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

February 13, 2006

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

SUBJECT: RIVER BEND STATION - NRC INTEGRATED INSPECTION REPORT 05000458/2005005

Dear Mr. Hinnenkamp:

On December 31, 2005, 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 January 4, 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, two NRC identified findings and one self-revealing finding 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

Enclosures:
NRC Inspection Report 05000458/2005005
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

Burt 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)**
J. Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
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\2005\RB2005-05RP-PJA.wpd

RIV:SRI:DRP/C	RI:DRP/C	C:DRS/OB	C:DRS/EB1	C:DRS/PSB
PJAlter	MOMiller	ATGody	JClark	MPShannon
T - KMKennedy	***E - KMKennedy***	***/RA/***	***/RA/***	***/RA/***
2/ /06	2/ /06	2/ /06	2/ /06	2/ /06

C:DRS/EB2	C:DRP/C			
LJSmith	KMKennedy			
GDReplogle for	***/RA/***			
2/13/06	2/13/06			

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

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-458
License:	NPF-47
Report:	05000458/2005005
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	October 1 through December 31, 2005
Inspectors:	P. Alter, Senior Resident Inspector, Project Branch C M. Miller, Resident Inspector, Project Branch C J. Keeton, Consultant, Region IV P. Elkmann, Emergency Preparedness Inspector, Operations Branch G. Johnston, Senior Operations Engineer, Operations Branch L. Ricketson, Senior Health Physicist, Plant Support Branch
Approved By:	Kriss M. Kennedy, Chief Project Branch C Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000458/2005005; 10/01/2005 - 12/31/2005; River Bend Station; Licensed Operator Requalification, Operator Performance During Nonroutine Plant Evolutions, Permanent Plant Modifications.

The report covered a 3-month period of routine baseline inspections by resident inspectors and announced baseline inspections by regional emergency planning, operations, and radiation protection 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 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: Initiating Events

- Green. The NRC identified a noncited violation of Technical Specification 3.4.1.A for the licensee's failure to shut down one reactor recirculation loop within 2 hours of determining that jet pump loop flow mismatch was greater than 5 percent while operating at greater than 70 percent of rated core flow. On October 31, 2005, the Reactor Recirculation Flow Control Valve B hydraulic power unit tripped because of a blown control power fuse, causing Flow Control Valve B to drift open. Operators throttled closed Flow Control Valve A to maintain reactor power at 100 percent, resulting in a jet pump loop flow mismatch of approximately 8.2 percent. The flow mismatch existed for 4.5 hours. The licensee entered this into their corrective action program as Condition Report CR-RBS-2006-00274.

  The finding was more than minor because, if left uncorrected, it would become a more significant safety concern. Matched recirculation loop flows is an assumption used in the accident analysis for a loss of coolant accident resulting from a loop break. A flow mismatch could result in core response that is more severe than assumed in the accident analysis. The significance of this finding could not be evaluated using MC 0609, "Significance Determination Process." Based on management review, the finding was determined to be of very low safety significance based on the short duration of the flow mismatch, 4.5 hours, and the low likelihood of a loss of coolant accident during that time. The cause of this finding is related to the crosscutting element of human performance in that operators failed to implement Technical Specification requirements (Section 1R14).

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, was identified for the licensee's failure to address the worst case conditions in the sizing calculation for the reactor core isolation cooling turbine exhaust line vacuum breaker system as part of a plant modification to remove the internals of the reactor core isolation cooling turbine exhaust line check valve. As a result, on December 10, 2004, when the reactor core isolation cooling system was started and subsequently shutdown on high reactor water level following a scram and loss of feedwater, the turbine exhaust line filled with water from the suppression pool, causing the operators to consider the system unavailable and complicating their response to the event. The licensee entered this finding into their corrective action program as CR-RBS-2005-00724 and reinstalled the turbine exhaust line check valve internals in February 2005.

The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and affected the cornerstone objective to ensure the availability and reliability of the reactor core isolation cooling system, a system that responds to initiating events (loss of feedwater and station blackout), to prevent undesirable consequences. Using Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding was determined to have very low safety significance because it represented a design deficiency that did not result in a loss of system function (Section 1R17).

Cornerstone: Emergency Preparedness

- Green. The NRC identified a noncited violation of 10 CFR Part 50, Appendix E, Section IV. B., as a result of inadequate procedures for the implementation of an emergency action level. The criteria in Procedure EIP-2-001, "Classification of Emergencies," Revision 12, for declaring an Alert emergency action level based on primary coolant leak rate, relied solely on a computer generated leakrate report that would not be valid under all conditions. The licensee entered this finding into their corrective action program as CR-RBS-2005-03078 and issued Standing Order 192, as an interim corrective action, to provide additional criteria to determine whether a primary coolant leak rate Alert emergency action level declaration was required.

  The finding is more than minor because it is associated with the Emergency Preparedness Cornerstone attribute of procedural quality and affects the cornerstone objective to ensure the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. The inadequate procedure could result in a failure to declare an Alert emergency classification when required. Using Manual Chapter 0609, Appendix B, "Emergency Preparedness Significance Determination Process," this finding was determined to be of very low safety significance since it was a failure to comply with a regulatory requirement associated with a risk-significant planning standard that did not result in the loss or degradation of that risk-significant planning standard function (Section 1R11).

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

On October 1, 2005, reactor power was lowered to 70 percent to perform a rod sequence exchange and insert two control rods for planned maintenance. The reactor was returned to 100 percent power on October 2, 2005. On October 21, 2005, reactor power was lowered to 63 percent to perform power suppression testing for a leaking fuel bundle. The reactor was returned to 100 percent power on October 23, 2005. On November 5, 2005, reactor power was lowered to 90 percent to adjust the control rod pattern and the reactor was returned to 100 percent later that day. On December 2, 2005, reactor power was lowered to 83 percent to insert three control rods for planned maintenance. The reactor was returned to 100 percent power on December 3, 2005. On December 9, 2005, reactor power was lowered to 58 percent to perform a control rod pattern adjustment and conduct turbine valve testing. The reactor was returned to 100 percent power on December 11, 2005. On December 17, 2005, reactor power was lowered to 62 percent to perform power suppression testing for a leaking fuel bundle. The reactor was returned to 100 percent on December 19, 2005, and remained at 100 percent for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection

b. Inspection Scope

Cold Weather Preparation

During the week of December 5, 2005, the inspectors reviewed the licensee’s implementation of Operations Section Procedure OSP-0043, “Freeze Protection and Temperature Maintenance,” Revision 6, to protect mitigating systems from cold weather conditions. Specifically, the inspectors: (1) verified that risk-significant structures, systems, and components will remain functional when challenged by cold weather conditions; (2) verified that cold weather features such as heat tracing and space heaters are operable and monitored; and (3) verified that the cold weather procedures attachments were being completed for changing temperatures as required by the procedure. The inspectors completed one inspection sample.

c. Findings

No findings of significance were identified.

1R04 Equipment Alignment

1. Partial System Walkdowns

a. Inspection Scope

On October 25, 2005, the inspectors walked down residual heat removal Division II while residual heat removal Division I was out of service for scheduled maintenance. On October 26, 2005, the inspectors walked down the piping and valve lineup of the condensate storage tank, including emergency core cooling system suction and test return valves. In each case, the inspectors verified the correct valve and power alignments by comparing positions of valves, switches, and electrical power breakers to the system operating procedures (SOP) and piping and instrument drawings listed below and applicable sections of the Updated Safety Analysis Report (USAR). The inspectors completed two inspection samples.

