UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E. LAMAR BLVD.
ARLINGTON, TX 76011-4511

August 14, 2014

EA-11-096

Mr. Eric W. Olson, Site Vice President
Entergy Operations, Inc.
River Bend Station
5485 U.S. Highway 61N
St. Francisville, LA 70775

SUBJECT: RIVER BEND STATION – NRC INTEGRATED INSPECTION REPORT 05000458/2014003

Dear Mr. Olson:

On June 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the River Bend Station, Unit 1. On July 15, 2014, the NRC inspectors discussed the results of this inspection with you and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented one finding of very low safety significance (Green) in this report. This finding involved the violation of NRC requirements. Further, inspectors documented one licensee-identified violation which was determined to be of very low safety significance in this report. The NRC is treating these violations as non-cited violations consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of these non-cited 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, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at the River Bend Station.

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV; and the NRC resident inspector at the River Bend Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/ Ray V. Azua for

Donald B. Allen, Branch Chief
Project Branch C
Division of Reactor Projects

Docket No.: 50-458
License No.: NPF-47

Enclosure:
Inspection Report 05000458/2014003
w/Attachment: Supplemental Information

cc w/ encl:
Electronic Distribution for River Bend Station

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See next page

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Letter and Inspection Report to Eric W. Olson from Donald B. Allen, dated August 14, 2014

SUBJECT: RIVER BEND STATION – NRC INTEGRATED INSPECTION REPORT 05000458/2014003

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000458
License:	NPF-47
Report:	05000458/2014003
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station, Unit 1
Location:	5485 U.S. Highway 61N St. Francisville, LA 70775
Dates:	April 1 through June 30, 2014
Inspectors:	G. Larkin, Senior Resident Inspector A. Barrett, Resident Inspector R. Azua, Senior Project Engineer R. Latta, Senior Reactor Inspector, Engineering Branch 1
Approved By:	Donald B. Allen Chief, Project Branch C Division of Reactor Projects

Enclosure

SUMMARY

IR 05000458/2014003; 04/01/2014 – 06/30/2014; River Bend Station; Integrated Resident and Regional Report; Problem Identification and Resolution

The inspection activities described in this report were performed between April 1 and June 30, 2014, by the resident inspectors at the River Bend Station and inspectors from the NRC's Region IV office. One finding of very low safety significance (Green) is documented in this report. This finding involved the violation of NRC requirements. Additionally, NRC inspectors documented in this report one licensee-identified violation of very low safety significance. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, "Significance Determination Process." Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, "Aspects Within The Cross-Cutting Areas," issued December 19, 2013. Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Cornerstone: Mitigating Systems

- Green. The inspectors reviewed a self-revealing non-cited violation of Technical Specification 5.4.1.a., "Procedures," for the failure to adhere to procedural requirements to ensure that other fire suppression ring header valves are/are not correctly positioned. Specifically, on May 19, 2014, the licensee failed to follow the specified instructions in tagging clearance 1C16 / 251-001-O-FPW-P1A, to verify that there were no other ring header valves isolated before implementing the clearance, resulting in the inadvertent isolation of the fire protection ring header. The licensee entered this issue into their corrective action program as Condition Report CR-RBS-2014-02489.

  The failure to follow procedures is a performance deficiency. The performance deficiency is more than minor and, therefore, a finding because it adversely impacted the protection against external factors attribute of the Mitigating System Cornerstone, in that the licensee isolated the fire suppression header to the majority of the plant for approximately 36 hours. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, the inspectors determined that the issue affected the Mitigating Systems Cornerstone and that the finding pertained to a degraded condition while the plant was in operation. As a result, the inspectors were directed to Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," dated September 20, 2013. The inspectors determined that Appendix F did not address the loss of the fire protection ring header to most of the facility and Appendix F, "Assumptions and Limitations," states "the SDP approach is intended to support the assessment of known issues only in the context of an individual fire area. A systematic plant-wide search and assessment effort is beyond the intended scope of the fire protection SDP." Therefore, a senior reactor analyst (SRA) performed a detailed risk evaluation. The total exposure period was 36 hours. The bounding change to the core damage frequency was 2E-7/year. The bounding change to the large early release frequency was 4E-8 per year. The finding was of very low safety significance (Green). The dominant core damage sequences included a fire-induced loss of offsite power, failure of operators to suppress the fire, and damage to

Division I, II, and III components. The reactor core isolation cooling system and the short exposure period helped to minimize the risk. The finding has a cross-cutting aspect in the area of human performance associated with avoiding complacency because the licensee failed to recognize and plan for the possibility for mistakes and did not implement appropriate error reduction tools [H.12]. (Section 4OA2)

Licensee-Identified Violations

One violation of very low safety significance that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and associated corrective action tracking numbers are listed in Section 4OA7 of this report.

PLANT STATUS

The River Bend Station began the inspection period at 100 percent reactor power. It departed from full power as follows:

- On April 17, 2014, operators reduced power to approximately 70 percent to perform a planned rod sequence exchange, control rod settle time testing, a repair of reactor feed pump B steam leak, and a fully withdrawn rod operability test. The licensee returned the plant to full power on April 17.

- On April 24, 2014, operators reduced power to approximately 85 percent to perform further repairs to eliminate a steam leak from the suction end bell on reactor feed pump B. The licensee returned the plant to full power on April 24.

- On June 13, 2014, operators reduced power to approximately 93 percent to perform control rod settle time testing on three controls rods (08-45, 48-45, and 48-13) that tested slow on April 17. The licensee returned the plant to full power on June 13.

The plant remained at 100 percent reactor power for the remainder of the inspection period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Summer Readiness for Offsite and Alternate AC Power Systems

a. Inspection Scope

On May 7, 2014, the inspectors completed an inspection of the station's off-site and alternate-ac power systems. The inspectors inspected the material condition of these systems, including transformers and other switchyard equipment to verify that plant features and procedures were appropriate for operation and continued availability of off-site and alternate-ac power systems. The inspectors reviewed outstanding work orders and open condition reports for these systems. The inspectors walked down the switchyard to observe the material condition of equipment providing off-site power sources. The inspectors assessed corrective actions for identified degraded conditions and verified that the licensee had considered the degraded conditions in its risk evaluations and had established appropriate compensatory measures. The inspectors verified that the licensee's procedures included appropriate measures to monitor and maintain availability and reliability of the off-site and alternate-ac power systems.

These activities constituted one sample of summer readiness of off-site and alternate-ac power systems, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

.2 Readiness to Cope with External Flooding

a. Inspection Scope

On April 30, 2014, the inspectors completed an inspection of the station's readiness to cope with external flooding. After reviewing the licensee's flooding analysis, the inspectors chose three plant areas that were susceptible to flooding:

- West Creek
- East Creek
- Auxiliary Building – 98' external doors

The inspectors reviewed plant design features and licensee procedures for coping with flooding. The inspectors walked down the selected areas to inspect the design features, including the material condition of seals, drains, and flood barriers. The inspectors evaluated whether credited operator actions could be successfully accomplished.

These activities constituted one sample of readiness to cope with external flooding, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdown

a. Inspection Scope

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

- April 1, 2014, Division I standby liquid control with Division II out of service for planned maintenance

- April 8, 2014, residual heat removal B during Division I residual heat removal system outage

- April 10, 2014, residual heat removal A following system maintenance

- April 10, 2014, control building chilled water system chiller B during unplanned outage and inoperability of control building chilled water system chillers A and D

- May 20, 2014, fire water system following discovery of improper isolation of firewater loop

The inspectors reviewed the licensee's procedures and system design information to determine the correct lineup for the systems. They visually verified that critical portions of the systems or divisions were correctly aligned for the existing plant configuration.

These activities constituted five partial system walk-down samples, as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

.2 Complete Walkdown

a. Inspection Scope

On June 19, 2014, the inspectors performed a complete system walk-down inspection of the residual heat removal system. The inspectors reviewed the licensee's procedures and system design information to determine the correct system lineup for the existing plant configuration. The inspectors also reviewed outstanding work orders, open condition reports, in-process design changes, temporary modifications, and other open and closed items tracked by the licensee's operations and engineering departments. The inspectors then visually verified that the system was correctly aligned for the existing plant configuration.

