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

February 9, 2011

EA-11-012

Mr. R. M. Krich
Vice President, Nuclear Licensing
Tennessee Valley Authority
3R Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2010005, 05000260/2010005, 05000296/2010005, AND NOTICE OF VIOLATION

Dear Mr. Krich:

On December 31, 2010, 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 11, 2011 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.

This report documents one self-revealing apparent violation (AV) concerning the failure of a Unit 1 Residual Heat Removal (RHR) system low pressure injection valve. This violation has potential safety significance greater than very low safety significance (Green). The violation did not present an immediate safety concern because Unit 1 was shutdown for a refueling outage and the other division of RHR was operable and available for service. Additionally, the licensee repaired the low pressure injection valve prior to the startup of Unit 1. This violation with the supporting circumstances and details are documented in the inspection report.

Additionally, the NRC has determined that a Severity Level IV violation of NRC requirements occurred. The violation was evaluated in accordance with the NRC Enforcement Policy. This violation is cited in the enclosed Notice of Violation (EA-11-012) and the circumstances surrounding it are described in detail in the subject inspection report. The violation is being cited in the enclosed Notice because information provided in the second revision of LER 05000296/2009-003 was also not complete and accurate in all material respects. This violation is being cited because the criterion specified in Section 2.3.2.a.3 of the NRC Enforcement

Policy for a non-cited violation was not met. This criterion was not met because the violation was repetitive and identified by the NRC. The initial violation, also identified by the NRC, was documented in NRC inspection report 50-296/2010-003. The current Enforcement Policy is included on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.htmlhttp://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC review of your response to the Notice will also determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

Furthermore, this report contains one self-revealing finding that was evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that a violation is associated with this finding. This violation is being treated as a Non-Cited Violation (NCV), consistent with Section 2.3.2 of the Enforcement Policy. The NCV is described in the subject inspection report. If you contest this violation or significance of the NCV, 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 Senior Resident Inspector at 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, 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),accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal, privacy or proprietary information so that it can be made available to the public without redaction.

Sincerely,

/RA/

Eugene F. Guthrie, 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

Enclosures:
1. Notice of Violation
2. NRC Integrated Inspection Report 05000259/2010005, 05000260/2010005, 05000296/2010005

cc w/encl. (See page 3)

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X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: ☐ Yes ACCESSION NUMBER: ML110400431 ☐ SUNSI REVIEW COMPLETE

OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRP	RII:DRS	RII:DRS	RII:DRS
SIGNATURE	Via email	Via email	Via email	Via email	Via email	Via email	Via email
NAME	TRoss	CStancil	PNiebaum	LPressley	ARogers	RBaldwin	ELea
DATE	02/04/2011	02/02/2011	02/01/2011	02/01/2011	02/02/2011	02/01/2011	02/01/2011
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICE	RII:DRS	RII:DRP	RII:DRP	OE	OE	RII:DRP	
SIGNATURE	Via email	Via email	Via email	EFG /RA for/	Via email	EFG /RA/	
NAME	GJohnson	CKontz	MKing	JWray	LJarriel	EGuthrie	
DATE	02/03/2011	02/02/2011	02/02/2011	02/09/2011	02/03/2011	02/09/2011	
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\2010\2010005\BROWNS FERRY 2010005.DOCX

cc w/encl:
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Letter to R. M. Krich from Eugene Guthrie dated February 9, 2011

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2010005, 05000260/2010005, 05000296/2010005, AND NOTICE OF VIOLATION

Distribution w/encl:
C. Evans, RII
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OE Mail
RIDSNRRDIRS
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RidsNrrPMBrownsFerry Resource

NOTICE OF VIOLATION

Tennessee Valley Authority
Browns Ferry Nuclear Plant

Docket No. 50-296
License No. DPR-68
EA-11-012

During an NRC inspection conducted on December 6, 2010, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR 50.9, Completeness and Accuracy of Information, stated in part, that "Information provided to the Commission by a licensee shall be complete and accurate in all material respects."
>
> Contrary to the above, on August 31, 2010, the licensee submitted a revised LER, as a corrective action for a previous 10 CFR 50.9 violation involving inoperability of the Unit 3 RCIC system, that was not complete and accurate in all material respects. The revised LER did not report the correct event date, nor did it describe prior corrective actions (e.g., maintenance and testing) taken for a previous related event and why these corrective actions did not prevent recurrence (as specifically detailed in NCV 05000296/2010003-03).

This is a Severity Level IV violation.

Pursuant to the provisions of 10 CFR 2.201, the Tennessee Valley Authority is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region II, and a copy to the NRC Senior Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-11-012" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time. If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you <u>must</u> specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

Dated this 9th day of February 2011.