- SOP-0031, "Residual Heat Removal System," Revision 46
- SOP-0008, "Condensate Storage, Makeup and Transfer," Revision 16
- Piping and Instrument PID 04-03A, "Condensate Storage, Makeup and Transfer," Revision 13

b. Findings

No findings of significance were identified.

2. Complete System Walkdown

a. Inspection Scope

The inspectors conducted a complete walkdown of the drywell and containment leak detection system during the week of June 26, 2005, during a drywell closeout inspection and continuing the week of November 20, 2005. The methods of inspection included field walkdown, in-office reviews, observation of system operation, and interviews of computer engineering, operations, training, and emergency planning personnel. The inspectors verified: (1) proper valve and control switch alignments, (2) computer program algorithm, (3) power supply lineup, (4) associated support system status, and (5) that alarms and indications in the main control room were as specified in the following documents:

- SOP-0033, "Drywell and Containment Leak Detection System," Revision 11
- USAR Section 5.2.5.1.1, "Detection of Leakage within the Drywell"
- Technical Specifications (TS) Section 3.4.5, "RCS Operational Leakage"

The inspectors also verified electrical power requirements, labeling, hangers and support installation, and associated support systems status. The walkdowns included evaluation of system piping and supports to ensure (1) piping and pipe supports did not show evidence of damage, (2) hangers were secure, and (3) component foundations were not degraded. The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors walked down accessible portions of the plant described below to assess: (1) the licensee's control of transient combustible material and ignition sources; (2) fire detection and suppression capabilities; (3) manual firefighting equipment and capability; (4) the condition of passive fire protection features, such as, electrical raceway fire barrier systems, fire doors, and fire barrier penetrations; and (5) any related compensatory measures. The inspectors reviewed the Pre-Fire Plan/Strategy Book during the fire protection inspections. The areas inspected were:

- Auxiliary building, 70-foot, RHR Pump B Room, fire Area AB-3, on October 11, 2005
- Auxiliary building, 95-foot, HPCS piping area, fire Area AB-2/Z-2, on October 12, 2005
- Auxiliary building, 95-foot, LPCS panel room, fire Area AB-6/Z33, on October 12, 2005
- Control building, 116-foot, safety-related 125 Vdc switchgear room, fire Area C-24, on December 9, 2005
- Control building, 116-foot, safety-related Switchgear 1C room, fire Area C-22, on December 9, 2005
- Control building, 116-foot, safety-related ENB inverter Charger A room, fire Area C-18, on December 9, 2005

The inspectors completed six inspection samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

.1 Annual Operating Examination Review

Following the completion of the annual operating examination testing cycle, which ended the week of September 23, 2005, the inspectors reviewed the overall pass/fail results of the annual individual job performance measure operating tests and simulator operating tests administered by the licensee during the operator licensing requalification cycle. Eight separate crews participated in simulator operating tests and job performance measure operating tests, totaling 52 licensed operators. All of the crews tested passed the simulator portion of the annual operating test. Two of the 52 licensed operators failed the job performance measure portion and were successfully remediated. These results were compared to the thresholds established in MC 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process.” The inspector completed one inspection sample.

.2 Resident Inspector Quarterly Review

On November 15, 2005, the inspectors observed simulator training of an operating crew, as part of the operator requalification training program, to assess licensed operator performance and the training evaluator’s critique. The inspection included observation of high risk licensed operator actions, operator activities associated with the emergency plan, and lessons learned from industry and plant experiences. In addition, the inspectors compared simulator control panel configurations with the actual control room panels for consistency. The simulator examination scenario observed was RSMS-OPS-612, “Loss of Vacuum/ATWS/Drywell Steam Leak - RPV Flooding,” Revision 4. The inspectors completed one inspection sample.

.3 Inadequate Emergency Event Classification Guidance

On June 10, 2005, the inspectors observed operating crew performance in the simulator during annual requalification exam Scenario RSMS-OPS-509, “SRV Tailpipe Steam Leak Inside The Drywell,” Revision 3. The inspectors discussed crew actions and emergency planning requirements with the examination evaluators, training management, emergency planning coordinators, and operations management. The inspectors reviewed the following documents:

- EIP-2-001, “Classification of Emergencies,” Revision 12
- USAR 5.2.5.1.1, “Detection of Leakage within the Drywell”
- Vendor computer manual, VTD-A324-0109, “Analog Devices MICROMAC-5000 Final Draft, Leak Rate Detection PLC Documentation, River Bend Station - Reactor Building Sump Systems,” Revision 0

- Training Evaluation and Request, TEAR-RBS-2005-0477, “Validating Leakage Report,” issued August 23, 2005

- CR-RBS-2005-03078, “Validating Leakage Report,” initiated on August 26, 2005

- Standing Order Number 192, “Drywell Leakage Greater Than 50 gpm EAL Guidance,” Revision 0, issued November 3, 2005

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix E, Section IV.B, for inadequate procedures for implementation of an Alert emergency action level (EAL).

Description: On June 10 2005, the inspectors observed operating crew performance in the simulator during annual requalification exam Scenario RSMS-OPS-509, “SRV Tailpipe Steam Leak Inside The Drywell,” Revision 3. The inspectors noted that when the examination evaluators informed the team that the total drywell leakage report was 84 gpm, the team declared an Alert based on that report. Procedure EIP-2-001, “Classification of Emergencies,” Revision 12, listed the criteria for an Alert EAL classification as “Total drywell LEAKAGE greater than 50 gpm.”

Based on their observations in the simulator, the inspectors questioned the ability of the leakage computer installed in the plant to accurately calculate total drywell leakage under certain conditions. The inspectors analyzed the program run by the drywell leakage computer and determined: (1) the drywell leakage computer would not calculate total drywell leakage while a drywell sump pump was running; (2) computer reports of total drywell leakage printed while a drywell sump pump was running would be invalid; and (3) if a drywell high pressure or low reactor vessel level signal was present, the valves in the drywell sump pump discharge lines would close, causing the drywell sump pumps to run continuously, resulting in an invalid drywell total leakage report. The inspectors determined that the indication used by operators to determine if the criteria was met for declaring an Alert EAL due to total drywell leakage exceeding 50 gpm would not be valid under certain conditions.

On August 23, 2005, the licensee initiated training evaluation action request TEAR-2005-0477 to evaluate this condition to determine what training actions were necessary. On August 26, 2005, the licensee initiated CR-RBS-2005-03078 that requested an alternate means of determining the primary coolant leak Alert EAL using main control room indications. The CR also requested additional training materials and classroom instruction to reinforce this change.

On November 3, 2005, the licensee issued Standing Order 192 that provided additional criteria to be used to make the determination of whether a primary coolant leak rate Alert EAL declaration was required, without relying solely on the drywell leakage computer. The inspectors concluded that Standing Order 192 was an adequate interim compensatory measure until the licensee implemented permanent corrective actions.

