UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

May 5, 2006

Paul D. Hinnenkamp
Vice President - Operations
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION - NRC INTEGRATED INSPECTION REPORT 05000458/2006002

Dear Mr. Hinnenkamp:

On March 31, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your River Bend Station. The enclosed integrated inspection report documents the inspection findings which were discussed with you and other members of your staff on April 6, 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.

Based on the results of this inspection, three self-revealing findings were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that violations are associated with these findings. However, because these violations were of very low safety significance and were entered into your corrective action program, the NRC is treating these violations as noncited violations, consistent with Section VI.A.1 of the NRC's Enforcement Policy. If you contest the violations or the significance of the violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the River Bend Station facility.

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 Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Kriss M. Kennedy, Chief
Project Branch C
Division of Reactor Projects

Docket: 50-458
License: NPF-47

Enclosure:
NRC Inspection Report 05000458/2006002
w/Attachment: Supplemental Information

cc w/enclosure:
Senior Vice President and
Chief Operating Officer
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

Vice President
Operations Support
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

General Manager
Plant Operations
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

Director - Nuclear Safety
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

Wise, Carter, Child & Caraway
P.O. Box 651
Jackson, MS 39205

Winston & Strawn LLP
1700 K Street, N.W.
Washington, DC 20006-3817

Manager - Licensing
Entergy Operations, Inc.
River Bend Station
5485 US Highway 61N
St. Francisville, LA 70775

The Honorable Charles C. Foti, Jr.
Attorney General
Department of Justice
State of Louisiana
P.O. Box 94005
Baton Rouge, LA 70804-9005

H. Anne Plettinger
3456 Villa Rose Drive
Baton Rouge, LA 70806

Bert Babers, President
West Feliciana Parish Police Jury
P.O. Box 1921
St. Francisville, LA 70775

Michael E. Henry, State Liaison Officer
Department of Environmental Quality
Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, TX 78711-3326

Chairperson
Denton Field Office
Chemical and Nuclear Preparedness
and Protection Division
Office of Infrastructure Protection
Preparedness Directorate
Dept. of Homeland Security
800 North Loop 288
Federal Regional Center
Denton, TX 76201-3698

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(RJC1)**
Senior Resident Inspector **(PJA)**
Branch Chief, DRP/C **(KMK)**
Senior Project Engineer, DRP/C **(WCW)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**
DRS STA **(DAP)**
S. O'Connor, OEDO RIV Coordinator **(SCO)**
ROPreports
RBS Site Secretary **(LGD)**
W. A. Maier, RSLO **(WAM)**

SUNSI Review Completed: _KMK _ ADAMS: / Yes ☐ No Initials: KMK______
/ Publicly Available ☐ Non-Publicly Available ☐ Sensitive / Non-Sensitive

R:_REACTORS_RB\2006\RB2006-02RP-PJA.wpd

RIV:SRI:DRP/C	RI:DRP/C	C:DRS/OB	C:DRS/EB1	C:DRS/PSB
PJAlter	MOMiller	ATGody	JAClark	MPShannon
E-KMKennedy	**E-KMKennedy**	**/RA/**	**LJSmith for**	**LCCarson for**
5/5/06	5/5/06	5/5/06	5/5/06	5/5/06

C:DRS/EB2	C:DRP/C			
LJSmith	KMKennedy			
/RA/	**/RA/**			
5/5/06	5/5/06			

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-458
License:	NPF-47
Report:	05000458/2006002
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	January 1 to March 31, 2006
Inspectors:	P. Alter, Senior Resident Inspector, Project Branch B M. Miller, Resident Inspector, Project Branch B M. Hay, Senior Resident Inspector, Project Branch E W. Sifre, Senior Reactor Inspector, Engineering Branch 1 L. Ellershaw, PE, Consultant
Approved By:	Kriss M. Kennedy, Chief Project Branch C Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000458/2006002; 01/01/2006 - 03/31/2006; River Bend Station; Postmaintenance Testing, Refueling and Other Outage Activities, Event Followup

The report covered a 3-month period of routine baseline inspections by resident inspectors and regional engineering inspectors. Three Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (MC) 0609, “Significance Determination Process.” Findings for which the significance determination process 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. A self-revealing noncited violation of Technical Specifications Section 5.4.1.a. was identified for the failure of procurement engineers to specify the correct replacement relief valve in a repetitive maintenance task to periodically replace thermal relief valves in the standby service water system. As a result, an incorrect valve was installed in the system which, following a system pressure transient, failed to reseat, creating a 10 gpm leak from the system. The valve was replaced and the issue was entered into the licensee's corrective action program as CR-RBS-2006-1054.

  The finding is more than minor because it would become more significant if left uncorrected in that additional makeup to the standby service water system would be required during a sustained loss of off-site power. The finding affected the mitigating system cornerstone. Using Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding was determined to have very low safety significance because it did not result in the loss of the standby service water system safety function. The cause of the finding is related to the crosscutting element of problem identification and resolution because the problem which led to the installation of the incorrect valve had been previously identified and corrective actions were not effective in preventing recurrence (Section 1R19).

- Green. A self-revealing noncited violation of Technical Specification Section 5.4.1.a, was identified for the failure of mechanical maintenance technicians to correctly reassemble Low Pressure Coolant Injection Testable Check Valve E12-AOVF041A during Refueling Outage 12. As a result, a steam leak from a valve flange caused a rise in drywell unidentified leakage. The issue was entered into the licensee’s corrective action program as CR-RBS-2006-00546 and the valve was repaired.

  The finding is more than minor because it would have become a more significant safety concern if left uncorrected. The leakage would have continued to increase during the cycle, and it would have continued to have an adverse affect on indicated reactor vessel level. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding was determined to have very low safety significance because it did not result in a loss of the low pressure coolant injection system safety function and was not potentially risk significant due to seismic, flooding, or severe weather related initiating events. The finding had crosscutting aspects associated with human performance in that maintenance technicians incorrectly reassembled the valve during refueling outage 12 (Section 1R20).