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.:	05000259/2010005, 05000260/2010005, 05000296/2010005
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, 2010 through December 31, 2010
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector P. Niebaum, Resident Inspector L. Pressley, Resident Inspector A. Rogers, Reactor Inspector (1R08) R. Baldwin, Senior Operations Engineer (1R11.2) E. Lea, Senior Operations Engineer (1R11.3) G. Johnson, Operations Engineer (1R11.3) C. Kontz, Senior Project Engineer (4OA2.4, 4OA5.4) M. King, Senior Project Inspector (4OA2.4) J. Wray, Senior Enforcement Specialist (4OA5.4) L. Jarriel, Agency Allegation Advisor (4OA5.4)
Approved by:	Eugene F. Guthrie, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure 2

SUMMARY OF FINDINGS

IR 05000259/2010005, 05000260/2010005, 05000296/2010005; 10/01/2010 – 12/31/2010; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Refueling and Other Outage Activities, Event Follow-up.

The report covered a three month period of inspection by the resident inspectors, two senior reactor operations engineers, a reactor operations engineer, two senior project engineers and a reactor inspector from Region II. One apparent violation (AV), one severity level IV cited violation (VIO), and one non-cited violation (NCV) were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP); the cross-cutting aspect was 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: Mitigating Systems

(TBD). A self-revealing Apparent Violation (AV) of Unit 1 Technical Specifications (TS) Limiting Condition for Operations (LCO) 3.5.1, Emergency Core Cooling System (ECCS) - Operating, was identified for the licensee's failure to comply with the TS LCO required actions for an inoperable Residual Heat Removal (RHR) and Low Pressure Coolant Injection (LPCI) subsystem due to a failure of the RHR Loop II LPCI Outboard Injection Valve (1-FCV-74-66) to open. The licensee entered this issue into their corrective action program as problem evaluation report (PER) 271338. The 1-FCV-74-66 was subsequently repaired and returned to service during the Unit 1 outage prior to restart.

This finding has potential safety significance greater than very low safety significance (Green) and will remain indeterminate pending completion of the significance determination process. The inspectors determined that the licensee's failure to establish adequate design control and perform adequate maintenance on the Unit1 outboard LPCI injection valve, 1-FCV-74-66, which resulted in the valve being left in a significantly degraded condition and RHR loop II unable to fulfill its safety function, was a performance deficiency. This finding was considered more than minor because it was associated with the Protection Against External Factors attribute of the Reactor Safety/ Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring availability and reliability of systems designed to respond to initiating events to prevent undesirable consequences. Specifically, the RHR subsystem was rendered incapable of being aligned to perform its safe shutdown function due to the failure of 1-FCV-74-66. The safety characterization of this finding is not yet finalized and is currently characterized as To Be Determined (TBD). This finding does not have a cross-cutting aspect because it is not reflective of current licensee performance in the last three years. (Section 1R20.1(1))

- Green. A self-revealing non-cited violation (NCV) of Unit 1 Technical Specifications (TS) Limiting Condition for Operations (LCO) 3.6.2.3, Suppression Pool Cooling was identified for the licensee's failure to correct a degraded condition of the 1C Residual Heat Removal (RHR) pump motor that rendered it inoperable for greater than the TS allowed outage time of 30 days. Specifically, the 1C RHR pump motor suffered a catastrophic failure on October 27, 2010 and was subsequently determined to have been in a degraded condition since November 2007. This condition would have prevented the pump from performing its intended safety functions during the system's required mission time. The licensee entered this issue into the corrective action program as problem evaluation report (PER) 274840. The 1C RHR pump motor was subsequently repaired during the Unit 1 refueling outage and returned to service on November 10, 2010 prior to Unit 1 restart.

  This performance deficiency was considered greater than minor because it was associated with the Mitigating Systems cornerstone and adversely affected the equipment performance objective to ensure the availability and capability of the RHR system to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the 1C RHR subsystem was degraded to the point that it was incapable of performing its intended safety functions for the system's required mission time. Since the 1C RHR pump motor failure occurred during Mode 5 shutdown conditions after a significant period of shutdown cooling operation, the finding was evaluated according to Inspection Manual Chapter 609, Appendix G, Shutdown Operations Significance Determination Process, Attachment 1, Phase 1 Operational Checklists, Checklist 7, Refueling Operation with Reactor Coolant Level Above 23'. Accordingly, the finding was determined to be of very low safety significance (Green) because the 1A RHR pump and the Auxiliary Decay Heat Removal (ADHR) system were available, when only one RHR pump was needed per Section I.C of Checklist 7. The cause of this finding was directly related to the cross cutting aspect of Thorough Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, because the licensee did not adequately evaluate the precursors related to the degraded 1C RHR motor performance and properly prioritize the resolution of a known condition adverse to quality in time to preclude motor failure [P.1(c)]. (Section 1R20.1(2))

