UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

February 13, 2012

Mr. J.W. Shea
Manager, Corporate Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 4B-C
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2011005, 05000260/2011005, AND 05000296/2011005

Dear Mr. Shea:

On December 31, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. The enclosed inspection report documents the inspection results which were discussed on January 20, 2012, with Mr. Keith Polson and other members of your staff.

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

Two self-revealing findings of very low safety significance (Green) were identified during this inspection. One of these findings was determined to involve a violation of NRC requirements. Additionally, the NRC has determined that a traditional enforcement Severity Level IV violation occurred. Furthermore, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating the violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy. If you contest 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 Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to: (1) the Regional Administrator, Region II; (2) the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and (3) the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

In addition, if you disagree with any cross-cutting aspect assignment in the 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 II, and the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any), will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Eugene F. Guthrie, Chief
Special Project, Browns Ferry
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: NRC Integrated Inspection Report 05000259/2011005, 05000260/2011005, and 05000296/2011005

cc w/encl. (See page 3)

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 the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Eugene F. Guthrie, Chief
Special Project, Browns Ferry
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: NRC Integrated Inspection Report 05000259/2011005, 05000260/2011005, and 05000296/2011005

X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE
ADAMS: ☐ Yes ACCESSION NUMBER: ML12045A063 X SUNSI REVIEW COMPLETE

OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRS	RII:DRP	RII:DRP
SIGNATURE	/RA By-E-mail/	/RA By-E-mail/	/RA By-E-mail/	/RA By-E-mail/	/RA By-E-mail/	/RA By-E-mail/	/RA/
NAME	TRoss	CStancil	PNiebaum	LPressley	RBaldwin	CKontz	EGuthrie
DATE	2/13/2012	2/13/2012	2/13/2012	2/13/2012	2/13/2012	2/13/2012	2/13/2012
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\RPB6\BROWNS FERRY\REPORTS\2011\BF 005\BFN 11-05 FINAL DRAFT ALL COMMENTS INCLUDED REV 2.DOCX

cc w/encl:
K. J. Polson
Site Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

C.J. Gannon
General Manager
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

J. E. Emens
Manager, Licensing
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Manager, Corporate Nuclear Licensing - BFN
Tennessee Valley Authority
Electronic Mail Distribution

E. J. Vigluicci
Assistant General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

T. A. Hess
Tennessee Valley Authority
Electronic Mail Distribution

Chairman
Limestone County Commission
310 West Washington Street
Athens, AL 35611

Donald E. Williamson
State Health Officer
Alabama Dept. of Public Health
RSA Tower - Administration
Suite 1552
P.O. Box 30317
Montgomery, AL 36130-3017

James L. McNees, CHP
Director
Office of Radiation Control
Alabama Dept. of Public Health
P. O. Box 303017
Montgomery, AL 36130-3017

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
Browns Ferry Nuclear Plant
U.S. Nuclear Regulatory Commission
10833 Shaw Road
Athens, AL 35611-6970

Letter to Joseph W. Shea from Eugene Guthrie dated February 13, 2012

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2011005, 05000260/2011005, AND 05000296/2011005

Distribution w/encl:
C. Evans, RII EICS (Part 72 Only)
L. Douglas, RII EICS (Linda Douglas)
OE Mail (email address if applicable)
RIDSNRRDIRS
PUBLIC
RidsNrrPMBrownsFerry Resource

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2011005, 05000260/2011005, 05000296/2011005
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	October 1, 2011, through December 31, 2011
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector P. Niebaum, Resident Inspector L. Pressley, Resident Inspector C. Kontz, Senior Project Engineer (4OA2.2) R. Baldwin, Senior Operations Engineer (1R11.2)
Approved by:	Eugene F. Guthrie, Chief Reactor Projects Special Branch Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2011005, 05000260/2011005, 05000296/2011005; 10/01/2011 –12/31/2011; Browns Ferry Nuclear Plant, Units 1, 2 and 3; , Event Follow-up.

The report covered a three month period of inspection by the resident inspectors. One non-cited violation (NCV) and one Finding (FIN) were identified. The significance of most findings is identified by their color (Green, White, Yellow, and Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP); and, the cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas". Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Barrier Integrity

- Green. A self-revealing finding (FIN) was identified for the licensee's failure to adequately evaluate historically high vibrations on the Unit 1 Reactor Protection System (RPS) Motor Generator (M-G) Set 1B. Consequently, the impact of high vibrations was not considered in the determination of an adequate preventive maintenance frequency to ensure proper wire and cable terminal tightness in the RPS M-G Set control panel. The failure to ensure proper wire and cable tightness resulted in a loss of all Technical Specifications required reactor coolant system (RCS) leak detection. The licensee replaced the voltage regulator and performed all required tightness checks on RPS M-G Set 1B. In addition, the licensee verified appropriate tightness checks were scheduled in the next component outage window for the remaining M-G sets, and initiated actions to increase the preventive maintenance (PM) frequency to every two years, perform a design review to relocate the control panel, and evaluate the vibration program alert limit evaluation process. This issue was entered into the licensee's corrective action program as problem evaluation report (PER) 412934.

  The finding was determined to be more than minor because it was associated with the Barrier Integrity Cornerstone attribute of RCS Equipment and Barrier Performance, and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers (reactor coolant system) protect the public from radionuclide releases caused by accidents or events. Specifically, the failure to ensure proper wire and cable tightness resulted in loose connectors and/or cable assemblies that caused the failure of the Unit 1 RPS M-G Set 1B which resulted in a loss of all Unit 1 RCS leakage detection systems and an unplanned power reduction on August 6, 2011. The significance of the finding was evaluated using Phase 1 of the SDP in accordance with the IMC 0609 Attachment 4, and was determined to be of very low safety significance (Green) because the finding did not represent a pressurized thermal shock, fuel barrier, or spent fuel pool issue.

The cause of this finding was directly related to the cross-cutting aspect of Long Term Plant Safety Through Proper Maintenance Practices in the Resources component of the Human Performance area, because the vibration issues associated with Unit 1 RPS M-G Set 1B had been a long-standing equipment issue that was not adequately addressed by the vibration program alert limit evaluation process [H.2(a)]. (Section 4OA3.2)

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings was identified for the licensee's failure to install and maintain adequate control of temporary lighting in the intake cable tunnel as required by the Tennessee Valley Authority (TVA) Safety Manual and NPG-SPP-09.17, Temporary Equipment Control. Consequently, a temporary light string was left improperly installed, without ground fault circuit interrupt (GFCI) device(s), for over two years until it faulted electrically and caused a fire in the intake cable tunnel on October 12, 2011. The fire brigade extinguished the fire in approximately 10 minutes and removed the temporary light string from the cable tunnel. The licensee entered this event into their corrective action program as PER 445331.

  The finding was determined to be more than minor because it was considered sufficiently similar to example 4.f of Inspection Manual Chapter (IMC) 0612, Appendix E, for an issue of concern that resulted in a fire hazard in a safety-related area of the plant. The finding was associated with the Initiating Events Cornerstone and characterized according to IMC 0609, Significance Determination Process (SDP), Attachment 04, Phase 1 - Initial Screening and Characterization of Findings. The results of this analysis required an evaluation in accordance with IMC 0609, Appendix F, Attachment 01, Part 1, Fire Protection SDP Phase 1 Worksheet. For the SDP Phase 1 evaluation a high degradation rating was assigned for this fire event with a duration factor greater than 30 days. When compared against the SDP Phase 1 screening criteria, this resulted in a SDP Phase 2 evaluation. The inspectors concluded that this finding screened to Green in the Appendix F Phase 2 analysis using Appendix F Attachment 01, Part 2, Fire Protection SDP Phase 2 Worksheet. Specifically, it was determined that the fire could not reach the temperature threshold for fire-induced cable failure and would not spread to other combustible materials in the area. The cause of this finding was directly related to the cross cutting aspect of Long-Standing Equipment Issues in the Resources component of the Human Performance area, because the deficiencies with the permanently installed lighting system in the intake cable necessitated the use of the temporary light stringer for more than two years [H.2(a)]. (Section 4OA3.4)

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full Rated Thermal Power (RTP) for most of the report period except for one unplanned downpower and one shutdown. On October 24, 2011, Unit 1 performed an unplanned downpower to 50 percent RTP due to a trip of 1A variable frequency drive (VFD) from a spurious electrical fault that caused the 1A recirculation pump to shutdown. Operators established single loop operation (SLO). The VFD was repaired and the Unit returned to RTP on October 26, 2011. On December 9, 2011, Unit 1 performed a planned shutdown and cooldown due to RCS unidentified leakage of about 1.65 gpm. A packing leak was discovered on the 1B recirculation system discharge valve (1-FCV-68-79 valve). Following repairs the Unit was restarted on December 13, 2011 and the Unit returned to RTP on December 15, 2011.

Unit 2 operated at essentially full RTP for most of the report period except for a planned downpower on October 28, 2011, to 23 percent RTP power to reset a fault on the main turbine generator auto voltage regulator (AVR). The Unit returned to RTP on October 30, 2011.

Unit 3 operated at essentially full RTP for most of the report period except for a planned downpower to 76 percent RTP on November 19, 2011, for electrical repairs to the 3B VFD and the unit returned to RTP the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 External Flood Protection

a. Inspection Scope

The inspectors reviewed plant design features and licensee procedures intended to protect the plant and its safety-related equipment from external flooding events. The inspectors reviewed flood analysis documents including: UFSAR Section 2.4, Hydrology, Water Quality, and Marine Biology, which included Appendix 2.4A, Maximum Possible Flood; and UFSAR Section 12.2.9.2.3, Flood Gate, BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding for licensee commitments. The inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the RHRSW and EECW pump rooms. The inspectors performed walkdowns of the Unit 1/2 and Unit 3 emergency diesel generator (EDG) rooms. The inspectors' review included flood-significant features such as sump pump flowrates, sump drains, door seals and the Reactor Building Flood Gate. Plant procedures and calculations for coping with flooding events were also reviewed to verify that licensee actions and maintenance practices were consistent with the plant's design basis assumptions.

The inspectors also reviewed licensee corrective action documents for flood-related items identified in PERs written from 2008 through early 2011 to verify the adequacy of the corrective actions. The inspectors reviewed selected completed preventive maintenance procedures and work orders for identified level switches, pumps and flood barriers (e.g., Flood Doors) for completeness and frequency.

b. Findings

No findings were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors reviewed licensee procedure 0-GOI-200-1, Freeze Protection Inspection, and reviewed licensee actions to implement the procedure in preparation for cold weather conditions. The inspectors also reviewed the list of open Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting potential problems relating to cold weather operations. In addition, the inspectors reviewed procedure requirements and walked down selected areas of the plant, which included residual heat removal service water (RHRSW) system and Emergency Equipment Cooling Water (EECW) system rooms, Emergency Diesel Generators (EDGs) building, and systems in the Intake Structure, to verify that affected systems and components were properly configured and protected as specified by the procedure. The inspectors discussed cold weather conditions with Operations personnel to assess plant equipment conditions and personnel sensitivity to upcoming cold weather conditions.

During actual cold weather conditions in December, when outside temperatures dropped below the 32 degree Fahrenheit (F) and 25 degree F thresholds of 0-GOI-200-1, the inspectors conducted tours of the main control rooms to assess system performance and alarm conditions of systems susceptible to cold weather conditions. Furthermore, the inspectors verified that the applicable equipment walkdown checklists required by 0-GOI-200-1 were implemented as required.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted three partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, while the other train or subsystem was inoperable or out of service. The inspectors reviewed the functional systems descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system.

