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

February 12, 2016

EA-16-14

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3R-C
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2015004, 05000260/2015004, AND 05000296/2015004; AND APPARENT VIOLATIONS

Dear Mr. Shea:

On December 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. On January 21, 2016, the NRC inspectors discussed the results of this inspection with Mr. L. Hughes and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

The enclosed inspection report discusses two findings for which the NRC has not yet reached a preliminary significance determination. As described in Section 4OA3.3 of the enclosed report, two findings related to the failure of the Unit 2 High Pressure Coolant Injection (HPCI) turbine steam admission valve 2-FCV-73-16 packing. The first finding was identified for Tennessee Valley Authority's (TVA) failure to maintain the design of 2-FCV-73-16 packing assembly. The failure to correctly install the packing gland follower and the use of an incorrect packing type resulted in the development of a progressively degrading high pressure steam leak through the packing gland of 2-FCV-73-16. A second finding was identified for TVA's failure to characterize the steam leak in accordance with procedure NPG-SPP-06.8, Leak Reduction Program, which required it to have been characterized as the highest priority, a Category 1, Severity level 5 leak. This classification would have required an expedited repair of the steam leak.

On September 16, 2015, the packing catastrophically failed requiring isolation of the HPCI steam supply and rendering the system inoperable. This condition initially presented an immediate safety concern based on the size and effects of the resulting steam leak. Prompt operator action to isolate the leak resolved the immediate safety concern. The system has been subsequently returned to service and the circumstances that led to the valve packing degradation no longer exist.

The NRC will inform you in a separate correspondence when the preliminary significance has been determined. We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's significance determination process (SDP) is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination. Because the NRC has not made a final determination in this matter, no notice of violation is being issued for these inspection findings at this time.

Additionally, two self-revealing findings of very low safety significance (Green) were identified during this inspection. Each of these findings was determined to involve a violation of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest the violation or significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at the Browns Ferry Nuclear Plant.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding," 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's Public Document Room or from the Publicly Available Records (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Alan Blamey, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure:
NRC IR 05000259/2015004,
05000260/2015004 and 05000296/2015004

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☒ PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE ☒ NON-SENSITIVE
ADAMS: ☒ Yes ACCESSION NUMBER: ML16043A248 ☒ SUNSI REVIEW COMPLETE ☒ FORM 665 ATTACHED

OFFICE	DRP	DRP	DRP	DRS	DRP	DRP
SIGNATURE	Via Email/RA/ DED	Via Email/RA/ TAS4	Via E-mail/RA/ AMR4	Via Teleconfor/RA/ CRK1	CRK1	AJB3
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DATE	2/10/2016	2/9/2016	2/9/2016	2/11/2016	2/11/2016	2/12/2016
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

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Letter to Joseph W. Shea from A. Blamey dated February 12, 2016.

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2015004, 05000260/2015004, AND 05000296/2015004

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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.:	05000259/2015004, 05000260/2015004, 05000296/2015004
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Road Athens, AL 35611
Dates:	October 1, 2015, through December 31, 2015
Inspectors:	D. Dumbacher, Senior Resident Inspector T. Stephen, Resident Inspector A. Ruh, Resident Inspector S. Roberts, Project Engineer R. Baldwin, Senior Operations Engineer
Approved by:	Alan Blamey, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

Table of Contents

SUMMARY

IR 05000259/2015004, 05000260/2015004, 05000296/2015004; 10/01/2015–12/31/2015; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Maintenance Risk Assessments and Emergent Work Evaluation, Follow-up of Events and Notices of Enforcement Discretion.

The report covered a three month period of inspection by resident and regional inspectors. The significance of inspection findings are indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using IMC 0609, "Significance Determination Process" dated April 29, 2015. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 5, dated February 2014.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation (NCV) of 10 CFR Part 50.65(a)(4) was identified for the licensee's failure to properly assess and manage the risk associated with performing maintenance on the Standby Gas Treatment (SBGT) system piping. Specifically, the licensee failed to evaluate the effects of excavation activities associated with the SBGT piping repairs on the condensing coils of the Control Bay (CB) chillers which resulted in the fouling of the condensing coils of the 'A' CB chiller. The licensee's immediate corrective action was to clean the 'A' CB chiller condensing coils and restore it to an operable status. The issue was entered into the licensee's corrective action program (CAP) as condition report (CR) 1056829.

  The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to events and prevent undesirable consequences. Specifically, with the 'B' CB chiller out of service for maintenance, the 'A' CB chiller lost the ability to perform its safety function due to excessive dirt buildup caused, in part, by the nearby excavation activities. The inspectors characterized the finding using IMC 0609, Appendix A, Significance Determination Process, Exhibit 2, Mitigating Systems. The finding was screened to Green because although the 'A' CB chiller was inoperable, the performance deficiency did not cause the loss of system function, and the inoperability did not exceed the 24 hours. The finding does not represent an immediate safety concern because the licensee had cleaned the 'A' CB chiller condensing coils and restored the system's safety function. A cross cutting aspect of Teamwork was assigned due to the licensee's Engineering, Maintenance, Work Control, and Operations staffs' failure to adequately coordinate or communicate prior to commencing the 'B' CB chiller maintenance. (H.4) (Section 1R13)

- Green. A self-revealing NCV of Technical Specifications (TS) 5.4.1.a was identified for the licensee's failure to use appropriate maintenance procedures to ensure appropriate system start functions worked after maintenance activities on the 2A Residual Heat Removal (RHR) Pump breaker. Specifically, the licensee's failure to follow procedure

MAI-3.3, Cable Terminating and Splicing for Cables Rated up to 15000 Volts resulted in the loose lead in the 2A RHR pump breaker. The licensee's immediate corrective actions were to properly tighten the terminal screw. The issue has been entered into the licensee's CAP as CR 1040950.

The performance deficiency was more than minor because it was associated with the Human Performance attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of the Unit 2 RHR system to respond to events and prevent undesirable consequences. Specifically, the failure to retighten a terminal screw in the 2A RHR pump breaker resulted in the 2A RHR pump being unable to be started from the control room. The inspectors characterized the finding using IMC 0609, Appendix A, Significance Determination Process, Exhibit 2, Mitigating Systems. The inspectors determined the finding screened as very low safety significance (Green) because the finding did not represent an actual loss of function of at least a single Train for greater than its Tech Spec Allowed Outage Time. The finding does not represent an immediate safety concern because the automatic functions of the RHR pump were not lost and manual starts were available from the 4kV shutdown board. The cause of the finding was directly related to the cross-cutting aspect of Procedure Adherence due to the individuals failing to follow their work instructions. (H.8) (Section 4OA3.2)

- <u>TBD</u>. A self-revealing apparent violation (AV) of 10 CFR Part 50, Appendix B, Criterion III, Design Control was identified for the licensee's failure to properly install the Unit 2 High Pressure Coolant Injection (HPCI) turbine steam admission valve packing assembly. The licensee installed a valve packing type that was not as specified in design control drawings and due to inadequate maintenance drawings installed the packing gland follower upside down. Upon discovery of the packing failure, the licensee took action to isolate the associated steam leak and declare the HPCI system inoperable. Repairs were completed and tested on September 19, 2015. The licensee entered the issue into their corrective action program as CRs 1114188 and 1127172.

  The performance deficiency was more-than-minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, the failure to maintain design control led to the loss of function of the HPCI system when valve 2-FCV-73-16 packing failed. The finding could not be screened to Green and is pending a significance determination. The inspectors determined that the finding had a cross cutting aspect of Design Margins because the licensee allowed non-equivalent packing material to be installed in the Unit 2 HPCI steam admission valve. (H.6). (4OA3.3)

- <u>TBD.</u> A self-revealing Apparent Violation (AV) of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, was identified for the licensees failure to take corrective following the discovery of a significant steam leak from the packing gland of the Unit 2 HPCI steam inlet isolation valve, 2-FCV-73-16. Specifically, the licensee failed to correctly classify the severity of the leak on 2-FCV-73-16 as described in NPG-SPP-06.8, Leak Reduction Program, and allowed the condition to degrade until packing failure. Upon discovery of the packing failure, the licensee took action to isolate the associated steam leak and declare the HPCI system inoperable. Repairs were completed and tested on September 19, 2015. The licensee entered the issue into their corrective action program as CR 1082405

The performance deficiency was determined to be more-than-minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, misclassification of the leak severity as minor led to the loss of function of the HPCI system when valve 2-FCV-73-16 packing degraded until packing failure. The finding could not be screened to Green and is pending a significance determination. The inspectors determined that the finding had a cross cutting aspect of Resolution because the licensee did not take timely corrective action to repair the Unit 2 HPCI steam leak before it lead to a Safety System Functional Failure. (P.3) (4OA3.3)

B. <u>Licensee Identified Violations</u>

None

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at 100 percent of rated thermal power (RTP) except for one planned forced outage that was conducted from November 15, 2015, until the unit restarted on November 20, 2015.