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at full Rated Thermal Power (RTP) for most of the report period except for three unplanned downpowers, and a scheduled refueling outage (RFO). On October 4, 2010, an unplanned downpower to approximately 94 percent RTP occurred due to a power cell failure in the 1B variable frequency drive (VFD). Unit 1 returned to full RTP later that same day. On October 23, 2010, Unit 1 was shutdown for a scheduled refueling outage that lasted 31 days. The unit was restarted on November 22, 2010. During the power ascension, there was a planned downpower from approximately 60% to 30% RTP on November 24, 2010, for single loop operations in order to repair a power cell in the 1A VFD. The unit returned to full RTP on November 25, 2010. On December 2, 2010, Unit 1 experienced an unplanned downpower to 45 percent RTP due to failures of a 1A VFD power cell. The unit returned to full RTP on December 3, 2010 following repairs to the 1A VFD unit.

Unit 2 operated at essentially full RTP the entire report period except for two planned downpowers. On October 24, 2010, a planned downpower to 90 percent RTP was conducted to support a control rod exercise and the unit returned to full RTP later that same day. On December 11, 2010, a planned downpower to 70 percent RTP was conducted to support a control rod sequence exchange and the unit returned to full RTP later that same day.

Unit 3 operated at essentially full RTP the entire report period except for three planned downpowers and one unplanned reactor shutdown. On October 3, 2010, a planned downpower to 94 percent RTP was conducted for a control rod exercise and the unit returned to full RTP later that same day. On October 26, 2010 a planned downpower to 93 percent RTP was conducted for a control rod exercise and the unit returned to full RTP later that same day. On December 17, 2010 a planned downpower was conducted to support a control rod sequence exchange and the unit returned to full RTP later that same day. On December 26, 2010, Unit 3 experienced an unplanned downpower to 90 percent RTP followed by a manual reactor scram due to high vibration on the main generator exciter bearings. Unit 3 remained shutdown through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Impending Adverse Weather Conditions – Cold Weather

a. Inspection Scope

On December 13th, 14th and 15th an adverse cold weather advisory was issued for the Northern Alabama area. The inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions and observed the licensee's implementation of general operating instruction GOI-200-1, Freeze Protection Inspection. The inspectors also reviewed and discussed the implementation of

GOI-200-1 with the responsible Unit Supervisors and Shift Managers. Furthermore, the inspectors witnessed the licensee's execution of freeze protection of vulnerable areas and buildings inside and outside the power block. The inspectors also verified operator staffing for the given conditions was adequate and reviewed any active, upcoming and delayed work orders and surveillances. The inspectors also verified completion of the freeze protection checklists. This satisfied one inspection sample.

b. Findings

No findings were identified.

.2 Impending Adverse Weather Conditions – Tornado Warning

a. Inspection Scope

On October 26, 2010, a Tornado Warning was declared for adjacent counties. The inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions and observed the licensee's implementation of abnormal operating instruction (AOI) 100-7, Severe Weather. The inspectors also reviewed and discussed the implementation of AOI 100-7 with the responsible Unit Supervisor and Shift Manager; along SSI-19.1, Post Requirements and Responsibilities, Temporary Suspension of Security Measures, Tornado Emergency Guide/Checkoff with Security supervision. Furthermore, the inspectors witnessed the licensee's execution of evacuation orders of vulnerable areas and buildings in and outside the power block, including the termination of work and evacuation of the main turbine deck and refueling floor. The inspectors also conducted walkdowns of critical plant areas and a general tour of the plant grounds. Lastly, the inspectors reviewed available operator and security staffing, and verified access controls and indications for those systems required for safe control and physical protection of the plant. This satisfied one inspection sample.

b. Findings

No findings were identified.

.3 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. Furthermore, 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 the later part of December, when outside temperatures dropped below the 32 degree Fahrenheit (F) and 25F thresholds of 0-GOI-200-1, the inspectors conducted walkdown tours of the main control rooms to assess system performance and alarm conditions of systems susceptible to cold weather conditions. In addition, the inspectors verified effectiveness of licensee implementation of procedure EPI-0-000-FRZ001, Freeze Protection Program for RHRSW Pump Rooms, to ensure RHRSW system and components were not adversely affected by the cold weather. Furthermore, the inspectors verified that the applicable equipment walkdown checklists required by 0-GOI-200-1 were implemented accordingly. This satisfied one inspection sample.

b. Findings

No findings were identified.