- Unit 2 High Pressure Cooling Injection (HPCI) System
- Unit 1, 2 and 3 Emergency Equipment Cooling Water (EECW) North Header
- Unit 2 Reactor Core Isolation Cooling (RCIC) System

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Fire Protection Tours

a. Inspection Scope

The inspectors reviewed licensee procedures, Nuclear Power Group Standard Programs and Processes (NPG-SPP)-18.4.7, Control of Transient Combustibles, and NPG-SPP-18.4.6, Control of Fire Protection Impairments, and conducted a walkdown of four fire areas (FA) and fire zones (FZ) listed below. Selected FAs/FZs were examined in order to verify licensee control of transient combustibles and ignition sources; the material condition of fire protection equipment and fire barriers; and operational lineup and operational condition of fire protection features or measures. Also, the inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedure NPG-SPP-18.4.6. Furthermore, the inspectors reviewed applicable portions of the Fire Protection Report, Volumes 1 and 2, including the applicable Fire Hazards Analysis, and Pre-Fire Plan drawings, to verify that the necessary firefighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. This activity constituted four inspection samples.

- Unit 1 Reactor Building, EL 621', 480V Shutdown Board Room 1A (FA 6)
- Unit 1 Reactor Building, EL 621', 480V Shutdown Board Room 1B (FA 7)
- Unit 2 Control Bay EL 593', Battery Board Room 2, Battery Room 2 (FA 18)
- Unit 3 Reactor Building, EL 593', 480V RMOV Board Room 3B, (FA 12)

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On November 15, 2011, the inspectors observed two licensed operator requalification simulator examinations for an operating crew according to the following Simulator Evaluation Guides:

- LOR-Exam-04, Rev. 2
- LOR-Exam-17, Rev. 2

The inspectors specifically evaluated the following attributes related to the operating crew's performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of Abnormal Operating Instructions (AOIs), and Emergency Operating Instructions (EOIs)
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedures (EPIP)
- Control board operation and manipulation, including high-risk operator actions
- Command and Control provided by the Unit Supervisor and Shift Manager

The inspectors attended the post-examination critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspectors. The inspectors also reviewed simulator physical fidelity (i.e., the degree of similarity between the simulator and the reference plant control room, such as physical location of panels, equipment, instruments, controls, labels, and related form and function). This activity counts for one inspection sample.

b. Findings

No findings were identified.

.2 Annual Review of Licensee Requalification Examination Results

a. Inspection Scope

On December 23, 2011, the licensee completed the annual requalification operating test required to be administered to all licensed operators in accordance with 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of individual operating tests and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, "Operator Requalification Human Performance Significance Determination Process."

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors reviewed the two specific structures, systems and components (SSC) within the scope of the Maintenance Rule (MR) (10CFR50.65) with regard to some or all of the following attributes, as applicable: (1) Appropriate work practices; (2) Identifying and addressing common cause failures; (3) Scoping in accordance with 10 CFR 50.65(b) of the MR; (4) Characterizing reliability issues for performance monitoring; (5) Tracking unavailability for performance monitoring; (6) Balancing reliability and unavailability; (7) Trending key parameters for condition monitoring; (8) System classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); (9) Appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2); and (10) Appropriateness and adequacy of 10 CFR 50.65 (a)(1) goals, monitoring and corrective actions (i.e., Ten Point Plan). The inspectors also compared the licensee's performance against site procedure NPG-SPP-3.4, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; and NPG-

SPP 3.1, Corrective Action Program. The inspectors also reviewed, as applicable, work orders, surveillance records, PERs, system health reports, engineering evaluations, and MR expert panel minutes; and attended MR expert panel meetings to verify that regulatory and procedural requirements were met.

- Residual Heat Removal Service Water (RHRSW) 023-C, Vessel / Containment Flooding MR Function Reclassified as Risk Significant
- Unit 1, Loop I RHR Low Pressure Coolant Injection (LPCI) Outboard Injection Valve (1-FCV-74-52) Failure and 10CFR50.65(a)(1) corrective action plan

b. Findings

Introduction: The NRC inspectors identified a Severity Level (SL) IV non-cited violation (NCV) of Title 10 of the Code of Federal Regulations (CFR) Part 21, Reporting of Defects and Noncompliance, for the licensee's failure to report a known defect as soon as practicable, but in all cases within 60 days of discovery. More specifically, the licensee did not submit an interim report or notify the NRC in a timely manner pursuant to 10CFR21.21 regarding a manufacturing defect that caused a failure of the Unit 1 RHR Loop I outboard injection valve (1-FCV-74-052) on August 2, 2011.

Description: On August 2, 2011, the Unit 1 Loop I LPCI Outboard Injection Valve (1-FCV-74-52), experienced a failure of the motor operator during performance of surveillance test procedure 1-SR-3.3.5.1.6(C I), Functional Testing of RHR Loop I Valve Logic and Interlocks. During this surveillance test, 1-FCV-74-52 was cycled successfully multiple times until it suddenly failed to reopen. The licensee promptly entered the required TS Limiting Condition of Operation (LCO) 3.5.1 seven day action statement, and initiated PER 410394 to also enter this issue into the corrective action program (CAP). The valve was repaired and returned to service within its TS allowed outage time (AOT). The actual failure of 1-FCV-74-52 did not involve a past operability concern or licensee performance deficiency.

The root cause evaluation for PER 410394 was presented to the Corrective Action Review Board (CARB) on September 14, 2011. As part of the root cause analysis the licensee determined the motor operator failure was a manufacturing defect due to inadequate vendor assembly procedures and manuals for the SMB-5(T) motor operator which led to incomplete lug engagement of the clutching mechanism that subsequently rendered the valve non-functional. At the conclusion of the CARB, the NRC inspectors questioned the root cause team leader regarding the lack of a Part 21 evaluation and notification. The inspectors were informed that the licensee was working with the valve motor operator vendor on further corrective actions, and any required Part 21 notification would be addressed with the vendor. On September 20, 2011, PER 435444 was initiated stating that the root cause determination did not include a Part 21 evaluation. As a result of this PER, the licensee implemented their procedure NPG-SPP-03.5, Regulatory Reporting Requirements, and recognized this issue was potentially reportable per the requirements of 10CFR21.21. The inspectors subsequently concluded that the time of discovery for a Part 21 evaluation was September 14, 2011, for which 10CFR21.21 required the licensee to complete their Part 21 evaluation within the next 60 days, and then notify the NRC within the following seven days; or submit an interim report within 60 days of discovery if the Part 21 evaluation could not be completed within the 60 days. This timeframe required the issuance of a Part 21 interim report to the NRC by November 15, 2011, or a Part 21 initial Notification by November 20, 2011. However, no interim report was issued, and the licensee did not make an initial Part 21 Notification. The valve motor operator vendor (Flowserve) did submit the required Part 21 written report on November 29, 2011. The untimely Part 21 Notification was entered into licensee's CAP as PER 487357.

Analysis: The inspectors determined that the licensee's failure to issue an interim report within 60 days or make an initial Notification of a Part 21 reportable condition constituted a violation of 10CFR21.21. Specifically, the licensee did not ensure that the failure of the 1-FCV-74-52 motor operator due to a manufacturing defect was evaluated and reported in accordance with the timeliness requirements of Part 21. This violation was evaluated using traditional enforcement because it had the potential for impacting the regulatory process. In accordance with the guidance in Section 2.2.2 and Section 6.9.d. of the NRC Enforcement Policy, the inspectors determined this violation was a Severity Level (SL) IV violation of low safety significance because the failure to report this condition did not substantially impact the Agency's regulatory responsibilities and the Agency would not have responded in a significantly different manner had the information been properly reported. The inspectors also concluded that failing to recognize this as a Part 21 reportable issue in a timely manner was a performance deficiency under the Reactor Oversight Process (ROP). In accordance with NRC IMC 0612, Appendix B, Issue Screening, the inspectors concluded that this performance deficiency was minor. Because this performance deficiency was minor and the violation was evaluated using Traditional Enforcement, a cross-cutting aspect is not assigned in accordance with IMC 0612.

Enforcement: 10CFR21.21(a) required in part that the licensee shall evaluate deviations to identify defects associated with a substantial safety hazard as soon as practicable, but in all cases within sixty (60) days of discovery. Upon completion of this evaluation, an initial Notification to the Commission was required within seven days. However, if an evaluation of an identified defect potentially associated with a substantial safety hazard could not be completed within 60 days from discovery of the deviation, an interim report was required to be submitted to the Commission within the 60 days of discovery. Contrary to the above requirements, following the discovery of a manufacturing defect associated with the motor operator for 1-FCV-74-52, Loop I LPCI Outboard Injection Valve on September 14, 2011, the licensee failed to make either an initial Notification or submit an interim report within the time requirements of 10CFR21.21. The NRC was not notified of the Part 21 defect until the vendor (Flowserve) submitted a written report on November 29, 2011. This violation was a SL IV violation of low safety significance because the failure to report this condition did not substantively impact the Agency's regulatory responsibilities and the Agency would not have responded in a substantially different manner had the information been properly reported. Because this violation was of very low safety significance and it was entered into the licensee's CAP as PER 487357, this violation was treated as an NCV, consistent with the NRC Enforcement Policy. This NCV is identified as NCV 05000259, 260, 296/2011005-01, Failure to Report a Valve Motor Operator Manufacturing Defect Pursuant to 10CFR21.21 in a Timely Manner.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

For planned online work and/or emergent work that affected the combinations of risk significant systems listed below, the inspectors examined five on-line maintenance risk assessments, and actions taken to plan and/or control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and applicable risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) and applicable plant procedures such as NPG-SPP-7.0, Work Management; NPG-SPP-7.1, On-Line Work Management; 0-TI-367, BFN Equipment to Plant Risk Matrix; NPG-SPP-7.3, Work Activity Risk Management Process; and NPG-SPP-7.2, Outage Management. Furthermore, as applicable, the inspectors verified the actual in-plant configurations to ensure accuracy of the licensee's risk assessments and adequacy of RMA implementation.