Unit 2 operated at 100 percent of RTP except for one planned forced outage that was conducted from December 6, 2015 until the unit restarted on December 12, 2015. There was also one planned downpower on December 22, 2015, to restore the 2A Reactor Feed Pump Turbine to service following maintenance.

Unit 3 operated at 100 percent of RTP except for one unplanned and four planned downpowers. A one day, unplanned, downpower to 95 percent occurred on October 3, 2015, due to a fault in a power cell for the 3A recirculation pump. Another, one day, unplanned downpower from 94 percent to 78 percent occurred due to an oil leak on the 3C condensate booster pump. The planned downpowers on October 9, October 23, November 6, and November 17, 2015, were due to maintenance. The unit began a planned coastdown on November 17, 2015, for an upcoming refueling outage.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, while the other subsystems were 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. Documents reviewed are listed in the attachment. This activity constituted three Equipment Alignment Partial Walkdown inspection samples, as defined in Inspection Procedure 71111.04.

- Unit 1 Residual Heat Removal Train II while Train I providing shutdown cooling flow
- High Pressure Fire Protection System following isolation of a pipe break
- Unit 3 Primary Containment System with a degraded depressurization valve, 3-FCV-64-31

b. Findings

Introduction: The inspectors identified an Unresolved Item (URI) associated with a high pressure fire protection system pipe rupture on November 7, 2015.

Description: On November 7, 2015, following a smoke alarm caused by overheating some food in an operator kitchen (no fire occurred), the B electric fire pump started. Once the B electric fire pump started, a large break developed in a 14 inch section of the high pressure fire system piping between the Unit 1 and 2 diesel generator building and the offgas treatment building. Due to a lack of system pressure caused by the leak, the A and C electric fire pumps and the channel diesel driven fire pump started in their expected sequence. The required system pressure could not be maintained with all four fire pumps running. The leak was not able to be isolated effectively for approximately 1 hour and 13 minutes due to its location. The last successful test of a fire pump at rated system pressure occurred on November 1, 2015. This issue has been entered into the licensee's CAP as CR 1102016. The inspectors determined that the licensee's analysis of the piping failure mechanism was required to determine if a performance deficiency was associated with the piping rupture. This issue will be tracked as URI 05000259/260/296/2015-004-01, High Pressure Fire Protection System Piping Failure.

1R05 Fire Protection (71111.05)

.1 Fire Protection Tours

a. Inspection Scope

The inspectors reviewed licensee procedures for transient combustibles and fire protection impairments, and conducted a walkdown of the 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. The inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedures. 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. Documents reviewed are listed in the attachment. This activity constituted six Fire Protection Walkdown inspection samples, as defined in Inspection Procedure 71111.05.

- Fire Zone 1-1, Unit 1 Reactor Building, Elevation 519' to 565', from column line R1 to column line R7
- Fire Zone 1-2, Unit 1 Reactor Building, Elevation 519' to 565', from column line R7 to column line R4
- Fire Zone 1-5, Unit 1 Reactor Building, elevation 621' and 639' north of column line R
- Fire Zone 1-3, Unit 1 Reactor Building, Elevation 593, north of column line R
- Fire Zone 1-4 Unit 1 Reactor Building, Elevation 593, south of column line Q, and RHR Heat Exchanger rooms
- Fire Area 21, Unit 3 Emergency Diesel building, Elevation 565.

b. Findings

No findings were identified.

.2 Observe Fire Brigade

a. Inspection Scope

The inspectors witnessed the fire brigade response during an unannounced fire drill that simulated a fire in the intake structure. The inspectors assessed the response time for notifying and assembling the fire brigade; the readiness of firefighting equipment; use of fire protective clothing and equipment (e.g., turnout gear, self-contained breathing apparatus); communications; incident command and control; teamwork; and firefighting strategies. The inspectors also attended the post-event critique to assess the licensee's ability to review fire brigade performance and identify areas for improvement. Following the critique, the inspectors compared their observations with the requirements specified in the licensee's Fire Protection report. This activity constituted one Fire Brigade response inspection sample, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06)

.1 Annual Review of Cables Located in Underground Bunkers/Manholes

a. Inspection Scope

The inspectors conducted a review of licensee inspections of safety-related cables located in underground bunkers/manholes subject to flooding. Specifically, inspectors reviewed maintenance records and observed an inspection to determine if water was present and, if found, whether it would affect safety-related system operation. In addition, the inspectors reviewed the licensee's CAP to ensure that the licensee was identifying underground cabling issues and that they were properly addressed for resolution. Documents reviewed are listed in the Attachment. This activity constituted one underground cable inspection sample, as defined in Inspection Procedure 71111.06.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification and Performance (71111.11)

.1 Licensed Operator Requalification

a. Inspection Scope

On October 7, 2015, the inspectors observed a licensed operator training session for an operating crew according to the Unit 2 Browns Ferry Integrated Training Drill Guide, Rev 3.

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 procedures including Abnormal Operating Instructions (AOIs), Emergency Operating Instructions (EOIs) and Safe Shutdown Instructions (SSI)
- Timely control board operation and manipulation, including high-risk operator actions
- Timely oversight and direction provided by the shift supervisor, including ability to identify and implement appropriate technical specifications actions such as reporting and emergency plan actions and notifications
- Group dynamics involved in crew performance

The inspectors assessed the licensee's ability to assess the performance of their licensed operators. The inspectors reviewed the post-examination critique performed by the licensee evaluators, and verified that licensee-identified issues were comparable to issues identified by the inspector. The inspectors 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). Documents reviewed are listed in the attachment. This activity constituted one Observation of Requalification Activity inspection sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

.2 Control Room Observations

a. Inspection Scope

Inspectors observed and assessed licensed operator performance in the plant and main control room, particularly during periods of heightened activity or risk and where the activities could affect plant safety. Inspectors reviewed various licensee policies and procedures covering Conduct of Operations, Plant Operations and Power Maneuvering.

Inspector's utilized activities such as post maintenance testing, surveillance testing and other activities to focus on the following conduct of operations as appropriate;

- Operator compliance and use of procedures
- Control board manipulations
- Communication between crew members
- Use and interpretation of plant instruments, indications and alarms

- Use of human error prevention techniques
- Documentation of activities, including initials and sign-offs in procedures
- Supervision of activities, including risk and reactivity management
- Pre-job briefs

This activity constituted one Control Room Observation inspection sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

.3 Annual Review of Licensee Requalification Examination Results:

a. Inspection Scope

On December 17, 2015, the licensee completed the comprehensive biennial requalification written examinations and the annual requalification operating examinations required to be administered to all licensed operators in accordance with Title 10 of the Code of Federal Regulations 55.59(a)(2), "Requalification Requirements," of the NRC's "Operator's Licenses." The inspectors performed an in-office review of the overall pass/fail results of the individual operating examinations, written examinations, and the crew simulator operating examinations in accordance with Inspection Procedure (IP) 71111.11, "Licensed Operator Requalification Program." These results were compared to the thresholds established in Section 3.02, "Requalification Examination Results," of IP 71111.11. Documents reviewed are listed in the Attachment. This activity constituted one annual review of licensee requalification examination results inspection sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine

a. Inspection Scope

The inspectors reviewed the 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. The inspectors compared the licensee's performance against site procedures. The inspectors reviewed, as applicable, work orders, surveillance records, condition reports, 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. Documents reviewed are listed in the attachment. This activity constituted one Maintenance Effectiveness inspection samples, as defined in Inspection Procedure 71111.12.

- Unit 2 Reactor Water Cleanup System

b. Findings

No findings were identified.