- Green. A self-revealing noncited violation of Technical Specifications Section 5.4.1.a. was identified for the failure to provide adequate procedural guidance for the use of a test plug during the performance of a required surveillance test procedure. The use of the wrong test plug caused an initiation of the high pressure core spray system and injection into the vessel. The issue was entered in the licensee's corrective action program as CR-RBS-2006-00283.

  The finding is more than minor because it is associated with the mitigating system cornerstone attribute of equipment performance and the cornerstone objective to ensure the availability and reliability of high pressure core spray, a system that responds to initiating events to prevent undesirable consequences. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because there was an actual loss of system safety function. Based on the results of the Phase 2 analysis, the finding was determined to have very low safety significance. The cause of the finding is related to the crosscutting element of human performance because the technicians did not verify that they were using the correct test plug for the surveillance test being performed (Section 4OA3).

REPORT DETAILS

Summary of Plant Status: The plant was operated at 100 percent power until January 17, 2006, when reactor power was lowered to 90 percent to perform turbine testing and a control rod shuffle. Power was returned to 100 percent later that day. On February 4, 2006, reactor power was reduced to 75 percent due to concerns with reactor steam carryover. The plant was shut down on February 10, 2006, to inspect the steam dryer. The reactor was restarted on February 17, 2006, and achieved 100 percent power on February 22, 2006. Reactor power was lowered on March 3, 2006, to 85 percent power to perform turbine testing and a control rod shuffle. Power was returned to 100 percent later that day and remained there for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R04 Equipment Alignment

4. Partial System Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the three risk important systems listed below; (2) reviewed system operating procedures (SOPs) and documents to verify that critical portions of the selected systems were correctly aligned; and (3) compared deficiencies identified during the walkdown to the licensee's Updated Safety Analysis Report (USAR) and corrective action program (CAP) to ensure problems were being identified and corrected.

- January 25, 2006, Division I standby service water system
- March 14, 2006, Division I containment atmosphere monitoring system
- March 15, 2006, Division II emergency diesel generator

Documents reviewed by the inspectors included:

- SOP-0042, “Standby Service Water System,” Revision 24
- System Tagout 1-C13-01 (1-SWP-P7A), performed on January 24, 2006
- SOP-0084, “Containment Atmosphere Monitoring System,” Revision 11A
- SOP-0053, “Standby Diesel Generator and Auxiliaries,” Revision 44A

The inspectors completed three inspection samples.

i. Findings

No findings of significance were identified.

2. Complete System Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the USAR, and Technical Specifications (TS) to determine the correct alignment of the Division I 125 Vdc system; (2) reviewed outstanding design issues, operator workarounds, and USAR documents to determine if open issues affected the functionality of the Division I 125 Vdc system; and (3) verified that the licensee was identifying and resolving equipment alignment problems. Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

b. Inspection Scope

.1 Quarterly Inspection

The inspectors walked down the six plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the USAR and CAP to determine if the licensee identified and corrected fire protection problems.

- January 13, 2006, Reactor Building, 141-foot, Standby Liquid Control, Fire Area RC-4/Z-4

- January 13, 2006, Reactor Building, 162-foot, Hydrogen Mixing Fan, Fire Area RC-3/Z-5

- January 13, 2006, Reactor Building, 162-foot, Containment Unit Coolers, Fire Area RC-4/Z-5

- January 13, 2006, Reactor Building, 186-foot, Hydrogen Recombiner Area, Fire Area RC-3/Z-5

- March 17, 2006, Main Control Room, Fire Area C-25

- March 17, 2006, Control Building, 116-foot, ENB Inverter Charger A Room, Fire Area C-18

Documents reviewed by the inspectors included:

- Pre-Fire Plan/Strategy Book
- USAR Section 9A.2, “Fire Hazards Analysis,” Revision 10
- River Bend Station postfire safe shutdown analysis
- RBNP-038, “Site Fire Protection Program,” Revision 6B

The inspectors completed six inspection samples.

.2 Annual Inspection

On February 8, 2006, the inspectors observed a fire brigade drill to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) the number of personnel assigned to the fire brigade, (2) use of protective clothing, (3) use of breathing apparatuses, (4) use of fire procedures and declarations of emergency action levels, (5) command of the fire brigade, (6) implementation of prefire strategies and briefs, (7) access routes to the fire and the timeliness of the fire brigade response, (8) establishment of communications, (9) effectiveness of radio communications, (10) placement and use of fire hoses, (11) entry into the fire area, (12) use of firefighting equipment, (13) searches for fire victims and fire propagation, (14) smoke removal, (15) use of prefire plans, (16) adherence to the drill scenario, (17) performance of the postdrill critique, and (18) restoration from the fire drill. The licensee simulated a fire in the switchgear house for circulating water system Cooling Tower 1B. The inspectors reviewed the prefire plan, “Normal Cooling Towers, Elevation 110-foot,” Revision 0, and Fire Brigade Drill DRL-FP-00105, “NHS-MCC13C, Cooling Tower C Switchgear,” dated February 8, 2006, as part of this inspection.

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Semiannual Internal Flooding

The inspectors: (1) reviewed the USAR, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; (2) reviewed the USAR and CAP to determine if the licensee identified and corrected flooding problems; (3) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (4) walked down the area to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

C Auxiliary building piping tunnel was inspected during the week of March 20, 2006,

Documents reviewed by the inspectors included:

- River Bend Individual Plant Examination of External Events
- USAR Section 3.4.1, “Flood Protection,”
- G13.18.12.3*15, “Internal Flooding Screening Analysis”
- G13.2.3 PN-317, “Max Flood Elevations for Moderate Energy Line Cracks in Cat I Structures”

The inspectors completed one inspection sample.

e. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed licensee programs, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for the residual heat removal pumps’ seal coolers. The inspectors verified that: (1) performance tests were satisfactorily conducted for heat exchangers/heat sinks and reviewed for problems or errors; (2) the licensee properly utilized biofouling controls; (3) the licensee’s heat exchanger inspections adequately assessed the state of cleanliness of their tubes; and (4) the heat exchanger was correctly categorized under the maintenance rule.