- Unit 1,2,3 South EECW Header Modification/Flush, with B3 and D3 EECW pumps out of service (OOS), B Common Station Service Transformer (CSST) OOS, and Trinity Line 161KV OOS, and B RHRSW header piping leak to 2B RHR HX (modeled as 2-CHK-023-0580 OOS);
- Unit 2A/2B Electric Board Room Air Handling Units (AHU) OOS, B CSST OOS, Trinity Line 161kV OOS, and B RHRSW header piping leak to 2B RHR HX (modeled as 2-CHK-023-0580 OOS);
- Unit 2 Main Bank Battery (MBB) Charger Breaker Found Open with Unit 1 MBB Performance Test in Progress and Plant Control Air Compressor (CAC) B, CSST B, Condenser Circulating Water (CCW) Pump 1A, and Raw Cooling Water (RCW) Pumps 1A and 3D OOS;
- 161 KV Trinity Line, CSST B, 2C RHR Pump, 2B Reactor Water Cleanup (RWCU) pump, 2C RHRSW Outlet Valve, and Battery Board 5 OOS.
- Unit 2 HPCI, CSST B, 1B and 2C CCW Pumps, 1A RCW Pump, 3C and D EDG Exhaust Fans B, MBB 3 Charger, 3B1 Shutdown Board Room Chiller, and Plant CAC A, OOS

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the eight operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors also reviewed applicable sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, where appropriate, the inspectors reviewed licensee procedure NEDP-22, Functional Evaluations, to ensure that the licensee's evaluation met procedure requirements. Furthermore, where applicable, inspectors examined the implementation of compensatory measures to verify that they achieved the intended purpose and that the measures were adequately controlled. The inspectors also reviewed PERs on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- Unit 1 HPCI Booster Pump Thrust Bearing Failure – Past Operability Evaluation (PER 408067)
- 1-SR-3.6.2.5.2(II) Residual Heat Removal System Loop II Drywell Spray Air Test incomplete (PER 438727)
- Emergency Diesel Generator (EDG) heat exchanger fouling (PERs 238502, and 254463)
- Watertight Personnel Access Door, BFN-2-DOOR-260-235 (PER 4455469)
- 250 volt direct current (VDC) Main Bank Battery 2 Low Voltage (PER 456197)
- 3A Diesel Generator Engine/Turbo Vibration (PER 478250)
- Part 21 for safety-related General Electric HGA relays (PER 454956)
- 250/125 VDC Battery Charger Capacitors Exceeded Service Life (PER 469567)

b. Findings

No findings were identified.

1R18 Plant Modifications

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed one temporary modification listed below to verify regulatory requirements were met, along with procedures such as NPG-SPP-9.3, Plant Modifications and Engineering Change Control; NPG-SPP-9.5, Temporary Alterations; and NPG-SPP-6.9.3, Post-Modification Testing. The inspectors also reviewed the associated 10 CFR 50.59 screening and evaluation when appropriate and compared each against the UFSAR and TS to verify that the modification did not affect operability or availability of the affected system. Furthermore, the inspectors walked down each modification to ensure that it was installed in accordance with the modification documents and reviewed post-installation and removal testing to verify that the actual impact on permanent systems was adequately verified by the tests.

- Configuration Control of Jumpers and Boots During Implementation of 3-SR-3.8.1.6, Common Accident Signal Logic

b. Findings

No findings were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the Design Change Notice (DCN) and completed work packages (WOs 111570652 and 112393678) for DCN 70234, Install Branch Connections on EECW System Piping and Perform Flush of EECW North/South Supply Headers, Remove/Install Check Valves 619/671 to Facilitate Flush, including related documents and procedures. The inspectors reviewed licensee procedures NPG-SPP-9.3, Plant Modifications and Engineering Change Control, and NPG-SPP-6.9.3, Post-Modification Testing, and observed part of the licensee's activities to implement this design change made while the unit was online. The inspectors reviewed the associated 10CFR 50.59 screening against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors reviewed selected ongoing and completed work activities to verify that installation was consistent with the design control documents. This activity counts for one inspection sample.

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed and reviewed the six post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following the described maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors verified that PMT activities were conducted in accordance with applicable WO instructions, or procedural requirements, including NPG-SPP-06.3, Pre-/Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors verified that problems associated with PMTs were identified and entered into the CAP.

- Unit 1/2/3 Emergency Equipment Cooling Water (EECW) Flow Verification to Emergency Diesel Generators Following EECW South Header Flush.
- Unit 1 Standby Liquid Control (SLC) Pump 1B Accumulator Bladder Replacement
- Unit 1 250 VDC Main Bank Battery Board 10CFR50 App R Fuse Modification per DCN 70434 and WO 112898072
- Unit 2 High Pressure Coolant Injection (HPCI) system outage

- Unit 3A EDG gear train boroscope inspections performed per WO 112895182
- C1 RHRSW pump motor power cable replacement per 2-SI-4.5.C.1(3-COMP), RHRSW Comprehensive Pump and Header Test

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 1 Planned Mid-Cycle Outage

a. Inspection Scope

From December 9 through December 13, 2011, the inspectors examined critical outage activities to verify that they were conducted in accordance with TS, applicable plant procedures, and the licensee's outage risk assessment and management plans. The inspectors also monitored critical plant parameters, and observed operator control of plant conditions, during Cold Shutdown (Mode 4), Startup (Mode 2), and Power Operation (Mode 1). Furthermore, the inspectors conducted an independent walkdown, and closeout inspection of the Unit 1 drywell prior to reactor startup.

Some of the significant outage activities specifically reviewed and/or witnessed by the inspectors were as follows:

- Reactor shutdown on December 9, including manual reactor scram, in accordance with 1-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reductions in Power During Power Operations
- Plant Oversight Review Committee (PORC) event review and restart meeting on December 10
- Licensee closeout of the Unit 1 Drywell in accordance with 1-GOI-200-2, Primary Containment Initial Entry and Closeout
- Reactor startup on December 13, including rod withdrawal for criticality; reactor heatup; and power ascension to full power; in accordance with General Operating Instruction (GOI) 1-GOI-100-1A, Unit Startup, 2-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring, and 1-GOI-100-12, Power Maneuvering
- Outage risk assessment and management
- Control and management of outage and emergent work activities
- Identification, resolution, and/or implementation of corrective actions, for selected PERs (especially those designated as "Restart")

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions of, and/or reviewed completed test data for the following three surveillance tests of risk-significant and/or safety-related systems to verify that the tests met TS surveillance requirements, UFSAR commitments, and in-service testing and licensee procedure requirements. The inspectors' review confirmed whether the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions and fulfilled the intent of the associated surveillance requirement.

In-Service Tests:

- 3-SR-3.5.3.3, RCIC Rated Flow at Normal Operating Pressure

Routine Surveillance Tests:

- 3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test

Reactor Coolant System Leak Detection Tests:

- 2-SR-3.4.5.2, Drywell Leak Detection Radiation Monitor Functional Test 2-RM-90-256

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

During the report period, the inspectors observed an Emergency Preparedness (EP) training drill that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures on November 8, 2011. This drill was intended to identify any licensee weaknesses and deficiencies in classification, notification, dose assessment and protective action recommendation (PAR) development activities. The inspectors observed emergency response operations in the simulated control room, Technical Support Center, and Operations Support Center to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Classification Procedure, and licensee conformance with other applicable Emergency Plan Implementing Procedures. The inspectors also attended the post-drill critiques to compare any inspector-observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying EP related issues and entering them in to the CAP, as appropriate.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Cornerstone: Mitigating Systems

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following Mitigating Systems Performance Index (MSPI) Performance Indicators (PIs), which included NPG-SPP-02.2, Performance Indicator Program, and applicable MSPI Derivation Reports. The inspectors examined the licensee's MSPI PI data for the specific PIs listed below for the third quarter of 2010 through the second quarter of 2011. The inspectors reviewed the licensee's data and graphical representations as reported to the NRC for the second quarter of 2011to verify that the data was correctly reported. The inspectors also validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the Day, Licensee Event Reports, Maintenance Rule (MR) Cause Determination and Evaluation Reports, and licensee MR unavailability tracking tools, etc.), and assessed any reported problems regarding implementation of the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the MSPI PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors also used the Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to ensure that industry reporting guidelines were appropriately applied.

- Unit 1 MSPI - Cooling Water System (RHRSW/EECW)
- Unit 2 MSPI - Cooling Water System (RHRSW/EECW)
- Unit 3 MSPI - Cooling Water System (RHRSW/EECW)

b. Findings

No findings were identified.

.2 Cornerstone: Initiating Events

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the PIs listed below, including procedure NPG-SPP-02.2. The inspectors examined the licensee's PI data for the specific PIs listed below for the fourth quarter of 2010 through the third quarter of 2011. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC for the third quarter of 2011 to verify that the data was correctly reflected in the report. Furthermore, the inspectors validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the Day, LERs, etc.), and assessed any reported problems regarding implementation of the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors also used the Nuclear Energy Institute (NEI) 99-02, to ensure that industry reporting guidelines were appropriately applied.

- Unit 1 Unplanned Scrams
- Unit 2 Unplanned Scrams
- Unit 3 Unplanned Scrams
- Unit 1 Unplanned Scrams with Complications
- Unit 2 Unplanned Scrams with Complications
- Unit 3 Unplanned Scrams with Complications
- Unit 1 Unplanned Power Changes
- Unit 2 Unplanned Power Changes
- Unit 3 Unplanned Power Changes

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems

.1 Review of items entered into the Corrective Action Program:

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished by reviewing daily PER and Service Request (SR) reports, and periodically attending Corrective Action Review Board (CARB) and PER Screening Committee (PSC) meetings.

.2 Annual Follow-up of Selected Issues – Corrective Action associated with Yellow Violation

Inspection Scope

The inspector reviewed specific aspects of corrective actions associated with the licensee's effort following Yellow Violation 05000259, 260, 296/2009009-03, "Failure to Ensure One Train of Cables of Systems Necessary to Achieve and/or Maintain Post-Fire Safe Shutdown is Free of Fire Damage in Accordance With 10 CFR Part 50, Appendix R, Section III.G.". These actions included physical plant modifications, analysis updates, and procedural changes for which the licensee was indicating a reduction in the overall risk associated with the Yellow finding.

Findings and Observations

No findings were identified. However, the inspector identified the following observations which were discussed with the licensee:

During the review of changes made to Safe Shutdown Instructions (SSIs), the inspector noted that additional guidance was added to identify potential equipment that may be available for operators use at the end of the SSI's. These procedures still employ a Self Induced Station Black Out (SISBO) strategy during fire mitigation and although the additional information could be useful to operators, successful use appears to be heavily dependent on the skill of the operator and current plan conditions.

Additionally, the inspector noted that one original SSI had been separated into four separate instructions that no longer employed a SISBO strategy for fire mitigation. These four procedures were designed to be used concurrently with existing Emergency Operating Instructions (EOIs). Integration of external procedures had not previously been employed in the use of SSIs. After reviewing the information concerning these new procedures that were implemented in September 2011, the inspector raised concerns to licensee personnel about the implementation of the procedure changes and the scope of training that was provided to plant operators on the use of the new procedures. The licensee initiated SR469503 - Determine whether the level of Training for the recent (2011) SSI revisions was appropriate and if recent changes to procedures governing Change Management (PB-242 to COOSPP-01.2) would result in a different level of training. Additionally, during the review the inspector identified a potential procedure weakness that made the inspector question the level of rigor put into the development and implementation of the new procedures. The licensee initiated procedure change request (PCR) numbers 11003882 and 11003881 to address the issue.

.3 Semiannual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's CAP implementation and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review included the results from daily screening of individual PERs (see Section 4OA2.1 above), licensee trend reports and trending efforts, and independent searches of the PER database and WO history. The review also included issues documented outside the normal CAP in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of July 2011 through December 2011, although some searches expanded beyond these dates. Additionally, the inspectors' review also included the Integrated Trend Reports (ITR) from the third and fourth quarters of fiscal year 2011. The licensee reports covered the period of

April 1, 2011 to September 30, 2011. Furthermore, the inspectors verified that adverse or negative trends identified in the licensee's PERs, periodic reports and trending efforts were entered into the CAP. Inspectors interviewed the appropriate licensee management and also reviewed procedures, NPG-SPP-02.8, Integrated Trend Review, Rev. 1 and NPG-SPP-02.7 PER Trending, Rev. 2.