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

a. Inspection Scope

For planned online work and/or emergent work that affected the combinations of risk significant systems listed below, the inspectors examined 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/or using applicable plant procedures. As applicable, the inspectors verified the actual in-plant configurations to ensure accuracy of the licensee's risk assessments and adequacy of RMA implementations. Documents reviewed are listed in the attachment. This activity constituted four Maintenance Risk Assessment inspection samples, as defined in Inspection Procedure 71111.13.

- Entry into TS LCO 3.0.3 due to concurrent inoperability of both the A and B, Unit 1 and 2 Control Bay Chiller (EN 51231)
- Unit 2 risk associated with Core Spray loop II out of service
- Emergency risk associated with Main Bank Battery #2 outage and the 3D Emergency Diesel Generator (EDG) out of service
- Yellow shutdown risk associated with reduced water inventory in mode 4 for repairs to 1A Recirculating pump

b. Findings

Introduction: A self-revealing Green NCV of 10 CFR Part 50.65(a)(4) was identified for the licensee's failure to properly assess and manage the risk associated with performing maintenance on the Standby Gas Treatment (SBGT) system piping . Specifically, the licensee failed to evaluate the effects of excavation activities associated with the SBGT piping repairs on the condensing coils of the Control Bay (CB) chillers.

Description: The 'A' and 'B' CB chillers are independent 100 percent capacity systems that provide chilled water for cooling the combined Unit 1 and 2 control room, all four of the Unit 1/2 4kV shutdown board rooms, and the relay room. The CB chillers must maintain chill water temperature less than 45 degrees in order to meet their safety function under design basis accident conditions.

On September 15, 2014, the licensee began performing excavation activities to perform repairs to the SBGT system piping. The excavation activities were within 100 feet of the A and B control bay chillers and had produced significant airborne dirt that had been noted during a June 2015 CB chiller inspection. The SBGT excavation work package did not include provisions to prevent or check air cooled portions of the CB chillers for dirt fouling.

On July 13, 2015, the licensee took the ‘B’ CB chiller out of service for planned maintenance. During daily operator equipment monitoring rounds performed on July 13, 2015 the operator recorded the chill water temperature at 42 degrees. At 5:15 p.m. on July 14, 2015, the licensee discovered that chill water temperatures had risen to 47 degrees and declared the ‘A’ CB chiller inoperable. Since the CB chillers also cool the four Unit 1/2 4kV shutdown boards, the licensee declared them inoperable. With the four 4kV shutdown boards inoperable, the ‘A’ and ‘B’ trains of the SBGT system were declared inoperable. With two trains of the SBGT system inoperable, the licensee entered action statement ‘D’ of TS 3.6.4.3 Standby Gas Treatment System and LCO 3.0.3 (actions that place the unit in a mode where the LCO is not applicable), for all three units. The licensee’s immediate action to clean the ‘A’ CB chiller resulted in chill water temperatures recovering to within the allowable band of 41 to 44 degrees. At 6:10 p.m. on July 14, 2015, the licensee reported per 10 CFR 50.72 (b)(i), Initiation of a reactor shutdown to comply with TS’s. The licensee restored the ‘A’ CB chiller to operable status and exited TS LCO 3.0.3 at 11:52 p.m. The failure to control maintenance of the SBGT system only caused the ‘A’ CB chiller to become inoperable.

Analysis: The licensee’s failure to assess and manage the increase in risk associated with performing maintenance activities on the SBGT system piping as required by 10 CFR 50.65 a(4) was a performance deficiency. Specifically, the licensee failed to evaluate the effects of excavation activities associated with the SBGT piping repairs on the condensing coils of the Control Bay chiller. The performance deficiency was more than minor because it was associated with the Equipment Performance attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to events and prevent undesirable consequences. Specifically, with the ‘B’ CB chiller out of service for maintenance, the ‘A’ CB chiller lost the ability to perform its safety function due to excessive dirt buildup caused, in part, by the nearby excavation activities. The inspectors characterized the finding using IMC 0609, Appendix A, Significance Determination Process, Exhibit 2, Mitigating Systems, dated June 19th, 2012. The finding was screened to Green because although the ‘A’ CB chiller was inoperable, the performance deficiency did not cause the loss of system function, and the inoperability did not exceed 24 hours. The inspectors assigned a cross cutting aspect of Teamwork due to the licensee’s Engineering, Maintenance, Work Control, and Operations staffs failure to adequately coordinate or communicate prior to commencing the ‘B’ CB chiller maintenance . (H.4)

Enforcement: 10 CFR 50.65 a(4) required, in part, that before performing maintenance activities (including corrective and preventative maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, from September 15, 2014 until July 14, 2015, the licensee’s SBGT piping repair activities did not include an assessment and provisions to manage the increased risk to the nearby control bay chillers due to dirt fouling. This condition resulted in the Unit 1 and 2 "A" CB Chiller being inoperable and losing the ability to perform its safety function from 5:15 p.m. to 11:52 p.m. on July 14, 2015. The licensee's immediate corrective action was to clean the condensing coils on the 'A' CB chiller to restore operability. This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. The violation was entered into the licensee's CAP as CR 1056829. (NCV 05000259/260/296/2015004-02; Failure to Properly Assess and Manage Risk During Planned Maintenance Activities).

1R15 Operability Determinations and Functionality Assessment (71111.15)

a. Inspection Scope

The inspectors reviewed the operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors 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 procedures to ensure that the licensee's evaluation met procedure requirements. 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 reviewed service requests on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the attachment. This activity constituted three regular Operability Evaluation inspection samples, as defined in Inspection Procedure 71111.15.

- Unit 1, 2, and 3 Inservice Testing classification of Spent Fuel Pool Cooling System valves (CR 1094365)
- Emergency Diesel Generator 3A speed below minimum speed range during slow start (CR 1086878)
- RHR Service Water sump pump Inservice Test accepts flowrates that are less than postulated room inleakage rates during maxium precipitation events (CRs 1089385 and 1090096)

b. Findings

No findings were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed and reviewed 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. The inspectors witnessed and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors verified that problems associated with PMTs were identified and entered into the CAP. Documents reviewed are listed in the attachment. This activity constituted two Post Maintenance Test inspection samples, as defined in Inspection Procedure 71111.19.

- 1A Recirc Pump seal replacement (WO 117032064)
- 3A EDG failed Exciter Current Regulator relay (WO 117323859)

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Unit 1 Forced Outage

a. Inspection Scope

The licensee began a planned forced outage on Unit 1 that lasted from November 15, 2015, until the unit was restarted on November 20, 2015. The forced outage was conducted to perform a seal replacement on the 1A recirculation pump. The inspectors reviewed the scope of the planned outage activities. The inspectors monitored the licensee's performance of the reactor plant shutdown and portions of the reactor plant cool down. The inspectors observed containment foreign material controls appropriate material and performed a containment closeout inspection to ensure containment readiness prior to restart. The inspectors observed portions of the plant startup including reactor criticality and power ascension.

b. Findings

No findings were identified.

.2 Unit 2 Forced Outage

a. Inspection Scope

The licensee began a planned forced outage on Unit 2 that lasted from December 6, 2015 until the unit was restarted on December 12, 2015. The forced outage was conducted to perform repairs to two reactor feed pump turbines, perform a repair to a miscellaneous drain header pipe that connected to the main condenser, and to perform a repair to a feedwater heater. The inspectors reviewed the scope of the planned outage activities. The inspectors monitored the licensee's performance of the reactor plant shutdown and portions of the reactor plant cool down. The inspectors observed containment foreign material controls appropriate material and performed a containment closeout inspection to ensure containment readiness prior to restart. The inspectors observed portions of the plant startup including reactor criticality and power ascension.

b. Findings

No findings were identified.

These activities constituted two forced outage inspection samples, as defined in Inspection Procedure 71111.20. Documents reviewed are listed in the attachment.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed portions of and reviewed completed test data for the following surveillance test of a risk-significant, safety-related system to verify that the tests met technical specification 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. Documents reviewed are listed in the attachment. This activity constituted two Surveillance Testing inspection samples: one routine test and one in-service test, as defined in Inspection Procedure 71111.22.