Analysis: The performance deficiency associated with this finding involved an inadequate procedural criteria for declaring an Alert EAL in the event that total drywell leakage exceeds 50 gpm under certain conditions. Specifically, computed drywell leakrate used by operators to determine if total drywell leakage exceeds 50 gpm may be invalid under certain conditions. The finding was more than minor because it is associated with the Emergency Preparedness Cornerstone attribute of procedural quality and affects the cornerstone objective to ensure the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. The inadequate procedure could result in a failure to declare an Alert emergency classification when required. Using Manual Chapter 0609, Appendix B, “Emergency Preparedness Significance Determination Process,” this finding was determined to be of very low safety significance since it was a failure to comply with a regulatory requirement associated with a risk-significant planning standard that did not result in the loss or degradation of that risk-significant planning standard function.

Enforcement: The failure to provide adequate procedures for implementation of an EAL was a violation of 10 CFR Part 50, Appendix E, Section IV.B., which requires, in part, that the licensee’s emergency plan describe the means to be used for determining the impact of the release of radioactive materials including EALs. Because this finding was of very low safety significance and was entered into the licensee’s corrective action program as CR-RBS-2005-03078, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000458/2005005-01, Inadequate procedure for implementation of an EAL.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed selected maintenance activities to verify the performance of assessments of plant risk related to planned and emergent maintenance work activities. The inspectors verified: (1) the adequacy of the risk assessments and the accuracy and completeness of the information considered, (2) management of the resultant risk and implementation of work controls and risk management actions, and (3) effective control of emergent work, including prompt reassessment of resultant plant risk. The inspectors completed three inspection samples.

.1 Risk Assessment and Management of Risk

On a routine basis, the inspectors verified performance of risk assessments, in accordance with administrative Procedure ADM-096, “Risk Management Program Implementation and On-Line Maintenance Risk Assessment,” Revision 04, for planned maintenance activities and emergent work involving structures, systems, and components within the scope of the maintenance rule. Specific work activities evaluated included the following planned and emergent work:

- October 23, 2005, Division I residual heat removal and standby service water equipment outage

- November 28, 2005, Division III work week and station blackout diesel generator planned maintenance

.2 Emergent Work Control

During emergent work, the inspectors verified that the licensee took actions to minimize the probability of initiating events, maintained the functional capability of mitigating systems, and maintained barrier integrity. The inspectors also reviewed the emergent work activities to ensure the plant was not placed in an unacceptable configuration. The specific emergent work activity followed was the cleaning of high voltage insulators in the main transformer switchyard with a high pressure spray on October 7, 2005.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Nonroutine Evolutions and Events

c. Inspection Scope

The inspectors completed the two inspection samples listed below.

.1 Power Suppression Testing

The inspectors observed portions of and reviewed control room records for power suppression testing conducted during the weekend of October 21, 2005. The inspectors reviewed the reactivity control plan, the prejob briefing given in the main control room at the beginning of the evolution and during control room operator and reactor engineer shift turnover. The inspectors also reviewed the results of the test with the reactor engineering representative and shift manager, including the recommendation to insert Control Rod 20-45 to suppress power in the vicinity of a potential leaking fuel bundle. Finally, the inspectors reviewed the postsuppression test off-gas pretreatment gaseous activity levels used to monitor the success of the suppression efforts.

.2 Trip of Reactor Recirculation (RR) Flow Control Valve (FCV) Hydraulic Power Unit (HPU)

On October 31, 2005, the inspectors observed operator response to a trip of RR FCV B HPU. As a result, RR FCV B began to drift open. The operators took action to limit or stop the gradual opening of RR FCV B. As RR FCV B continued to open, operators throttled closed RR FCV A to maintain reactor power less than 100 percent. These actions created an RR jet pump loop flow mismatch of greater than 5 percent requiring entry into TS Action 3.4.1.A. The inspectors reviewed the TS requirements for this condition and discussed the actions taken by the operators with the operations shift manager and members of plant management team present in the control room at the time. The following documents were reviewed by the inspectors as part of this inspection:

- Main Control Room Logs, October 31, 2005
- CR-RBS-2005-03748, During Filter RCS-FLTR2B replacement, technicians bumped an electrical cable, causing a trip of the reactor recirculation flow control Valve B hydraulic power unit
- W0 00075986, Replace grounded connection to Pressure Switch RCS-PDS90B
- SOP-0003, Reactor Recirculation System, Revision 35
- TS limiting condition for operation (LCO) 3.4.1 and applicable Bases

i. Findings

Introduction: The inspectors identified a Green noncited violation of TS Action 3.4.1.A.1 for the licensee's failure to restore compliance with LCO 3.4.1 or shut down one RR loop within 2 hours of determining that RR loop jet pump flow mismatch was greater than 5 percent while operating at greater than 70 percent of rated core flow.

Description: On October 31, 2005, at 2:54 p.m., the RR FCV B HPU tripped. As a result, RR FCV B began to drift open. The operators took action to limit or stop the gradual opening of RR FCV B. As RR FCV B continued to open, operators throttled closed RR FCV A to maintain reactor power less than 100 percent.

At 3:06 p.m., the operators entered TS LCO Condition 3.4.1.A because the RR loop jet pump flow mismatch exceeded 5 percent with the plant operating at greater than 70 percent rated core flow. The highest flow mismatch was 8.2 percent. TS Action 3.4.1.A.1 required the licensee to shut down one recirculation loop with 2 hours.

The licensee issued a work request and began to troubleshoot the HPU trip. At the same time, operators requested that reactor engineers develop a reactivity control plan to insert control rods to lower reactor power. This would allow operators to reopen RR FCV A to reduce the RR jet pump loop flow mismatch to less than the required 5 percent.

At 4:24 p.m., the licensee determined that the cause for the HPU trip was a blown control power fuse. The fuse blew as a result of a grounded wire to a filter high differential pressure switch, which was bumped by maintenance technicians who were changing the filter cartridge. The inspectors asked the operators and licensee management if they intended to shut down one RR loop or perform the actions necessary to reduce the jet pump flow mismatch to less than 5 percent, as required by TS 3.4.1. The licensee responded that they did not want to maneuver the plant and change core conditions, which might exacerbate the existing condition of two leaking fuel bundles.

At 5:06 p.m., the operators exited TS Action 3.4.1.A without shutting down one RR loop or reducing jet pump loop flow mismatch to less than 5 percent. Instead they entered TS Action 3.4.1.D.1, which required that the reactor be placed in Mode 3 in 12 hours. When asked, the operators and licensee management stated that they could commence a plant shutdown within the next 6 hours and still meet the requirement to be in Mode 3 in 12 hours. They also stated that at the 6-hour point, they would commence the shutdown with the reactivity control plan to reduce reactor power by inserting control rods and open RR FCV A to reduce jet pump loop flow mismatch to less than 5 percent. If that was successful, they would then exit TS LCO 3.4.1.

Subsequently, the repairs were completed to the pressure switch wire, the control power fuse was replaced, and RR FCV B HPU was restarted. Following a one-hour warmup, the RR FCV B HPU was returned to service. RR jet pump loop flow was reduced below 5 percent and the licensee exited TS LCO 3.4.1. at 7:36 p.m., 4.5 hours after entry into TS LCO Condition 3.4.1.A.

The inspectors determined that: (1) when the cause of the trip of RR FCV B HPU was determined to be the grounded pressure switch wire, the licensee knew that the time to make the repairs and return the HPU to service would exceed the 2-hour completion time of TS Action 3.4.1.A.1; and (2) the licensee was capable of restoring RR jet pump loop flow mismatch to less than 5 percent or shutting down one RR loop within the 2-hour completion time of TS Action 3.4.1.A.1.