These activities constituted one complete system walk-down sample, as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Inspection

a. Inspection Scope

The inspectors evaluated the licensee's fire protection program for operational status and material condition. The inspectors focused their inspection on eight plant areas important to safety:

- April 23, 2014, control building, 98-foot elevation, and diesel generator building, 98-foot elevation

- April 24, 2014, auxiliary building, 114-foot and 141-foot elevations

- April 28, 2014, reactor building, 186-foot, 162-foot, and 141-foot elevations

- May 1, 2014, auxiliary building, 95-foot and 170-foot elevations

- May 5, 2014, turbine building, 124-foot and 95-foot elevations

- May 5, 2014, auxiliary building, 78-foot elevation, and tunnels E, F, and G

- May 13, 2014, auxiliary building, residual heat removal C, low pressure core spray, and high pressure core spray pump rooms

- May 14, 2014, control building, 136-foot elevation

For each area, the inspectors evaluated the fire plan against defined hazards and defense-in-depth features in the licensee's fire protection program. The inspectors evaluated control of transient combustibles and ignition sources, fire detection and suppression systems, manual firefighting equipment and capability, passive fire protection features, and compensatory measures for degraded conditions.

These activities constituted eight quarterly inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11)

.1 Review of Licensed Operator Requalification

a. Inspection Scope

On May 6, 2014, the inspectors observed an evaluated simulator scenario performed by an operating crew. The inspectors assessed the performance of the operators and the evaluators' critique of their performance. The inspectors also assessed the modeling and performance of the simulator.

These activities constitute completion of one quarterly licensed operator requalification program sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

.2 Review of Licensed Operator Performance

a. Inspection Scope

On June 2, 2014, the inspectors observed the performance of on-shift licensed operators in the plant's main control room. At the time of the observations, the plant was in a period of heightened risk due to a planned Division I emergency diesel generator outage.

The inspectors assessed the operators' adherence to plant procedures, including the conduct of operations procedure and other operations department policies.

These activities constitute completion of one quarterly licensed operator performance sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed three instances of degraded performance or condition of safety-related structures, systems, and components:

- April 4, 2014, control room switches (GE CR 2940)
- April 10, 2014, average power range monitors
- April 14, 2014, CR120 relays

The inspectors reviewed the extent of condition of possible common cause structure, system, and component failures and evaluated the adequacy of the licensee's corrective actions. The inspectors reviewed the licensee's work practices to evaluate whether these may have played a role in the degradation of the structures, systems, and components. The inspectors assessed the licensee's characterization of the degradation in accordance with 10 CFR 50.65 (the Maintenance Rule), and verified that the licensee was appropriately tracking degraded performance and conditions in accordance with the Maintenance Rule.

These activities constituted completion of three maintenance effectiveness samples, as defined in Inspection Procedure 71111.12.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors observed portions of five emergent work activities that had the potential to cause an initiating event or to affect the functional capability of mitigating systems.

- April 14, 2014, breaker maintenance in Fancy Point with the potential for severe weather

- May 1, 2014, transformer yard maintenance with standby liquid control surveillances and Division II residual heat removal line fill pump emergent maintenance

- May 7, 2014, Fancy Point breaker YWC-GCB 20620 "A" SF6 (phase gas) leak inspection Condition Report CR-RBS-2014-02190 – no work order task for inspection

- May 14, 2014, Division II control building chilled water out of service with severe weather and breaker and relay work in Fancy Point

- May 21, 2014, Loss of fire water loop with residual heat removal B and C out of service for planned maintenance

The inspectors verified that the licensee appropriately developed and followed a work plan for these activities. The inspectors verified that the licensee took precautions to minimize the impact of the work activities on unaffected structures, systems, and components.

These activities constitute completion of five maintenance risk assessments and emergent work control inspection samples, as defined in Inspection Procedure 71111.13.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed eight operability determinations and functionality assessments that the licensee performed for degraded or nonconforming structures, systems, and components:

- April 2, 2014, operability determination of wear particles detected in reactor core isolation cooling pump inboard and outboard bearings (CR-RBS-2014-01020)

- April 3, 2014, operability determination of CCP-MOV16A system leakage not evaluated in operability (CR-RBS-2014-01181)

- April 7, 2014, operability determination of residual heat removal pump A motor breaker slow (CR-RBS-2014-01675)

- April 18, 2014, operability determination of standby cooling tower roof plugs not installed properly (CR-RBS-2013-06913)

- April 23, 2014, operability determination of control building chiller C motor current calibration 40 percent adjustment (CR-RBS-2014-00123)

- April 24, 2014, operability determination of control room fan for Division 1 emergency diesel generator noise evaluation (CR-RBS-2014-01814)

- April 29, 2014, operability determination of Division I emergency diesel generator low oil level alarm during operability surveillance (CR-RBS-2013-07367)

- May 7, 2014, functionality assessment of potential inappropriate installation of stainless steel flexible conduit fittings (CR-RBS-2014-01859)

The inspectors reviewed the timeliness and technical adequacy of the licensee's evaluations. Where the licensee determined the degraded structures, systems, and components to be operable or functional, the inspectors verified that the licensee's compensatory measures were appropriate to provide reasonable assurance of operability or functionality. The inspectors verified that the licensee had considered the effect of other degraded conditions on the operability or functionality of the degraded structures, systems, and components.

These activities constitute completion of eight operability and functionality review samples, as defined in Inspection Procedure 71111.15.

b. <u>Findings</u>

No findings were identified.

1R18 Plant Modifications (71111.18)

a. <u>Inspection Scope</u>

The inspectors reviewed two temporary plant modifications that affected risk-significant structures, systems, and components:

- May 23, 2014, Temporary Modification 48632, "Temporary Alternate Power for MTX-XM1," Revision 0

- May 23, 2014, Emergency Temporary Modification EC-57946, "Main Steam Isolation Valve Half Isolation," Revision 0

The inspectors verified that the licensee had installed these temporary modifications in accordance with technically adequate design documents. The inspectors verified that these modifications did not adversely impact the operability or availability of affected structures, systems, and components. The inspectors reviewed design documentation and plant procedures affected by the modifications to verify the licensee maintained configuration control.

These activities constitute completion of two samples of temporary modifications, as defined in Inspection Procedure 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed three post-maintenance testing activities that affected risk-significant structures, systems, and components:

- April 9, 2014, WO-52450952, "ENS-SWG1A-ACB03 Refurbish Spare Breaker"
- April 24, 2014, WO-52517720, "HVK-CHL1C Control Building Chiller Inspection"
- April 28, 2014, WO-00372105, "HVK-CHI1C Failed its Motor Current Calibration PM Task"

The inspectors reviewed licensing- and design-basis documents for the structures, systems, and components, and the maintenance and post-maintenance test procedures. The inspectors observed the performance of the post-maintenance tests to verify that the licensee performed the tests in accordance with approved procedures, satisfied the established acceptance criteria, and restored the operability of the affected structures, systems, and components.

These activities constitute completion of three post-maintenance testing inspection samples, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed four risk-significant surveillance tests and reviewed test results to verify that these tests adequately demonstrated that the structures, systems, and components were capable of performing their safety functions:

In-service tests:

- April 15, 2014, STP-209-6310, Revision 038, "RCIC Pump Quarterly Operability and Flow Test"
- May 23, 2014, STP-256-6304, Revision 303, "Standby Service Water B Loop Quarterly Pump and Valve Operability Test"

Other surveillance tests:

- May 21, 2014, STP-053-3001, Revision 021, "Jet Pump Operability Test"
- June 19, 2014, WO-00382733, Revision 0, "E31-PTN092 – Calibrate"

The inspectors verified that these tests met technical specification requirements, that the licensee performed the tests in accordance with their procedures and that the results of the test satisfied appropriate acceptance criteria. The inspectors verified that the licensee restored the operability of the affected structures, systems, and components following testing.

These activities constitute completion of four surveillance testing inspection samples, as defined in Inspection Procedure 71111.22.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors observed an emergency preparedness drill on May 20, 2014, to verify the adequacy and capability of the licensee's assessment of drill performance. The inspectors reviewed the drill scenario, observed the drill from the simulator, and attended the post-drill critique. The inspectors verified that the licensee's emergency classifications, off-site notifications, and protective action recommendations were

appropriate and timely. The inspectors verified that any emergency preparedness weaknesses were appropriately identified by the licensee in the post-drill critique and entered into the corrective action program for resolution.