.4 Readiness to Cope with External Flooding

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 licensing basis flood analysis documents including: Updated Final Safety Analysis Report (UFSAR) Section 2.4, Hydrology, Water Quality, and Marine Biology, which included Appendix 2.4A, Maximum Possible Flood; UFSAR Section 12.2.9.2.3 Flood Gate, and BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding. The inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the common Unit 1/2 ‘A’, ‘B’, ‘C’ and ‘D’ emergency diesel generator (EDG) rooms and the Unit 3 EDG rooms ‘3A’,’3B’, ‘3C’, and ‘3D’. The inspectors’ review included flood-significant features such as the portable bulkhead used as a temporary flood barrier, sump pump flowrates, sump drains and level switch setpoints and watertight door seals for the common U1/2 EDG building and the U3 diesel generator building. 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 2009 through early 2010 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. This satisfied one inspection sample.

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, 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.

- Auxiliary Decay Heat Removal (ADHR) System
- Standby EDG 3D
- Unit 3 Core Spray (CS) System - Division I

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Fire Protection Tours

a. Inspection Scope

The inspectors reviewed licensee procedures, Standard Programs and Processes (SPP)-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the 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 SPP-10.9. Furthermore, the inspectors reviewed applicable portions of the Site Fire Hazards Analysis Volumes 1 and 2 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.

- Unit 3 Fire Zone 3-2 EL 519 through 565, from column line R21 to 10 ft west of column line R18.
- Unit 3 4kV Shutdown Board 3EA,3EB (FA - 22)
- Unit 3 4kV Shutdown Board 3EC, 3ED (FA - 23)
- Unit 3 4kV Bus Tie Board (FA - 24)

b. Findings

No findings were identified.

1R08 Inservice Inspection (ISI) Activities (IP 71111.08B, Unit 1)

a. Inspection Scope

From November 1 through November 5, 2010, the inspectors observed and reviewed the implementation of the licensee's In-service Inspection (ISI) program for monitoring degradation of the reactor coolant system (RCS) boundary and risk-significant piping boundaries of Browns Ferry Unit 1 during the autumn 2010 refueling outage. The inspectors' activities consisted of an on-site review of nondestructive examination (NDE) and welding activities to evaluate compliance with Technical Specifications and the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Sections XI and V (Code of record: 2001 Edition through the 2003 Addenda), for Class 1, 2, and 3 systems; and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of the ASME Code Section XI acceptance standards. For Browns Ferry Unit 1, this was second outage in the first period of the second 10-year ISI inspection interval. The inspectors also reviewed a sample of inspection activities associated with components that were outside the scope of ASME Section XI requirements which were performed in accordance with commitments to follow industry guidance documents, such as the Boiling Water Reactor Vessel and Internals Project (BWRVIP).

.1 Piping Systems ISI.

a. Inspection Scope

The inspectors reviewed NDE activities, both by direct observation and record review, specifically including examination procedures, NDE reports, equipment and consumables certification records, personnel qualification records, and calibration reports for compliance to requirements of ASME Section V, ASME Section XI, BWRVIP documents, and other industry standards for the following examinations:

- Penetrant Testing (PT)
  - Feedwater Weld Overlay, Weld #: RFW-1-028-001
  - RHR Weld Attachment to Pipe, Weld #: 1-47B452-3047-IA
  - Recirculation Weld Attachment to Pipe, Weld #: 1-47B465-462-IA

- Ultrasonic Testing (UT)
    - Feedwater Weld Overlay, Weld #: RFW-1-028-001
    - Feedwater Pipe, Weld #: GFW-1-08
    - Feedwater Pipe Butt Weld, Weld #: N-11B-1
    - Feedwater Pipe Weld Overlay, Weld #: N-11B-1-OL
    - Feedwater Pipe Weld Overlay, Weld #: RFW-1-028-001
    - Feedwater Pipe, Weld #: KFW-1-29
    - Feedwater Pipe, Weld #: KFW-1-38
    - Feedwater Pipe, Weld #: KFW-1-39
    - Recirculation System, Weld #: RWR-1-002-042

The inspectors conducted a Unit 1 containment walk-down of multiple drywell elevations to assess, in general, the material condition of structures, systems, and components, including leaks from bolted connections, coating integrity, cleanliness, hangers and supports, etc.

The inspectors also reviewed welding activities from last outage for the following Class 1 and 2 components:

- Base Metal repairs to the cladding on the Reactor Vessel Head Flange
- Main Steam line Thermowell replacement

The inspectors completed a review of ISI-related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action documents to confirm that the licensee had appropriately described the scope of the problems, and had implemented appropriate corrective actions. The inspectors' review included confirmation that the licensee had an adequate threshold for identifying issues. Through interviews with licensee staff and review of corrective action documents, the inspectors evaluated the licensee's threshold for identifying lessons learned from industry issues related to ASME Section XI. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings were identified.