Routine Surveillance Test:
- 1-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure (WO 115555596)

In-service Test:
- 3-SR-3.5.1.7(COMP) HPCI Comprehensive Pump Test

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Cornerstone: Mitigating Systems

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following PIs. The inspectors examined the licensee's PI data for the specific PIs listed below for the fourth quarter 2014 through third quarter of 2015. The inspectors reviewed the licensee's data and graphical representations as reported to the NRC to verify that the data was correctly reported. The inspectors validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the Day, Licensee Event Reports, etc.), and assessed any reported problems regarding implementation of the PI program. The inspectors verified that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors used the Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to ensure that industry reporting guidelines were appropriately applied. Documents reviewed are listed in the attachment. This activity constituted nine PI inspection samples, as defined in Inspection Procedure 71151.

- Unit 1, 2, and 3 Unplanned Scrams
- Unit 1, 2, and 3 Unplanned Scrams with Complications
- Unit 1, 2, and 3 Unplanned Downpowers

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution of Problems (71152)

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

a. Inspection Scope

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 CR reports, and periodically attending Management Review Committee (MRC) and Plant Screening Committee (PSC) meetings.

b. Findings

No findings were identified.

.2 Focused Annual Sample Review – Corrective actions for issues identified during the October 7, 2015 Emergency Preparedness drill:

a. Inspection Scope

The inspectors conducted a review of the implementation of corrective actions from the October 7, 2015 Emergency Preparedness drill in preparation for the graded November 4, 2015 Emergency Preparedness drill. The inspectors reviewed corrective actions that were planned and completed associated with CRs 1092524, 1092525, 1092520, 1092523, 1092599, 1092597, and 1092608. The planned corrective actions and completion timelines were consistent with the Corrective Action Program procedure.

b. Findings

No findings were identified.

.3 Focused Annual Sample Review – Corrective actions for degraded Unit 1 recirculation pump seal:

a. Inspection Scope

The inspectors conducted a review of the implementation of corrective actions for the degraded Unit 1 recirculation pump seal for the 1A recirculation pump. The inspectors reviewed the decision making tools used by the operators to monitor and inform further actions based on continuing seal degradation. The licensee decided to replace the degraded pump seal during a forced outage that began on November 15, 2015. The inspectors interviewed licensee personnel to assess whether generic industry issues existed for the type of seal degradation that was exhibited.

b. Findings

No findings were identified.

.4 Focused Annual Sample Review – Corrective actions for degraded Unit 3 HPCI check valve leakage:

a. Inspection Scope

The inspectors conducted a review of the corrective actions for the degraded Unit 3 HPCI check valve 3-CHV-73-45. The check valve leakage was resulting in monthly elevated temperatures in the HPCI pump isolated discharge piping. The inspectors reviewed the decision making tools used by the operators and engineers to monitor and inform further actions based on the possibility of void formation. The inspectors interviewed licensee personnel to assess whether a water hammer concern could exist.

b. Findings

No findings were identified.

.5 Focused Annual Sample Review – Corrective actions associated with licensee-identified deficiencies resulting from Near-Term Task Force Recommendation 2.3 Flooding Walkdowns:

a. Inspection Scope

During a routine walkdown of plant areas, the inspectors identified a severely corroded 2" diameter abandoned pipe penetrating the floor of the 'B' Residual Heat Removal Service Water (RHRSW) compartment. The pipe had rusted through and caused the inspectors to question whether the open pipe created a pathway that would allow potential flood waters outside the room to flow into the compartment and flood the room. The licensee's evaluation discovered that the condition was previously identified in July 2012 during the licensee's flooding walkdowns required by the NRC order implementing Near-Term Task Force Recommendation 2.3 related to the Fukushima Dai-ichi nuclear power plant accident. Inspectors reviewed the licensee's flooding walkdown report and performed additional inspections of the licensee-identified deficiencies and the status of their corrective actions. In addition to the one condition described above, the inspectors found three additional items that had not been corrected. These inspections and reviews revealed weaknesses with the licensee's evaluation and timely disposition of the issues and the classification and prioritization of their resolution. The original walkdown forms evaluated the conditions as "unacceptable" and the final report, dated November 27, 2012, characterized them as "potentially deficient;" however, the CAP closed the conditions to a work order that classified the conditions as "not unacceptable" and the work order planning process was currently incomplete.

b. Findings

Introduction: The inspectors identified an URI associated with potentially deficient flood barrier penetrations in the RHRSW rooms. The inspectors determined that several of the conditions had been previously identified by the licensee and entered into the CAP in November of 2012; however, the conditions had not yet been corrected.

Description: Initially, the inspectors identified a potential flood barrier bypass in the 'B' RHRSW room associated with a 2 inch diameter pipe that had significantly corroded an open area through the pipe's wall. The inspectors reviewed the licensee's response and discovered that an immediate operability determination was hampered because the pipe and valves were not marked or labeled and could not be located on any reviewed drawings. The issue was closed before resolving whether operability of the compartment's pumps were affected. Upon additional questioning by the inspectors, the licensee reinitiated investigation of the issue. Since the pipe's penetration points could not be readily determined, the licensee closed a manual isolation valve that was discovered upstream of the break in the pipe. Closure of the valve eliminated the potential immediate operability concern.

The inspectors also identified that three other previously identified conditions had not been corrected in the 'B' RHRSW room: 1) The 'B' emergency equipment cooling water (EECW) strainer backwash valve conduit was severed where it penetrated the floor of the room, 2) There was an unsealed gap between a conduit sleeve and the enclosed conduit for powering the B1 RHRSW pump, 3) There was a 1/4 inch by 3/8 inch hole in a rubber boot at the 'B' EECW discharge pipe floor penetration. Initial evaluations by the licensee determined that the first condition did not bypass the flood barriers and that the other two would potentially introduce flood water into the compartment at rate of 35 gallons per minute. This amount of inleakage was within the available pumping capacity of a single compartment sump pump and was not an immediate operability concern. However, the licensee has not yet evaluated the aggregate effect of all of the conditions concurrently.

Because it is not yet clear whether the identified conditions could allow flood waters to bypass the RHRSW compartment flood barriers, more information is necessary to properly evaluate the licensee's past operability evaluations, and the adequacy of the licensee's corrective actions. Based on the available documentation of the walkdowns and corrective action documents, it was not clear to the inspectors how the licensee justified the reclassification of the conditions from initially unacceptable status to an indeterminate status and then finally to essentially acceptable status. Future inspection is required to determine if a more than minor performance deficiency or violation exists associated with these issues. Initial reviews have not identified any immediate safety concerns associated with the identified conditions. This issue has been entered in the licensee's corrective action program as CRs 1070658, 1075911 and 1119892. (URI 05000259/260/296/2015-004-03, Corrective Actions For 2012 Flooding Walkdowns).

These activities constituted four focused annual inspection samples, as defined in Inspection Procedure 71152. Documents reviewed are listed in the attachment.

.6 Semi-annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's CAP and other associated programs and documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, and also included licensee trending efforts and licensee human performance results. The inspectors' review nominally considered the six-month period of July through December 2015. The inspectors reviewed licensee trend reports and the Integrated Trend Reports in order to determine the existence of any adverse trends that the licensee may not have previously identified. Documents reviewed are listed in the attachment. This inspection constituted one semi-annual trend review inspection sample, as defined in Inspection Procedure 71152.

b. Observations and Findings

No findings were identified. The licensee had identified trends and appropriately addressed them in their CAP. The inspectors observed that the licensee had performed a detailed review. The licensee routinely reviewed cause codes, involved organizations, key words, and system links to identify potential trends in their data. The inspectors compared the licensee process results with the results of the inspectors' daily screening. Trends that have been identified by the inspectors and reported to the licensee were appropriately entered into the licensee's trending program.

Noteworthy Licensee identified trends included:

- Condition Reports being closed to work orders without all issues being addressed.
- System health report quality issues
- Nuclear Safety Monitoring panel noted a potential negative trend in rigor associated with trend evaluations

Noteworthy NRC identified degrading trends included:

- Elevated temperatures during Unit 3 HPCI venting surveillances
- Incorrectly using "Time of Discovery" for some operability evaluations
- Unit 2 Reactor Water Cleanup pumps having repeated seal leakage problems

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report (LER) 05000259/2015-003-00 Loss of Cooling to the Unit 1 and Unit 2 Shutdown Board Rooms Due to Fouled Chiller Coils

a. Inspection Scope

The inspectors reviewed the LER 05000259/2015-003-00 dated September 14, 2015. Inspectors also reviewed the applicable CR 1056829, including associated immediate cause determinations, analysis of the event and corrective actions.