The purpose of the licensee's integrated trend reviews was to identify the top site and departmental issues (gaps to excellence) requiring management attention. Other objectives were to provide status of the top issues and their progress to resolution, identify continuing issues, emerging trends and issues to be monitored, review progress towards resolving past top issues, review issues identified by external organizations such as the NRC, INPO, Nuclear Safety Review Board (NSRB), QA, etc., and determine why they were not identified by line organizations.

b. Findings and Observations

No findings were identified, but the inspectors identified a number of observations as discussed below.

Inspectors observed licensee-identified issues and trends in both the third and fourth quarter ITRs that were identical or similar in nature. Inspectors reviewed the repeat issues to confirm the licensee was continuing to take appropriate actions to alleviate the issues and trends identified. Some of the more notable site/departmental issues were as follows:

- Human Performance: Collective human performance practices resulted in consequential events, specifically; procedure use and adherence, procedure quality, accountability, human performance fundamentals, and the observation program. This issue was documented in PER 410308.
- Work Management: The site continued to be less than effective in the areas of schedule development database interface and milestone action performance, planning and work package documentation, and outage readiness. This issue was documented in PER 411518.
- Corrective Action Program (CAP): Improvements were required in the quality of CAP cause determinations, the effectiveness and timeliness of CAP resolutions, and internalization of CAP as a core business function. This issue was documented in PER 346645.

Most significant, was the recognition by the licensee that site efforts to date had not resulted in marked improvement in procedure use and adherence. From a review of the licensee's CAP database, the inspectors independently identified a continued adverse trend in procedure non-compliance and inadequacy. The licensee had come to the same conclusion, and in parallel, had documented the CAP requirement for a root cause determination in PER 484548.

The inspectors conducted an independent review to identify potential adverse trends. The notable trends were verified to be in the licensee's CAP and were referred to the licensee who entered them into their CAP. The inspector-identified apparent adverse trends were as follows:

- During an approximate nine month period, 27 PERs were initiated for numerous errors in the implementation of the Equipment Out Of Service (EOOS) on-line probability risk assessment tool. Many of which were NRC-identified PERs that were initiated for missing or incorrect equipment. Most notable was a continuing problem in providing new senior reactor operators with the necessary computer software suite to perform on-shift EOOS and work control assessments. The licensee initiated PER 486729 to address a potential adverse trend in EOOS implementation.

- Licensee Post Trip Reviews (PTRs) of the last three unit scrams revealed issues with completeness, timeliness, and inaccurate or missing data. The licensee corrected the specific PTRs, and completed some other actions outside the CAP, but had not documented any longer term corrective actions in their CAP. The licensee initiated PERs 486732 and 486736 to assess the PTR trend and evaluate further actions.

- Inadequate seismic restraint or location of temporary equipment within the plant was a continuing issue. In addition, there were administrative tagging and tracking implementation issues. Furthermore, the inspectors identified that the licensee's semiannual audit of the temporary equipment control program does not review CAP-identified deficiencies of the program. The licensee initiated PER 485908 for a potential adverse trend in temporary equipment control and PER 486702 for the evaluation of the programmatic gap.

- The licensee had not adequately assessed the In-Service Testing (IST) program for an adverse impact from not documenting valves and other IST components as a result of exceeding their alert range acceptance criteria. The licensee had adequately documented and assessed the extent of condition for IST pumps in alert, but had not documented that same assessment for other IST components. The licensee initiated PER 485900 to assess the potential trend in IST program deficiencies.

4OA3 Follow-up of Events

.1 (Closed) Licensee Event Report (LER) 05000259/2011-003-01, Loss of Safety Function (SDC) Resulting from Emergency Diesel Generator Output Breaker Trip

a. Inspection Scope

The inspectors reviewed Revision 1 of the LER dated December 21, 2011. This revised LER was submitted to provide the results of the licensee's completed investigation and evaluation. The original LER 50-259/2011-003-00 dated July 1, 2011, and applicable PER 362340, including cause determination and corrective action plans, were reviewed by the inspectors and documented in Section 4OA3.2 of NRC IR 05000259/2011004. As a result of this prior review, one violation of NRC requirements was identified: NCV

05000259/2011004-03, Unit 1 Loss of Shutdown Cooling Caused by the Emergency Diesel Generator Output Breaker Trip.

On April 27, 2011, severe weather in the Tennessee Valley service area caused a reactor scram on all three Browns Ferry units. On May 2, 2011, the output breaker of the Unit 1/2 A EDG tripped and caused a loss of shutdown cooling to Unit 1. The licensee determined the A EDG output breaker tripped from a misadjusted overspeed trip limit switch (OTLS) arm caused by inadequate engineering guidance for properly configuring the OTLS.

As documented in the revised LER, the licensee concluded that there was no firm evidence to indicate that the A EDG could have fulfilled its 7-day mission time during the previous 21 month period.

The inspectors reviewed the LER revision and verified that the supplemental information provided in the LER was complete and accurate and that the information was not of a significant nature to warrant any change to the original LER finding.

b. Findings

One finding of significance for the original LER was previously identified in IR 05000259/2011004 (see NCV 05000259/2011004-03). No additional findings were identified. The revised LER is considered closed.

.2 (Closed) LER 05000259/2011-007-00, Multiple Containment System Isolations from Loss of RPS M-G Set 1B

a. Inspection Scope

The inspectors reviewed LER 05000259/2011-007-00 dated October 5, 2011, and the applicable PER 412934, including associated apparent cause determination and corrective action plans.

On August 6, 2011, Unit 1 Reactor Protection System (RPS) Motor-Generator (M-G) Set 1B failed resulting in a partial loss of power to RPS and the Primary Containment Isolation System (PCIS). The loss of power to PCIS caused an invalid actuation of PCIS resulting in multiple system isolations, including isolation of the drywell floor drain sump and the drywell containment atmospheric monitor for both the particulate and gaseous activity. Thus, both means of automatic monitoring of reactor coolant system (RCS) leakage became inoperable which required entry into TS 3.0.3 and an unplanned Unit 1 power reduction.

The licensee's troubleshooting did not identify a specific condition that caused the voltage drop on the RPS M-G Set 1B. However, the licensee identified two potential causes: 1) a loose connector or cable assembly and 2) a potentiometer discontinuity.

b. Findings

One finding was identified. This LER is considered closed.

Introduction: A self-revealing finding (FIN) was identified for the licensee's failure to adequately evaluate historically high vibrations on the Unit 1 Reactor Protection System (RPS) Motor Generator (M-G) Set 1B per Vibration Program, 0-TI-230V. Consequently, the impact of high vibrations was not considered in the establishment of an adequate preventive maintenance frequency to ensure the proper wire and cable terminal tightness in the RPS M-G Set control panel.

Description: On August 6, 2011, Unit 1 RPS M-G Set 1B failed resulting in a partial loss of power to RPS and the PCIS. The loss of power to PCIS caused an invalid actuation of PCIS resulting in multiple system isolations. The PCIS Group 6 isolation resulted in the isolation of the drywell floor drain sump and the drywell containment atmospheric monitor for both the particulate and gaseous activity. Thus, both means of automatic monitoring of RCS leakage became inoperable. The licensee then entered Unit 1 TS LCO 3.4.5, Action D, which directed operators to immediately enter into TS 3.0.3 which required an orderly reactor plant shutdown due to all required leakage detection systems being inoperable. The licensee began an unplanned Unit 1 power reduction approximately one hour later. Following the completion of the troubleshooting and restoration of electrical power to the Unit 1 RPS M-G Set, the licensee exited the TS required shutdown action statement and stopped the Unit 1 downpower at 91 percent RTP approximately 7 hours later.

The licensee initiated PER 412934 to determine the cause of the RPS M-G Set 1B failure. The licensee's troubleshooting did not identify a specific condition that caused the voltage drop on the RPS M-G Set 1B. However, the licensee identified two potential causes: 1) Loose connector or cable assembly at a terminal on the RPS M-G Set control panel and 2) Discontinuity within the voltage adjustment potentiometer. The licensee previously experienced a voltage drop and failure of the RPS M-G Set 3B, which was determined to be premature degradation of the voltage regulator gain potentiometer due to lack of periodic maintenance. The licensee had also experienced previous voltage regulator card failures. Therefore, the licensee's troubleshooting efforts focused on the voltage adjustment potentiometer, the voltage regulator, and the connections in between. The voltage adjustment potentiometer was cycled while monitoring the resistive output and smooth changes indicated no discontinuities. The voltage regulator was replaced and failure analysis conducted by an independent laboratory validated that the old voltage regulator was fully functional. However, the as-found status of the electrical connections was indeterminate from the licensee's documented cause determination and inspector interviews with the licensee. A number of electrical connections were disturbed during voltage regulator replacement.

RPS M-G Set 1B is one of six M-G Sets, two for each of three units. The M-G sets were designed to run continuously and have the control panel bolted to the rotating equipment (versus detached on a wall or separate structure). Due to this design and operational characteristics, larger vibrations are induced into the control panel. The M-G set vendor manual listed “connectors or cable assemblies loose” as the number one probable cause for failure of the generator to build up rated voltage. Quarterly vibration data for the RPS M-G Set 1B generator outboard bearing was historically in alert which induced vibrations directly to the control panel mounted to the generator. The other M-G sets remained below the alert threshold. The alert limit was a required evaluation threshold as defined by the licensee’s predictive maintenance Vibration Program, 0-TI-230V. The licensee stated that they had accepted the RPS M-G Set 1B operation above the alert limit without any evaluation as required by procedure 0-TI-230V.

Additionally, the licensee’s preventive maintenance (PM) procedure EPI-1-099-MGZ002, Three Year Maintenance plan for 1B Reactor Protection System M-G Set, required a check of terminal tightness on a 3 year frequency, which was last performed on January 11, 2008. However, in the licensee’s PM tracking system, the PM was scheduled to be due on November 14, 2011, beyond the program specified 25 percent grace period. This condition was identified in the licensee’s CAP as PER 438509. The RPS M-G Set 1B failed within the 9 month grace window which indicated that the 3 year frequency for tightening connectors and cable assemblies was not adequate based on the current actual operating characteristics of the MG Set.

The licensee’s corrective actions included verification that the 3 year PMs were scheduled in the next component outage window for the remaining five M-G sets. In addition, the licensee’s actions to reduce the frequency to two years, combine all M-G set PMs into one, and conduct a design review to relocate the control panel to an adjacent wall or structure were ongoing. Furthermore, the licensee was evaluating the vibration program alert limit evaluation process. .

Analysis: The inspectors determined that the licensee’s failure to evaluate historically high vibrations on the Unit 1 RPS M-G Set 1B was a performance deficiency. This performance deficiency was considered more than minor because it was associated with the Barrier Integrity Cornerstone attribute of RCS Equipment and Barrier Performance, and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers (reactor coolant system) protect the public from radionuclide releases caused by accidents or events. Specifically, the failure to ensure proper wire and cable tightness was the most probable cause for the failure of the Unit 1 RPS M-G Set 1B which resulted in a loss of all Unit 1 Reactor Coolant System (RCS) leakage detection systems and an unplanned power reduction. The significance of the finding was evaluated using Phase 1 of the SDP in accordance with the IMC 0609 Attachment 4, and was determined to be of very low safety significance (Green) because the finding did not represent a pressurized thermal shock, fuel barrier, or spent fuel pool issue.