Documents reviewed by the inspectors included:

- River Bend Station (RBS) USAR Section 9.2.2, “Reactor Plant Component Cooling Water System”
- RBS System Design Criteria-204, “Residual Heat Removal System,” Revision 3
- RBS System Design Criteria-115, “Reactor Plant Component Cooling Water System,” Revision 1

- Generic Letter 89-13 initial response dated February 2, 1990, and follow-up response dated December 31, 1990

- Residual heat removal system health report and maintenance rule report

- River Bend Station Condition Report (CR-RBS) CR-RBS-2006-00792, Programmatic issues with the residual heat removal pump seal coolers

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

On March 21, 2006, the inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a loss of reactor protection system Bus B and a small steam leak in the drywell.

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two maintenance activities listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule; 10 CFR Part 50, Appendix B; and the TS.

- November 22, 2005, Reactor Building Unit Cooler HVR-UC7 cooling coils need cleaning

- February 3, 2006, Standby Gas Treatment Fan GTS-FN1B failed to start

Documents reviewed by the inspectors included:

- NUMARC 93-01, Nuclear Energy Institute Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
- Maintenance rule function list
- Maintenance rule performance criteria list
- GTS-FN1B and HVR-UC7 maintenance rule performance evaluations

The inspectors completed two inspection samples.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

.1 Risk Assessment and Management of Risk

The inspectors reviewed the three assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and administrative Procedure ADM-096, “Risk Management Program Implementation and On-Line Maintenance Risk Assessment,” Revision 04B, prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognized, and/or entered as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- Week of January 9, 2006, Switchyard work and reactor core isolation cooling (RCIC) planned maintenance
- Week of January 23, 2006, Circulating/Service Water Power Supply Transformer STX-XS2B replacement
- Week of February 26, 2006, Periodic fire water pump diesel inspection and maintenance during Division II workweek

Documents reviewed by the inspectors included:

- Risk assessment results and daily schedule for the weeks of January 9 and 22 and February 26, 2006
- Contingency action plan, “Operation with STX-XS2B Out of Service,” Revision 0

.2 Emergent Work Control

The inspectors: (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the CAP to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- Week of March 27, 2006, Emergent Division I work during Division II work week

Documents reviewed by the inspectors included:

- Risk assessment results and daily schedule for the week of March 26, 2006

The inspectors completed four inspection samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the USAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TS; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee had identified and implemented appropriate corrective actions associated with degraded components. The licensee operability evaluations were documented in the following CRs:

- CR-RBS-2006-00109, Unexpected cycling of RCIC minimum flow valve during slow roll startup following lube oil system maintenance, reviewed January 12, 2006

- CR-RBS-2006-00305, High pressure core spray (HPCS) system operable but degraded due to suspected leakage into suppression pool, reviewed on January 30, 2006

- CR-RBS-2006-00350, Leakage of HPCS pump discharge line fill pump discharge header pressure relief Valve E22-RVF035 to the suppression pool, reviewed on February 16, 2006

- CR-RBS-2006-00424, During troubleshooting for suppression pool level rise, RCIC pump suction check Valve E51-VF030 was identified to have minor leakage, reviewed on February 16, 2006

- CR-RBS-2006-00798, Low pressure core spray line break detection alarm did not clear as expected during power ascension following Forced Outage FO-06-01, reviewed on February 24, 2004

- CR-RBS-2006-00915, Suppression Pool Cooling Discharge Valve RHS-AOV64 failed acceptance criteria during quarterly surveillance testing, reviewed during the week of March 13, 2006

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six inspection samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

Annual Review

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flowpaths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the modification listed below. The inspectors verified that: (1) modification preparation, staging, and implementation did not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) postmodification testing maintained the plant in a safe configuration during testing by verifying that unintended system interactions would not occur, SSC performance characteristics still met the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria had been met; and (3) the licensee had identified and implemented appropriate corrective actions associated with permanent plant modifications.

- June 9, 2005, ER-RB-2002-0223-000, Remove Annulus Mixing From Technical Specifications and Disable Annulus Mixing

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors selected the five postmaintenance test activities listed below of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the CAP to determine if the licensee identified and corrected problems related to postmaintenance testing. The postmaintenance testing was performed as part of the following work orders (WO):

- WO00081785, Disassemble and inspect Valve E51-VF030, reviewed during the week of February 13, 2006

- WO 00081081, Replace Relief Valve E22-RVF0035, reviewed during the week of February 13, 2006

- WO 00064733, Replace and test LSV Compressor B after cooler service water supply header pressure Relief Valve SWP-RV49B, reviewed on March 13, 2006

- WO51002463, Repair RCIC set screw, reviewed on March 14, 2006

- WO50983127 01, Replace air-operated valve on diesel-driven air compressor dryer, reviewed on March 16, 2006

Documents reviewed by the inspectors included:

- Part Interchangeability Evaluation, PIE-00749, Crosby Relief Valve JBM-B (fixed blowdown) with JBM-WR (adjustable blowdown), dated June 21, 1996.

- CR-RBS-2003-03678, Part identified in the job plan and pulled from the warehouse was different from the one installed in the field.

- CR-RBS-2006-00988, Observed excessive makeup to normal service water system over the past 3 hours.

- CR-RBS-2006-01031, Valve SWP-RV49B, was replaced with a new valve in the warehouse, upon investigation it was discovered that PIE-00749 allows use of an alternate valve.

- CR-RBS-2006-01054, This condition report documents a process concern involving parts bill of materials for model work orders for repetitive tasks.

The inspectors completed five inspection samples.

b. Findings

Introduction: A self-revealing noncited violation (NCV) of TS Section 5.4.1.a. was identified for the failure of procurement engineers to specify the correct replacement relief valve in a repetitive maintenance task to periodically replace thermal relief valves in the standby service water system. As a result, following a system pressure transient, the relief valve failed to reseat, creating a 10 gpm leak from the system. The leak was discovered and the relief valve was reseated by isolating the heat load from the service water system.