These activities constitute completion of one emergency preparedness drill observation sample, as defined in Inspection Procedure 71114.06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures (MS05)

a. Inspection Scope

For the period of April 2013 through March 2014, the inspectors reviewed licensee event reports, maintenance rule evaluations, and other records that could indicate whether safety system functional failures had occurred. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, and NUREG-1022, "Event Reporting Guidelines: 10 CFR 50.72 and 50.73," Revision 3, to determine the accuracy of the data reported.

These activities constituted verification of the safety system functional failures performance indicator for Unit 1, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index: Emergency AC Power Systems (MS06)

a. Inspection Scope

The inspectors reviewed the licensee's mitigating system performance index data for the period of April 2013 through March 2014 to verify the accuracy and completeness of the reported data. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the reported data.

These activities constituted verification of the mitigating system performance index for emergency ac power systems for Unit 1, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index: High Pressure Injection Systems (MS07)

a. Inspection Scope

The inspectors reviewed the licensee's mitigating system performance index data for the period of April 2013 through March 2014 to verify the accuracy and completeness of the reported data. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the reported data.

These activities constituted verification of the mitigating system performance index for high pressure injection systems for Unit 1, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review

a. Inspection Scope

Throughout the inspection period, the inspectors performed daily reviews of items entered into the licensee's corrective action program and periodically attended the licensee's condition report screening meetings. The inspectors verified that licensee personnel were identifying problems at an appropriate threshold and entering these problems into the corrective action program for resolution. The inspectors verified that the licensee developed and implemented corrective actions commensurate with the significance of the problems identified. The inspectors also reviewed the licensee's problem identification and resolution activities during the performance of the other inspection activities documented in this report.

b. Findings

No findings were identified.

.2 Semiannual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program and associated documents to identify adverse trends. The inspectors focused their review on maintenance effectiveness, but also considered the results of daily corrective action item screening discussed in Section 4OA2.1, above, licensee trending efforts, and licensee human performance results. The inspectors nominally considered the 7-month period of December 2013 through June 2014; although, some examples expanded beyond those dates where the scope of the trend warranted.

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

These activities constitute completion of one semi-annual trend review sample, as defined in Inspection Procedure 71152.

b. Findings and Observations

No findings were identified, but the inspectors did have the following observations:

The inspectors reviewed equipment failures documented in the corrective action program for potential trends that have not been identified by the licensee. In addition, the inspectors assessed the effectiveness of maintenance to improve the equipment reliability at the station.

The inspectors identified an adverse trend in instrument air system equipment failures during this period, which increased from the previous semi-annual trend reviews. During the period, operations entered the abnormal operating procedure for loss of instrument air twice, and referenced the use of the procedure once. The station also documented failures of instrument air compressors, system valves, and automatic isolations of the service air system from the instrument air system due to declining instrument air header pressure. The inspectors noted that instrument air reliability had previously been a station top ten issue; however, the concern had since been removed due to modifications completed to improve the instrument air drying systems. On January 29, 2014, quality assurance issued a finding, documented in Condition Report CR-RBS-2014-00297, which associated adverse station personnel behaviors in regards to unavailability of equipment important to safety, including the instrument air system. The inspectors reviewed the corrective actions addressing the finding and found that the station did not issue specific actions to address instrument air reliability. The instrument air system health report indicates that the system has reliability issues;

however, modifications to improve reliability of the system are not scheduled to be complete until 2017.

The inspectors identified an adverse trend of failures of equipment, or unexpected control room annunciators due to ground faults on busses for safety-related equipment and equipment important to safety or reliability.

.3 Annual Follow-up of Selected Issues

a. Inspection Scope

The inspectors selected two issues for an in-depth follow-up:

- On April 18, 2013, the station experienced a loss of reactor water level during post-maintenance testing following a relay replacement on the setpoint setdown reactor water level control circuit. The station documented the event in Condition Report CR-RBS-2013-07482, and performed a root cause analysis. The station identified the cause as a failure of station personnel to adequately review the post-maintenance testing instructions. The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to prevent recurrence.

- On May 19, 2014, the licensee inadvertently isolated the fire protection ring header to most of the plant. The station documented the event in Condition Report CR-RBS-2014-2489, and performed an apparent cause evaluation. The station identified the cause of this event to be the failure of the control room supervisor to follow the tagging clearance instruction. The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to prevent recurrence.

These activities constitute completion of two annual follow-up samples, as defined in Inspection Procedure 71152.

b. Findings

Introduction. The inspectors reviewed a self-revealing Green non-cited violation of Technical Specification 5.4.1.a., "Procedures" for the failure to adhere to procedural requirements to ensure that other fire suppression ring header valves are/or are not isolated. Specifically, on May 19, 2014, the licensee failed to follow the specified instructions in tagging clearance 1C16 / 251-001-O-FPW-P1A, to verify that there were no other ring header valves isolated before implementing the clearance, resulting in the inadvertent isolation of the fire protection ring header.

Description. On November 11, 2012, the licensee identified that fire hydrant FPW-FHY16 had a below ground leak. As a result, on July 30, 2013, the fire hydrant was isolated from the fire protection ring header using tagging clearance 1C16-1 / 241-009-A-FPW-FHY16 which was part of Work Order 333281. However, due to too much in-leakage through hydrant isolation valve FPW-V68, the clearance boundary was subsequently expanded to include fire water header isolation valve FPW-V8. This essentially isolated the west path of the fire protection ring header.

On May 19, 2014, in preparation for preventive maintenance activities on diesel driven fire pump A, FPW-P1A, the licensee isolated the fire pump from the fire protection ring header using tagging clearance 1C16-1 / 251-001-O-FPW-P1A. Due to leakage past pump discharge isolation valve FPW-V153, the clearance boundary was expanded to include fire water header isolation valves FPW-V1 and FPW-V2. Clearance 1C16-1 / 251-001-O-FPW-P1A, specified in Section 1 of the "Placement Inst.," that "Due to FPW-V153 valve seat leakage…, this tagout isolates ring header isolation valves FPW-V1, and FPW-V2 with ring header impacted in terms of redundancy – are there other ring header valves isolated?" (emphasis added). The previous clearance for fire hydrant FPW-FHY16 (1C16-1 / 241-009-A-FPW-FHY16) was not identified before this clearance was implemented. These valves were closed at 4:26 a.m., on May 19. This essentially isolated the east path of the fire protection ring header. This clearance, in conjunction with the previous clearance, described above, resulted in the isolation of all the fire pumps from the fire protection ring header. On May 20, at 12:05 p.m., operators on tour noted that the fire water header was depressurized. An investigation revealed the two concurrent clearances that had isolated the fire protection ring header. The licensee declared the fire hydrants and hose stations inoperable due to the depressurized fire water header, and took immediate actions to restore the system. The station entered TR 3.7.9.1 Condition C (Fire suppression water system otherwise inoperable), a 24 hour action statement to establish backup fire water capability and begin system restoration or be in mode 3 in 12 hours and mode 4 in 36 hours. Operations established 17 fire watches, eight of which were continuous. At 4:32 p.m., on May 20, the licensee restored pressure to the fire water header with fire pumps FPW-P1B and FPW-P2. The fire protection ring header to the majority of the plant, had been inoperable for 36 hours. The licensee documented this issue in Condition Report CR-RBS-2014-02489.

Analysis. The failure to follow procedures is a performance deficiency. The performance deficiency is more than minor and, therefore, a finding because it adversely impacted the protection against external factors attribute of the Mitigating System Cornerstone, in that the licensee isolated the fire suppression header to the majority of the plant for approximately 36 hours. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, the inspectors determined that the issue affected the Mitigating Systems Cornerstone and that the finding pertained to a degraded condition while the plant was in operation. As a result, the inspectors were directed to Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," dated September 20, 2013. The inspectors determined that Appendix F does not address the loss of the fire protection ring header to most of the facility, and Appendix F, Assumptions and Limitations, states, "the SDP approach is intended to support the assessment of known issues only in the

context of an individual fire area. A systematic plant-wide search and assessment effort is beyond the intended scope of the fire protection SDP." Therefore, a senior reactor analyst (SRA) performed a detailed risk evaluation. The total exposure period was 36 hours.