The cause of this finding was directly related to the cross-cutting aspect of Long Term Plant Safety Through Proper Maintenance Practices in the Resources component of the Human Performance area, because the vibration issues associated with Unit 1 RPS M-G Set 1B had been a long-standing equipment issue that was not adequately addressed by the vibration program alert limit evaluation process. [H.2(a)].

Enforcement: This finding does not involve enforcement action because no violation of regulatory requirements was identified. Because this finding does not involve a violation of regulatory requirements, was entered in the licensee's CAP as PER 412934, and has very low safety significance, it is identified as FIN 05000259/2011005-02, Unit 1 TS 3.0.3 Entry Caused by the Failure of RPS M-G Set 1B.

.3 (Closed) LER 05000260/2011-001-00, Core Spray Relay Found in Incorrect Position

a. Inspection Scope

On August 8, 2011, during performance of biennial surveillance procedure 2-SR-3.3.5.1.6(CS II) Core Spray System Logic Functional Test Loop II, two pairs of contacts for normally energized relay 2-RLY-075-14A-K30B were found out of position (not fully open, when the expected position was fully open). On August 9, 2011, the relay cover was adjusted and the contacts repositioned to the proper position. The licensee recommenced 2-SR-3.3.5.1.6(CS II) and it was completed satisfactory on August 11, 2011. During a walkdown on August 12, 2011, the licensee discovered the same contacts for this relay were once again out of position. On August 13, 2011 the licensee replaced the relay and performed a satisfactory post maintenance test. A subsequent investigation revealed that the relay failed due to intermittent binding of the relay's hinged armature. Prior to the discovery of the mis-positioned relay contacts on August 8, 2011, the last known successful operation of relay 2-RLY-075-14A-K30B occurred during the three unit Loss of Offsite Power (LOOP) event on April 27, 2011. Additionally, this LER contains a report pursuant to 10CFR21.21 for failure of the General Electric (GE) 250VDC HGA electromagnetic relay with GE part number 1376C6183P014, model number 12HGA111A1F. The inspectors have reviewed PER 415242, which included the cause determination and corrective action plans.

b. Findings

One finding of significance for the original LER was previously identified in IR 05000260/2011004 (see Section 4OA7). No additional findings were identified. This LER is considered closed.

.4 Fire Event in the RHRSW Cable Tunnel

a. Inspection Scope

On October 12, 2011, the inspectors performed an event follow up inspection of a fire in the RHRSW cable tunnel. The site's fire brigade had promptly responded to the cable tunnel and the fire was extinguished in approximately ten minutes. The inspectors reviewed the Main Control Room logs and interviewed Fire Operations and Operations on-shift personnel and verified no spurious alarms or spurious safety-related equipment operation. The inspectors performed a walkdown of the cable tunnel with plant personnel to verify the extent of fire damage. It was determined that a temporary light string cable had shorted and caught fire. The light string burned in close proximity to a safety-related cable tray that resulted in minor cable jacket damage (i.e., discoloration) of four 600V rated cables. The inspectors performed walkdowns of other safety-related plant areas. No additional light strings were identified by the inspectors. The licensee performed additional inspections of the plant and either removed the temporary light strings where accessible or documented their location in the corrective action program for subsequent removal.

b. Findings

One finding was identified.

Introduction: A self-revealing NCV of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings was identified for the licensee's failure to properly install and maintain adequate control of temporary lighting in the intake cable tunnel as required by the TVA Safety Manual and licensee procedure NPG-SPP-09.17, Temporary Equipment Control. As a result, a temporary light string failed and caused a fire in the intake cable tunnel on October 12, 2011.

Description: On October 12, 2011, the licensee responded to a fire/smoke alarm on the remote fire detection system panel for the intake cable tunnel at 0530 Central Daylight Time (CDT). The fire brigade responded promptly and discovered a small fire in a cable tray at the bend of the tunnel. The fire was extinguished by the fire brigade using a dry chemical bottle at 0540 CDT. The inspectors verified that there were no spurious equipment operations and that safety-related equipment was not directly affected as a result of the fire. The inspectors performed a walkdown of the intake cable tunnel with licensee staff and discovered a temporary light string had faulted and burned, with a portion of melted insulation that fell onto the cable tray below. The licensee's subsequent cause determination report found that the light string had shorted and burned when a compact fluorescent light (CFL) bulb failed. The bulb cage from the temporary light string fell into safety-related cable tray GN-ESII. The licensee also determined that the temporary light string was not supporting active work in the area and had been installed in the intake cable tunnel for more than two years due to deficiencies with the permanently installed lighting system. Licensee procedure NPG-SPP-09.17, Revision 0, required a ninety (90) day limit for use of temporary equipment in plant operating areas. An exception existed in this procedure to exceed the ninety day limit, but it required re-initiation of the temporary equipment control approval process with specific approval from Operations. No record could be found approving the initial installation of the temporary light string, nor the subsequent ninety (90) day re-approval, as required. Additionally, TVA Safety Manual procedure 1007 required use of a power receptacle with an internal ground fault circuit interrupt (GFCI) device, or a portable GFCI device plugged into the power receptacle, when electrical extension cords are used. The extension cords used for the light stringer did not have a portable GFCI and the power receptacle that powered the temporary light string did not have an internal GFCI. The licensee entered this event into their corrective action process as PER 445331.

Analysis: Failure to install and maintain adequate control of temporary lighting in the intake cable tunnel per the TVA Safety Manual and licensee procedure NPG-SPP-09.17 was a performance deficiency. As a consequence, a temporary light string was installed without electrical fault protection and left in the cable tunnel for more than two years when it subsequently experienced an electrical fault which caused a fire in the intake cable tunnel on October 12, 2011. The performance deficiency was determined to be more than minor because it was considered sufficiently similar to example 4.f of Inspection Manual Chapter (IMC) 0612, Appendix E, for an issue that resulted in a fire hazard in a safety-related area of the plant. The finding was associated with the Initiating Events Cornerstone and initially characterized according to IMC 0609, Significance Determination Process (SDP), Attachment 4, Phase 1 - Initial Screening and Characterization of Findings. The results of this analysis required an evaluation in accordance with IMC 0609, Appendix F, Attachment 1, Part 1, Fire Protection SDP Phase 1 Worksheet. For the SDP Phase 1 evaluation a high degradation rating was assigned for this fire event with a duration factor greater than 30 days. When compared against the SDP Phase 1 screening criteria, this resulted in a SDP Phase 2 evaluation. The inspectors concluded that this finding screened to Green in the Appendix F Phase 2 analysis using Appendix F Attachment 1, Part 2, Fire Protection SDP Phase 2 Worksheet. Specifically, it was determined that the fire could not reach the temperature threshold for fire-induced cable failure and would not spread to other combustible materials in the area. The cause of this finding was directly related to the cross cutting aspect of Long-Standing Equipment Issues in the Resources component of the Human Performance area, because the deficiencies with the permanently installed lighting system in the intake cable necessitated the use of the temporary light string for more than two years [H.2(a)].

Enforcement: 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures and Drawings requires in part that activities affecting quality shall by prescribed by documented instructions and shall be accomplished in accordance with these instructions. Contrary to this requirement, the licensee failed to accomplish an activity affecting quality in accordance with documented instructions. Specifically, the licensee failed to control a temporary light string in accordance with NPG-SPP-09.17, Temporary Equipment Control for more than two years. The light string subsequently failed, resulting in a fire in the safety-related intake cable tunnel on October 12, 2011. The licensee’s fire brigade extinguished the fire and removed the temporary light stringer from the intake tunnel. Additionally, Operations staff performed additional inspections of plant areas and either removed the temporary light stringers where accessible or documented their location in the corrective action program for subsequent removal. Because the finding was of very low safety significance and has been entered into the licensee’s CAP as PER 445331, this violation is being treated as an NCV consistent with the NRC Enforcement Policy. This NCV is identified as NCV 05000259, 260, 296/2011005-03, Failure to Control Temporary Equipment Resulted in a Fire.

.5 (Closed) LER 05000296/2011-001-00, and 05000296/2011-001-01, Loss of Shutdown Cooling (RHR)

a. Inspection Scope

The inspectors reviewed LER 05000296/2011-001-00 dated July 11, 2011, and the revised LER 05000296/2011-001-01 dated January 5, 2012. The original LER 05000296/2011-001-00 was initially reviewed, with one finding of significance identified, in IR 05000296/2011004 (see NCV 05000296/2011004-04).

The LER revision was issued to provide additional clarification regarding the unexpected Unit 3 partial PCIS Group 2 actuation that was caused by an improperly lifted wire during a PCIS relay replacement, which resulted in a loss of shutdown cooling for Unit 3. The inspectors verified that the supplemental information provided in the LER revision was complete and accurate, and was not significant enough to warrant any change to the original LER finding.

b. Findings

One finding of significance related to the original LER 05000296/2011-001-00 was documented in IR 05000296/2011004 (see NCV 05000296/2011004-04). No additional findings were identified regarding the original or revised LER. These LERs are considered closed.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No findings were identified.

.2 (Closed) Apparent Violation (AV) Failure to Properly Install Unit 1 High Pressure Coolant Injection Booster Pump Outboard Bearings

a. Inspection Scope

A licensee-identified Apparent Violation (AV) of TS 5.4.1.a was identified in IR 259/2011-004 for the licensee’s failure to establish adequate work instructions to ensure proper installation of the Unit 1 HPCI booster pump outboard bearing assembly. The initial characterization of the safety significance of this finding was performed using IMC 609, Appendix A, Determining the Significance of Reactor Inspection Findings for At-Power Situations. Since this finding was potentially greater than Green according to the Phase 2 SDP of Appendix A, it necessitated a Phase 3 SDP to further characterize the safety significance. The Phase 3 SDP was subsequently completed, which determined the finding was of very low safety significance (i.e., Green) because the licensee identified and repaired the booster pump prior to an actual failure. Actions taken to repair HPCI prior to an actual failure meant that HPCI would have continued to perform its safety function for a significant period of time until it actually failed and therefore decreased the resulting risk by an order of magnitude. The additional, available run time of HPCI would have given operators more time and provided a higher likelihood of success to perform necessary actions to depressurize the reactor, if required, to mitigate a design-basis accident event.

b. Findings

One finding was identified as described in Section 4OA7 of this report. This AV is considered closed.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On January 20, 2012, the resident inspectors presented the inspection results to Mr. Keith Polson, Site Vice President, and other members of the licensee's staff, who acknowledged the findings. All proprietary information reviewed by the inspectors as part of routine inspection activities were properly controlled, and subsequently returned to the licensee or disposed of appropriately.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and was a violation of NRC requirements which met the criteria of the NRC Enforcement Policy for being dispositioned as a NCV.