.2 Reactor Vessel Internal Inspections

a. Inspection Scope

The inspectors reviewed the following NDE activities associated with the inspection of Reactor Vessel internal components (Boiling Water Reactors Vessel Internals Project):

- Visual Testing (VT)
  - Jet Pump assemblies on shroud and vessel side
  - Core Spray P4A downcomer

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On October 19, 2010, the inspectors observed two licensed operator requalification (LOR) program annual simulator examinations for an Operations group. During each exam the senior reactor operator and the reactor operator positions were rotated, except for the shift manager. The examinations observed by the inspectors were the 2010 LOR Exam-02 and the LOR Exam-13.

The inspectors specifically evaluated the following attributes related to each 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 US and Shift Manager (SM)

The inspectors attended a 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 inspector. 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).

b. Findings

No findings were identified.

.2 Annual Review of Licensee Requalification Examination Results

a. Inspection Scope

October 20, 2010, the licensee completed the comprehensive biennial requalification written examinations and annual requalification operating tests 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 the written examinations, individual operating tests and the crew simulator operating tests. These results were compared to the thresholds established in Inspection Manual Chapter 609, Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings were identified.

.3 Biennial Review

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the week of October 12, 2010, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of operating tests associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the facility licensee in implementing requalification requirements identified in 10 CFR Part 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The inspectors also evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-1981, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The inspectors observed three crews during the performance of the operating tests. Documentation reviewed included written examinations, Job Performance Measures (JPMs), simulator scenarios, licensee procedures, on-shift records, simulator modification request records, simulator performance test records, operator feedback records, licensed operator qualification records, remediation plans, watchstanding records, and medical records. These records were inspected using the criteria listed in Inspection Procedure 71111.11. Documents reviewed during the inspection are documented in the List of Documents Reviewed.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors examined two specific equipment issues listed below for 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) Charging 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 (a)(1) goals and corrective actions (i.e.- Ten Point Plan). The inspectors also compared the licensee's performance against site procedure SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; and 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.

- Units 1, 2, and 3 CS Systems Excessive Unavailability
- Failure of Magnesium Rotors in Safety-Related Motor Actuated Valve Actuators

b. Findings

No findings were identified.

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 reviewed three 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 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 adequacy of the licensee's risk assessments, implementation of RMAs, and plant configuration.

- On October 13, B Standby Gas Treatment (SBGT) Fan and G Control Air Compressor were out of service (OOS) for maintenance with emergent work on 3C EDG and B1 RHRSW Pump
- Unplanned Entry into Unit 1 ORAM Orange Condition Due To ADHR B Primary Heat Exchanger Leak While Both Divisions of Residual Heat Removal (RHR) OOS
- Unplanned Entry into Unit 1 ORAM Orange Condition Due To Onset of Severe Weather While Spent Fuel Gates Installed, and ADHR and Division II RHR OOS

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the six 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 3: 3B EDG Immersion Heater and Circulating Oil Soak Back Pump Standby Auxiliaries De-Energized in Manual Control (PER 260536)
- Unit 1 and 2 B EDG Unable to Achieve Maximum Rated Load per UFSAR (PER 209288)
- C3 EECW Pump Severe Shaft Degradation (PER 257317)
- EDG Buildings Emergency Drain Internal Flooding Operability Evaluation (PER 268624)
- Capability to Parallel Two EDGs on a 4KV Shutdown Board per Design Basis (PER 178142)
- Holtec MPC-68 Heat Load Limits (PER 255823)

b. Findings

No findings were identified.

1R18 Plant Modifications

Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the temporary modification listed below and licensee procedure NPG-SPP-9.5, Temporary Alterations, to verify regulatory requirements were met. The inspectors also reviewed the associated 10 CFR 50.59 screening and evaluation 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 the 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.

- 1-SI-4.7.A.2.a-f, Primary Containment Leak Rate Test, Jumpering and Inhibiting for Pressurization of Primary Containment

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the six post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following 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 witnessed the test and/or 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-6.3, Pre-/Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors reviewed problems associated with PMTs that were identified and entered into the CAP.