Description: On March 10, 2006, operators discovered a leak in the service water system. The leak was determined to be from a failed open relief valve on the service water supply header to Leakage Control Compressor B. The operators isolated service water to the leakage control compressor, which reseated the relief valve and slowly restored service water to the compressor. The leak was calculated to be approximately 10 gpm. Subsequent evaluation of the leak determined that if the standby service water system had been in service, the leak would have been within the capacity of the system and the makeup capability of the standby cooling tower.

The inspectors determined that the valve in question, SWP-RV49B, had been replaced on February 28, 2006, under WO 00064733, as a repetitive task to routinely replace thermal relief valves in the standby service water system. The replacement relief valve was an older style valve without an adjustable blowdown so that, if it lifted during a system pressure transient, it would remain partially open, because its reseat pressure was lower than normal system pressure at the leakage control compressor.

In June 1996, the licensee processed a part interchangeability evaluation to upgrade the type of relief valve to one with an adjustable blowdown feature with a higher reseat pressure for several applications within the service water system. Valve SWP-RV49B was part of that evaluation. Although the component database for SWP-RV49B was changed, the information was not transferred to preexisting repetitive task WOs to periodically replace thermal relief valves in the service water system. In December 2003, CR-RBS-2003-03678 was generated because of problems associated with part interchangeability evaluations not being incorporated into existing WOs for repetitive tasks. Since the licensee concluded that the procurement engineers had no effective way to search the existing repetitive tasks to correct deficient parts data, the corrective actions were focused on making sure that future repetitive task WOs included part interchangeability data. The licensee would depend on the work planning process, which required planners and technicians to review task instructions and information during the walkdown prior to performing work, to identify and correct similar problems in existing WOs. This corrective action was ineffective and led to the use of the wrong relief valve for Valve SWP-RV49B. The decision not to review existing repetitive tasks for correct part interchangeability data was the root cause for the use of the wrong replacement relief valve for Valve SWP-RV49B. In CR-RBS-2006-1054, the planned maintenance optimization working group committed to review all existing part interchangeability evaluations to ensure that all effected repetitive tasks have the correct replacement parts data.

Analysis: The performance deficiency associated with this finding involved the failure to update a repetitive task WO with the correct replacement valve part number. A parts interchangeability evaluation had been performed but it was not included in the repetitive task WO. The finding is more than minor because it would become more significant if left uncorrected in that additional makeup to the standby service water system would be required during a sustained loss of off-site power. The finding affected the mitigating system cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding was determined to have very low safety significance because it did not result in the loss of the standby service water system safety function because contingency plans are in place for makeup to the standby cooling tower during a sustained loss of off-site power.

The cause of the finding is related to the crosscutting element of problem identification and resolution because the problem with parts interchangeability data had been previously identified. The corrective actions to ensure that all new repetitive task WOs would include part interchangeability data were limited in scope in that they did not address repetitive WOs generated prior to December 2003. The licensee felt that a proper review of the component database during the work planning process would identify problems with existing repetitive tasks. The licensee has committed to reevaluate all existing repetitive task WOs to ensure that all replacement component data is updated to include the correct part interchangeability data.

Enforcement: TS Section 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9.a, states that maintenance activities that can affect the performance of safety-related equipment be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to this, the parts interchangeability data for replacement relief valves in the standby service water system was not included in the repetitive task WO to periodically replace thermal relief valves in the system. Therefore, when WO 00064733 was written in February 2006, it did not specify the correct part number for the replacement relief valve and the wrong relief valve was installed in the system. A pressure transient in the system lifted the relief valve and it failed to reseat, creating a 10 gpm leak. The inspectors determined that the failure to specify the proper replacement relief valve directly led to the use of the wrong part and the subsequent leak from the standby service water system. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-RBS-2006-01054, this violation is being treated as an NCV consistent with

Section VI. A of the Enforcement Policy: NCV 05000458/2006002-01, “Installation of Incorrect Relief Valve Caused Leak in Standby Service Water System.”

1R20 Refueling and Other Outage Activities

Forced Outage FO-06-01, February 10-17, 2006

On February 10, 2006, the licensee shut down the plant in response to an apparent increase in moisture carryover. In a boiling water reactor saturated steam system, a small amount of liquid water is entrained in the steam flow and transported out of the reactor vessel via the main steam lines. The moisture content of the steam is determined by monitoring the ratio of sodium (Na-24) content of the reactor water, condensate, and heater drains. Over the previous 60 days, the licensee had detected a steady increase in Na-24. Such an increase is normally an indication of steam dryer damage resulting in an increase in dryer leakage. In response to this indication, the licensee shut down the unit to perform inspections of the steam dryer.

a. Inspection Scope

The inspectors reviewed the following activities during the forced outage: (1) steam dryer inspection activities; (2) the licensee’s identification and resolution of sources of drywell unidentified leakage, suppression pool inleakage and increased containment airborne activity; (3) implementation of the Shutdown Operations Protection Plan (SOPP); (4) tagging/clearance activities; (5) decay heat removal; (6) reduction of inventory for reactor vessel disassembly and reassembly; (7) reactivity control; (8) containment closure; (9) heatup and cooldown activities; (10) restart activities; and (11) licensee identification and implementation of appropriate corrective actions associated with problems identified during the outage. The inspectors' drywell inspections included identification of sources of unidentified drywell leakage and inspections of control rod drive mechanisms and drywell floor and equipment drain sumps. Specific outage activities observed and reviewed included:

- Preoutage Onsite Safety Review Committee review of the SOPP
- Reactor shutdown and transition to shutdown cooling
- Operating shift review of SOPP against changing plant conditions
- Removal and inspection of the steam dryer
- Initial drywell entry to identify sources of drywell unidentified leakage
  - Reactor Water Cleanup Loop Isolation Valve 1G33-MOVF100
  - Low Pressure Coolant Injection Testable Check Valve E12-AOVF041A
  - Reactor Head Vent Valves B21-MOVF001 and F002
- Inspection and repair of sources of suppression pool inleakage
  - RCIC Pump Suction Check Valve E51-VF030
  - HPCS Pump Discharge Thermal Relief Valve E22-RVF035

- Inspection and repair of Reactor Water Cleanup Demineralizer Outlet Strainer Blowdown Valves G36-VF031A, VF031B, VF032A, and VF032B

- Onsite Safety Review Committee review of outage activities and recommendation for startup

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one inspection sample.

b. Findings and Observations

.1 Steam Dryer Inspection Activities

The inspectors observed and reviewed the licensee's steam dryer inspection activities. Prior to performing the inspections, the licensee conducted training using a dryer that had been stored in a warehouse. This training was conducted to identify each weld location, size, and layout.