<u>Analysis</u>: The licensee's failure to restore compliance with TS LCO 3.4.1 or complete the required action of TS 3.4.1.A.1 to shut down one RR loop within 2 hours was a performance deficiency. The finding was more than minor because, if left uncorrected, it would become a more significant safety concern. According to TS LCO 3.4.1 Bases, the operation of the RR pumps is an initial condition assumed for the design basis loss-of-coolant accident (LOCA). During a LOCA caused by a RR loop break, the intact RR loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the RR pump in the broken loop ceases to pump water through the vessel almost immediately. The pump in the intact loop coasts down more slowly. This pump coast down governs the core flow response for the next several seconds until the jet pump suctions are uncovered. The analyses assume that both RR loops are operating at the same flow prior to the LOCA. However, if the LOCA analysis is reviewed for an initial jet pump flow mismatch with the break assumed to be in the loop with the higher flow, the flow coast down and core response are potentially more severe, since the intact loop starts at a lower flow rate.

The significance of this finding could not be evaluated using MC 0609, "Significance Determination Process." Based on management review, the finding was determined to be of very low safety significance based on the short duration of the flow mismatch, 4.5 hours, and the low likelihood of a LOCA during that time. The cause of this finding is related to the crosscutting element of human performance in that operators failed to implement TS requirements.

<u>Enforcement</u>: TS LCO 3.4.1 states that two RR loops shall be in operation with matched flows when the reactor is in Modes 1 or 2. If RR loop jet pump flow mismatch

is not less than or equal to 5 percent of rated core flow when operating at greater than or equal to 70 percent of rated core flow (Condition 3.4.1.A), then the licensee must shut down one RR loop (Required Action A.1) within 2 hours (Completion Time). Contrary to the above, on October 31 , 2005, 2 hours after RR loop jet pump flow mismatch was greater than 5 percent of rated core flow, the licensee exited TS 3.4.1.A.1 without shutting down one RR loop or restoring the jet pump flow mismatch to less than 5 percent. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as CR-RBS-2006-00274, this violation is being treated as an NCV in accordance with Section IV.A of the NRC Enforcement Policy and is identified as NCV 05000458/2005005-02: Failure to complete TS required actions within allowed completion time.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability determinations on the basis of potential risk importance. The selected samples are addressed in the condition reports (CRs) listed below. The inspectors assessed: (1) the accuracy of the evaluations, (2) the use and control of compensatory measures if needed, and (3) compliance with TS, the Technical Requirements Manual, the USAR, and other associated design-basis documents. The inspectors' review included a verification that the operability determinations were made as specified by Entergy Procedure EN-OP-104, "Operability Determinations," Revision 1. The operability evaluations reviewed were associated with:

- CR-RBS-2004-1270, Check valves in primary Containment 113' elevation airlock not included in the in-service testing program, reviewed on October 11, 2005

- CR-RBS-2005-3563, Check valves in primary Containment 113' elevation airlock not included in the in-service testing procedure, reviewed on October 19, 2005

- CR-RBS-2005-3568, In-service test program changed for primary containment 113' elevation airlock without changing in-service test procedure, reviewed on October 19, 2005

- CR-RBS-2005-04251, -04252, Safety-related Inverter ENB-INV01B1 frequency and safety-related instrument Bus VBS-PNL01B voltage out of specification high, reviewed on December 27, 2005

The inspectors completed two inspection samples.

f. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

An operator workaround is defined as a degraded or nonconforming condition that complicates the operation of plant equipment and is compensated for by operator action.

During the week of November 28, 2005, the inspectors reviewed an operator workaround which required operators to hold the control switch for throttle valves for at least 5 seconds after the full closed indication is received. The inspectors interviewed operators to determine if they knew specifically which valves were affected and if they were aware of this operational requirement from memory.

During the week of December 5, 2005, the inspectors reviewed the cumulative effect of the existing operator workarounds on: (1) the reliability, availability, and potential for misoperation of any mitigating system; (2) whether they could increase the frequency of an initiating event; and (3) their effect on the operation of multiple mitigating systems. In addition, the inspectors reviewed the cumulative effects of the operator workarounds on the ability of the operators to respond in a correct and timely manner to plant transients and accidents. The procedures and other documents reviewed by the inspectors were:

- Operator Workaround - Control Room Deficiency Program Guidelines, Revision 11
- Operator workaround report
- Operator burden report
- Daily plant status reports
- Operations shift turnover sheet
- Standing Order Number 190, "Electrically Operated Throttle Valve Operations," Revision 0

The inspectors completed two inspection samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed MR96-0063, "Remove Internals of [Reactor Core Isolation Cooling Turbine (RCIC) Exhaust Check Valve] E51-VF040," dated September 18, 1996, and the assumptions made with respect to the capability of the RCIC turbine exhaust line vacuum breaker vent line. On December 10, 2004, the RCIC turbine was manually started and ran for a short period of time before shutting down on high reactor water level. The RCIC exhaust line drain trap high level alarm came in and operators observed water draining from the drain trap for 12 hours. The documents reviewed as part of this inspection are listed in the attachment. The inspectors completed one inspection sample.

b. Findings

Introduction: The inspectors identified a self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion III, Design Control, for failure to address a full spectrum of design conditions for the RCIC turbine exhaust line vacuum breaker system as part of a plant modification to remove the internals of the RCIC turbine exhaust line check valve. As a result, on December 10, 2004, when RCIC was started and subsequently shut down on high reactor water level following a scram and loss of feedwater, the RCIC exhaust line filled with water from the suppression pool, causing the operators to consider RCIC unavailable, complicating their response to the event.

Description: In September 1996, in response to a request from mechanical maintenance, design engineering processed a design change to remove RCIC Turbine Exhaust Check Valve E51-VF040. As part of Modification Request MR-96-0063, an evaluation was performed on the adequacy of the RCIC turbine exhaust line vacuum breaker system to prevent the siphoning of suppression pool water into the RCIC turbine exhaust line following a shutdown of the RCIC turbine. During the evaluation it was determined that the as-built vacuum breaker vent line was not in accordance with the original design of the vacuum breaker line. A new calculation was performed for the as-built configuration (globe valves and lift check valves versus gate valves and swing check valves). The basic assumption used for Calculation PH-056, “RCIC Turbine Exhaust Line Vacuum Breaker Vent Line Sizing Verification,” Revision 1A, was that the RCIC exhaust line would be at equilibrium conditions when the turbine tripped. The turbine would run long enough for the exhausted steam and exhaust piping to be at the same temperature and that the only cooling effect would be to ambient. The result was that the gradual cooldown of the steam and exhaust piping would cause the formation of a vacuum in approximately 35.5 minutes. The revised sizing calculation showed that the as-built vacuum breaker vent line was capable of relieving a vacuum created in as short a time as 3.5 minutes.

On December 10, 2004, following a reactor scram, RCIC was started to maintain reactor water level due to the pending loss of all reactor feed pumps. When RCIC Steam to Turbine Valve E51-MOV045 stroked full open, it automatically reclosed due to the high reactor water level interlock. It was later determined that steam was admitted to the turbine for approximately 11 seconds. As a result, the steam in the exhaust line condensed more rapidly than assumed and the exhaust line pressure became a vacuum within 17 seconds. This rapid pressure reduction overwhelmed the vacuum breaker vent line and 84 gallons of suppression pool water was siphoned into the RCIC turbine exhaust line.