- Unit 1: PMT for Installation of Alternate Supply Backup Diesel Generator for ADHR.
- Unit Common: PMT for Standby Gas Treatment Train B Roughing Filter Replacement and Outlet Damper Repair Per 0-SR-3.6.4.3.2(B VFTP), Standby Gas Treatment Filter Pressure Drop and In-Place Leak Tests – Train B

- Unit 1: PMT for Residual Heat Removal (RHR) System II Outboard Recirculation Loop Valve Stem/Disc Separation Repair Per Work Orders (WOs) 111571105, 111571764, and 09-723979-000; and 1-SR-3.6.1.3.5(RHR II), RHR System MOV Operability Loop II; and 1-SR-3.3.3.1.4(H II), Verification of Remote Position Indicators for RHR System II Valves.
- Unit 1: PMT for Reactor Protection System Scram Contactor Relay Replacements Per WOs 09-723912-000 and 09-723911-000; ECI-0-000-RLY003, Replacement of Relays; EPI-0-099-RLY001, Reactor Protection System Scram Solenoid and Reset Relays Channel A; and EPI-0-099-RLY002, Reactor Protection System Scram Solenoid and Reset Relays Channel B
- Unit 2: PMT for HPCI Steam Admission Valve 73-16 Repairs Per WO 110811072 and 2-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure
- Unit 3: PMT for Core Spray Division II Preventive Maintenance per 3-SR-3.5.1.6(CSII), Core Spray Flow Rate Loop II, and applicable WO's

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 1 Scheduled Refueling Outage (U1R8)

a. Inspection Scope

From October 23 through November 23, 2010, the inspectors examined critical outage activities associated with the U1R8 refueling outage and the Unit 1 restart to verify that they were conducted in accordance with TS, applicable operating procedures, and the licensee's outage risk assessment and management plans. Some of the more significant inspection activities conducted by the inspectors were as follows:

Outage Risk Assessment

Prior to the Unit 1 scheduled U1R8 refueling outage that began on October 23, the inspectors met with outage risk assessment team members and reviewed the Outage Risk Assessment Report to verify that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing an outage plan that assured the necessary levels of defense-in-depth of safety functions were maintained. The inspectors also reviewed the daily U1R8 Refueling Outage Reports, including the Outage Risk Assessment Management (ORAM) Safety Function Status, and regularly attended the licensee's outage status meetings. These reviews were compared to the requirements in licensee procedure NPG-SPP-07.2, Outage Management. These reviews were also done to verify that for identified high risk significant conditions, due to equipment availability, severe weather and/or system configurations, that contingency measures were identified and incorporated into the overall outage and contingency response plan. Furthermore, the inspectors frequently discussed risk conditions and designated protected equipment with Operations and outage management personnel to assess licensee awareness of actual risk conditions and mitigation strategies.

Shutdown and Cooldown Process

The inspectors witnessed the shutdown and cooldown of Unit 1 in accordance with licensee procedures OPDP-1, Conduct of Operations; 1-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations; and 1-SR-3.4.9.1(1), Reactor Heatup or Cooldown Rate Monitoring.

Decay Heat Removal

The inspectors reviewed licensee procedures 1-OI-74, Residual Heat Removal System (RHR); 1-OI-78, Fuel Pool Cooling and Cleanup System; and Abnormal Operating Instruction 0-AOI-72-1, Alternate Decay Heat Removal System Failures; and conducted main control room panel and in-plant walkdowns of system and components to verify correct system alignment. During planned evolutions that resulted in an increased outage risk condition of “Orange” for shutdown cooling, inspectors verified that the plant conditions and systems identified in the risk mitigation strategy were available. In addition, the inspectors reviewed controls implemented to ensure that outage work was not impacting the ability of operators to operate spent fuel pool cooling, RHR shutdown cooling, and/or the ADHR system. Furthermore, the inspectors conducted several walkdowns of the ADHR system during operation with the fuel pool gates removed.

Critical Outage Activities

The inspectors examined outage activities to verify that they were conducted in accordance with TS, licensee procedures, and the licensee’s outage risk control plan. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Walked down the following selected safety-related equipment clearance orders (i.e., tag-outs)
  - Tagout 1-TO-2010-0003, Clearance 1-074-0037A, RHR System II
  - Tagout 1-TO-2010-0003, Clearance 1-071-0011D, RCIC Bearing Repair
  - Tagout 1-TO-2010-0003, Clearance 1-063-0001A, SLC Injection Valve B
- Verified Reactor Coolant System (RCS) inventory controls
- Verified electrical systems availability and alignment
- Monitored important main control room plant parameters (e.g., RCS pressure, level, flow, and temperature) and TS compliance during the various shutdown modes of operation, and mode transitions
- Evaluated implementation of reactivity controls
- Reviewed control of containment integrity
- Examined foreign material exclusion controls particularly in proximity to and around the reactor cavity, equipment pit, and spent fuel pool
- Performed routine tours of the control room, reactor building, refueling floor and drywell