The analyst used the River Bend Station Standardized Plant Analysis Risk (SPAR) model, Revision 8.20, with a truncation limit of 1E-11. The analyst calculated the change to the core damage frequency (delta-CDF) and the change to the large early release frequency (delta-LERF).

The risk metric delta-CDF is the difference of two subcomponents:

$$\text{Delta-CDF} = CDF_{current} - CDF_{nominal}$$

Where,

$CDF_{current}$ = The calculated CDF that includes the performance deficiency.

$CDF_{nominal}$ = The nominal risk, as if the performance deficiency did not exist.

<u>Internal Events</u>: Fire water was credited in the SPAR model as a source of reactor water. To quantify the internal events, the analyst started by calculating $CDF_{nominal}$. The analyst did this by solving all of the event trees. The CDF was 6.4E-6/year, but this was for an entire year of exposure. To account for the 36 hour exposure period, the analyst multiplied the CDF by 36 hours/8760 hours (hours in a year). $CDF_{nominal}$ was 2.6E-8/year.

Next, the analyst used a change set and adjusted the firewater system pumps' failure to start basic events to a probability of 1.0. The analyst also set the operator manual actions to align fire water to 1.0. Using this approach, the analyst failed the pumps as a surrogate for isolating the firewater header. This produced the same outcome (firewater was unavailable). Then the analyst solved all of the internal event sequences. The CDF was 1.1E-5/year. $CDF_{current}$ was 4.5E-8/year. The delta-CDF for internal events was:

$\text{Delta-CDF}_{internal}$ = 4.5E-8/year – 2.6E-8/year = 1.9E-8/year.

<u>External Events</u>: To identify the external event fire initiators, the analyst reviewed the "River Bend Station Individual Plant Examination of External Events (IPEEE)," dated June 30, 1995.

The licensee had used a progressive screening technique that led to the identification of the risk important fire areas. The analyst reviewed all of the fire areas to identify which fire areas could be risk important considering the failure of the firewater header.

The analyst accepted the first three screens and eliminated those fire areas from further consideration. These screens included considerable conservatism and either bounded the risk associated with the performance deficiency or was not affected by the performance deficiency. Those screens were:

- Screen 1: No safe shutdown equipment in fire area
- Screen 2: Fire areas in containment
- Screen 3: CDF < 1E-6, assuming all equipment in area is damaged.

Screen 4 included fire areas where fire modeling was performed. The licensee screened out areas where the CDF was less than 1E-6 per fire area. The analyst included these fire areas in the population that warranted further quantification.

Screen 5 included areas where the ignition frequency alone was less than 1E-6 as calculated on a scenario basis. The analyst did not evaluate these areas further. Considering the exposure period and the CCDP, the CDF for each of these fire areas would be less than E-9/year.

Screen 6 included areas where feedwater could be credited as a recovery action. In these areas the CDF was less than 1E-6. The analyst included this group because of the possibility that the cumulative delta-CDF for all areas could be significant.

Table 4-12 included the remaining unscreened fire areas. The analyst included this group for further quantification.

The total group considered for further quantification included the fire areas identified in Screens 4 and 6 and Table 4-12. This group included 39 fire areas.

Fire Areas			
AB-1/Z-4	C-5	C-23	DG-5/Z-2
AB-2/Z-1	C-11	C-25	DG-6/Z-1
AB-2/Z-2	C-13	C-26	DG-6/Z-2
AB-6/Z-2	C-15	C-27	ET-1
AB-15/Z-2	C-17	DG-1	ET-2
C-1B	C-18	DG-2	PH-01/Z-1
C-1C	C-19	DG-3	PH-01/Z-2

C-2B	C-20	DG-4/Z-1	PH-02/Z-1
C-2C	C-21	DG-4/Z-2	PH-02/Z-2
C-4	C-22	DG-5/Z-1	

The analyst noted that the $CDF_{current}$ will always bound the delta-CDF. For simplicity, the analyst used $CDF_{current}$ as a surrogate for delta-CDF. This is acceptable because the final risk was of very low safety significance.

The equation to determine the $CDF_{current}$ for fires was:

$$CDF_{current} = \text{initiating event frequency } (\lambda) * \text{Probability of non-suppression (PNS)} * CCDP_{damage} * \text{ exposure period adjustment (4.1E-3)}$$

Additional Screening: In order to identify the fire areas with the most potential risk the analyst performed another level of screening. The analyst screened out fire areas when the $CDF_{current}$ was less than 1E-8/year. If all of the fire areas had a $CDF_{current}$ < 1E-8/year, the cumulative contribution of all fire areas would be much less than 1E-6/year.

The analyst conservatively assumed that all forms of fire suppression failed in this step (non-suppression probability = 1.0). In addition, all of the unprotected equipment in the fire area failed.

The CDF equation reduced to:

$$CDF_{current} = \lambda * CCDP_{damaged} * 4.1E\text{-}3$$

The analyst made the following assumptions.

- The analyst assumed a worst case fire and a simultaneous initiating event for each fire area. If a train of switchgear or divisional cables was affected, the analyst assumed that a concurrent loss of offsite power (LOOP) occurred. Otherwise a transient (scram) was assumed. The analyst then solved just the transient or LOOP sequences, as applicable. These assumptions were very conservative because the probability that either a transient or LOOP occurred, given a fire in the specific fire areas, was small.

- When a diesel failed, the analyst set the diesel's fail-to-start basic event to a failure probability of 1.0. The analyst allowed the normal emergency diesel generator recoveries to occur. Since the diesels were not directly connected to the site's switchyard, fires in the diesel generator rooms and diesel fuel oil compartments would not induce a LOOP. Therefore, a concurrent transient was assumed. This was very conservative because a simultaneous fire-induced transient was very unlikely.

- When Division I or II cables were affected, but specific components were not identified, the analyst set the basic event for the associated 4160 Vac bus to 1.0. This would fail all of the divisional pumps and other components that are powered from the safety bus. Since cables to the 4160 Vac buses could have been affected, the analyst assumed a simultaneous plant centered LOOP event.

- If any equipment in the high pressure core spray (HPCS) system was affected, the analyst set the HPCS pump failure-to-start to 1.0.

- If a chiller or room cooler was affected, and it was not specifically modeled in the SPAR model, the analyst set the failure probability for the supported equipment to 1.0.

- If the CCDP was less than 1.0E-7, the analyst assumed the CCDP was 1.0E-7.

In addition to the criteria specified above, the analyst screened certain fire areas from further consideration based on the following:

- Fire Area AB-1/Z-4 included only the standby gas treatment system room cooling equipment. The standby gas treatment system is not included in the SPAR model and is not relied upon to preclude core damage. Further, the standby gas treatment system is not important to the large early release frequency.

- The analyst screened out fire areas that included only HPCS equipment. This included Fire Areas AB-2, C-20, C-21, C-22, DG-1, and DG-5. The CCDP given a loss of the HPCS system and a simultaneous transient was less than 1E-7. If a LOOP occurred (in lieu of a transient) the CCDP was 1.3E-6. Since the fire area initiating event frequencies were less than 1E-2 and exposure period adjustment was 4.1E-3, the calculated $CDF_{current}$ for each area was less than 1E-10.

- Fire Area AB-6 included only the low pressure core spray system components. Assuming a transient and the loss of the low pressure core spray system, the CDF was less than 2E-13.

- Fire Area C-25 (Control Room): Water would not normally be used to extinguish a fire in the control room until operators established alternate operations from the remote shutdown panel. Therefore, the unavailability of water in this fire area did not affect the ability of operators to achieve safe shutdown.