The licensee later determined that the static and dynamic loads on the turbine exhaust line for a restart on the RCIC turbine would be within design limits, although a water hammer transient would occur. Based on test data provided by the turbine manufacturer, the licensee also determined that the turbine would experience no damage and not trip on overspeed if it were to be started with water in its exhaust line. The turbine startup would be slower than normal, but within the assumed values in the safety analysis. The turbine exhaust line check valve internals were reinstalled in February 2005.

Analysis: The failure to adequately address worst case design conditions in the sizing calculation for the RCIC turbine exhaust line vacuum breaker vent line to allow for the removal of the exhaust line check valve was a performance deficiency. The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and affected the cornerstone objective to ensure the availability and reliability of the RCIC system, a system that responds to initiating events (loss of feedwater and station blackout), to prevent undesirable consequences. Using the MC 0609, "Significance Determination Process," Phase 1 Worksheet, the finding was determined to have very low safety significance because it represented a design deficiency that did not result in a loss of system function.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, Design Control, states, in part, that design changes, including field changes, shall be subject to design change control measures commensurate with those applied to the original design. Contrary to the above, the RCIC turbine exhaust line vacuum breaker vent line sizing calculation, used as part of the modification process to remove the exhaust line check valve, did not take into consideration the most limiting exhaust line conditions. As a result the vacuum breaker vent line was not capable of preventing the siphoning of suppression pool water into the RCIC Turbine Exhaust line. Because this finding was of very low safety significance and was documented in the licensee's corrective action program as CR-RBS-2005-00724, it is being treated as an NCV in accordance with Section IV. A of the NRC Enforcement Policy and is identified as NCV 05000458/2005005-03: Inadequate design assumption results in RCIC turbine exhaust header filling with water following an automatic high water level shutdown.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors reviewed selected work orders (WO) to ensure that testing activities were adequate to verify system operability and functional capability. The inspectors: (1) identified the safety function(s) for each system by reviewing applicable licensing basis and/or design-basis documents; (2) reviewed each maintenance activity to identify which maintenance function(s) may have been affected; (3) reviewed each test procedure to verify that the procedure did adequately test the safety function(s) that may have been affected by the maintenance activity; (4) reviewed the acceptance criteria in the procedure to ensure consistency with information in the applicable licensing basis and/or design-basis documents; and (5) identified that the procedure was properly reviewed and approved. The eight WOs inspected are listed below:

- WO 00063768, replace hydrogen igniter in containment dome, review conducted during the week of October 31, 2005

- WO 00075881, replace rod control and information system isolation transformer, reviewed during the week of October 31, 2005

- WO 00074806, rebuild control rod drive Hydraulic Control Unit 4833, review conducted during the week of December 12, 2005

- WO 50969759, rebuild control rod drive Hydraulic Control Unit 1625, review conducted during the week of December 12, 2005

- WO 00066597, rework Inverter BYS-INV01A to fix blown fuse problem, review conducted during the week of December 12, 2005

- WO 50968926, replace frequency detector board on Inverter ENB-INV01B1, review conducted during the week of December 12, 2005

- WO 00072137, quarterly inspection and lubrication of the station blackout diesel, review conducted during the week of December 19, 2005

- WO 50967030, clean, inspect, and lubricate the station blackout diesel, review conducted during the week of December 19, 2005

The inspectors completed eight inspection samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors verified, by witnessing and reviewing test data, that risk-significant system and component surveillance tests met TS, USAR, and procedure requirements. The inspectors ensured that surveillance tests demonstrated that the systems were capable of performing their intended safety functions and provided operational readiness. The inspectors specifically: (1) evaluated surveillance tests for preconditioning; (2) evaluated clear acceptance criteria, range, accuracy and current calibration of test equipment; and (3) verified that equipment was properly restored at the completion of the testing. The inspectors observed and reviewed the following surveillance tests and surveillance test procedures (STP):

- STP-552-4202, "Post Accident Monitoring/Remote Shutdown System - Suppression Pool Water Level Channel Calibration (CMS-LT23B, CMS-ESX23B, CMS-LI23B, CMS-TR40B, CMS-LIX23B)," Revision 9A, performed on October 13, 2005

- MCP-4303, “Functional Test of Standby Cooling Tower #1 Station Blackout Division I Standby Service Water Return Valve and Valve Logic (SWP-AOV599),” Revision 01A, performed on October 25, 2005

- STP-552-4502, "Post Accident Monitoring/Remote Shutdown System - Drywell Pressure Channel Calibration (CMS-PT2A, CMS-T103, CMS-PR2A)," Revision 14A, performed on November 28, 2005

The inspectors completed three inspection samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

During the week of December 19, 2005, the inspectors reviewed the following temporary plant modifications: (1) temporary Alteration TA05-0015-00 to supply Division II safety-related 120 volt ac electrical distribution Panel SCM-PNL01B from safety-related power Supply RPS-XRC10B1 so that repairs to safety-related power Supply SCM-XRC14B1 could be made; and (2) temporary Alteration TA05-0014-01 to install radiation shielding in front of standby gas treatment control Panels GTS-PNL28A/B until a permanent solution could be installed. This shielding was installed after an equipment qualification evaluation showed that the total integrated dose for standby gas treatment Panel GTS-PNL28A/B could exceed qualification doses of internal electrical equipment after the annulus mixing system was retired. Specifically, the inspectors: (1) reviewed each temporary modification and its associated 10 CFR 50.59 screening against the system's design basis documentation, including the USAR and TS; (2) verified that the installation of the temporary modification was consistent with the modification documents; and (3) reviewed the postinstallation test results to confirm that the actual impact of the temporary modification on SCM-PNL01B and GTS-PNL28A/B had been adequately verified. The inspectors completed two inspection samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Testing

a. Inspection Scope

The inspector discussed with licensee staff the status of offsite siren systems to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, Federal Emergency Management Agency (FEMA) Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," and the licensee's current FEMA-approved alert and notification system design report. The inspector also reviewed Procedures EPP-2-701, "Prompt Notification System Maintenance and Testing," Revision 18, and EPP-2-401, "Inadvertent Siren Sounding," Revision 7. The inspector completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation

a. Inspection Scope

The inspector reviewed the following documents to determine the licensee's ability to staff emergency response facilities in accordance with the licensee emergency plan and the requirements of 10 CFR Part 50, Appendix E.

- EIP-2-006, "Notifications," Revision 32
- EPP-2-502, "Emergency Communications Equipment Testing," Revision 21
- Details of 10 staffing augmentation and quarterly pager drills

The inspector completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspector reviewed the following documents related to the licensee's corrective action program to determine the licensee's ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E:

- Quality assurance audits of the emergency preparedness program conducted in 2003, 2004, and 2005

- Four licensee self-assessments

- Licensee evaluation reports for 11 drills and exercises

- Summaries of 146 corrective actions assigned to the emergency preparedness department between February 2003 and October 2005

- Details of 17 selected CRs

The licensee's corrective action program was also compared with the requirements of Procedure EN-LI-102, "Corrective Action Process," Revision 2. The inspector independently evaluated the emergency operations facility during an October 18, 2005, drill and compared the postdrill critique of licensee performance. The inspector completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed the emergency preparedness drill conducted on October 18, 2005, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors also evaluated the licensee assessment of classification, notification, and protective action recommendation development during the drill in accordance with plant procedures and NRC guidelines. The inspectors also observed the drill evaluator immediate critiques of the drill participants classification, notification, and protective action recommendation activities. The following procedures and documents were reviewed during the assessment:

C EIP-2-001, "Classification of Emergencies," Revision 13
C EIP-2-006, "Notifications," Revision 32
C EIP-2-007, "Protective Action Guidelines Recommendations," Revision 21

The inspectors completed one inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by TS as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Three on-line maintenance work activities scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the highest personnel collective exposures
- Site-specific ALARA procedures
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Dose rate reduction activities in work planning
- Method for adjusting exposure estimates, or replanning work, when unexpected changes in scope or emergent work were encountered
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding
- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas
- Self-assessments and audits related to the ALARA program since the last inspection
- Corrective action documents related to the ALARA program and follow-up activities such as initial problem identification, characterization, and tracking

The inspector completed 9 of the required 15 inspection samples and 2 of the optional inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Emergency Preparedness Cornerstone

a. Inspection Scope

The inspector sampled licensee submittals for the performance indicators listed below for the period July 1, 2004, through September 30, 2005. The definitions and guidance of NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revisions 2 and 3, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period. The licensee’s performance indicator data was also reviewed against the requirements of Procedure EN-LI-114, “Performance Indicator Process,” Revision 0.

- Drill and Exercise Performance
- Emergency Response Organization Participation
- Alert and Notification System Reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios, licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspector reviewed emergency responder qualification, training, and drill participation records for 20 key licensee emergency response personnel. The inspector reviewed procedures for conducting siren testing and a 100 percent sample of siren test records. The inspector also interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data.

The inspector completed three inspection samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

1. Emergency Preparedness Annual Sample Review

a. Inspection Scope

The inspector reviewed a summary listing of 146 corrective actions assigned to the emergency preparedness department, reviewed 17 CRs in detail, and independently assessed the licensee’s ability to identify problems associated with an October 18, 2005, integrated drill, in order to assess the licensee’s ability to identify and correct problems. The inspector completed one inspection sample.

b. Findings

No findings of significance were identified.

2. ALARA Planning and Controls Annual Sample Review

a. Inspection Scope

The inspector evaluated the effectiveness of the licensee's problem identification and resolution processes regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. The inspector reviewed the corrective action documents listed in the attachment against the licensee’s problem identification and resolution program requirements. The inspector completed one inspection sample.

b. Findings

No findings of significance were identified.

3. Semiannual Trend Review

a. Inspection Scope

The inspectors performed a 6-month review of the licensee’s corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspector’s review was focused on repetitive issues, but also considered the results of daily inspector screening of CRs and licensee trending efforts. The inspector’s review considered the six month period of July through December 2005. Inspectors reviewed 76 specific CRs and their associated operability evaluations. Operability determinations set the priority for corrective actions to resolve conditions adverse to quality. The CR numbers are listed in the attachment.

The inspectors also evaluated the CRs and the operability determinations against the requirements of the following guidance documents:

- Procedure EN-LI-102, “Corrective Action Process,” Revision 1
- Procedure EN-OP-104, “Operability Determinations,” Revision 1
- Procedure OSP-0040, “LCO Tracking and Safety Function Determination Program,” Revision 10
- MC 9900, “Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety,” dated September 26, 2005

The inspectors completed one inspection sample.

b. Assessment and Observations

There were no findings of significance identified. The inspectors determined that a number of operability determinations stated that the equipment that was the subject of the CR was currently inoperable and being tracked using the LCO Tracking System. The inspectors found that this system was an effective mechanism for resolution of TS LCOs. However, from a corrective action program perspective, there was no closure of the condition adverse to quality (system inoperability) or a discussion of the corrective actions taken to restore the equipment to operable status in the subject CR. In addition, the inspectors observed that a number of operability determinations described conditions where the system was declared operable but the system or a support system was in a degraded or nonconforming condition. In some cases, compensatory actions were being taken to ensure system operability, but no mechanism was in place to ensure that these compensatory measures remained in place until the degraded or nonconforming condition was corrected. The inspectors did not find any examples where the nonconforming condition was not corrected within a reasonable period of time.

4. Resident Inspector Annual Sample Review

The inspectors completed two inspection samples.

Ultimate Heat Sink Long Term Heat Removal Capacity

c. Inspection Scope

The inspectors reviewed CR-RBS-2002-01243, ultimate heat sink capacity less than the 30-day requirement, during the week of November 28, 2005. The inspectors evaluated the CR against the requirements of the licensee's corrective action program as described in nuclear management manual Procedure LI-102, "Corrective Action Process," Revision 4, and 10 CFR Part 50, Appendix B, Criterion XVI.

b. Findings and Observations

There were no findings of significance identified. On August 28, 2002, the inspectors found: (1) the single failure assumption made for the design of the ultimate heat sink was a trip of standby diesel Generator B immediately after a small line break event, with bypass, coincident with a loss-of-offsite power and plant trip, (2) the ultimate heat sink capacity would be less than 30 days if, instead, all ECCS systems worked as designed and no operator actions were taken to secure ECCS, and (3) specific procedures to replenish the ultimate heat sink during a loss-of-offsite power had not been written. In response to the inspectors' concerns, the licensee wrote CR-RBS-2002-01243 and took the following corrective actions: (1) revised their procedures to clarify operator actions if no single failure occurred and to provide instructions for makeup to the ultimate heat sink during a 30-day loss-of-offsite power; and (2) issued license amendment Request LAR-2001-026, dated March 18, 2003, to revise their TS Bases 3.7, “Standby Service Water System and Ultimate Heat Sink,” and USAR.

Simulator Fidelity Issue Regarding Wide-Range Level Recorders

d. Inspection Scope

The inspectors reviewed the corrective actions taken by the licensee in response to NCV 05000458/2004005-02, wide-range reactor water level indication did not respond as expected by operators following an unplanned reactor scram. On December 10, 2004, a failure of a balance of plant instrument bus caused the feedwater regulating valves to fail in their 100 percent flow position. Following a reactor scram, the feedwater pumps overfed the reactor and tripped on high reactor water level. The excess feedwater caused reactor water level to continue to rise after the feed pump trip. The wide-range level recorders' digital output continued to indicate reactor water level greater than +60 inches, the top end of the wide-range level instruments. The reactor operators were not aware that the recorders’ digital output would continue to increase beyond +60 inches because the digital readout of wide-range level recorders in the simulator stopped at +60 inches. This response caused some confusion and complicated the operators' response to the event. The inspectors reviewed CR-RBS-2004-04289, -04295, -04296 and -04299 written by the licensee in response to this event.

e. Findings and Observations

There were no findings of significance identified. The inspectors found that, when a design change was implemented changing the wide-range reactor water level recorders from analog to digital models, the simulator modification made the software for the recorders stop indicating at the top of scale (+60 inches). The digital recorders installed in the control room, however, had no upper limit on the digital indication. On December 10, 2004, reactor water level rose above the reference leg tap for the level transmitter and, as the reference leg condensing chamber cooled down, the wide-range level transmitters’ output continued to increase and the digital indication showed a level as high as +140 inches. The inspectors reviewed the corrective actions taken by the licensee and determined that they were reasonable and adequate to correct the operator knowledge deficiency caused by the simulator fidelity issue. The inspectors interviewed a cross-section of control room operators and determined that the phenomena was understood and they understood that any wide-range digital indication greater that +60 inches was invalid and not indicative of actual reactor water level.