- Unit 1 TS 5.4.1.a, required that written procedures recommended in RG 1.33, Revision 2, Appendix A, shall be established, implemented, and maintained. Item 9.a of RG 1.33, Appendix A, stated, in part, that maintenance affecting the performance of safety-related equipment be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on March 16, 2005, the licensee failed to establish an adequate procedure for the performance of maintenance that affected the performance of a piece of safety related equipment. Specifically, the level of detail in work order package WO 2002-013120-030 and procedure MCI-0-073-PMP002 was inadequate to ensure the proper installation of the Unit 1 HPCI booster pump outboard thrust bearings, which directly led to severe bearing damage and would have eventually resulted in failure of the HPCI pump. The licensee initiated PER 408067 to enter this issue into their CAP and performed corrective maintenance to replace the bearings. The finding was determined to be of very low safety significance in accordance with a Phase 3 SDP of IMC 0609 because the licensee identified and repaired the booster pump prior to an actual failure.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
S. Bono, Maintenance Manager
J. Boyer, Acting Assistant Director of Engineering
O. Brooks, Licensed Operator Requalification Training Supervisor
B. Bruce, Acting Systems Engineering Manager
J. Colvin, Engineering Programs Manager
M. Durr, Director of Engineering
M. Ellet, Maintenance Rule Coordinator
J. Emens, Nuclear Site Licensing Manager
A. Feltman, Emergency Preparedness Manager
N. Gannon, Plant General Manager
D. Hughes, Operations Manager
W. Hayes, Reactor Engineering Manager
S. Kelly, Senior Outage Manager
D. Kettering, Electrical Systems Engineering Manager
R. King, Design Engineering Manager
D. Malinowski, Operations Training Manager
D. Matherly, Assistant to the Site Vice President
P. Summers, Director of Safety and Licensing
R. Norris, Radiation Protection Manager
W. Nurnberger, Work Control Manager
P. Parker, Site Security Manager
W. Pearce, Performance Improvement Manager
K. Polson, Site Vice President
M. Rasmussen, Operations Superintendent
H. Smith, Fire Protection Supervisor
R. Stowe, Equipment Reliability Manager
J. Underwood, Chemistry Manager
S. Walton, Electrical Maintenance Superintendent
M. Wilson, Director of Training
A. Yarbrough, BOP System Engineering Supervisor

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000259, 260, 296/2011005-01	NCV	Failure to Report a Valve Motor Operator Manufacturing Defect Pursuant to 10CFR21.21 in a Timely Manner (Section 1R12)
05000259/2011005-02	FIN	Unit 1 TS 3.0.3 Entry Caused by the Failure of RPS M-G Set 1B (Section 4OA3.2)
05000259, 260, 296/2011005-03	NCV	Failure to Control Temporary Equipment Resulted in a Fire (Section 4OA3.4)

Closed

05000259/2011-003-01	LER	Loss of Safety Function (SDC) Resulting from Emergency Diesel Generator Output Breaker Trip (Section 4OA3.1)
05000259/2011-007-00	LER	Multiple Containment System Isolations from Loss of RPS M-G Set 1B (Section 4OA3.2)
05000260/2011-001-00	LER	Core Spray Relay Found in Incorrect Position (Section 4OA3.3)
05000296/2011-001-00	LER	Loss of Shutdown Cooling (RHR) (Section 4OA3.5)
05000296/2011-001-01	LER	Loss of Shutdown Cooling (RHR) (Section 4OA3.5)
05000259/2011-004-02	AV	Failure to Properly Install Unit 1 High Pressure Coolant Injection Booster Pump Outboard Bearings (Section 4OA5.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection – Severe Weather Readiness and External Flooding

UFSAR, Section 2.4, Hydrology, Water Quality, and Aquatic Biology, Amendment 19
UFSAR, Section 2.4A, Maximum Possible Flood, Amendment 24
UFSAR, Section 12.2, Principal Structures and Foundations, Amendment 24
Individual Plant Examination For External Events (IPEEE), July 1995
Calculation MD-Q0999-920112, Prevention of Backflooding, Rev. 4
EPIP-1, Emergency Classification Procedure, Rev. 47
0-AOI-100-3, Flood Above Elevation 558', Rev. 35
0-AOI-100-4, Breach of Wheeler Dam, Rev.15
EPI-0-000-SWZ-006, Cal. & Inspect. of Station Drain. & Intake Sump Pump Level Switches, Rev. 20
PER 151919, Sink Drains
PER 158381, Errors in codes used in Probable Maximum Flood (PMF)
PER 177501, Hydrology - Fort Loudoun Dam Spillway Discharge Coefficient Inconsistencies
PER 178130, Hydrology Study Update impacts Flood Analysis
PER 202827, Hydrology - Potential Overtopping of Tellico Dam and Watts Bar Dam
PER 208169, EDG Floor Drain Plugs
PER 272691, Drain Plugs
PER 289066, Room Bulkheads
PER 309084, Unit 2/3 Airlock Hatch
PER 422953, Documentation of PMF
PER 455469, Unit 1/2 Airlock Hatch
PER 467958, Degraded Plug and Lack of PM's, DWG, etc.
FE PER 177501, Technical Basis for Functionality, Rev. 1
FE 43067, (PER 158381), Errors in codes used in Probable Maximum Flood (PMF)
FE 422953, Documentation of PMF
FE for PER 309084, Door 248
FE for PER 455469, Door 235
WO 09-724579-000, Plugs
WO 111573632, Plugs
WO 111675388, Plugs
PM 29157, Inspection and Calibration of the D/G Bldg. Floor Drain Sump Pump, Unit 1/2
PM 500127332, Inspection and Calibration of the D/G Bldg. Floor Drain Sump Pump, Unit 3
PM 500134357, Inspect U1 Reactor Building Floor Drain Sump
PM 500134363, Inspect U2 Reactor Building Floor Drain Sump
PM 500134367, Inspect U3 Reactor Building Floor Drain Sump
3-082-OWA-2011-0240, 3EA,3EB, 3EC DG room heaters not operating.
BFN-50-7030B, Diesel Generator Building Environmental Control System, Rev. 9
0-GOI-200-1, Freeze Protection Inspection, Rev. 67
NPG-SPP-10.14, Freeze Protection, Rev. 0
RPT-NWM-117, Freeze Protection Work Order Report, Nov. 21, 2011
47W225-16, Diesel Generator Building Units 1-3, Environmental Data El 583.5, Rev. 4
47W225-17, Diesel Generator Building Units 1&2, Environmental Data El 565.5, Rev. 4
47W225-18, Diesel Generator Building Unit 3, Environmental Data El 565.5, Rev. 4

47W225-19, Diesel Generator Building Unit 3, Environmental Data El 583.5, Rev. 4
WO 112973497, Place 2B CCW Pump MTR CLG & BLW Systems in dry tube configuration – Freeze Protection
PER 465191, Required Sections of 0-GOI-200-1 not completed before October 1, 2011
PER 466415, SBGT room and 'D' EDG room heaters tagged out
PER 466237, Room Temperature requirement clarification
PER 471375, Freeze Protection Deficiencies
PER 471377, Missed opportunity for freeze protection on 2B CCW pump motor

Section 1R04: Equipment Alignment
2-OI-73, High Pressure Coolant Injection System, Rev. 87
2-OI-73/ATT-2, Attachment 2 Panel Lineup Checklist, Rev. 82
2-OI-73/ATT-3, Attachment 3 Electrical Lineup Checklist, Rev. 83
2-OI-73, High Pressure Coolant Injection System, Rev. 87
PER 443418, NRC Identified housekeeping issues Unit 2 Rx Bldg
1-47E859-1, Flow Diagram Emergency Equipment Cooling Water, Rev. 80
3-47E859-1, Flow Diagram Emergency Equipment Cooling Water, Rev. 38
3-47E859-2, Flow Diagram Emergency Equipment Cooling Water, Rev. 24
PER 449073, Packing leak from 2-SHV-067-0658
BFN-50-7067, General Design Criteria Document for the EECW System, Rev. 18
0-OI-67/ATT-1, EECW System Valve Lineup Checklist Unit 0, Rev. 83
0-OI-67/ATT-1A, EECW System Valve Lineup Checklist Unit 1, Rev. 84
0-OI-67/ATT-1B, EECW System Valve Lineup Checklist Unit 2, Rev. 85
0-OI-67/ATT-1C, EECW System Valve Lineup Checklist Unit 3, Rev. 87
0-OI-67/ATT-2C, EECW System Panel Lineup Checklist Unit 3, Rev. 83
2-OI-71, Attachment 1, Reactor Core Isolation Cooling Valve Lineup Checklist, Rev. 58
2-OI-71, Attachment 2, Reactor Core Isolation Cooling Panel Lineup Checklist, Rev. 59
2-OI-71, Attachment 3, Reactor Core Isolation Cooling Electrical Lineup Checklist, Rev. 59

Section 1R05: Fire Protection
Fire Protection Report Vol. 1, Fire Area 12, Rev. 10
Fire Protection Report Vol. 2, Section IV.9, Pre-Plan No. RX3-593, Rev. 8
Fire Protection Report, Volume 1, Rev. 9
Fire Protection Report, Volume 2, Section IV.9, Pre-Plan No. CB2-593, Rev. 8
FPDP-1, Conduct of Fire Protection, Rev. 2
FPDP-2, Administration of PreFire Plans, Rev. 0
PER 451435, NRC identified items adrift in the U1 Aux Inst Room
PER 451436, NRC questioned a gap in wall material in Battery Board room 1
PER 451378, Fire seals B25933369 and B25933370 appear to not be sealed
0-47E392-1, Fire Protection 10CFR50 Appendix R Penetration Seal Tabular Drawings General Notes and Legends
0-47W391-9, Fire Protection 10CFR50 Appendix R Penetration Internal Conduit Fire Seals Flexible Fire Seal EC-1 and EC-1A
2-47W2392-232, Fire Protection 10CFR50 Appendix R Penetration Seal Tabular Drawings Elevation 593.0
2-47W2392-349, Fire Protection 10CFR50 Appendix R Penetration Seal Tabular Drawings Elevation 593.0 Area 2 - Walls
Fire Protection Impairment Permit (FPIP) 09-1920, App R Safe Shutdown Instructions

Fire Protection Impairment Permit (FPIP) 11-3191, 3-ACU-31-7205, U3 SD BD Rm ACU
Fire Protection Report, Volume 1, Fire Hazards Analysis Units1/2/3, Fire Areas 6 and 7, Rev. 10
Fire Protection Report, Volume 2, Section IV.3, Pre-Plan No. RX1-621, Unit 1 Reactor Building Elevation 621'-0", Rev. 8
NPG-SPP-18.4.6, Control of Fire Protection Impairments, Rev. 0
Roving Fire Watch Route/Coverage Sheet, Unit 1, 2, 3, CB, DG Blds

Section 1R11: Licensed Operator Requalification

NPG-SPP-17.8.1, Licensed Operator Requalification Examination Development and Implementation, Rev. 3
OPDP-1, Conduct of Operations, Rev. 19
EPIP-1, Event Classification Procedure, Rev. 47
EPIP-2, Notification of Unusual Event, Rev. 30
EPIP-3, Alert, Rev. 33
PER 465208, Crew and Individual Failure for Operating LOR 2011 Operating Exam
PER 465230, Scenario for LOR 2011 Operating Exam needs revision