The analyst solved the remaining fire areas in the following table:

Fire Area	Equip in Area	Initiating Freq per year	Assumed transient or LOOP	CCDP	Exposure Period 36/8760 = 4.1E-3	CDF Current Case only	Screen Out? Y or N
AB-15/Z-2	HPCS + RHR B & C	3.4E-4	Transient	1.90E-07	**4.1E-3**	2.65E-13	Y
C-1B	Division II cables	3.5E-4	LOOP	9.80E-03	**4.1E-3**	1.41E-08	N
C-1C	Division II Cables	3.4E-4	LOOP	9.80E-03	**4.1E-3**	1.37E-08	N
C-2B	Division II and III cables	3.5E-4	LOOP	1.80E-02	**4.1E-3**	2.58E-08	N
C-2C	Division II and III cables	3.6E-4	LOOP	1.80E-02	**4.1E-3**	2.66E-08	N
C-4	Division I and II switchgear cooling	5.0E-4	Transient	<1.0E-7	**4.1E-3**	2.05E-13	Y
C-5	Division I, II, and III cables	3.6E-4	LOOP	1.80E-01	**4.1E-3**	2.66E-07	N
C-11	Division I cables	3.2E-4	LOOP	7.40E-03	**4.1E-3**	9.71E-09	Y
C-13	Division II cables	6.7E-4	LOOP	9.80E-03	**4.1E-3**	2.69E-08	N
C-15	Division I switchgear	1.4E-3	LOOP	7.40E-03	**4.1E-3**	4.25E-08	N

C-17	Division I, II, and III cables. remote shutdown panel available.	1.0E-3	LOOP	1.80E-02	**4.1E-3**	7.38E-08	N
C-18	Division I 125 Vdc and inverter	8.2E-4	Transient	1.20E-05	**4.1E-3**	4.03E-11	Y
C-19	Division II 125 Vdc and inverter	8.2E-4	Transient	1.20E-05	**4.1E-3**	4.03E-11	Y
C-27	Division II cables	3.4E-4	LOOP	8.90E-03	**4.1E-3**	1.24E-08	N
DG-1	DG Division II fuel oil	2.8E-4	Transient	<1.0E-7	**4.1E-3**	1.15E-13	Y
DG-2	DG Division III fuel	2.8E-4	Transient	<1.0E-7	**4.1E-3**	1.15E-13	Y
DG-3	DG Division I fuel	2.8E-4	Transient	<1.0E-7	**4.1E-3**	1.15E-13	Y
DG-4/Z-1	DG Division II	1.6E-2	Transient	<1.0E-7	**4.1E-3**	6.56E-12	Y
DG-4/Z-2	DG Division II	1.3E-2	Transient	<1.0E-7	**4.1E-3**	5.33E-12	Y
DG-5/Z-1	DG Division III	1.6E-2	Transient	<1.0E-7	**4.1E-3**	6.56E-12	Y
DG-5/Z-2	DG Division III	1.3E-2	Transient	<1.0E-7	**4.1E-3**	5.33E-12	Y
DG-6/Z-1	DG Division I	1.6E-2	Transient	<1.0E-7	**4.1E-3**	6.56E-12	Y

DG-6/Z-2	DG Division I	1.3E-2	Transient	<1.0E-7	**4.1E-3**	5.33E-12	Y
ET-1	Division I cables	1.0E-3	LOOP	7.40E-03	**4.1E-3**	3.03E-08	N
ET-2	Division II cables	4.7E-4	LOOP	8.90E-03	**4.1E-3**	1.72E-08	N
PH-01/Z-1	Division I and III standby service water	6.0E-3	Transient	<1.0E-7	**4.1E-3**	2.46E-12	Y
PH-01/Z-2	Division I and III standby service water	2.9E-3	Transient	<1.0E-7	**4.1E-3**	1.19E-12	Y
PH-02/Z-1	Division II standby service water	6.0E-3	Transient	<1.0E-7	**4.1E-3**	2.46E-12	Y
PH-02/Z-2	Division II standby service water	2.9E-3	Transient	<1.0E-7	**4.1E-3**	1.19E-12	Y

Remaining Fire Areas: The following table includes the remaining fire areas. All of the fire areas associated with transients were screened out in the previous step. The analyst considered fire suppression at this stage. Chemical fire extinguishers and fire detection (alarm in the control room) were available in all of the fire areas. The analyst assumed that fire brigade members or personnel in the vicinity of the fire would use the extinguishers. The analyst assumed that the fire brigade, or an equipment operator, could reach each area within 10 minutes following detection. Since the analyst took a bounding approach with respect to damage, the analyst qualitatively determined that personnel would have sufficient time to reach the fire areas. The analyst used the non-suppression curves in Appendix F, Attachment 8, "Guidance for Fire Non-Suppression," dated February 28, 2005. The analyst used a non-suppression probability of 0.3 for all areas.

Fire Area	Equip in Area	Available Suppression	CDF Current Case only No Suppression	Manual Non-Suppression Probability	Adjusted CDF
C-1B	Division II cables	Fire extinguishers	1.4E-08	0.3	4.2E-9
C-1C	Division II cables	Fire extinguishers	1.4E-08	0.3	4.2E-9
C-5	Division I, II, and III cables	Fire extinguishers	2.7E-07	0.3	8.1E-8
C-2B	Division II and III cables	Fire extinguishers	2.6E-08	0.3	7.8E-9
C-2C	Division II and III cables	Fire extinguishers	2.6E-08	0.3	7.8E-9
C-13	Division II cables	Fire extinguishers	2.6E-08	0.3	7.8E-9
C-15	Division I switchgear	Fire extinguishers	4.3E-08	0.3	1.3E-8
C-17	Division I, II, and III components remote shutdown panel available.	Fire extinguishers	7.4E-08	0.3	2.2E-8
C-27	Division II cables	Fire extinguishers	1.2E-08	0.3	3.6E-9
ET-1	Division I cables	Fire extinguishers	3.0E-08	0.3	9.0E-9
ET-2	Division II cables	Fire extinguishers	1.7E-08	0.3	5.1E-9

The cumulative current case CDF was approximately 1.7E-7/year. As noted previously, the current case CDF bounds the delta-CDF.

Total Delta-CDF: The total delta-CDF was the sum of the internal events CDF and the external events CDF.

Delta-CDF = 1.9E-8/year + 1.7E-7/year = 2E-7/year

The dominant core damage sequences included a fire-induced LOOP, failure of operators to suppress the fire, and damage to Division I, II, and III components. The reactor core isolation cooling system and the very short exposure period helped to minimize the risk.

Large Early Release Frequency (LERF): To address the contribution to the LERF the analyst used NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," dated May 6, 2004. For the LERF analysis, the analyst used the "Risk-Informed Inspection Notebook for River Bend Station (RBS) Unit 1," Revision 2.1a. The analyst identified the LERF factors for the applicable LOOP sequences. In a few instances the LERF factor was 0, but in most cases the LERF factor was 0.2. The analyst conservatively used the 0.2 factor for all sequences. The change to the LERF was therefore:

Delta-LERF = 0.2 * Delta-CDF = 0.2 * 2E-7/year = 4E-8/year

Since the delta-CDF was less than 1E-6/year and the delta-LERF was less than 1E-7/year, the finding was of very low safety significance.

The finding has a cross-cutting aspect in the area of human performance associated with avoiding complacency because the licensee failed to recognize and plan for the possibility for mistakes, and did not implement appropriate error reduction tools [H.12].

<u>Enforcement</u>. Technical Specification 5.4.1., "Procedures," states that "Written procedures shall be established, implemented, and maintained covering the following activities:…Subsection 5.4.1.a. - The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978." Regulatory Guide 1.33, Appendix A, Section 1.c., specifies "Equipment Control (e.g., locking and tagging)." Licensee Tagging Clearance Instructions 1C16-1 / 251-001-O-FPW-P1A, specify that "Due to FPW-V153 valve seat leakage…, this tagout isolates ring header isolation valves FPW-V1 and FPW-V2 with ring header impacted in terms of redundancy – are there other ring header valves isolated?" Contrary to the above, on June 19, 2014, the licensee failed to follow the instructions and failed to identify that ring header isolation valves FPW-V8 and FPW-V10 were also closed, resulting in the complete isolation of the fire suppression ring header. This violation is being treated as a non-cited violation (NCV), consistent with Section 2.3.2.a of the Enforcement Policy, because it was of very low safety significance (Green) with no actual safety consequence and it was entered into the licensee's corrective action program as Condition Report CR-RBS-2014-02489 to address recurrence (NCV 05000458/2014003-01, "Failure to Follow Tagging Clearance Instructions").