The inspectors reviewed the licensee's plan for inspecting the dryer and found that it was based on industry operating experience associated with previous dryer failures. The plan included:

1. Dryer Hood Welds

   - Welds V1 through V50 (vertical welds)
   - Welds H1 through H5 (horizontal welds)

2. Dryer Inspections Below the Support Ring

   - Earthquake block cover plates - Welds EBP 1 through 6
   - Circumferential seam weld - Weld SK-H1
   - Skirt to lower side of support ring - Weld SK-H2
   - Skirt vertical seams - Welds SK-V1 and SK-V2

The licensee did not identify any defects during their initial inspections and expanded the inspection scope to include the following:

3. Underside of the Steam Dryer

   - Drain pipes and their connections to the drain channel
   - Bottom of inner hood connection to the horizontal plate
   - Inlet side of vane module for damage to perforated plates

The inspection equipment (underwater camera and control system) used during the inspection of Items 1 and 2 above was appropriate for the task in that it provided excellent coverage and resolution.

The inspections performed for Item 3 were conducted using a submarine type robot with a fixed camera. The camera had excellent resolution. However, control of the submarine was difficult. Maintaining smooth movements was difficult and time consuming and location determination was not easily achieved. In addition, since the submarine was controlled through the use of fan-like thrusters, silt-like deposits occasionally were stirred up, making observation quite difficult at best. The inspectors observed several welds that appeared to be coated with a black crud or oxide-like substance which clearly had the potential for masking certain types of indications in the welds. Subsequent discussion with licensee personnel revealed that the crud-like deposits were most likely the result of less than adequate chemistry control during earlier cycles.

4. Inspections Other than the Steam Dryer

- Feedwater spargers
- Steam separator structural assessment (i.e., stand pipes and assemblies, upper and middle support rings, outside surfaces of the steam separator, and hold down bolts)

The inspectors observed portions of the above inspections in Items 1, 2, and 3. These inspections were conducted using Nondestructive Examination Level II and Level III personnel. While the inspections were not conducted to ASME Code visual examination criteria (i.e., VT-1), they were performed using documented visual instructions which were generally sufficient to detect the types of defects expected for the amount of moisture carryover that had been thought to exist.

Upon further investigation, the licensee determined that the apparent increase in dryer leakage was the result of inaccurate Na-24 measurement. The Na-24 isotope is identified using 1368.55 Kev gamma energy and is measured to indicate dryer leakage. The licensee determined that the sodium count was being masked by the presence of Iodine-135 which is identified at 1367.89 Kev. The iodine occurrence was the direct result of known fuel leaks. The licensee’s sodium measurement methodology did not have sufficient sensitivity to allow discrimination between the two isotope energy levels. As a result, the two isotopes’ energies were measured additively, resulting in a false high Na-24 reading indicative of a dryer leak. As a corrective action for this condition, the licensee recalibrated the sodium measurement to account for the increase in Iodine-135.

.2 Leak from Low Pressure Coolant Injection Testable Check Valve E12-AOVF041A

Introduction. A self-revealing NCV of TS Section 5.4.1.a was identified for failure to correctly reassemble Low Pressure Coolant Injection Testable Check Valve E12-AOVF041A during Refueling Outage 12. As a result, a steam leak from a valve flange caused a rise in drywell unidentified leakage during the current operating cycle.

Description: During Refueling Outage 12, mechanical maintenance technicians removed a flange from the high pressure side of Valve E12-AOV041A to permit inservice test program exercising of the valve disk. When the valve was reassembled, technicians did not properly align the required steam gasket within the flanged fitting. When the flange bolts were torqued down, the gasket was crushed unevenly. As a result, the sealing function of the gasket was compromised and a seat leak developed during the operating cycle.

The steam leak was the major contributor to drywell unidentified leakage prior to the shutdown and caused elevated temperatures in that area of the drywell. During the operating cycle, a concern arose that there was an decrease in moisture carryover out of the reactor, indicating potential problems with the steam dryer. One of the indications that contributed to the potential for steam dryer degradation was an anomalous decrease in Channel A reactor water level indication. Inspection of the drywell revealed that the indicated decrease in Channel A reactor water level was due to heating of the instrument variable leg by the steam leaking out of Valve E12-AOVF041A, not problems with the steam dryer as had originally been thought by the licensee. During the forced outage, the flange was disassembled and the steam gasket was replaced.

Analysis: The performance deficiency associated with this finding involved failure to correctly reassemble Low Pressure Coolant Injection Testable Check Valve E12-AOVF041A during Refueling Outage 12. The inspectors determined that the steam leak from the valve contributed to an indicated decrease in Channel A reactor water level. This indicated decrease was a factor in the licensee’s conclusion that there was potential damage to the steam dryer and in their decision to shut down the dryer for inspection. The finding was more than minor because it would have become a more significant safety concern if left uncorrected. The leakage would have continued to increase during the cycle, and it would have continued to have an adverse affect on indicated reactor vessel water level. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheets, the finding was determined to have very low safety significance because it did not result in a loss of the system safety function and was not potentially risk significant due to seismic, flooding, or severe weather related initiating events. The inspectors reviewed the licensee’s analysis of the potential impact of the worse case degradation of the flanged fitting on Valve E12-AOV041A and agreed that there would not be a loss of the low pressure coolant injection Train A safety function due to the margin between the analyzed system injection flow rates and recorded surveillance test data.

This finding had crosscutting aspects associated with human performance in that maintenance technicians incorrectly reassembled the valve during Refueling Outage 12.