Reactor Vessel Disassembly and Refueling Activities

The inspectors witnessed selected activities associated with reactor vessel disassembly, and reactor cavity flood-up and drain down in accordance with 1-GOI-100-3A, Refueling Operations (Reactor Vessel Disassembly and Floodup). Also, on numerous occasions, the inspectors witnessed fuel handling operations during the Unit 1 reactor core fuel shuffle performed in accordance with TS and applicable operating procedures, such as GOI-100-3A, Refueling Operations (In Vessel), GOI-100-3B, Operations in the Spent Fuel Pool, and GOI-100-3C, Fuel Movement Operations During Refueling. The inspectors verified specific fuel movements as delineated by the Fuel Assembly Transfer Sheets (FATF).

Drywell Closeout

Between November 19 and November 21, 2010, the inspectors reviewed the licensee's conduct of 1-GOI-200-2, Drywell Closeout, and performed an independent detailed closeout inspection of the Unit 1 Torus and drywell.

Restart Activities

The inspectors specifically conducted the following:

- Witnessed heatup and pressurization of Unit 1 reactor pressure vessel in accordance with 1-SI-3.3.1.A, ASME Section XI System Leakage Test of the Reactor pressure Vessel and Associated Piping
- Reviewed and verified completion of selected items of 0-TI-270, Refueling Test Program, Attachment 2, Startup Review Checklist
- Reviewed 2-SR-3.6.1.1.1(OPT-A) Primary Containment Total Leak Rate - Option A, Revision 6
- Attended multiple Unit 1 Restart PORC Meetings
- Witnessed Unit 1 approach to criticality and power ascension per 1-GOI-100-1A, Unit Startup, and 1-GOI-100-12, Power Maneuvering
- Reactor Coolant Heatup/Pressurization to Rated Temperature and Pressure per 1-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring

Corrective Action Program

The inspectors reviewed PERs generated during U1R8 and attended management review committee meetings to verify that initiation thresholds, priorities, mode holds, operability concerns and significance levels were adequately addressed. Resolution and implementation of corrective actions of several PERs were also reviewed for completeness.

b. Findings

Two findings were identified.

(1) Introduction: A self-revealing apparent violation (AV) of Unit 1 TS Limiting Condition for Operation (LCO) 3.5.1, Emergency Core Cooling System (ECCS) - Operating, was identified for the licensee's failure to establish adequate design control and perform adequate maintenance on the Unit 1 outboard Low Pressure Coolant Injection (LPCI) valve, 1-FCV-74-66, which resulted in the valve being left in a significantly degraded condition and RHR loop II unable to fulfill its safety function.

Description: On October 23, 2010, RHR Loop II LPCI Outboard Injection Valve, 1-FCV-74-66 (Walworth 5509, 24 inch 600 pound angle globe valve), failed to open when operators attempted to place RHR Shutdown Cooling, Loop II, in service to support U1R8 refueling activities. Control room indications indicated the valve was open but no flow was indicated in RHR Loop II with the 1B RHR pump in service. Operators concluded the RHR Loop II flow path was inoperable, and proceeded to secure the 1B RHR pump and promptly placed RHR Loop I in-service for shutdown cooling. Unit 1 was in Mode 3 at the time.

Subsequent visual inspections of the FCV-74-66 valve stem, upper disc skirt, disc, skirt to disc tack welds, and thread engagements identified the following:

- The valve disc was found to be seated and stuck in the valve seat, essentially blocking all RHR Loop II flow.

- The disc was found separated from the stem and upper disc skirt, which would normally be threaded onto the disc skirt and tack welded.

- The two 8 inch fillet welds between the disc skirt and the disc were fractured (welds completely broken apart). Also, further examination discovered the welds to be undersized.

- No upper disc skirt locking key was present.

- The threads on the upper disc skirt were found to be undersized, resulting in partial engagement of thread faces between the disc skirt and disc.

- The thrust washer between the stem and disc was missing.

The licensee initiated PER 271338 to determine the root cause of the valve failure. The licensee's root cause analysis of 1-FCV-74-66 was not complete by the end of the inspection. As part of their immediate corrective actions, the licensee implemented appropriate repairs and modifications to restore FCV-74-66 prior to Unit 1 restart. Also, the licensee conducted an internal inspection of the RHR Loop I LPCI outboard injection valve (1-FCV-74-52) prior to Unit 1 restart. The FCV-74-52 was determined to be intact with no apparent damage or significant degradation. Furthermore, as extent of condition compensatory measures, the licensee has conducted and continued to perform a combination of internal inspections, partial motor-operated valve actuator testing, UT testing, shutdown cooling operation, and/or monthly venting to verify proper conditions of the Unit 2 and 3 FCV-74-52 and 66 LPCI outboard injection valves.