4OA5 Other Activities

Follow-up on Traditional Enforcement Actions Including Violations, Deviations, Confirmatory Action Letters, Confirmatory Orders, and Alternative Dispute Resolution Confirmatory Orders (IP 92702)

a. Background:

On August 24, 2011, the NRC issued a Confirmatory Order (EA-11-096) to Entergy Operations, Inc., and Entergy Nuclear Operations, Inc. (collectively referred to as Entergy). The Confirmatory Order actions were agreed upon by Entergy and the NRC during an alternative dispute resolution session held on July 18, 2011, to resolve NRC concerns regarding an apparent violation of employee protection requirements at the River Bend Station. The actions focused on reorganizing the Quality Control reporting relationships, ensuring adequate training of 10 CFR 50.7, "Employee Protection," and performing an effectiveness review of the Employee Concerns Program procedures at all Entergy facilities. The order also required that a safety culture survey be conducted at the River Bend Station.

By letter, dated August 23, 2012, Entergy notified the NRC of the actions that had been taken in response to the requirements imposed by the Confirmatory Order. Accordingly, during the week of April 29, 2013, NRC staff from the Office of Enforcement and Region IV performed an inspection at the River Bend Station to assess the specific actions identified in Entergy's response letter. NRC staff also verified implementation of

the remaining actions required to satisfy the conditions set forth in the Confirmatory Order. Subsequent to this inspection, NRC staff continued to interact with Entergy regarding the adequacy of the corrective and preventive actions related to the underlying discriminatory issue.

b. Findings and Observations:

During the inspection, the NRC staff interviewed employees from the various Quality Control, maintenance, and Employee Concerns Program organizations, reviewed Entergy's Employee Concerns Program supervisory training and general employee training documents, and evaluated the relevant "lessons learned" from the facts of this matter. NRC staff also examined the results of the associated action plans derived from the River Bend safety culture assessment and the fleet-wide written communication reinforcing Entergy's commitment to maintaining a safety-conscious work environment.

Consistent with the requirements specified in the Confirmatory Order, a Nuclear Safety Culture Assessment was administered at the River Bend Station by Synergy in February 2012. The results were subsequently made available to Entergy in August 2012. Based on the review of the assessment, the NRC staff determined that the survey instrument, methodology, and the analysis appeared to be adequate. However, the results indicated a declining trend in all areas of the survey (i.e., Safety Conscious Work Environment, Leadership, Management and Supervision, General Culture and Work Environment, and

Nuclear Safety Culture) when compared with the results of the previous assessment administered by Synergy in 2009.

The NRC staff reviewed the River Bend Station 2012 Site Improvement Plan which contained basic actions for addressing the assessment results, including: discussing the results with department managers and supervisors; briefing workers; and developing a site level change management plan.

The NRC staff also reviewed the General Employee Training and Supervisory Training modules. Based on these reviews, it was determined that these training modules adequately addressed employee protection and included insights from the underlying discriminatory matter. The NRC staff determined that the supervisory training module appeared complete and included case studies as well as the specific elements from the underlying § 50.7, "Employee Protection," violation. However, it was noted that although employees receive General Employee Training on an annual basis, Entergy does not require supervisors to take employee protection refresher training on a recurring basis as a means to reinforce these standards.

Additionally, NRC staff evaluated the results of Entergy's effectiveness review of the Employee Concerns Program (ECP) enhancements and the associated training that arose from the corrective actions taken to address this matter. Based on the results of this evaluation, the NRC staff determined that Entergy had performed the requisite reviews at each station including: examination of selected ECP Case Files, Records Retention, Concerned Individual follow-up, and ECP Coordinator training. Within the areas examined, no findings were identified and, in general, the NRC staff determined that Entergy had adequately performed the effectiveness review of ECP procedural enhancements and the ECP training related to this matter.

During the follow-up review of the Quality Control/Quality Assurance reporting relationship, the NRC staff determined that Entergy's response did not ensure that persons performing the quality assurance function of receipt inspection reported to a management level sufficient to maintain organizational freedom and independence from cost and schedule were maintained. Subsequent to the identification of this performance issue, which affected the implementation of the Quality Assurance program at all nine Entergy sites, the condition was entered into the licensee's corrective action program as Condition Report CR-HQN-2013-00466.

Following the identification of this issue, additional discussions were held between NRC and Entergy to clarify the intent of the settlement agreement and subsequent Confirmatory Order stemming from the earlier alternate dispute resolution mediation. As a result of these discussions, Entergy's Corporate Licensing organization developed a fleet reconciliation plan to modify Entergy's Quality Assurance Program Manual to require that individuals performing inspections in accordance with Quality Assurance Program Manual, Section B.12, "Inspection," functionally report to the associated manager responsible for Quality Assurance. As described in the corrective actions associated with Condition Report CR-HQN-2013-00466, the affected individuals were those requiring certification in accordance with Quality Assurance Program Manual, Table 1, Regulatory Commitments, Section G, Regulatory Guide 1.58, Revision 1,

"Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel," dated September 1980. In addition to revising the applicable provisions in the Quality Assurance Program Manual, corrective actions were initiated to revise implementing procedures to reflect the change in reporting relationship during the performance of required inspections as well as providing training to the affected individuals. The NRC staff confirmed that the remaining conditions of the Confirmatory Order were adequately addressed.

c. <u>Conclusion</u>:

Based on the above reviews, the NRC determined that Entergy properly implemented the conditions specified in the Confirmatory Order and the associated actions were adequately implemented.

d. <u>Findings</u>:

No findings were identified.

4OA6 Meetings, Including Exit

<u>Exit Meeting Summary</u>

On July 15, 2014, the inspectors presented the integrated inspection results to Mr. E. Olson, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

On July 30 and August 14, 2014, the inspectors performed a re-exit with Mr. J. Clark, Manager, Regulatory Assurance, to brief the licensee regarding changes to the inspection report from what was previously described in the exit meeting, dated July 15, 2014.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of the NRC Enforcement Policy for being dispositioned as a non-cited violation:

- License Condition 2.C(10), "Fire Protection," requires the licensee to "…comply with the requirements of the fire protection program as specified in Attachment 4 (of the license)." Provision 1 of Attachment 4 states in part:

  "EOI shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility through Amendment 22 and as approved in the SER dated May 1984 and Supplement 3 dated August 1985 subject to provisions 2 and 3."

Section 9.5.1 of the Updated Final Safety Analysis Report (UFSAR), "Fire Protection System," Subsection 9.5.1.4., "Inspection and Testing Requirements," states that "Periodic operational checks, inspections, and servicing required to maintain fire protection systems that protect equipment that is important to safety, including the alarm and detection systems, conform with the RBS Technical Requirements Manual." Technical Requirements Manual, Section TRM 3.7.9.2, Action A.2, states that if "One or more of the…required spray or sprinkler systems (are) inoperable," the licensee would be required to "Establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged," and "Establish an hourly fire watch patrol for other areas," within a completion time requirement of one hour. Contrary to the above, on May 20, 2014, the licensee failed to establish fire watches within the one hour requirement, specified in TRM 3.7.9.2., after it was determined that the fire protection ring header was inoperable.

The failure to adhere to the requirements of TRM 3.7.9.2 action A.2, to ensure that all required hourly fire watches are posted within one hour from the time of entry into the TRM, is a performance deficiency. The performance deficiency was more than minor and, therefore, a finding because it adversely impacted the protection against external factors attribute of the Mitigating System Cornerstone, in that the failure to post fire watches, in a timely manner, could result in preventing prompt detection and extinguishing of fires. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," dated June 19, 2012, the inspectors determined that the issue affected the Mitigating Systems Cornerstone and that the finding pertained to a degraded condition while the plant was in operation. As a result, the inspectors were directed to Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," dated September 20, 2013. Since the finding affected many fire areas, the inspector consulted with a senior reactor analyst. The analyst determined that Appendix F was not a suitable tool to process this finding, and that a detailed risk evaluation needed to be performed. Although the exposure period for this finding was just a few hours, the risk analyst determined that the detailed risk evaluation performed for the finding described above (Section 4OA2.3.b.) fully bounded this finding as well. As a result of the referenced evaluation, the finding was found to be of very low safety significance (Green). The dominant core damage sequences included a fire-induced loss of offsite power, failure of operators to suppress the fire, and damage to Division I, II, and III components. The reactor core isolation cooling system and the short exposure period helped to minimize the risk.