Enforcement. TS Section 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9.a, requires procedures for maintenance that can affect the performance of safety-related equipment. WO 50573954, step 4.7, directs maintenance personnel to reinstall the end cover on the valve. Contrary to the above, maintenance technicians incorrectly reassembled Valve E12-AOVF041A during Refueling Outage 12, which resulted in a drywell steam leak from the flange covering the disk operator on the high pressure side of the valve. Because this violation was of very low safety significance and was documented in the licensee's CAP as CR-RBS-2006-00546, it is being treated as an NCV in accordance with Section VI. A of the NRC Enforcement Policy: NCV 05000458/2006002-02, "Inadequate maintenance results in a drywell steam leak from Low Pressure Coolant Injection Train A Testable Check Valve."

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the USAR, procedure requirements, and TS to ensure that the six surveillance activities listed below demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator (PI) data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing. The specific surveillance test procedures (STP) reviewed were:

- System Operating Procedure SOP-0104, "Floor and Equipment Drain System," Revision 27, Section 5.2, "Determining Identified and Unidentified Leakage Rates Manually," reviewed on January 8, 2006

- STP-203-6305, "HPCS Quarterly Pump and Valve Operability Test," Revision 13, reviewed on January 28, 2006

- STP-256-6302, "Division II Standby Service Water Quarterly Valve Operability Test," reviewed on March 3, 2006

- STP-204-4203, "LPCI Pump A Discharge Flow-Low, Channel Calibration and Logic System Functional Test (E12-N652A, E12-N052A)," Revision 8A, reviewed on March 20, 2006

- STP-303-1601, "120 and 480 VAC Breaker Overload Functional Test," Revision 23, reviewed on March 20, 2006

- STP-205-6301, "LPCS Quarterly Pump and Valve Operability Test," Revision 14, inservice test, this inservice test program surveillance was reviewed on March 23, 2006

The inspectors completed six inspection samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

b. Inspection Scope

The inspectors reviewed the USAR, plant drawings, procedure requirements, and TS to ensure that the two temporary modifications listed below were properly implemented. The inspectors: (1) verified that the modifications did not have an affect on system operability/availability; (2) verified that the installation was consistent with modification documents; (3) ensured that the postinstallation test results were satisfactory and that the impact of the temporary modifications on permanently installed SSCs were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that the licensee identified and implemented any needed corrective actions associated with temporary modifications.

- TA05-0013, Temporary monitoring equipment installed in control room chilled water Pump HVK-P1A circuit, reviewed on March 21, 2006

- TA06-0006, Temporary monitoring equipment installed in the reactor recirculation pump trip circuits, reviewed on March 22, 2006

The inspectors completed two inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

Cornerstone: Initiating Events

The inspectors sampled licensee submittals for the three PIs listed below for the period of January 2004 through December 2005. The definitions and guidance of Nuclear Energy Institute 99-02, “Regulatory Assessment Indicator Guideline,” Revision 2, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors reviewed licensee event reports (LERs), monthly operating reports, and operating logs as part of the assessment.

- Unplanned Scrams Per 7,000 Critical Hours
- Unplanned Scrams With Loss of Normal Heat Removal
- Unplanned Power Changes Per 7,000 Critical Hours

The inspectors completed three inspection samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope

.1 Routine Review of Identification and Resolution of Problems

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing CRs and work requests. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional follow-up through other baseline inspection procedures.

.2 Selected Issue Follow-up Inspection

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

- CR-RBS02006-00805, Potential adverse trend in the area of work management and coordination of scheduled maintenance items causing unnecessary unavailability of risk important and safety-related systems

Other CRs reviewed during this assessment included:

CR-RBS-2005-01400	CR-RBS-2005-03520	CR-RBS-2005-03863
CR-RBS-2005-03219	CR-RBS-2005-03768	CR-RBS-2005-00103

The inspectors completed one inspection sample.

b. Findings and Observations

There were no findings of significance identified associated with the CRs reviewed.

However, the inspectors identified several occasions in which licensee personnel were not adequately prepared to perform the intended work due inadequate system tagouts. The licensee identified several occasions where incomplete component and system impact statements led operators to prepare and hang tagouts for safety-related equipment when the actual job scope was not clearly defined. As a result, safety-related equipment was tagged out unnecessarily, or the tagout was not sufficient for the work being performed. The inspectors noted that in all cases the licensee identified the condition and restored the equipment and systems to service within hours. The inspectors reviewed the apparent cause analysis and the measures put in place by the licensee to correct the problem and plan to perform an effectiveness review as part of normal inspection activities throughout the remainder of the year.

4OA3 Event Follow-up

The inspectors completed the following three inspection samples.

7. Failure of Standby Gas Treatment System (SGTS) Train B

On February 2, 2006, while operators manually aligned SGTS Train B in preparation for the calibration of time delay relays in the automatic start sequencing circuit for motor operated dampers, the train failed to start. Prior to aligning Train B, operators disabled SGTS Train A in accordance with Procedure SOP-0059, "Containment HVAC System," Revision 25, Section 5.2, "Standby Gas Treatment Manual Start." As a result, for a period of time both trains of SGTS were inoperable, requiring operators to enter TS Section 3.0.3. SGTS Train A was immediately returned to its normal standby lineup and TS Section 3.0.3 was exited. The inspectors reviewed the operators' action and the shift manager's evaluation of the event against the reporting requirements of 10 CFR Part 50.72. The inspectors reviewed the restoration and postmaintenance testing of the SGTS Fan B circuit breaker under WO 00081357 and CR-RBS-2006-00454. No findings of significance were identified.

8. (Closed) LER 05000458/2004-002-00, Automatic Reactor Scram and System Actuations Due to Insulator Flashover in Switchyard

On October 1, 2004, a ground fault caused by insulator flashover on one 230 kV line that supplied off-site power to Division I resulted in the loss of Division I off-site power. This also caused a loss of power to one half of the balance of plant equipment. Another ground fault caused by insulator flashover occurred a few minutes later on the main unit transformers and resulted in a generator lockout, turbine trip, and generator load reject scram. The loss of the Division I line also led to the loss of the main condenser. The NRC's inspection of this event was documented in NRC Special Inspection Report 05000458/2004012, issued February 10, 2005. Additional inspection was documented in NRC Supplemental Inspection Report 05000458/2005012, issued October 24, 2005.