On July 13, 2015, the licensee took the 'B' CB chiller out of service for planned maintenance and condenser coil cleaning. Prior to removing the 'B' CB chiller from service, the licensee verified that no work would occur on the 'A' CB chiller and posted protected train signs. At 5:15 p.m. on July 14, 2015, the licensee discovered that chill water temperatures had risen to 47 degrees and declared the 'A' CB chiller inoperable. Since the CB chillers also cool the four Unit 1 and 2 4kV shutdown boards, the licensee declared all of them inoperable. With four 4kV shutdown boards inoperable, the 'A' and 'B' trains of the SBGT system were declared inoperable. With two trains of the SBGT system inoperable, the licensee entered action statement 'D' of TS 3.6.4.3 SBGT and TS LCO 3.0.3 (actions that place the unit in a mode where the LCO is not applicable), for all three units. At 6:10 p.m. on July 14, 2015, the licensee reported per 10 CFR 50.72 (b)(i), Initiation of a reactor shutdown to comply with TS's. The inspectors verified that the licensee met all the reporting requirements. All other aspects of this event were inspected as part of the Maintenance Risk Assessment (Section 1R13) inspection.

b. Findings

The finding associated with this event is in Section 1R13. There are no additional findings contained in this LER. This LER is closed.

.2 (Closed) LER 05000260/2015-001-00, 2A RHR Pump Start Failure

a. Inspection Scope

The inspectors reviewed the LER 05000260/2015-001-00 dated August 17, 2015. Inspectors also reviewed the applicable CR 1040950, including associated immediate cause determinations, analysis of the event and corrective actions.

On June 17, 2015, at 10:15, Unit 2 operators attempted to place RHR loop 1 into suppression pool cooling. Upon actuating the 2-HS-74-5A hand switch from the control room, the 2A RHR pump failed to start. Initial troubleshooting incorrectly determined that only cleaning of the 2A RHR pump breaker, 2-BKR-74-5, was required. The subsequent start attempt again failed. Additional troubleshooting revealed that a loose lead in the breaker had been created by maintenance on March 20, 2015, at terminal point TP ZW-15.

The licensee performed a past operability evaluation and determined the cause of the loose wire in the breaker to be a lack of procedural adherence by electrical maintenance contractors. The terminal screw for the wire had been intentionally backed out 3/16 of an inch and not re-tightened. Corrective actions were to tighten the wire, provide counseling to electrical maintenance workers, and enhance similar maintenance procedures to more clearly require a Quality Control (QC) hold point verification of tightness. Because of the inoperable condition the following TS conditions and actions were not complied with:

TS 3.4.8	RHR – Shutdown Cooling System – Cold Shutdown
TS 3.5.1	ECCS – Operating
TS 3.5.2	ECCS – Shutdown
TS 3.6.2.3	RHR Suppression Pool Cooling
TS 3.6.2.4	RHR Suppression Pool Spray
TS 3.6.2.5	RHR Drywell Spray

One finding was identified. This LER is considered closed.

b. Findings

Introduction: A self-revealing Green NCV of TS 5.4.1.a was identified for the licensee's failure to use appropriate maintenance procedures to ensure appropriate system start functions were maintained during maintenance activities on breakers. This caused two successive 2A RHR Pump Start Failures.

Description: On June 17, 2015, at 10:15, Unit 2 operators attempted to place RHR loop 1 into suppression pool cooling. Upon actuating the 2-HS-74-5A hand switch from the control room the 2A RHR pump failed to start. Initial troubleshooting incorrectly determined that only cleaning of the 2A RHR pump breaker, 2-BKR-74-5, was required. The subsequent start attempt again failed. Additional troubleshooting revealed that a loose lead in the breaker caused the pump start failures.

The licensee performed a past operability evaluation and determined the cause of the loose lead to be a lack of procedural adherence during maintenance performed on March 20, 2015 at terminal point TP ZW-15. The terminal screw for the lead had been backed out 3/16 of an inch and not re-tightened per maintenance procedure MAI-3.3, Cable Terminating and Splicing for Cables Rated up to 15000 Volts.

The improper maintenance resulted in Operations declaring the 2A RHR pump inoperable from March 20, 2015, to June 19, 2015. During that period the plant had transitioned from a cold shutdown condition to operating at 100% power.
The licensee evaluation of the failure to re-tighten the terminal screw determined that the lead only affected the ability to manually start the 2A RHR pump from the control room. The licensee determined that the ability to have an automatic start signal or a manual start from the breaker itself remained available. Alignment of Suppression Pool cooling is a manual start from the control room. Corrective actions were to tighten the terminal screw, provide counseling to the electrical maintenance workers, and enhance the procedure MAI-3.3 to more clearly require a QC hold point verification of tightness.

Analysis: The licensee's failure to follow procedure MAI-3.3, Cable Terminating and Splicing for Cables Rated up to 15000 Volts was a performance deficiency. Specifically, the performance deficiency resulted in the loose lead in the 2A RHR pump breaker. This performance deficiency was considered more than minor because it was associated with the Human Performance attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of the Unit 2 RHR system to respond to events and prevent undesirable consequences. Specifically, the failure to retighten a terminal screw in the 2A RHR pump breaker resulted in the 2A RHR pump being unable to be started from the control room. The inspectors characterized the finding using IMC 0609, Appendix A, Significance Determination Process, Exhibit 2, Mitigating Systems, dated June 19th, 2012. The inspectors determined the finding screened as very low safety significance (Green) because the finding did not represent an actual loss of function of at least a single Train for greater than its TS Allowed Outage Time and did not represent an actual loss of function of non-Tech Spec Trains per the licensee's maintenance rule program for greater than 24 hours. The cause of the finding was directly related to the cross-cutting aspect of Procedure Adherence due to the individuals failing to follow their work instructions. (H.8)

Enforcement: Unit 3 TS 5.4.1.a. required that written procedures recommended in Regulatory Guide 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 20, 2015, the licensee failed to use work instructions for maintenance affecting the performance of safety-related equipment. Specifically, maintenance procedure MAI-3.3, Cable Terminating and

Splicing for Cables Rated up to 15000 Volts was not followed to properly re-terminate loosened wires. This directly resulted in the June start failures of the 2A RHR pump. The licensee's immediate corrective actions were to reterminate the loosened wires, provide counseling to the electrical maintenance workers, and enhance the procedure MAI-3.3 to more clearly require a QC hold point verification of tightness. However, because the finding was of very low safety significance and has been entered into the licensee's CAP as CR 1040950, this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000260/2015-004-04, Failure of 2A RHR Pump to Start from the Control Room due to a Loose Fastener).

.3 (Closed) LER 05000260/2015-002-00, HPCI Turbine Steam Supply Valve Packing Failure

a. Inspection Scope

The inspectors reviewed the LER 05000260/2015-002-00 dated November 16, 2015. Inspectors also reviewed the applicable CR 1082405, including associated immediate cause determinations, analysis of the event and corrective actions.

On September 16, 2015, a steam leak occurred in the Unit 2 HPCI room. Operators closed 2-FCV-73-3, HPCI outboard isolation valve to isolate the steam and declared the HPCI train inoperable. The licensee determined that the causes of the event were a packing gland follower on 2-FCV-73-16 turbine steam supply valve that was installed upside down and untimely action by the site to repair the valve after a smaller leak was identified in June 2015. Additional reviews determined that maintenance procedures were not adequately updated after a design change was made to the valve 2-FCV-73-16 in 2013. The licensee did verify, as immediate corrective action, that the gland follower was correctly installed on the Unit 1 and Unit 3 which had the same design change. This LER is closed.

b. Findings:

.1 Failure to Maintain the Design Packing Features of the Unit 2 HPCI Turbine Steam Admission Valve

Introduction: A self-revealing, apparent violation (AV) of 10 CFR Part 50, Appendix B, Criterion III, Design Control was identified for the licensee's failure to properly install the Unit 2 HPCI turbine steam admission valve packing assembly. The licensee installed a valve packing type that was not as specified in design control drawings and due to inadequate maintenance drawings installed the packing gland follower upside down. These issues led to a degrading packing leak in June and eventual failure in September 2015.

Description: The HPCI steam isolation valve 2-FCV-73-16 had been replaced as part of Design Change Number (DCN) 70578 in April 2013 with a new 10 x 8 inch Flex Wedge disc gate design. The licensee installed a live-loaded graphitic packing system as part of the DCN.