4OA3 Event Followup

1. (Closed) Licensee Event Report (LER) 50-458/04-001-00, Automatic Reactor Scram Due to Main Generator Trip Resulting from Switchyard Fault

On August 15, 2004, a transmission tower guy wire failed. This allowed a 230 kV transmission line structure between Port Hudson and Fancy Point (Line 353) to fall and create a ground fault condition on the line. Four breakers in the station switchyard were slow to open to clear the fault. As a result: (1) Reserve Station Transformer 2 was deenergized, causing a partial loss of off-site power and start of the Division 2 emergency diesel generator; and (2) main transformer protection relays caused a main generator lockout, which resulted in a generator load reject reactor scram.

NRC Integrated Inspection Report 05000458/2004005, issued February 14, 2005, documented a Green, self-revealing finding associated with this event for preconditioned speed testing of station switchyard breakers and three similar failures of station switchyard breakers. The licensee revised the speed testing procedures to avoid preconditioning the breakers.

NRC Supplemental Inspection Report 05000458/2005012, issued October 24, 2005, documented a supplemental inspection performed in accordance with Inspection Procedure 95001. The supplemental inspection was in response to four unplanned reactor scrams that occurred between August 15, 2004, and January 15, 2005. The licensee's root cause analysis identified several programmatic changes which were incorporated into a switchyard reliability program to improve switchyard maintenance practices.

The inspectors reviewed the LER and the licensee's resolution of identified problems and determined there were no findings of significance and no other violations of NRC requirements. The licensee documented the failed equipment in CR-RBS-2004-02332.

4OA6 Meetings, Including Exit

Exit Meetings

On October 21, 2005, the inspector presented the emergency preparedness inspection results to Mr. J. Leavines, Manager, Emergency Planning, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On November 4, 2005, the inspector presented the licensed operator requalification program inspection results to Mr. Mike Cantrell, Operations Training Supervisor, and other members of the licensee's management staff. The licensee acknowledged the findings presented. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On December 8, 2005, the inspector presented the ALARA inspection results to Mr. R. King, Director, Nuclear Safety Assurance, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On January 4, 2006, the inspectors presented the integrated baseline inspection results to Paul Henninkamp, Vice President, Operations, and other members of licensee management. The inspector confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

M. Boyle, Manager, Radiation Protection
D. Burnett, Superintendent, Chemistry
M. Cantrell, Operations Training Supervisor
J. Clark, Assistant Operations Manager - Training
T. Coleman, Manager, Planning and Scheduling/Outage
M. Davis, Acting Manager, Radiation Protection
C. Forpahl, Manager, Corrective Actions
H. Goodman, Director, Engineering
P. Hinnenkamp, Vice President - Operations
B. Houston, Manager, Plant Maintenance
G. Huston, Assistant Operations Manager - Shift
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
P. Russell, Manager, System Engineering
C. Stafford, Manager, Operations
W. Trudell, Manager, Training and Development
D. Vinci, General Manager - Plant Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000458/2005005-01	NCV	Inadequate procedure for implementation of an EAL
05000458/2005005-02	NCV	Failure to complete TS required actions within allowed completion time
05000458/2005005-03	NCV	Inadequate design assumption results in RCIC turbine exhaust header filling with water following an automatic high water level shutdown

Closed

05000458/2004-001-00	LER	Automatic Reactor Scram Due to Main Generator Trip Resulting from Switchyard Fault

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:

Section 1R11: Licensed Operator Requalification Program

Job Performance Measures

RJPM-OPS-052-04, Alternate Control Rod Drive Pumps, August 4, 2005

RJPM-OPS-053-03R5, Reset a FCV runback, July 26, 2005

RJPM-OPS-109.4, July 26, 2005

RJPM-OPS-110-04, Synchronize the Main Generator with the Grid, August 2, 2005

RJPM-OPS-256-03R4, Restore level in the SBCT with deepwell pumps, July 26, 2005

RJPM-OPS-309-050, July 19, 2005

RJPM-OPS-508-04, Restore RPS B Normal Power Supply, August 19, 2005

RJPM-OPS-508-07, Respond to reactor scram with control rods failing to insert, August 2, 2005

RJPM-OPS-800-17R1, Vent the CCRD over-piston volume, July 26, 2005

RJPM-OPS-05206R2, Control rod operability faulted, July 12, 2005

RJPM-OPS-05207R2, Alternate control rod drive pumps (Fuel Bldg), July 12, 2005

RJPM-OPS-05304R, Startup A recirc HPU, July 12, 2005

RJPM-OPS-20005R, Perform ATC actions for remote shutdown, August 2, 2005

RJPM-OPS-20006R5, Perform Attachment 13 UO actions, July 26, 2005

Scenarios

RSMS-OPS-822, Loss of All Feed Water / RCIC Failure / LOCA, Revision: 00

RSMS-OPS-823, APRM Failure /SRV Failure / EHC Failure / ATWS, Revision: 00

RSMS-OPS-824, LPRM Failure / Loss of Vacuum with MSIV Closure / ATWS, Revision: 00

RSMS-OPS-825, Loss of RPS B / Relief Valve Fails Open / Steam Leak in the Drywell With Failure of the Drywell, Revision: 00

RSMS-OPS-827, Rod Drop / Fuel Failure / RCIC Steam Leak / Partial ATWS, Revision: 00

RSMS-OPS-829, Failure Of STX-XS2B / Loss Of Condenser Vacuum / ATWS, Revision: 00

RSMS-OPS-830, Inadvertent HPCS Injection and Loss of Stator Cooling, Revision: 00

<u>Section 1R17: Permanent Plant Modifications</u>

Event Notification 41252, Reactor Scram due to Loss of Vital Instrument Bus

LER 05-458/04-005-01, Unplanned Automatic Scram due to Loss of Non-Vital 120 Volt Instrument Bus, June 22, 2005

CR-RBS-2004-04291 RCIC system initiated and subsequently tripped on Level 8

CR-RBS-2005-00724 MR96-0063 removed internals from RCIC Turbine Exhaust Check Valve E51-VF040

SDRP-P43, System Design Requirements Document, Reactor Core Isolation Cooling, Revision 0

SDC-209, Reactor Core Isolation Cooling System Design Criteria, Revision 0, November 9, 1998

SDC-209, Reactor Core Isolation Sooling System Design Criteria, Revision 3, September 27, 2004

RBS USAR Section 5.4.6, Reactor Core Isolation Cooling System, Revision 17

NUREG-0989, RBS Safety Evaluation Report and Supplements, May 1984 through October 1985

GE SIL-30, HPCI/RCIC Turbine Exhaust Line Vacuum Breakers, October 31, 1973

GS AID-56, HPCI/RCI Turbine Exhaust Check Valve Cycling, August 1985

VPF-3622-353 (1) - 1, RCIC Turbine Instruction Manual, January 1975 through March 1978

MR96-0063, Remove Internals of [RCIC Exhaust Check Valve] E51-VF040, September 18, 1996

CR-RBS-1996-1671, Existing plant configuration of RCIC turbine exhaust line vacuum breaker vent line does not correspond with configuration assumed in Calculation PH-56, Revision 0

Calculation PH-56, RCIC Turbine Exhaust Line Vacuum Breaker Vent Line Sizing Verification, Revision 1A, November 27, 1996

Piping and Instrument Drawing PID-27-06A, Reactor Core Isolation Cooling System, Revision 42