Section 1R12: Maintenance Effectiveness

UFSAR, Section 4.8 Residual Heat Removal System, (RHRS), Amendment 20
UFSAR, Section 10.9, RHR Service Water System, Amendment 20
TRM 3.5.2 Standby Coolant Supply, Rev. 0
0-TI-346, MR Perf. Indicator Monitoring, Trending, and Reporting - 10CFR50.65, Rev. 37
U0 RHRSW, Functions 023-C, Vessel/Containment flooding (a)(1) Plan, Rev. 1
2-SI-3.2.10.B, Verification of Remote Position Indicators for RHRSW System Valves, Rev. 14
0-OI-23, Residual Heat Removal Service Water System, Rev. 92
1-47E858-1; Flow Diagram RHRSW System, Rev. 64
2-47E858-1; Flow Diagram RHRSW System, Rev. 28
3-47E858-1; Flow Diagram RHRSW System, Rev. 33
1-47E811-1, Flow Diagram RHR System, Rev. 64
2-47E811-1, Flow Diagram RHR System, Rev. 64
3-47E811-1, Flow Diagram RHR System, Rev. 37
PER 366367, Function 23-C (a)(1) Due to Reclassification as Risk Significant
PER 437036, MR (a)(2) Monitoring Not Being Performed as Specified in TI-346
PER 490547, MR Unavailability Data Collection
PER 488144, RHR Crosstie Function 074-H does not currently have Unreliability Performance
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev. 36
NPG-SPP-03.4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev. 0
U1 System 074 1-FCV-74-52 (a)(1) Plan, Rev. 0
PERs: 410394, 470397
CDEs: 1148
Unavailability data for RHR System August 2009 to August 2011
NPG-SPP-03.5, Regulatory Reporting Requirements, Rev. 3
PER 245173, Untimely 10 CFR 21 Notification
PER 475537, Evaluate NPG-SPP-03.5 for consistency with 10 CFR 21
PER 441339, PER 410394 is missing Part 21 evaluation action

PER 435444, Evaluate need for Part 21 for 1-FCV-074-052
PER 465011, Evaluate the valve failure for common cause

Section 1R13: Maintenance Risk Assessments and Emergent Work Control
EOOS Operator's Risk Report dated 10/27/11
NPG-SPP-09.11, Probabilistic Risk Assessment (PRA) Program, Rev. 01
NPG-SPP-9.11.1, Equipment Out of Service (EOOS) Management, Rev. 02
NPG-SPP-07.1, On Line Work Management, Rev. 04
NPG-SPP-07.3, Work Activity Risk Management Process, Rev. 04
0-OI-31, Control Bay and Off-Gas Treatment Building Air Conditioning System, Rev. 136
Scheduler's EOOS evaluation from 10/23 to 10/30/2011
EOOS Operator's Risk Report dated 10/17/11
2-47E858-1, RHR Service Water System Flow Diagram, Rev. 28
2-47E811-1, RHR Service Water System Flow Diagram, Rev. 68
3-47E811-1, RHR Service Water System Flow Diagram, Rev. 64
PER 450126, EOOS usage
PER 449248, WO priority not classified per NPG-SPP-07.1
WO 112817797, through wall leak in 2B RHRSW inlet piping
EOOS Operator's Risk Report dated 11/02/11
PER 462003, EOOS Risk Assessment not Correct due to Incorrect "In-Service" Equipment Status
EOOS Operator's Risk Report dated 12/01/2011
EOOS Operator's Risk Report dated 12/13/2011
NPG-SPP-09.11, Probabilistic Risk Assessment (PRA) Program, Rev. 01
NPG-SPP-9.11.1, Equipment Out of Service (EOOS) Management, Rev. 03
NPG-SPP-07.1, On Line Work Management, Rev. 05
NPG-SPP-07.3, Work Activity Risk Management Process, Rev. 06
PER 471726, Error Message Received in EOOS for All Three Units
PER 450126, EOOS Usage
PER 475549, Untimely Communication with OPS Concerning EOOS Changes
Operations Excellence Communication, Issue Summary PER 450126

Section 1R15: Operability Evaluations
PER 408067, Unit 1 HPCI Booster Pump outboard bearings found installed incorrectly
Operability Evaluation for PER 455469
Response to NRC Request for Information, 11/2/2011, Rev. 2
MCI-0-073-PMP002, HPCI Booster Pump – Inspection, Rework and Reassembly, Rev. 19
0-TI-230V, Vibration Program, Rev. 8
1-SI-3.1.5, HPCI Pump Performance, Rev. 4
Operations Logs, dated 5/18/2011 to 7/27/2011
SKF Failure Analysis Report, dated 8/1/2011
Southwest Research Institute Reports, dated 9/21/2011 and 9/29/2011
NEDP-22, Functional Evaluations, Rev. 9
NPG-SPP-07.1, On Line Work Management, Rev. 4
Functional Evaluation for PER 454956, Part 21 for HGA relays
SC 11-09, Failure of HGA Relay (137C6183P014), October 27, 2011
NPG-SPP-03.5, Regulatory Reporting Requirements, Rev. 03
PER 454956, Review Part 21 GEH 11-09 "HGA Relays
UFSAR, Section 2.4A, Maximum Possible Flood, Amendment 24
UFSAR 5.3 Secondary Containment System, Amendment 22

UFSAR 12.2, Principal Structures And Foundations, Amendment 24
EPI-0-000-SWZ-006, Cal. & Inspect. of Station Drain. & Intake Sump Pump Level Switches, Rev. 20
PER 309084, Unit 2/3 Airlock Hatch
PER 455469, Unit 1/2 Airlock Hatch
FE for PER 309084, Door 248
FE for PER 455469, Door 235
PM 500134357, Inspect U1 Reactor Building Floor Drain Sump
PM 500134363, Inspect U2 Reactor Building Floor Drain Sump
PM 500134367, Inspect U3 Reactor Building Floor Drain Sump
WO 08-721887-000, Repair Door 248
WO 112871448, Inspect Door 235
MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev. 39
PER 406703, 3A D/G Main Gear Wear and Metal Shavings Found in Oil
PER 455324, Document Vibration Step Increase
PER 457400, Initiate WO to Perform Boroscope Inspection
PER 460488, ODMI Needed
PER 478250, Site not meeting Interim Action date for DG 3A Vibration - FE 455324
PER 480509, 3A EDG Operability concern due to timeliness of Interim Action
WO 112548463, Perform a Thorough Inspection of D/G 3A Rear Gear Train
WO 112895182, Boroscope Gear Inspection within 1 month
WO 112903711, Troubleshoot and Repair
FE, 3A Diesel Generator Engine/Turbo Vibration, PER 455324
ACE, Step Increase in Diesel Generator 3A Turbocharger Vibration Data, PER 455324
Browns Ferry Operations Newsletter, dated November 4, 2011
Calculation EDQ024820020042, 250V DC Unit Batt Load Study, VD, SC and Batt Capacity for LOCA/LOOP, Station Blackout, and App. R Analysis for Unit/Shutdown Bd Batt, Rev. 35
Electrical Preventive Instruction (EPI)-0-248-CHG002, 250V Main Bank Battery Charger 2A Load Test, Rev. 0
FSAR Section 8.6, 250 VDC Power Supply and Distribution, BFN-20
NPG Standard Programs and Processes (SPP)-01.2, Administration of Site Technical Procedures, Rev. 3
Operations Instruction 0-OI-57D, DC Electrical System, Rev. 133
Operations Department Procedure (OPDP)-1, Conduct of Operations, Rev. 20
Operations Section Instruction Letter (OSIL)-124, Procedure and Work Instruction Use and Adherence, 8/26/11
Past Operability for PER 456197
PER 456197, Breaker 608 on Battery Board 2 Found Open
Quick Human Error Analysis Tool, dated 11/01/11 for SR 453625
PER 456197, Breaker 608 on Battery Board 2 Found Open
Technical Specifications and Bases 3.8.4, DC Sources - Operating, Amendment 255
NEDP-22, Functional Evaluations, Rev. 11
Functional Evaluation for PER 438727
MCR logs
BFN-50-7074, Design Criteria Document, Residual Heat Removal System, Rev. 20
Apparent Cause Evaluation (ACE) Report for PER 438727
LCO tracking log: 1-064-TS-2011-0425
1-EOI Appendix-17B, RHR System Operation DW Sprays, Rev. 0
NDQ0064980007, Primary Containment Analysis, Rev. 5

1-SR-3.6.2.5.2(II), Residual Heat Removal System Loop II Drywell Spray Header Air Test, Rev. 03 performed on Dec. 10, 2011
PER 469567, Battery Charger Capacitors Not Replaced - Functional Evaluation

Section 1R18: Plant Modifications
3-SR-3.8.1.6, Common Accident Signal Logic, Rev. 15
PCR 11003616, Add IV and Relay Cover Reinstallations
PER 452776, Boot Removal Not Independently Verified
PER 451673, Place Craft on 12 Hour Schedules to Support Testing
PER 451678, 3 Hour Delay Due to Failure to Review Procedure
BFN Daily Schedule DCN 70234 STG 01, dated July 21, 2011
Calculation CDQ3067890030, Pipe Stress Analysis of Stress Problem No. N1-367-7T, Rev. 3
Calculation CDQ3067890031, Pipe Stress Analysis of Stress Problem No. N1-367-8T, Rev. 4
Calculation CDQ3067891215, Qualification of Pipe Support No. 3-17B300S2001, Rev. 2
Calculation CDQ3067891216, Qualification of Pipe Support No. 3-17B300S2002 and 3-17B300S2005, Rev. 3
Calculation CDQ3067900251, Qualification of Pipe Support No. 3-17B300S0157 and 3-17B300S2001, Rev. 2
Calculation MDQ0067930028, EECW System Pressure Drop - Multiflow, Rev. 5
Design Change Notice (DCN) 70234, Install Branch Connections on EECW System Piping, Rev. A
DMS Ultrasonic Calibration Data Sheet R-BOP-927, EECW North Header, dated 8/12/11
DMS Ultrasonic Calibration Data Sheet R-BOP-932, EECW South Header, dated 8/19/11
Drawing 1-47E858-1, Flow Diagram RHR Service Water System
Engineering Concept to Flush the North and South Headers
General Design Criteria BFN-50-7067, Emergency Equipment Cooling Water System, Rev. 18
PER 243132, EECW D EDG Functional Failure
PER 407459, Thickness Readings of EECW North and South Supply Headers
PER 437156, Receipt of Non-Reducing Elbow for the EECW North (and South) Header Flush
PER 452257, U3 RHRSW Tunnel 3B/3D Door Warped from Welding
PER 455038, Results From EECW Main Header Flushes
WO 111570652, Perform Flush of EECW North Supply Header, Remove/Install CKV 671 to Facilitate Flush
WO 112148977, DCN 70234, Stage 1, Install Branch Connection and Blind Flange on EECW North Header Supply
WO 112371077, Parts Fabrication for EECW Flush
WO 112393678, Perform Flush of EECW South Supply Header, Remove/Install CKV 619 to Facilitate Flush
WO 112502374, Perform Thickness Readings of EECW North and South Supply Headers
WO 112171827, DCN 70234, Stage 2, Install Branch Connection and Blind Flange on EECW South Header Supply

Section 1R19: Post-Maintenance Testing
0-OI-67, Emergency Equipment Cooling Water System, Rev. 94
3-SI-3.2.4(DG A), EECW Check Valve Test On Diesel Generator A, Rev. 5
FSAR 10.10 Emergency Equipment Cooling Water System, Amendment 24
Operations Logs Dated, 10/20/2011, 10/22/2011