During this inspection period, the inspectors reviewed the LER and the root cause analysis and corrective actions documented in CR-RBS-CR-RBS-2004-02841 and 02842. No additional findings of significance were identified. This LER is closed.

9. (Closed) LER 05000458/2006-002-00, Loss of Safety Function of High Pressure Core Spray Due to Manual Deactivation

Introduction. A self-revealing NCV of TS Section 5.4.1.a was identified for the failure to provide adequate procedural guidance for the use of a test plug during the performance of a TS-required surveillance test. The use of the wrong test plug caused an initiation of the HPCS and injection into the vessel.

Description. On January 24, 2006, instrument and controls technicians were performing Surveillance Test Procedure (STP)-051-4356, “HPCS - Drywell Pressure - High Channel Calibration and Logical System Functional Test,” Revision 11, when they caused an inadvertent initiation of HPCS. Operators immediately responded by verifying that an actual high drywell pressure condition did not exist and that HPCS operation was not required. They stopped HPCS injection into the reactor vessel by closing HPCS Injection Isolation Valve E22-MOVF004. The manual override of the automatic opening of Valve E22-MOVF004 disabled the system because the valve would not automatically reopen on a lowering reactor water level. The simulated high drywell pressure signal was cleared and the test plug was removed from the HPCS logic panel. The initiation signal was then reset and HPCS was returned to its normal standby lineup. HPCS was inoperable for 97 minutes.

The test plug used was developed in response to the September 27, 2003, inadvertent initiation of HPCS at Grand Gulf Nuclear Station. During that event, technicians hooked up a volt-ohm meter to the wrong test connections of a multipoint cannon plug on the front of the HPCS logic cabinet. River Bend’s instrument and control department’s response was to create two test plugs that would separate out the test lead connections for each half of the system initiation logic. Even though the test plugs were made up and training was conducted on the Grand Gulf event and the RBS solution, the use of the test plugs was not included in the appropriate STPs.

Analysis. The performance deficiency associated with this finding was the failure to include specific procedural guidance on the use of the correct test plug in STP-051-4356. This resulted in the technicians’ use of the wrong test plug for the surveillance test being performed. The finding is more than minor because it is associated with the mitigating systems cornerstone attribute of equipment performance and affects the associated cornerstone objective to ensure the availability and reliability of a system that responds to initiating events to prevent undesirable consequences because operators had to override HPCS injection. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because there was an actual loss of system safety function. The inspectors performed a Phase 2 analysis using Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and the Phase 2 worksheets for RBS. The inspectors used an out-of-service time of 97 minutes and assumed that, since the operators had manually inhibited HPCS injection, it was reasonable to assume that they would have reopened the injection valve if HPCS was required to maintain reactor water level following a plant trip. The dominant transients from the Phase 2 analysis were a plant trip and loss of normal feedwater, stuck open relief valve, loss of normal service water, and a loss of off-site power with a failure of the Divisions I and II emergency diesel generators. Using the Counting Rule Worksheet, this finding was estimated to be of very low safety significance (Green). This characterization was verified and validated by a senior reactor analyst.

The inspectors determined that this finding had crosscutting aspects associated with human performance. The root cause for the human performance error of using the wrong test plug was inadequate procedural guidance for its use during the surveillance test. Additionally, the technicians did not independently verify they had the correct test plug in the shop during their prejob walkthrough and did not verify that they were using the correct test plug before inserting it into the logic cabinet cannon plug.

Enforcement. TS Section 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9.a, requires that maintenance that can effect performance of safety-related equipment be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings that are appropriate to the circumstances. Contrary to this, STP-051-4356 did not contain specific procedural guidance for the use of the correct test plug. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-RBS-2006-00283, this violation is being treated as an NCV consistent with Section VI. A of the Enforcement Policy: NCV 05000458/2006002-03, "Inadvertent Initiation of High Pressure Core Spray Caused by the Use of the Wrong Test Plug During Surveillance Testing." This LER is closed.

4OA6 Meetings, Including Exit

Exit Meetings

On April 6, 2006, the inspectors presented the integrated baseline inspection results to P. Hinnenkamp, Vice President - Operations, and other members of licensee management. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

L. Ballard, Manager, Quality Programs
M. Boyle, Manager, Radiation Protection
D. Burnett, Superintendent, Chemistry
C. Bush, Manager, Outage
J. Clark, Assistant Operations Manager - Training
T. Coleman, Manager, Planning and Scheduling/Outage
C. Forpahl, Manager, Corrective Action Program
T. Gates, Manager, Equipment Reliability
H. Goodman, Director, Engineering
K. Higginbotham, Assistant Operations Manager - Shift
P. Hinnenkamp, Vice President - Operations
B. Houston, Manager, Plant Maintenance
A. James, Superintendent, Plant Security
N. Johnson, Manager, Engineering Programs & Components
R. King, Director, Nuclear Safety Assurance
J. Leavines, Manager, Emergency Planning
D. Lorfing, Manager, Licensing
J. Maher, Superintendent, Reactor Engineering
W. Mashburn, Manager, Design Engineering
J. Miller, Manager, Training and Development
P. Russell, Manager, System Engineering
C. Stafford, Manager, Operations
D. Vinci, General Manager - Plant Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000458/2006002-01	NCV	Installation of Incorrect Relief Valve Caused Leak in Standby Service Water System
05000458/2006002-02	NCV	Inadequate maintenance results in a drywell steam leak from Low Pressure Coolant Injection Train A Testable Check Valve
05000458/2006002-03	NCV	Inadvertent Initiation of High Pressure Core Spray Caused by the Use of the Wrong Test Plug During Surveillance Testing.