On June 19, 2015, the licensee documented that the Unit 2 HPCI steam admission valve, 2-FCV-73-16 had a packing leak. A work order was initiated and scheduled for December 14, 2015 to repair the steam leak. On July 16, 2015 NRC inspectors notified the licensee staff that the leak had worsened and was very loud. Again, on July 31st, NRC inspectors noted the steam leak was excessively loud and provided the licensee staff a video of the leak. The licensee re-inspected the valve and concluded that the leak was a packing leak of minor significance and that the component and system were operable. No engineering reviews were performed.

On September 16, 2015, valve stroke surveillance 2-SR-3.6.1.3 cycled valve 2-FCV-73-16. Approximately 13 minutes later, Operations personnel received a fire alarm and reports of significant steam in the Unit 2 HPCI room. The steam leak had actuated temperature sensors in the Unit 2 HPCI room designed to initiate fire suppression water and, for large steam leaks, to isolate the steam supply to the HPCI turbine. Quick action by the operators to manually isolate the turbine prevented the auto isolation. The leak rendered the HPCI pump inoperable. The licensee made an 8-hour notification (Event Notice 51398) per 10 CFR 50.72(b)(3)(v)(D) for a loss of HPCI system safety function.

Following the steam leak on September 16th the licensee identified that the valve's gland follower had been installed upside down. After the failure the licensee re-reviewed the DCN package. The DCN issued valve detail drawing CD05897, which specified a different packing material than installed by the licensee. The installed packing was verified by the licensee to be susceptible to observed failure mechanism. The failure mechanism is accelerated in the presence of a steam leak. Although the drawing specification stated "OR EQL", a formal equivalency evaluation was not performed by Engineering for the different packing material. An evaluation should have identified the concerns about the observed failure mechanism. The licensee Design Engineering staff determined that the installed packing (which contains Teflon) did not conform with the current design.

The packing and gland follower were replaced and the HPCI turbine and steam admission valve re-tested successfully on September 19, 2015. The licensee initiated corrective actions to replace the packing on the steam admission valve for each of the three units.

Analysis: The inspectors determined that the failure to properly install the new HPCI turbine steam admission valve packing assembly per valve detail drawing CD05897 was a performance deficiency. Specifically, the licensee installed improper packing and installed the packing gland follower upside down. The performance deficiency was more-than-minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, the failure to maintain design control led to the loss of function of the HPCI system when valve 2-FCV-73-16 packing failed. The finding could not be screened to Green and is pending a significance determination.

This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Exhibit 2 "Mitigating Systems Screening Questions," dated June 19, 2012. The inspectors determined the finding required a Detailed Risk Evaluation because the finding represented a loss of system and/or function. The finding does not present an immediate safety concern because the packing has been replaced on the Unit 1 and Unit 2 HPCI steam admission valves and is scheduled for replacement on the Unit 3 HPCI steam admission valve during the unit outage. Because the final safety characterization of this finding is not yet finalized, it is being documented with a significance of To Be Determined (TBD). The inspectors determined that the finding had a cross cutting aspect of Design Margins because the licensee allowed non-equivalent packing material to be installed in the Unit 2 HPCI steam admission valve. (H.6)

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, Design Control states, in part, that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components. Contrary to the above, from April 16, 2013 to September 16th, 2015, the licensee failed to provide adequate measures to control correct packing material and parts installation for the Unit 2 HPCI steam admission valve 2-FCV-73-16. The valve's unsuitable packing material and the gland follower being installed upside down led to a degrading packing leak starting in June 2015 and eventual failure in September 2015.

Upon discovery of the packing failure, the licensee took action to isolate the steam leak and declare the HPCI system inoperable. Repairs were completed and tested on September 19, 2015. The licensee is developing corrective actions to resolve the engineering design issues. The licensee entered the issue into their CAP as CRs 1114188 and 1127172. This violation is being treated as an AV as defined in the Enforcement Policy. (AV 05000260/2015004-05, Failure to Maintain The Design Packing Features of the Unit 2 HPCI Turbine Steam Admission Valve).

.2 Failure to Identify Significant Steam Leak on the Unit 2 HPCI Turbine Steam Admission Valve

Introduction: A self-revealing Apparent Violation (AV) of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, was identified for the licensees failure to take corrective actions following the discovery of a significant steam leak from the packing gland of the Unit 2 HPCI steam inlet isolation valve, 2-FCV-73-16. Specifically, the licensee failed to correctly classify the severity of the leak on 2-FCV-73-16 as described in NPG-SPP-06.8, Leak Reduction Program, and allowed the condition to degrade until packing failure.

Description: On June 19, 2015, the licensee documented that the Unit 2 HPCI steam admission valve, 2-FCV-73-16 HPCI had a packing leak. A work order was initiated and scheduled for December 14, 2015, to repair the steam leak. On July 16, 2015, NRC inspectors notified the licensee staff that the leak had worsened and was very loud. Again, on July 31, 2015, NRC inspectors noted the steam leak was excessively loud and provided the licensee staff a video of the leak. The licensee re-inspected the valve and concluded that the leak was a packing leak of minor significance and that the component and system were operable. The licensee scheduled repairs for December 14, 2015.

On September 16, 2015, valve stroke surveillance 2-SR-3.6.1.3 cycled valve 2-FCV-73-16. Approximately 13 minutes later, Operations personnel received a fire alarm and reports of significant steam in the Unit 2 HPCI room. The steam leak had actuated temperature sensors in the Unit 2 HPCI room designed to initiate fire suppression water and, for large steam leaks, to isolate the steam supply to the HPCI turbine. Quick action by the operators to manually isolate the turbine prevented the auto isolation. The leak rendered the HPCI pump inoperable. The licensee made an 8-hour notification (Event Notice 51398) per 10 CFR 50.72(b)(3)(v)(D) for a loss of HPCI system safety function.

The inspectors identified that using NPG-SPP-06.8, Leak Reduction Program, the appropriate characterization of the packing leak was a Category 1, Severity level 5, the highest possible severity leak. This characterization should have been used to assign work priorities for repairing the valve as described in NPG-SPP-07.1.4 Work Management Prioritization – On Line. If properly characterized as at least a Priority 2 – Urgent, this condition would have required the repair of the leak to be scheduled at the earliest opportunity within T-3 work week schedule (i.e. within a maximum of 30 days).

Following the steam leak on September 16, 2015, the licensee identified that the valve's packing had failed causing the steam leak. The licensee determined that the mischaracterization of the packing leak severity was a direct cause of not ensuring corrective action was taken in a timely manner to address the steam leak. The packing and gland follower were replaced and the system re-tested successfully on September 19, 2015. The licensee initiated corrective actions in CR 1082405 to inspect similar valve design changes on Units 1 and 3 and training for engineers to better understand severity classifications for steam leaks.

Analysis: The inspectors determined that the licensee's failure to correctly classify the significance of the leak on the Unit 2 HPCI turbine steam admission valve, 2-FCV-73-16, packing was a performance deficiency. Specifically, the licensee classified the steam leak on 2-FCV-73-16 as minor which was not in accordance with the requirements of NPG-SPP-06.8, which would have assigned the most significant classification of steam leak, Category 1, Severity level 5. The performance deficiency was determined to be more-than-minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, misclassification of the leak severity as minor led to the loss of function of the HPCI system when valve 2-FCV-73-16 packing degraded until packing failure. The finding could not be screened to Green and is pending a significance determination.

This finding was evaluated in accordance with IMC 0609, Appendix A, Significance Determination Process, Exhibit 2, Mitigating Systems, dated June 19, 2012. The inspectors determined the finding required a Detailed Risk Evaluation because the finding represented a loss of system and/or function for the HPCI system. The finding does not present an immediate safety concern because the packing has been replaced on the Unit 1 and Unit 2 HPCI steam admission valves and is scheduled for replacement on the Unit 3 HPCI steam admission valve during the unit outage. Because the final safety characterization of this finding is not yet finalized, it is being documented with a significance of To Be Determined (TBD). The inspectors determined that the finding had a cross cutting aspect of Resolution because the licensee did not take timely corrective action to repair the Unit 2 HPCI steam leak before it lead to a Safety System Functional Failure. (P.3)

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviation, defective material, and equipment and non-conformances are promptly identified and corrected. Contrary to the above, from July 16, 2015 to September 16, 2015, the licensee failed to promptly identify and correct a condition adverse to quality associated with the Unit 2 HPCI system. Specifically, on July 16 and 31, 2015, the licensee failed to correctly identify the severity of the packing leak on the Unit 2 HPCI steam admission valve, 2-FCV-73-16, per procedure NPG-SPP-06.8. This precluded the licensee from taking appropriate actions to correct the steam leak commensurate with its significance allowing the degradation and ultimate failure of the valve packing. Upon discovery of the packing failure, the licensee took action to isolate the steam leak and declare the HPCI system inoperable. Repairs were completed and tested on September 19, 2015. The licensee entered this issue into the CAP as CR 1082405. This violation is being treated as an AV as defined in the Enforcement Policy. (AV 05000260/2015-004-06, Failure to Identify Significant Steam Leak on the Unit 2 HPCI Turbine Steam Admission Valve).

