C-270 would not have been acceptable for continued operation if the BWRVIP-18 flaw evaluation methodology would have been applied in previous evaluations.

Analysis. The licensee failed to appropriately evaluate and take corrective measures for a pre-existing flaw on the Unit 1 core spray loop B pipe weld P3C-270 in accordance with BWRVIP-18 which was committed to by the licensee. This resulted in the Unit 1 core spray loop B subsystem being inoperable for an indeterminate amount of time. This finding is greater than minor because it is associated with core spray system equipment performance and affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Although the core spray system mitigates several NRC Significance Determination Process Phase II core damage sequences, core spray loop B was still capable of mitigating all of the sequences with the exception of large break loss of coolant accident (LOCA). Making the conservative assumption that the flawed weld would not remain intact, core spray loop B was capable of delivering flow to the reactor vessel outside the shroud. Based on design calculations, the core would remain flooded over the entire fuel length and injection from any one emergency core cooling system pump is sufficient to maintain adequate core cooling for all sequences with the exception of the large break LOCA. In order for the core spray system to mitigate the large break LOCA, the core spray pattern over the top of the core must be maintained. Based on core spray loop B conservatively assumed to be not capable of mitigating only the large break LOCA core damage sequence during the time period assumed (i.e., one year), this finding was determined to be of very low safety significance (Green).

Enforcement. Technical Specification 3.5.1, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling System, requires each low pressure ECCS injection/spray subsystem be operable in Modes 1, 2 and 3. Contrary to Technical Specification 3.5.1, a crack was identified on March 15, 2006 on the Unit 1 Core Spray Loop B header piping which was determined to have rendered the loop inoperable for a past indeterminate amount of time (i.e., up to several cycles). Because this finding is of very low safety significance and has been entered into the licensee's CAP (ARs 188836 and 187867), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000325/2006002-01, Failure to Appropriately Evaluate Core Spray Header Piping Flaw.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Plant Operating Manual 0PLP-22, Temporary Changes, to assess implementation of EC 63335, Unit 1 HPCI Valve 1-E41-F079, Stroke Length Reduction. The inspectors reviewed these temporary modifications to verify that the modifications were properly installed and whether they had any effect on system operability. The inspectors also assessed drawings and procedures for appropriate updating and post-modification testing.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the Units 1 and 2 performance indicators (PIs) listed below for the period January 2004 through December 2005. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline", Revision 3, were used to confirm the reporting basis for each data element.

Reactor Safety Cornerstone

- Safety System Unavailability, Emergency AC Power Systems.
- Unplanned Scrams per 7,000 critical hours.
- Unplanned Scrams with Loss of Normal Heat Removal.

A sample of plant records and data was reviewed and compared to the reported data to verify the accuracy of the PIs. The licensee's corrective action program records were also reviewed to determine if any problems with the collection of PI data had occurred. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Routine Review of ARs

To aid in the identification of repetitive equipment failures or specific human performance issues for followup, the inspectors performed frequent screenings of items entered into the CAP. The review was accomplished by reviewing daily ARs.

.2 Annual Sample Review

a. Inspection Scope

The inspectors performed an in-depth annual sample review of the below-listed issues as documented in licensee correction action documents to verify that conditions adverse to quality were addressed in a manner that was commensurate with the safety significance of the issue. The inspectors reviewed the actions taken to verify that the licensee had adequately addressed the following attributes:

- Complete, accurate, and timely identification of the problem
- Evaluation and disposition of operability and reportability issues
- Consideration of previous failures, extent of condition, generic or common cause implications
- Prioritization and resolution of the issue commensurate with the safety significance
- Identification of the root cause and contributing causes of the problem
- Identification and implementation of corrective actions commensurate with the safety significance of the issue

The inspectors reviewed the following two issues:

- AR 179631, Unit 2 minimum critical power ratio exceeded Technical Specification Limiting Condition for Operation

- AR 180041, Unit 1 transient due to rinsing condensate deep bed demineralization on January 4, 2006

b. Findings

Introduction: A Green self-revealing NCV of TS 5.4.1, Administrative Controls (Procedures), was identified for failure to properly implement requirements for procedure adherence when rinsing a Unit 1 condensate deep bed demineralizer.

Description: On January 4, 2006, with Unit 1 at approximately 100 percent power, operators entered Abnormal Operating Procedure (AOP) 23, Condensate/Feedwater System Failure, due to lowering condensate system pressures. In accordance with AOP 23, operators reduced reactor power to approximately 90 percent power to stabilize the plant and to avoid an automatic plant response. At the time of the transient, operators were rinsing the A condensate deep bed demineralizer (CDD) to the main condenser in preparation for placing it in service following repairs.