Closed

05000458/2004-002-00	LER	Automatic Reactor Scram and System Actuations Due to Insulator Flashover in Switchyard

05000458/2006-002-00	LER	Loss of Safety Function of High Pressure Core Spray Due to Manual Deactivation

LIST OF DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

<u>Section 1R04: Equipment Alignment</u>

SOP-0049, “125 VDC System,” Revision 23

USAR Section 8.3.2, “DC Power System”

TS Section 3.8.4, “DC Sources Operating”

125 Vdc system health report and maintenance rule report

EE-001ZG, “125 VDC One Line Diagram, Standby Bus A, ENS-SWG-1A, ENS-PNL02A,” Revision 19

CAP data base search on keyword “ENB”

Open work requests and work orders

<u>Section 1R15: Operability Evaluations</u>

Nuclear Management Manual Procedure EN-OP-104, Operability Determinations, Revision 01

Drawing PID-27-04A, “System 203 HPCS System,” Revision 26

Surveillance Procedure STP-000-6606, “Section XI Safety and Relief Valve Testing,” Revision 16

TS Section 3.6.1.3, “Primary Containment Isolation Valves”

USAR Table 6.2-37, “Primary Containment Isolation Pipes that Penetrate the Containment and Connect to the Containment Atmosphere”

USAR Table 6.2-40, “Containment Isolation Provisions for Fluid Lines”
Engineering Calculation PX-897, “RCIC Pump Discharge Lines Water Hammer Analysis with Trapped Air,” dated October 3, 1983

CR-RBS-1997-00804, Root Cause Analysis Report: Bellows Failure of HPCS Pump Discharge Header Pressure Relief Valve E22-RVF035

MR-1995-0048, Modify Four Motor Operated Valves to Eliminate Their Susceptibility to Pressure Locking, dated August 24, 1995

ER-RB-2004-0510, Evaluate piping segments of CSH, CSL and RHS for the water hammer loads due to inadvertent voiding of pump discharge lines, dated November 12, 2004

Procedure EN-MA-125, Troubleshooting Control of Maintenance Activities for Unexplained Suppression Pool Level Rise, dated January 27, 2006

Condition Reports

CR-RBS-2006-00305	CR-RBS-2006-00353	CR-RBS-2006-00372

Section 1R17: Permanent Plant Modifications

Drawing PID-22-01C, “HVAC - Containment BLDG,” Revision 14

Elementary Diagram, ESK-06HVR21, Sheet 001, “480V SWGR Annulus Mixing Fan 1HVR*FN11A,” Revision 22

Test Loop Diagram, TLD-HVR-093, sheet 001, “Annulus Mixing Fan Fn11B Discharge Damper - HVR-AOD53B,” Revision 1

USAR Sections 9.4.5.2.5 and 9.4.6

TS Section 3.6.4.1, “Secondary Containment-Operating”

Maintenance Rule Function RBS-2-F-403

System Operating Procedure SOP-59, “Containment HVAC System,” Revision 25

ER-RBS-2002-0223-000, “Eliminate Annulus Mixing from Technical Specifications,” dated April 3, 2002

ER-RBS-2002-0223-001, “Update EQ Documentation for GTS-PNL28A/B for Removal of Annulus Mixing System and Installation of Temporary Shielding,” Dated 10/20/2004

License Amendment Request 2003-21, “Delete Annulus Mixing/Revise MSIV Leakage Limits,” Revision 0

Docket 50-458, “Amendment to Facility Operating License,” Amendment 144, License NPF-47

Section 1R20: Outage Activities

OSRC Meeting Minutes for February 9, 15, and 16, 2006

General Operating Procedure GOP-0003, “Scram Recovery [Report],” dated February 15, 2006

Forced Outage FO-06-01 Activities Schedule

Forced Outage FO-06-01 Outage Risk Assessment, dated February 9, 2006

Operations Section Procedure OSP-0037, “Shutdown Operations Protection Plan,” Revision 14

Drywell Leakage Inspection Plan and Pre-Job Briefing Package, dated February 9, 2006

Drywell Closeout Inspection Plan and Pre-Job Briefing Package, dated February 18, 2006

Control Room Logs for Startup, February 16-21, 2006

Condition Reports

CR-RBS-2002-00594
CR-RBS-2002-00691
CR-RBS-2002-01663
CR-RBS-2006-00305
CR-RBS-2006-00372
CR-RBS-2006-00594
CR-RBS-2006-00633

Steam Dryer Inspection Activities

Procedures

CEP-NDE-0904, “Program Section For Reactor Pressure (RPV) Internal Examinations,” Revision 0

CEP-RVI-003, “Appendix D - Steam Dryer,” Revision 5

COP-0001, “Sampling Via Various Balance-of-Plant Systems,” Revision 13

COP-0305, “Operation of the Countroom Analysis System,” Revision 1A

COP-0619, “Gamma Isotopic Analysis Sample Preparation,” Revision 5

CSP-0006, “Chemistry Surveillance and Scheduling System,” Revision 15

CSP-0100, “Chemistry - Required Surveillances and Actions,” Revision 21

Miscellaneous Documents

“River Bend Station Dryer February 2006 Signature Log, IVVI Procedure Indoctrination, Pre-Job Brief, Signature Authorization & BWRVIP Site Specific Training,” February 11, 2006

Dryer IVVI (In-Vessel Visual Inspection) Examination Data Sheet RBS-04-01

SIL 644, “Steam Dryer Integrity,” Revision 1

ILD-DLV-00014, “River Bend Moisture Carryover History,” February 2, 2006

Condition Reports

CR-RBS-2006-00245
CR-RBS-2006-00642

LIST OF ACRONYMS

CAP	corrective action program
CFR	*Code of Federal Regulations*
CR	condition report
CR-RBS	River Bend Station condition report
HPCS	high pressure core spray system
LER	licensee event report
Na-24	sodium
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
PI	performance indicator
RBS	River Bend Station
RCIC	reactor core isolation cooling system
SGTS	standby gas treatment system
SOP	system operating procedures
SOPP	Shutdown Operations Protection Plan
SSC	structures, systems, or components
STP	surveillance test procedure
TS	Technical Specifications
USAR	Updated Safety Analysis Report
WO	work order