WO 112393678, Perform flush of EECW South Supply Header. Remove/reinstall 0-CKV-67-619 to facilitate flush.
WO 112676345, 0-PDI-67-30
WO 112841529, Relay inside B diesel panel sounds like it is going bad
WO 112832643, Flush gauges and sense line to 3A DG TACF gauges
PER 451196, Relay Noise
PER 449559, Flush gauges and sense line to 3A DG TACF gauges
WO 112833173, Contingency WO to flush sense lines to 3B DG
WO 112833176, Contingency sense line flush 3C DG
WO 112833178, Contingency WO to flush sense lines on 3D DG
WO 111454053, Replace 1B Accumulator Bladder
WO 112366370, SLC Pump Functional Test, 1B Pump Only
1-SI-4.4.A.1, Standby Liquid Control Pump Functional Test, Rev. 11
MCI-0-063-ACC001, SLC Accumulator Maintenance, Rev. 13
DWG 1-47E854-1, Flow Diagram Standby Liquid Control System, Rev. 13
PER 460406, Delays associated with SLC Pump Functional
PER 460421, Packing Leak
PER 461460, Floor Drains
PER 461609, SLC measurement stick not in test tank
UFSAR, 6.4.1 High Pressure Coolant Injection System, Amendment 24
7.4 Emergency Core Cooling, Control and Instrumentation, Amendment 24
7.4.3.2 HPCI Control and Instrumentation, Amendment 24
2-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure, Rev. 60
WO 112414935, Flow Rate Test
WO 111445076, 2-HS-073-0040B, HPCI CNDS Tank Suction Valve
WO 111451855, 2-HS-073-0016A, HPCI Turbine Steam Supply Valve
WO 111759122, 2-HS-073-0016B, HPCI Turbine Steam Supply Valve
WO 112368640, 2-PMP-073-0029, HPCI Booster Pump
WO 112385256, 2-FCV-073-0006A, HCPI Steam Line CNDS INBD DRAIN VLV
WO 111324831, 2-ZS-073-0019B, Open Limit Switch for 2-FCV-0019
WO 111879081, 2-TCV-073-0502, TEMP CNTL VLV, HPCI Oil Cooler
WO 112687184, 2-PI-073-0506, HPCI OIL SYS Turbine Inlet, Pressure Indicator
WO 112922451, 2-PI-073-0501A, HPCI OIL SYS, Oil Cooler Supply Pressure Indicator
WO 113009693, 2-MTR-073-0047, HPCI Auxiliary Oil Pump Motor
WO 112707728, 2-ZI-073-0006A, HPCI Steam Line Inboard Drain Valve
WO 112712594, 2-FSV-073-0006A, HPCI Steam Line Condensate Inboard Drain Valve
WO 111369679, 2-RTV-073-0201A, LS-73-5L
WO 111759122, 2-HS-073-0016B, HPCI Turbine Steam Supply Valve
WO 112594427, 2-PMP-073-0029, HPCI Booster Pump
WO 112301474, 2-SHV-073-0587, Aux Steam Supply Shutoff Valve
WO 112507916, 2-PMP-073-0029, HPCI Booster Pump
Prompt Functionality Analysis for 2-FVC-073-0016
PER 479053 Difficulties Encountered With the Mounting Plates for this DCN
PER 480371, HPCI Performance Issues Related to Procedure Caution
Drawing 0-75D537727-1, Instrument Wiring, Rev. 5
DCN 70434, Add Fuses to the Remote Ammeter Circuits to Prevent Fire Propagation
Tagout 1-TO-2011-001, Clearance 1-280-0014, 250 VDC Battery Board 1

WO 112898072, Implement DCN 70434 Stage 1
WO 112895182, Perform boroscope inspection on the 3A EDG gear train (generator side)
3-SR-3.8.1.1(3A), Diesel Generator 3A Monthly Operability Test, Rev. 47 performed on 12/29/2011
0-TI-298, Diesel Generator Operating Data Acquisition, Rev. 14 performed on 12/29/2011
0-TI-230, Predictive Maintenance Program, Rev. 24
0-TI-230V, Vibration Program, Rev. 08

Section 1R22: Surveillance Testing
3-SI-4.4.A.1, Standby Liquid Control Pump Functional Test, Rev. 45
FSAR, Chapter 3.8 Standby Liquid Control System, Amendment 24
WO 112243962, 3-SI-4.4.A.1 - SLC Pump Functional Test
PER 449110, Hose blew off vent valve while performing SLC functional test
11-3-IST-071-449, Evaluation of Test Results for 3-SR-3.5.3.3, Rev. 54, October 27, 2011
PER 452834, RCIC failed an AC step for pump required differential pressure
Instruction Manual for Shimpo Instruments Handheld LCD Digital Laser Tachometer Model DT-205L
3-SR-3.5.3.3, RCIC Rated Flow at Normal Operating Pressure, Rev. 54
3-SR-3.5.3.3(COMP), RCIC Comprehensive Pump Test, Rev. 15
0-TI-362, Inservice Testing of Pumps and Valves, Rev. 27
SR 453557, 3-SR-3.5.3.3 Test Conditions
SR 453086, 3-FIC-71-036A Indicating 2 gpm high
2-SR-3.4.5.2, Drywell Leak Detection Radiation Monitor Functional Test 1-RM-90-256, Rev. 12, performed December 1, 2011
0-TI-230V, Vibration Program, Rev. 08

Section 4OA2: Identification and Resolution of Problems
0-TI-471, Temporary Equipment Control, Rev. 6
Integrated Trend Report, Q3FY11, April 1 - June 30, 2011
Integrated Trend Report, Q4FY11, July 1 - September 30, 2011
NPG-SPP-9.17, Temporary Equipment Control, Rev. 1
PER 467717, Failure to Meet IST Program Requirements
PER 334246, Adverse trend of Temporary Equipment Control (Tagging)
PER 461399, Temporary Equipment Training and Plant Compliance
PER 407109, Potential Adverse Trend in Procedure Use and Adherence
PER 486729, EOOS Trend Evaluation
PER 486732, Assignment to Post-Trip Reviews
PER 486736, Potential Trend on Post Trip Reviews
PER 486702, Gap in temporary equipment program
PER 478923, Weaknesses with Maintaining Accurate/Correct Procedures
Temporary Equipment Control Audit Report, dated October 2011
Temporary Equipment Control Audit Report, dated April 2011
PER 220850
DCN 69786A U1,2,3 APP R Improvements
PIC 70276A Revise Turbine BLDG Fire Area Boundaries
PCN 69957 APP R Pump House Tunnel Fire Barrier
DCN 70011A Install Incipient Fire Detection in the Electric Board Rooms

DCN 70019 Resolve Cable Tray Separation Issue by Installing Barriers Between Affected Cable Trays.
0-SSI-25-1 Intake Pumping Station ELI 550 Cable Tunnel Fire
0-SSI-25-2 RHRSW PMP RM A
0-SSI-25-3 RHR SW Pump RM C
0-SSI-26 Turbine Bldg Side Of Cable Tunnel to Door 440
0-SSI-001 Safe Shutdown Instructions
0-SSI-1-1 Unit 1 Reactor BLDG Fire

Section 4OA3: Event Follow-up
PER 415242, Core Spray Relay 2-RLY-075-14A-K30B Found in Incorrect Position
PER 440472, 0-TI-230T specifies 24-week frequency for thermography
PER 458439, Typographical errors in LER50-260/2011-001-00
PER 454948, Review Part 21 GEH 11-09 HGA relays.
PM #500134198 Evaluation
NPG-SPP-09.18, Integrated Equipment Reliability Program, Rev. 01
Drawing 1-45E641-3, Wiring Diagrams Instr & Controls Power Sys Schematic Diagram SH-3, Rev. 5
Drawing 0-45E701-2, Wiring Diagram Battery BD 1, Panel 8-12, Single line, Rev. 45
Drawing 0-730E927, Primary Containment Isolation System
Drawing 1-730E927, Primary Containment Isolation System
Drawing 3-730E927, Primary Containment Isolation System
EPI-0-099-MGC002, 18 Month Maintenance for Reactor Protection System M-G Sets, Rev. 21
EPI-1-099-MGZ002, Three Year Maintenance for 1B RPS M-G Set, Rev. 8
PER 412934, Loss of RPS B on Unit 1
PER 70538, Equipment Reliability PER - Failure Caused Half Scram CM WO
PER 70182, Voltage Regulator Card for RPS 3B
PER 102620, Defective Voltage Regulators for RPS MG Set
PER 438509, PM 500109019 Discovered Not Due in Maximo, But at End of Grace
PM 500136660, Wipe the Gain Potentiometer on the Voltage Regulator
Technical Specifications and Bases 3.4.5, RCS Leakage Detection Instrumentation
LER 50-259/2011-003-00, Loss of Safety Function (SDC) Resulting from Emergency Diesel Generator Output Breaker Trip
PER 362340, A DG Output Breaker Opened Under Load, Cause Not Known
PER 445331, Fire in the intake cable tunnel
0-TI-471, Temporary Equipment Control, Rev. 05
0-TI-471, Temporary Equipment Control, Rev. 06
NPG-SPP-09.17, Temporary Equipment Control, Rev. 00
NPG-SPP-09.17, Temporary Equipment Control, Rev. 01
0-SSI-25-1, intake Pumping Station El. 550, Cable Tunnel to Fire Door 440, RHRSW Pump Room B, RHRSW Pump Room D
Response to Generic Letter 88-20, Supplement 4, Individual Plant Examination for External Events (IPEEE – Fire)
Fire Protection Report, Volume 1, Fire Hazards Analysis, Rev. 11
Fire Protection Report, Volume 1, Safe Shutdown Analysis, Rev. 11
Fire Protection Report, Volume 1, Appendix R Safe Shutdown Program, Rev. 11
Fire Protection Report, Volume 2, Section IV.14, Pre-Plan No. ISCT-GRD, Rev. 9
OI-23/ATT-3, Residual Heat Removal System Electrical Lineup Checklist, Rev. 86

LER 05000296/2011-001-00, Loss of Shutdown Cooling (RHR)
LER 05000296/2011-001-01, Loss of Shutdown Cooling (RHR)
PER 462305, Inconsistent Discussion of Group 2 isolation in LER 50-296/2011-001-00

LIST OF ACRONYMS

ADAMS	-	Agencywide Document Access and Management System
ADS	-	Automatic Depressurization System
ARM	-	area radiation monitor
CAD	-	containment air dilution
CAP	-	corrective action program
CCW	-	condenser circulating water
CFR	-	Code of Federal Regulations
CoC	-	certificate of compliance
CRD	-	control rod drive
CS	-	core spray
DCN	-	design change notice
EECW	-	emergency equipment cooling water
EDG	-	emergency diesel generator
FE	-	functional evaluation
FPR	-	Fire Protection Report
FSAR	-	Final Safety Analysis Report
IMC	-	Inspection Manual Chapter
LER	-	licensee event report
NCV	-	non-cited violation
NRC	-	U.S. Nuclear Regulatory Commission
ODCM	-	Off-Site Dose Calculation Manual
PER	-	problem evaluation report
PCIV	-	primary containment isolation valve
PI	-	performance indicator
RCE	-	Root Cause Evaluation
RCW	-	Raw Cooling Water
RG	-	Regulatory Guide
RHR	-	residual heat removal
RHRSW	-	residual heat removal service water
RTP	-	rated thermal power
RPS	-	reactor protection system
RWP	-	radiation work permit
SDP	-	significance determination process
SBGT	-	standby gas treatment
SLC	-	standby liquid control
SNM	-	special nuclear material
SRV	-	safety relief valve
SSC	-	structure, system, or component
TI	-	Temporary Instruction
TIP	-	transverse in-core probe
TRM	-	Technical Requirements Manual
TS	-	Technical Specification(s)
UFSAR	-	Updated Final Safety Analysis Report
URI	-	unresolved item
WO	-	work order