These activities constituted completion of three event follow-up samples, as defined in Inspection Procedure 71153. Documents reviewed are listed in the attachment.

4OA5 Other Activities

.1 Review of the Operation of an Independent Spent Fuel Storage Installation (ISFSI) (60855.1)

a. Inspection Scope

The inspectors performed a walkdown of the onsite ISFSI. The inspectors reviewed changes made to the ISFSI programs and procedures, including associated 10 CFR 72.48, “Changes, Tests, and Experiments,” screens and evaluations to verify that changes made were consistent with the license or certificate of compliance. The inspectors reviewed records to verify that the licensee recorded and maintained the location of each fuel assembly placed in the ISFSI. The inspectors also reviewed surveillance records to verify that daily surveillance requirements were performed as required by technical specifications. Documents reviewed are listed in the attachment. This activity constituted one semi-annual Operation of an ISFSI inspection sample, as defined in Inspection Procedure 60855.1.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

On January 21, 2016, the resident inspectors presented the quarterly inspection results to L. Hughes, Plant Manager, and other members of the licensee’s staff, who acknowledged the findings. The inspectors verified that all proprietary information was returned to the licensee.

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee
S. Bono, Site Vice President
L. Hughes, General Plant Manager
P. Summers, Director of Safety and Licensing
J. Paul, Nuclear Site Licensing Manager
M. McAndrew, Manager of Operations
D. Campbell, Superintendent of Operations
L. Slizewski, Ops Shift Manager
M. Kirschenheiter, Assistant Director for Site Engineering
M. Oliver, Licensing Engineer
E. Bates, Licensing Engineer
M. Acker, Licensing Engineer
R. Guthrie, System Engineer
M. Lawson, Radiation Protection Manager
J. Smith, System Engineer
P. Campbell, System Engineer
J. Kulisek, EP Manager
K. Skinner, System Engineer
L. Holland, System Engineer
Q. Leonard, System Engineering Manager
D. Rinne, Program Engineer
D. Drummonds, Program Engineer

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened		
05000259/260/296/2015004-01	URI	High Pressure Fire Protection System Piping Failure Following Pump Start (Section 1R04)
05000259/260/296/2015004-03	URI	Corrective Actions For 2012 Flooding Walkdowns (Section 4OA2)
0500260/2015004-05	AV	Failure to Properly Install the Unit 2 HPCI Turbine Steam Admission Valve Packing (Section 4OA3.3)
05000260/2015004-06	AV	Failure to Identify Significant Steam Leak on the Unit 2 HPCI Turbine Steam Admission Valve. (Section 4OA3.3)
Opened and Closed		
05000259/260/296/2015004-02	NCV	Failure to Properly Manage Risk During Planned Maintenance Activities (Section 1R13)
05000260/2015004-04	NCV	Failure of 2A RHR Pump to Start from the Control Room due to a Loose Fastener (Section 4OA3.2)
Closed		
05000259/2015-003-00	LER	Loss of Cooling to the Unit 1 and Unit 2 Shutdown Board Rooms Due to Fouled Chiller Coils (Section 4OA3.1)
05000260/2015-001-00	LER	2A RHR Pump Start Failure (Section 4OA3.2)
05000260/2015-002-00	LER	HPCI Turbine Steam Supply Valve Packing Failure (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Procedures

3-OI-64 Primary Containment System, Rev 59
0-SSI-001 Safe Shutdown Instructions, Rev 25

Drawings

DWG 3-47E862-1 Containment Atmospheric Dilution System Flow Diagram, Rev 32
DWG 1-47E836-1-1 Unit 1 Flow Diagram Raw Service Water and Fire Protection System, Rev 4
DWG 1-47E850-5 Unit 1 Flow Diagram Fire Protection and Raw Service Water, Rev 13
DWG 2-47E836-1 Unit 2 Flow Diagram Fire Protection and Raw Service Water, Rev 15
DWG 3-47E836-1 Unit 3 Flow Diagram Fire Protection and Raw Service Water, Rev 18

Other Documents

Operator Work Around 3-064-OWA-2015-0162
CR 1092861 3-FCV-64-31 Operates erratically
CR 1102016 Fire Header rupture on the Southwest side of protected area
WO 115939233 Replace diaphragm on 3-FCV-64-31
Fire Protection Report Volume 1, Appendix R Safe Shutdown Program, Rev 23
Fire Protection Report Volume 1, Safe Shutdown Analysis, Rev 23
Fire Protection Report Volume 1, Fire Hazard Analysis, Rev 23
FSAR Section 10.11 Fire Protection System, Amendment 26
FSAR Appendix O, Aging Management Programs, Amendment 26
NPG-SPP 09.15 Underground Piping and Tanks Integrity Program, Rev 7
0-TI-561 Underground Piping and Tanks Integrity Program, Rev 19
0-TI-623 Aging Management Program Basis Document for Buried Piping and Tanks Inspection Program, Rev 1
National Fire Protection Association's Fire Protection Handbook, 15th edition
Equipment Apparent Cause Evaluation for CR 1102016, Rev 0
Surveillance data for the Fire Pump Operability Test from August 2008 until October 2015

Section 1R05: Fire Protection

Procedures

NPG-SPP 18.4.7 Control of Transient Combustibles, Rev 5

Other Documents

Fire Protection Report Volume 1, Rev 20
Fire Protection Report Volume 2, Rev 52

Section 1R06: Flood Protection Measures

Procedures

Browns Ferry PM 67718 Evaluation for Sump Pump Check for Handholes 15 and 26

Other Documents

DCN 71458 Add support to get cables off floor of HH26, Rev A
Vendor Manual for web slings used in DCN 71458
CR 979724 Water found in HH 15 and HH 26

Section 1R11: Licensed Operator Requalification

Procedures
1-GOI-100-12A Unit shutdown from power operation to cold shutdown and reductions in power during power operations, Rev 23
2-GOI-100-12A Unit shutdown from power operation to cold shutdown and reductions in power during power operations, Rev 108

Other Documents
Unit 2 Browns Ferry Integrated Training Drill for October 7, 2015, Rev 3

Section 1R12: Maintenance Effectiveness

Procedures
0-TI-346 Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev 47

Other Documents
System Health Report for system 069, Reactor Water Cleanup
FSAR chapter 7.3, Primary Containment Isolation
CR 1100727
CR 1097178
CR 997898
Discussion with Reactor Water Cleanup system engineer

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
NPG-SPP-09.11.1 Equipment Out of Service Management, Rev. 10
NPG-SPP-07.3.4 Protected Equipment, Rev. 2

Drawings
DWG 0-47E866-3 Heating and Air Conditioning Flow Diagram, Rev 35
DWG 0-47E866-9 Chill Water Pump Flow Diagram, Rev 10

Other Documents
Browns Ferry Unit 1, 2, and 3 Equipment Out Of Service Report dated July 14, and October 19, 2015
eSOMS Action Tracking Status for Units 1, 2 and 3 on July 14, 2015 and October 19, 2015
eSOMS Narrative Logs dated July 14, 2015 and October 19, 2015
TS 3.7.4 Control Room Air Conditioning System, Rev 234
TS 3.7.4 Basis, Rev 234
TRM 3.7.6 Electric Board Room Air Conditioning Units, Rev 115
TRM 3.7.6 Basis, Rev 115
Clearance Tag List for Tagout 0-PE-2015 Clearance: 3-082-0023

Section 1R15: Operability Evaluations

Procedures
0-TI-362 Inservice Testing Program, Rev 48
1-EOI-3 Flowchart Secondary Containment Control, Rev 4