Calculation G13.18.2.0-079, Determination of Quantity of Water Entering RCIC Turbine Exhaust Line, May 11, 2005

Calculation G13.18.10.2*225, RCIC Fluid Transient Analysis - Water in Turbine Exhaust Line, May 17, 2005

ER-RB-2005-0084-000, Replace Check Valve E51-VF040 or Reinstall Internal Parts, February 20, 2005

Terry Turbine SAM-12, Terry Wheel Water Slug Test, March 1, 1973

Section 1EP2: Alert and Notification System Testing

River Bend Station Emergency Plan, Revision 28

River Bend Station Prompt Notification System Design Report, Revision 1, December 2001

Section 1EP3: Emergency Response Organization Augmentation Testing

Evaluation Reports for Pager and Augmentation Tests conducted:

February 10, 2004	December 8, 2004	July 25, 2005
June 17, 2004	January 25, 2005	September 27, 2005
August 24, 2004	March 22, 2005	
September 23, 2004		

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Procedures

EN-LI-118, “Root Cause Analysis Process,” Revision 1
EN-LI-119, “Apparent Cause Evaluation Process,” Revision 3

Quality Assurance

Quality Assurance Audit Report, QA-7-2003-RBS-1
Quality Assurance Audit Report, QA-7-2004-RBS-1
Quality Assurance Audit Report, QA-7-2005-RBS-1

Condition Reports

CR-RBS-1999-1316
CR-RBS-2003-0586
CR-RBS-2003-0624
CR-RBS-2003-1950
CR-RBS-2003-1992
CR-RBS-2003-2094
CR-RBS-2003-3050
CR-RBS-2004-1090
CR-RBS-2004-1159
CR-RBS-2004-3086
CR-RBS-2004-3811
CR-RBS-2005-1433
CR-RBS-2005-1602
CR-RBS-2005-1632
CR-RBS-2005-1391
CR-RBS-2005-2516
CR-RBS-2005-2646

Evaluation Reports for Drills conducted

September 3, 2003
March 2 2004
April 20, 2004
May 25, 2004
June 9, 2004
July 27, 2004
December 1, 2004 (simulator)
December 1, 2004 (medical)
March 24, 2005
April 19, 2005
June 21, 2005

Licensee Self-Assessments

2004 Evaluated Exercise Pre-Assessment
LO-RLO-2004-00004 CA56, “2004 Long Range ERO Staffing Assessment”
2005 Emergency Planning Program Assessment
Snapshot Assessment of RBS Siren System

Section 4OA1: Performance Indicator Verification

Procedures

EN-EP-201, “Emergency Planning Performance Indicators,” Revision 2
EPP-2-703, “Performance Indicators,” Revision 2
EIP-2-001, “Classification of Emergencies,” Revision 12
EIP-2-002, “Classification Actions,” Revision 24
EIP-2-006, “Notifications,” Revision 32
EIP-2-007, “Protective Action Recommendation Guidelines,” Revision 20
EIP-2-007, “Protective Action Recommendation Guidelines,” Revision 21

Section 2OS2: ALARA Planning and Controls

Condition Reports

CR-RBS-2005-01472	CR-RBS-2005-02558
CR-RBS-2005-01474	CR-RBS-2005-03382
CR-RBS-2005-02076	CR-RBS-2005-04004

Audits and Self-Assessments

QA-14-2005-RBS-1	Quality Assurance Audit of Radiation Protection Snapshot Assessment /Benchmark on: Effectiveness of the RP TAC/TRG (July 11-13, 2005)
QS-2005-RBS-009	ALARA Planning and Controls (August 22 through September 1, 2005)
LO#2005-00123	Radiation Protection Program (July 11-15, 2005)

Radiation Work Permits

2005-1073	Change out filter elements LWS-SKD5-F100A
2005-1110	Clean-up FB 113' cask pool and install cask pool impact limiter
2005-1310	Recirc Flow Control Valve Maintenance

Procedures

ENS-RP-105	Radiation Work Permits, Revision 7
RP-110	ALARA Program, Revision 2

ALARA Committee Minutes

AMC 05-01	January 11, 2005
AMC 05-02	January 12, 2005
AMC 05-03	January 17, 2005
AMC 05-11	July 14, 2005

Section 4OA2: Identification and Resolution of Problems

Condition reports

CR-RBS-2005-02444	CR-RBS-2005-02570
CR-RBS-2005-02481	CR-RBS-2005-02590
CR-RBS-2005-02486	CR-RBS-2005-02605
CR-RBS-2005-02494	CR-RBS-2005-02621
CR-RBS-2005-02548	CR-RBS-2005-02624
CR-RBS-2005-02563	CR-RBS-2005-02626

CR-RBS-2005-02645
CR-RBS-2005-02649
CR-RBS-2005-02659
CR-RBS-2005-02664
CR-RBS-2005-02686
CR-RBS-2005-02693
CR-RBS-2005-02695
CR-RBS-2005-02722
CR-RBS-2005-02724
CR-RBS-2005-02727
CR-RBS-2005-02738
CR-RBS-2005-02754
CR-RBS-2005-02760
CR-RBS-2005-02767
CR-RBS-2005-02768
CR-RBS-2005-03106
CR-RBS-2005-03111
CR-RBS-2005-03114
CR-RBS-2005-03125
CR-RBS-2005-03131
CR-RBS-2005-03138
CR-RBS-2005-03151
CR-RBS-2005-03152
CR-RBS-2005-03165
CR-RBS-2005-03178
CR-RBS-2005-03182
CR-RBS-2005-03220
CR-RBS-2005-03242
CR-RBS-2005-03265
CR-RBS-2005-03273
CR-RBS-2005-03279
CR-RBS-2005-03443
CR-RBS-2005-03446
CR-RBS-2005-03471
CR-RBS-2005-03474
CR-RBS-2005-03503
CR-RBS-2005-03509
CR-RBS-2005-03513
CR-RBS-2005-03515
CR-RBS-2005-03554
CR-RBS-2005-03586
CR-RBS-2005-03594
CR-RBS-2005-03619
CR-RBS-2005-03629
CR-RBS-2005-03645
CR-RBS-2005-03670
CR-RBS-2005-03706
CR-RBS-2005-03728
CR-RBS-2005-03747
CR-RBS-2005-03753
CR-RBS-2005-03787
CR-RBS-2005-03831
CR-RBS-2005-03847
CR-RBS-2005-03887
CR-RBS-2005-03918
CR-RBS-2005-03948
CR-RBS-2005-03969
CR-RBS-2005-04018
CR-RBS-2005-04064
CR-RBS-2005-04071
CR-RBS-2005-04095
CR-RBS-2005-04103
CR-RBS-2005-04106
CR-RBS-2005-04118

LIST OF ACRONYMS

ALARA	as low as is reasonably achievable
CFR	*Code of Federal Regulations*
CR	condition report
CR-RBS	River Bend Station condition report
EAL	emergency action level
FEMA	Federal Emergency Management Agency
FCV	flow control valve
HPU	hydraulic power unit
MC	manual chapter
LER	licensee event report
LCO	limiting condition for operation
LOCA	loss of coolant accident
NCV	noncited violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
RCIC	reactor core isolation cooling system
RCS	reactor coolant system
RR	reactor recirculation system
SOP	system operating procedures
STP	surveillance test procedure
TS	Technical Specification
USAR	Updated Safety Analysis Report
WO	work order