This violation is being treated as a non-cited violation (NCV), consistent with Section 2.3.2.a of the Enforcement Policy because it was of very low safety significance (Green) and it was entered into the licensee's corrective action program as Condition Report CR-RBS-2014-02489 to address recurrence.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Bolke, Licensing Technician
D. Burnett, Manager, Emergency Preparedness
G. Bush, Manager, Material, Procurement, and Contracts
M. Chase, Manager, Training
J. Clark, Manager, Regulatory Assurance
B. Cole, Manager, Radiation Protection
F. Corley, Manager, Design Engineering
M. Feltner, Manager, Production
M. Ferrentelli, Manager, Maintenance
B. Ford, Senior Manager, Nuclear Safety and Licensing
R. Gadbois, General Manager, Plant Operations
T. Gates, Assistant Operations Manager – Shift
K. Hallaran, Manager, Chemistry
A. Johnson, Fire Marshall
G. Krause, Assistant Operations Manager – Training
P. Lucky, Manager, Corrective Actions and Assessments
J. Maher, Manager, System Engineering
W. Mashburn, Director, Engineering
E. Olson, Site Vice President
J. Reynolds, Assistant Operations Manager - Support
T. Santy, Manager, Security
T. Shenk, Manager, Operations
J. Vukovics, Supervisor, Reactor Engineering
J. Wieging, Manager, Planning and Scheduling, Outages
D. Yoes, Manager, Quality Assurance

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000458/2014003-01	NCV	Failure to Follow Tagging Clearance Instructions (Section 4OA2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Condition Reports

CR-RBS-2007-00171	CR-RBS-2007-00979	CR-RBS-2009-02655	CR-RBS-2010-00256
CR-RBS-2010-01946	CR-RBS-2011-02007	CR-RBS-2011-02904	CR-RBS-2011-03259
CR-RBS-2011-03260	CR-RBS-2011-03261	CR-RBS-2011-03346	CR-RBS-2011-03357
CR-RBS-2011-03933	CR-RBS-2011-05841	CR-RBS-2011-06233	CR-RBS-2011-06331
CR-RBS-2012-02054	CR-RBS-2012-02121	CR-RBS-2012-02165	CR-RBS-2014-00678
CR-RBS-2014-00923	CR-RBS-2014-02128	CR-RBS-2014-02240	CR-RBS-2014-02242
OE-NOE-2007-00076	WT-WTRBS-2014-00198		

Calculations

Number	Title	Revision
8.3.1.32	Design Basis Flood – River Bend Station (West Creek and Grants Bayou)	1
8.3.1.33	25-Year Flood for West & Grants Bayou	0
8.3.1.34	PMP in Site Area (Assuming No Berm Around Excavation)	1
8.3.1.35	Flow Velocities in West Creek Fabriform Channel	0
8.3.1.37	Determination of Water Surface Elevations in Grants Bayou and West Creek Near Plant Site for PMF and 25-Year Flood & SSE	1
G13.18.8.0*004	Impact of the Construction of the Independent Spent Fuel Storage Installation (ISFSI) in the Unit 2 Excavation Area on the Design Basis Flood Levels for RBS Structures	0
G13.18.8.0*004	Impact of Independent Spent Fuel Storage Installation on Ponding in Unit 2 Excavation	0A

Engineering Documents

Number	Title	Revision
EC 32683	Independent Spent Fuel Storage Installation Concrete Erosion Protection Slope Repair Ref. CR-RBS-2009-02655	0
EC 34785	Analyze the G-Tunnel for an 80.5' MSL Ponding Level in the Unit 2 Hole Ref. CR-RBS-2011-06331	0

Maintenance Documents

PM 28501-19	WO 00258260	WO 00265496	WO 00279376
WO 52273201	WO 52275383	WO 52284000	WO 52286490
WO 52300752	WO 52306720	WO 52327141	WO 52340366
WO 52346784	WO 52352196	WO 52359014	WO 52366030
WO 52372957	WO 52379254	WO 52383260	WO 52390962
WO 52398356	WO 52403287	WO 52410817	WO 52419514
WO 52422605	WO 52427039	WO 52428126-01	WO 52433231
WO 52439890	WO 52446191	WO 52462322	WO 52481503
WO 52510491	WO 52520000		

Miscellaneous Documents

Number	Title	Revision/Date
	River Bend Station Summer Reliability Plan	2014
	River Bend Station West Creek Inspection Log	December 12, 2011
51-9207360	Areva, Inc., Engineering Information Record – Entergy Fleet Fukushima Program Flood Hazard Reevaluation Report for River Bend Station	0

NRC Information Notice

Number	Title	Date
2005-30	Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design	November 7, 2005

Procedures

Number	Title	Revision
ESP-8-019	Terrestrial Ecological Monitoring	1 and 7
ESP-8-048	West Creek Inspection	8
OSP-0045	Summer Reliability Equipment Monitoring	007

Section 1R04: Equipment Alignment

Condition Reports

CR-RBS-2010-02591	CR-RBS-2010-02609	CR-RBS-2010-06804	CR-RBS-2011-00308
CR-RBS-2011-01285	CR-RBS-2011-02067	CR-RBS-2011-02070	CR-RBS-2011-03117

Condition Reports

CR-RBS-2011-03813	CR-RBS-2011-07474	CR-RBS-2011-07713	CR-RBS-2011-08956
CR-RBS-2012-00177	CR-RBS-2012-00178	CR-RBS-2012-00191	CR-RBS-2012-00207
CR-RBS-2012-01750	CR-RBS-2012-01752	CR-RBS-2012-02022	CR-RBS-2012-02201
CR-RBS-2012-02503	CR-RBS-2012-03307	CR-RBS-2012-03310	CR-RBS-2012-04274
CR-RBS-2013-01742	CR-RBS-2013-04291	CR-RBS-2013-04326	CR-RBS-2013-05593
CR-RBS-2014-01413	CR-RBS-2014-02115	CR-RBS-2014-02200	

Procedure

Number	Title	Revision
SOP-0009	Reactor Feedwater System (SYS #107)	062

Section 1R05: Fire Protection

Pre-Fire Strategies

Number	Title	Revision
CB-098-117	Standby Switchgear 1B Room Fire Area C-14	4
CB-098-118	Standby Switchgear 1A Room Fire Area C-15	2
CB-098-122	Water Chiller Equipment 1A Room Fire Area C-13W	3
CB-098-123	Water Chiller Equipment 1B Room Fire Area C-13E	3
AB-141-531	SGTS Filter A Room Fire Area AB-14	2
AB-141-532	SGTS Filter B Room Fire Area AB-13	2
RB-114-004	HCU Area East Fire Area RC-3/Z-3	3
RB-141-008	SLC Area Fire Area RC-4/Z-4	3

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance

Procedures

Number	Title	Revision
AOP-0001	Reactor Scram	028
AOP-0002	Main Turbine and Generator Trip	026
AOP-0003	Automatic Isolations	033
EOP-0001	RPV Control	026
EOP-0002	Primary Containment Control	015

Training Document

Number	Title	Revision
RSMS-OPS-0657	Trip of CNM Pump, Turbine Trip, Low Power ATWS, Fire in RTX-XSR1E	0

Section 1R12: Maintenance Effectiveness

Condition Reports

CR-RBS-2013-07201	CR-RBS-2013-07222	CR-RBS-2014-00958	CR-RBS-2014-00961
CR-RBS-2014-01638			

Maintenance Document

WO 00333860-01

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision
ADM-0096	Risk Management Program Implementation and On-Line Maintenance Risk Assessment	314
OSP-0048	Switchyard, Transformer Yard, and Sensitive Equipment Controls	024

Section 1R15: Operability Determinations and Functionality Assessments

Calculation

Number	Title	Revision
G13.18.1.2-043	Requalification of the Concrete Roof Plugs for the Standby Service Water Building for Tornado Loads EL 152'-6"	0