The licensee determined that the cause for the reduction in condensate system pressure was due to rinsing the A CDD to the main condenser at full power with only two condensate pumps in operation. Operating experience demonstrated that rinsing CDDs at high condensate system flow rates, corresponding to reactor power levels of approximately 95 percent or greater, diverted enough condensate flow through the CDD to the main condenser, to induce a reduction in system pressure sufficient to cause a transient. Therefore, Operating Procedure 0OP-32.1, Condensate Deep Bed Demineralizer System, Rev. 68, Section 5.2, Manually Rinsing a Deep Bed Demineralizer From an Out-of-Service Condition, contained instructions that three condensate pumps should be running during high power operations while rinsing CDDs. In addition, the procedure requires notifying the control room operator that a lowering of condensate pump discharge pressure is possible during the rinse, and starting of an additional pump may be necessary. The operators (radioactive waste operators) marked this section of the procedure as N/A (not applicable) based on the CDD being in a filled and pressurized condition and, therefore, considered the CDD not OOS.

The licensee's investigation determined the root cause to be due to not meeting procedure use and adherence requirements of Nuclear Generation Group Standard Procedure PRO-NGGC-0200, Procedure Use and Adherence, Revision 8. Steps of 0OP-32.1 containing instructions to start a third condensate pump and to notify the control room operator, were marked N/A without the proper review by the responsible supervisor prior to performance. PRO-NGGC-0200 requires that steps or sections of procedures, that do not provide specific conditions for being marked N/A, may be marked as such, provided the step or section is concurred in by the responsible supervisor prior to performance. In this case, the responsible supervisor would have been a shift operator holding a senior reactor operator's license with sufficient integrated plant knowledge to recognize the necessity of starting the third condensate pump prior to rinsing the CDD. The licensee found that the pre-job brief for the evolution did not meet plant requirements in that critical tasks were not identified and internal operating experience for rinsing CDDs was not referenced.

Analysis: The improper marking of procedure steps in Operating Procedure 0OP-32.1, as N/A (not applicable) without obtaining concurrence by the responsible supervisor prior to performance of the procedure is greater than minor and resulted in a Unit 1 manual but unanticipated power reduction. The finding is more than minor because the procedure is associated with system configuration control and affected the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during power operations. This self-revealing finding was determined to be of very low safety significance (Green) because it did not contribute to the likelihood that mitigation equipment or functions would not be available. The finding was related to the cross-cutting area of Human Performance because the root cause was determined to be failure to adhere to procedures.

Enforcement: TS 5.4.1.a. requires that written procedures shall be implemented covering applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972. Regulatory Guide 1.33 requires written procedures for procedure adherence and for the operation of the BWR condensate system (including the demineralizers). Operating Procedure 0OP-32.1, Condensate Deep Bed Demineralizer System, Rev. 68, Section 5.2, Manually Rinsing a Deep Bed Demineralizer From an Out-of-Service Condition, contained instructions related to the number of running condensate pumps and situations when the control room must be notified. Nuclear Generation Group Procedure PRO-NGGC-0200, Procedure Use and Adherence, Revision 8, step 9.1.10.4 required that procedure steps or sections may be marked N/A (not applicable) provided the steps or section is initialed by the responsible supervisor prior to performance.

Contrary to these requirements, on January 4, 2005, procedure steps of Operating Procedure 0OP-32.1, Condensate Deep Bed Demineralizer System, Revision 68, were marked N/A and thus not performed, without being concurred in by the responsible supervisor, resulting in a Unit 1 power reduction which challenged control room operators. Because this finding is of very low safety significance and has been entered into the CAP (AR 180041), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000325/2006002-02, Failure to Follow Procedure Resulting in Condensate System Transient.

4OA3 Event Followup

The inspectors reviewed plant parameters and evaluated the significance upon the discovery of a flaw on the Unit 1 core spray loop B in-vessel pipe weld (AR 187867) which rendered the subsystem inoperable for a past indeterminate amount of time. The inspectors verified that the licensee properly assessed 10CFR50.72 notification requirements.