1-AOI-78-1 Fuel Pool Cooling System Failure, Rev 22
1-OI-74 Residual Heat Removal System, Rev 93
0-AOI-100-5 Earthquake, Rev 39
1-SI-3.2.10.P Verification of Remote Position Indicators for Fuel Pool Cooling System Valves, Rev 9
MDQ0023890078, Pump Performance Analysis for New RHRSW Compartment Sump Pumps, Rev 4
MDQ0023870149, RHRSW Pump Compartment Sump and Sump Pump Capacity, Rev 12

Drawings
DWG 3-47E855-1-ISI Fuel Pool Cooling System code class boundaries, Rev 8

Other Documents
ASME OM Code section ISTA and ISTC, 2004 edition with 2006 Addenda
CR 1086878
CR 1094365
CR 1089385
CR 1090096
NUREG 1482 Guidelines for Inservice Testing at Nuclear Power Plants, Rev 2
Response to Request for Additional Information Related to Potential Los of Spent Fuel Pool Cooling (ML 14248A681)
FSAR Section 8.0, Amendment 26

Section 1R19: Post Maintenance Testing
Procedures
WO 117323859 3-SR-3.8.1.1(3A) EDG 3A Monthly Operability Test
3-OI-82 Unit 3 EDG Operating Procedure, Rev 138

Drawings
DWG 3-47E767-5-1 EDG 3A Engine Control Logic Diagram

Other Documents
CR 1099740 3A EDG did not stop when shutdown
CR 1101483 Inappropriate Common Cause Analysis for the 3A EDG failure
CR 1108084 1A Recirc pump seal failed
EACE 1105618
WO 117032064
Daily Operator Logs for November 1 and 2, 2015
TS 3.8.1 and TS basis 3.8.1
FSAR Chapter 8, Amendment 26
Supplement 6 to the Original Safety Evaluation Report

Section 1R20: Refueling and Other Outage Activities
Procedures
1-GOI-100-1A Unit Startup, Rev 44
1-GOI-200-2B Primary Containment Closeout, Rev 1
2-GOI-100-1A Unit Startup, Rev 165

2-GOI-200-2B Primary Containment Closeout, Rev 1
2-SR-3.4.9.1(1) Reactor Heatup and Cooldown Rate Monitoring, revision 28

Other Documents
Outage daily work planning reports from November 15, 2015 to November 20, 2015
Outage daily work planning reports from December 6, 2015 to December 11, 2015
Calculation MDQ0303200600021, Primary Containment Uncontrolled Coating Calculation for Units 1, 2, 3

Section 1R22: Routine Surveillance
Procedures
3-SR-3.5.1.7(COMP) HPCI Comprehensive Pump Test, Rev 23
1-SR-3.5.1.7, HPCI Main & Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure, Rev 33
WO 115555596

Drawings
47W335-9, HPCI Isometric drawing

Section 4OA1: Performance Indicator (PI) Verification
Other Documents
NEI 99-02 Regulatory Assessment Performance Indicator Guideline, Rev 7
FAQ for NEI 99-02 Regulatory Assessment Performance Indicators as of February 9, 2015
Daily logs from October 1, 2014 until September 30, 2015

Section 4OA2: Identification and Resolution of Problems
Procedures
NPG-SPP 22.300 Corrective Action Program, Rev 5
Operations Decision Making Instruction (ODMI) 1063853 for degraded recirculation pump seal on Unit 1
Surveillance Procedure 3-SR-3.5.1.1 (HPCI) Maintenance of Filled HPCI Discharge Piping.
WO 115566531
WO 114086270

Drawings
47W335-9, Isometric drawing of Unit 3 HPCI system

Other Documents
CR list: 1063853, 1092524, 1092525, 1092520, 1092523, 1092599, 1092597, 1092608, 1098691, 1070658, 1075911, 1119892
SR 633945
Browns Ferry Nuclear Plant Flooding Walkdown Report by WoorleyParsons, dated April 10, 2014, Rev 3
Walkdown Record Forms per CTP-FWD-100 Flood Protection Walkdowns NEI 12-07
TVA Letter, Fleet Response to NRC Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding the Flooding Walkdown Results of Recommendation

2.3 of the Near-Term Task Force Review of Insights from the Fukushima di-ichi Accident, dated November 27, 2012

Section 4OA3: Event Follow-up
Other Documents
LER 05000259/2015-003-00 Loss of Cooling To the Unit 1 and Unit 2 Shutdown Board Rooms Due to Fouled Chiller Coils

Section 4OA5: Other Activities
Other Documents
10 CFR 72.48 screening for the following documents:
MSI-0-079-DCS100.7, Rev. 5
MSI-0-079-DCS036, Rev. 6
MSI-0-079-DCS100.11(FW), Rev. 1
MSI-0-079-DCS 500.3(FW), Rev. 0
MSI-0-079-DCS 500.5FW, Rev. 0
MSI-0-079-DCS 400.1FW, Rev. 0
MSI-0-079-DCS 300.2FW, Rev. 0
MSI-0-079-DSC 200.1FW, Rev. 0
MSI-0-079-DCS 100.8, Rev. 3
MSI-0-079-DCS 100.6(FW), Rev. 1
MSI-0-079-DCS 100.11FW, Rev. 0
MSI-0-079-DCS 035, Rev. 13
MSI-0-079-DCS 500.5, Rev. 5
MSI-0-000-LFT 004(FW), Rev. 0
MSI-0-079-DCS300.2, Rev. 5
BFN ISFSI FSAR, change 15-02
DCN 70980, Rev. A
ECP 71767, Rev. A
PFE-747, Rev. 2
EDMG-18, Rev. 02 TN 03
MPC-BFN-003, Rev. 1
MPC-BFN-003, Rev. 0
MPC-BFN-004, Rev. 0
0-AOI-100-3, Rev. 42 TN 43

Work orders
116664462 for loading of the 10th cask of the dry cask campaign
115513902 for loading of the 4th cask of the dry cask campaign

DCN 70980 Design change for use of the Holtec HI-STORM FW casks, Rev A

LIST OF ACRONYMS

ADAMS	Agencywide Document Access and Management System
ADS	Automatic Depressurization System
AOI	Abnormal Operating Instruction
ARM	area radiation monitor
AV	Apparent Violation
CAD	containment air dilution
CAP	corrective action program
CB	control Bay
CCW	condenser circulating water
CFR	Code of Federal Regulations
COC	certificate of compliance
CR	condition report
CRD	control rod drive
CS	core spray
DCN	design change notice
EECW	emergency equipment cooling water
ED	Electronic dosimeter
EDG	emergency diesel generator
EOI	Emergency Operating Instruction
FE	functional evaluation
FA	Fire Area
FCV	flow control valve
FPR	Fire Protection Report
FSAR	Final Safety Analysis Report
FZ	Fire Zone
HRA	High Radiation Area
HPCI	high pressure coolant injection
IP	Inspection Procedure
IMC	Inspection Manual Chapter
ISFSI	Independent Spent Fuel Storage Facility
kV	Kilovolts (1000 volts)
LCO	limiting condition for operation
LER	licensee event report
LHRA	Locked High Radiation Area
MR	Maintenance Rule
MRC	Management Review Committee
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
NSTS	National Source Tracking System
ODCM	Off-Site Dose Calculation Manual
OSLD	Optically Stimulated Luminescence Dosimeter
PCM	Personnel Contamination Monitor
PER	problem evaluation report

PCIV	primary containment isolation valve
PI	performance indicator
PM	portal monitor
PMT	post maintenance test
PSC	Plant Screening Committee
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCE	Root Cause Evaluation
RCIC	reactor core isolation cooling
RCW	Raw Cooling Water
REMP	Radiological Environmental Monitoring Program
RG	Regulatory Guide
RHR	residual heat removal
RHRSW	residual heat removal service water
RMA	risk management actions
RPT	Radiation Protection Technician
RS	Radiation Safety
RTP	rated thermal power
RPS	reactor protection system
RWP	radiation work permit
SAM	Small Article Monitor
SDP	significance determination process
SBGT	standby gas treatment
SLC	standby liquid control
SNM	special nuclear material
SR	service request
SRV	safety relief valve
SSC	structure, system, or component
SSI	Safe Shutdown Instruction
TBD	To Be Determined
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
VHRA	Very High Radiation Area
WO	work order