Condition Reports

CR-RBS-2013-06893	CR-RBS-2013-06895	CR-RBS-2013-06896	CR-RBS-2013-06902
CR-RBS-2013-06904	CR-RBS-2013-06905	CR-RBS-2013-06913	CR-RBS-2013-06916
CR-RBS-2013-07367	CR-RBS-2014-00625	CR-RBS-2014-00627	CR-RBS-2014-01181
CR-RBS-2014-01206	CR-RBS-2014-01675		

Drawings

Number	Title	Revision
CCP-001-069	Auxiliary Building 70-Foot CCP Isometric Drawing	3
PID-09-10D	System 118 Service Water – Normal	34
PID-09-01B	System 115 Closed Cooling Water – Reactor Plant	20
SWP-001-840	Auxiliary Building 70-Foot SWP Isometric Drawing	3

Engineering Documents

Number	Title	Revision
EC 47851	Evaluation of Roof Plugs of the Standby Cooling Tower Building With No Threaded Rods for Tornado Uplift Pressure	0
EC 49789	Apply a Freeze Seal to Allow Replacement of Internals CCP-V300 Check Valve Ref. CR-RBS-2014-01181	0

Maintenance Documents

WO 00079347-01 WO 00366624

Procedure

Number	Title	Revision
STP-309-0201	Division I Diesel Generator Operability Test	055

Section 1R18: Plant Modifications

Condition Reports

CR-RBS-2013-07597 CR-RBS-2014-02527

Maintenance Document

WO 0037406

Section 1R19: Post-Maintenance Testing

Condition Reports

CR-RBS-2013-06789 CR-RBS-2014-00645 CR-RBS-2014-01690

Maintenance Documents

WO 00345754-03 WO 52450952-03 WO 52452659-05 WO 52457558-05

WO 52541387-05	WO 52541390-05	WO 52546756-01

Procedures

Number	Title	Revision
SOP-0035	Reactor Core Isolation Cooling System (SYS #209)	046
STP-204-0201	LPCI A Discharge Piping Fill and Valve Lineup Verification	307
STP-204-6301	DIV I LPCI (RHR) Pump and Valve Operability Test	025
STP-204-6303	DIV I RHR Quarterly Valve Operability Test	020
STP-204-6601	DIV I RHR Position Indication Verification Test	301

Section 1R22: Surveillance Testing

Condition Report

CR-RBS-2014-02350

Maintenance Documents

WO 00129828	WO 00353141	WO 00382733	WO 52331819	WO 00129828
WO 52537839				

Section 1EP6: Drill Evaluation

Scenario

Number	Title	Revision
RDRL-EP-1404	Site Drill Scenario	0

Section 4OA1: Performance Indicator Verification

Miscellaneous Documents

Number	Title	Revision/Date
Engineering Report ECH-NE-11-00040	RBS Mitigating System Performance Index (MSPI) Basis Document	0
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	6

Miscellaneous Documents

Number	Title	Revision/Date
RBG-47203	Electronic Submittal of Fourth Quarter 2011 NRC Performance Indicator Information	January 23, 2012
RBG-47377	Electronic Submittal of Second Quarter 2013 NRC Performance Indicator Information	July 22, 2013
RBG-47396	Electronic Submittal of Third Quarter 2013 NRC Performance Indicator Information	October 21, 2014
RBG-47421	Electronic Submittal of Fourth Quarter 2013 NRC Performance Indicator Information	January 21, 2014
RBG-47462	Electronic Submittal of First Quarter 2013 NRC Performance Indicator Information	April 23, 2014

Procedure

Number	Title	Revision
EN-LI-114	Performance Indicator Process	6

Section 4OA2: Problem Identification and Resolution

Condition Reports

CR-RBS-2013-07482	CR-RBS-2014-00071	CR-RBS-2014-00072	CR-RBS-2014-00076
CR-RBS-2014-00120	CR-RBS-2014-00228	CR-RBS-2014-00285	CR-RBS-2014-00297
CR-RBS-2014-00300	CR-RBS-2014-00332	CR-RBS-2014-00409	CR-RBS-2014-01030
CR-RBS-2014-01223	CR-RBS-2014-01410	CR-RBS-2014-01411	CR-RBS-2014-01440
CR-RBS-2014-01526	CR-RBS-2014-02061	CR-RBS-2014-02083	CR-RBS-2014-02112
CR-RBS-2014-02169	CR-RBS-2014-02286	CR-RBS-2014-02473	CR-RBS-2014-02474
CR-RBS-2014-02475	CR-RBS-2014-02478	CR-RBS-2014-02489	CR-RBS-2014-02493
CR-RBS-2014-02504	CR-RBS-2014-02587	CR-RBS-2014-02594	CR-RBS-2014-02653
CR-RBS-2014-02849	CR-RBS-2014-02881	CR-RBS-2014-02898	CR-RBS-2014-03169

Tagout Clearances

C16-1 251-009-B-FPW-FHY16 C16-1 251-001-O-FPW-P1A

Control Room Log & Fire Brigade Log (Dates)

06/30/2013 05/19/2014 05/20/2014 05/21/2014

Procedures

Number	Title	Revision
EN-OP-102	Protective and Caution Tagging	16
EN-FAP-OP-019	eSOMS Clearance Module Users Manual	0
OSP-0022	Operations General Administrative Guidelines	72

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Condition Reports

CR-RBS-2010-06771	CR-RBS-2012-07372	CR-RBS-2013-00225	CR-RBS-2013-01920
CR-RBS-2013-01966	CR-RBS-2013-02021	CR-RBS-2013-02039	CR-RBS-2013-02326
CR-RBS-2013-04300	CR-RBS-2013-04899		

Section 4OA5: Other Activities

Condition Reports

CR-HQN-2011-00979 CR-HQN-2013-00466

Licensing Document

Title	Revision
Entergy Quality Assurance Program Manual	25

Procedures

Number	Title	Revision
EN-MP-120	Material Receipt	7
EN-MP-121	Materials, Purchasing and Contracts Indoctrination and Training	5
EN-MP-138	Commercial Grade Dedication Lab Conduct of Operation	1
EN-QV-100	Conduct of Nuclear Oversight	9
EN-QV-111	Training and Certification of Inspection/Verification and Examination Personnel	13

Safety Culture Assessment Documents

Title	Revision Date
Entergy Nuclear Lesson Plan FCBT-GET-PATSS	16
Synergy Nuclear Safety Culture Assessment, Entergy Nuclear, Attachment I, River Bend	August 1, 2012

Safety Culture Assessment Documents

Title	Revision Date
Synergy Nuclear Safety Culture Assessment, Entergy Nuclear, Attachment J, River Bend	June 2009
Synergy Nuclear Safety Culture Assessment, Entergy Nuclear, Attachment J, River Bend	March 2006
Entergy Nuclear Safety Culture Assessment 2012 Survey	April 30, 2013
Nuclear Safety Culture Assessment , Entergy Nuclear, Attachment L, River Bend	February 2012
Nuclear Safety Culture Assessment , Entergy Nuclear, Attachment I, River Bend	August 1, 2012

Synergy Survey Action Plans

Number	Title	Date
LO-RLO-2012-00058	Maintenance Support	August 22, 2012
LO-RLO-2012-00056	Electrical Maintenance	August 22, 2012
LO-RLO-2012-00055	Mechanical Maintenance	August 22, 2012
LO-RLO-2012-00064	Security	August 22, 2012
LO-RLO-2012-00063	Training	August 22, 2012
LO-RLO-2012-00061	System Engineering	August 22, 2012
LO-RLO-2012-00060	Materials and Engineering	August 22, 2012
LO-RLO-2012-00059	Radiation Protection	August 22, 2012

Section 4OA7: Licensee-Identified Violations

Condition Reports

CR-RBS-2010-06771	CR-RBS-2012-07372	CR-RBS-2013-00225	CR-RBS-2013-01920
CR-RBS-2013-01966	CR-RBS-2013-02021	CR-RBS-2013-02039	CR-RBS-2013-02326
CR-RBS-2013-04300	CR-RBS-2013-04899	CR-RBS-2014-02489	CR-RBS-2014-02493
CR-RBS-2014-02504			