4OA5 Other

Implementation of Temporary Instruction (TI) 2515/165 - Operational Readiness of Offsite Power and Impact on Plant Risk

a. Inspection Scope

The objective of TI 2515/165, “Operational Readiness of Offsite Power and Impact on Plant Risk,” was to gather information to support the assessment of nuclear power plant operational readiness of offsite power systems and impact on plant risk. The inspectors evaluated licensee procedures against the specific offsite power, risk assessment and system grid reliability requirements of TI 2515/165. They also discussed the attributes with licensee personnel.

The information gathered while completing this TI was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On April 13, 2006, the resident inspectors presented the inspection results to Mr. T. Cleary and other members of his staff. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for disposition as an non-cited violation (NCV).

TS 5.4.1 requires the licensee to implement the procedures recommended by Regulatory Guide 1.33, Appendix A, November 1972, which includes access control procedures for radiation safety. Procedure 0E&RC-0040, Administrative Controls for High Radiation Areas, Locked High Radiation Areas, and Very High Radiation Areas, Rev. 26, requires the licensee to lock all Very High Radiation Area (VHRA) entryways to prevent unauthorized access. Contrary to this, on March 1, 2006, the outer airlock door into the U1 drywell (a VHRA when the unit is at power) was found unlocked. The unlocked door was discovered by a health physics technician who took immediate corrective actions. This event is documented in the licensee’s CAP as AR 186023. This finding is of very low safety significance because there were no overexposures, no substantial potential for overexposure, and no loss of ability to assess dose. In addition, the outer airlock door has an alarm which would alert control room operators if unauthorized entry was attempted.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Atkinson, Supervisor - Emergency Preparedness
L. Beller, Supervisor - Licensing/Regulatory Programs
A. Brittain, Manager - Security
T. Cleary, Director - Site Operations
M. McPherson, Manager (Acting) - Maintenance
C. Elberfeld, Lead Engineer - Technical Support
L. Grzeck, Lead Engineer - Technical Support
R. Kitchen, Engineering Manager
G. Miller, Lead Engineer - Technical Support
E. O'Neil, Manager - Site Support Services
A. Pope, Manager - Operations
D. Griffith, Manager - Outage and Scheduling
S. Rogers, Manager Nuclear Assessment
J. Scarola, Site Vice President
M. Turkal, Lead Engineer - Technical Support
M. Williams, Manager - Operations Support
B. Waldrep, Plant General Manager

NRC Personnel

P. Fredrickson, Chief, Reactor Projects Branch 4, Division of Reactor Projects Region II

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000325/2006002-01	NCV	Failure to Appropriately Evaluate Core Spray Header Piping Flaw (Section1R22.2)
05000325/2006002-02	NCV	Failure to Follow Procedure Resulting in Condensate System Transient (Section 4OA2.2)

Closed

None

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Plant Operating Manual (POM), Volume III, Operating Procedure, 1OP-17, Residual Heat Removal System Operating Procedure, Rev. 86
POM, Volume III, Operating Procedure, 0OP-39, Emergency Diesel Generator Operating Procedure, Rev. 108

Section 1R05: Fire Protection

POM, Volume XIX, Prefire Plan, 1PFP-RB, Reactor Building Prefire Plans, Rev. 6
POM, Volume XIX, Prefire Plan, 2PFP-RB, Reactor Building Prefire Plans, Rev. 6

Section 1R14: Operator Performance During Non-Routine Evolutions and Events

POM, Volume XXI, Abnormal Operating Procedure, 1AOP-3, Positive Reactivity Addition, Rev. 8
POM, Volume XXI, Abnormal Operating Procedure, 0AOP-23.0, Condensate/Feedwater System Failure, Rev. 24

Section 1R20: Refueling and Other Outage Activities

POM, Volume III, Operating Procedure, 1OP-17, Residual Heat Removal System Operating Procedure, Rev. 86
POM, Volume III, Operating Procedure, 1OP-13, Fuel Pool Cooling and Cleanup System Operating Procedure, Rev. 58
POM, Volume III, Operating Procedure, 0OP-13.1, Supplemental Spent Fuel Pool Cooling System Operating Procedure, Rev. 18
POM, Volume IV, General Plant Operating Procedure, 0GP-05, Unit Shutdown, Rev. 122
POM, Volume IV, General Plant Operating Procedure, 0GP-06, Cold Shutdown to Refueling (Head Unbolted), Rev. 30
POM, Volume IV, General Plant Operating Procedure, 0GP-07, Preparations for Core Alterations, Rev. 39
POM, Volume IX, Fuel Handling Procedure, 0FH-11, Refueling, Rev. 81
POM, Volume X, Periodic Test, 0PT-18.1, Refueling Position Interlock Check, Rev. 52