The inspectors found that 1-FCV-74-66 had been modified in 1983 by engineering change notice ECN L2107 to install a V-notch lower disc skirt which was intended to eliminate excessive vibrations experienced at low flow and high pressure drop conditions and provide improved flow control.

Also in 2006, during the Unit 1 recovery an internal inspection of the 1-FCV-74-66 valve was performed. Following this inspection, the 1-FCV-74-66 valve was refurbished and the valve stem was replaced. However, this valve maintenance was performed using an out-dated valve drawing, 0-A-12337-M-1E, and inadequate maintenance procedure for valve internal assembly removal and reinstallation, MCI-0-74-VLV008. This procedure and applicable drawings did not specify appropriate details for the disassembly of the disc, stem, and skirt; installation of the disc locking key, modified skirt, and modified stem; and overall correct design configuration of the valve. During the 2006 valve stem replacement, the stem disc thrust washer was not installed, the disc-to-skirt joint was not welded to specifications, and the installed disc skirt had undersized threads.

The licensee's inspection of the valve found the threads on both the disc and upper disc skirt in generally good condition. However, laboratory microscopic analysis indicated "beaking" or rollover of disc skirt thread crowns. Laboratory analysis of the disc-to-skirt welds also found that the welds were significantly undersized (i.e., a 0.20 inch fillet versus 0.50 inch fillet) with general porosity and cracking. The licensee's root cause analysis of the stem and disc separation was still in progress at the end of the inspection period.

The licensee had identified evidence of multiple impact strikes on the FCV-74-66 valve disc from the blunt end of the separated stem. The inspectors found this to be evidence pointing to how long the disc may have been separated from the stem because during plant operations, the valve was only cycled during quarterly surveillance testing. The inspectors concluded that FCV-74-66 was incapable of performing its safety function for longer than its TS 3.5.1 allowed outage time (AOT) of seven days. As part of their root cause analysis, the licensee was attempting to determine a more exact failure time and duration in order to better evaluate the resultant safety significance. The last time Unit 1 RHR Loop II was successfully placed in-service, thereby demonstrating FCV-74-66 was still operable, was on March 12, 2009 for shutdown cooling.

<u>Analysis</u>: The inspectors determined that the licensee's failure to establish adequate design control and perform adequate maintenance on the Unit 1 outboard LPCI injection valve, 1-FCV-74-66, which resulted in the valve being left in a significantly degraded condition and RHR loop II unable to fulfill its safety function, was a performance deficiency. This performance deficiency was considered greater than minor because it was associated with the Protection Against External Factors attribute of the Reactor Safety/ Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring availability and reliability of systems designed to respond to initiating events to prevent undesirable consequences. Specifically, the RHR subsystem was rendered incapable of being aligned to perform its safe shutdown function due to the failure of 1-FCV-74-66. The inspectors assessed the finding using Inspection Manual Chapter (IMC) 0609, Significance Determination Process (SDP), and determined the finding was potentially greater than very low safety significance because it adversely

affected the operators' ability to achieve safe shutdown. Since this finding was potentially greater than Green it will require a Phase 3 SDP assessment. The safety characterization of this finding is not yet finalized and is currently characterized as To Be Determined (TBD). This finding does not have a cross-cutting aspect because it is not reflective of current licensee performance.

Enforcement: Technical Specification LCO 3.5.1, ECCS-Operating, in part, required that each RHR subsystem shall be operable in Modes 1, 2 and 3, with an allowed outage time of 7 days, or place the unit in Hot Shutdown (Mode 3) within 12 hours and Cold Shutdown (Mode 4) within 36 hours. Contrary to the above, between March 13, 2009, and October 23, 2010, the Loop II RHR subsystem was inoperable without the licensee taking the required TS actions. Pending determination of safety significance, this finding is identified as an apparent violation: AV 05000259/2010005-01, RHR Subsystem Inoperable Beyond the Technical Specifications Allowable Outage Time.

(2) Introduction: A Green self-revealing non-cited violation (NCV) of Unit 1 RHR TS LCO 3.6.2.3, Suppression Pool Cooling, was identified for the licensee's failure to comply with the LCO required actions for an inoperable RHR suppression pool cooling subsystem.

Description: On October 27, 2010, the 1C RHR pump motor seized while Loop I was in operation for shutdown cooling. Unit 1 was in Mode 5 with reactor vessel water level greater than 23' above the flange, fuel pool gates open, and the auxiliary decay heat removal (ADHR) in-service. Operators promptly started the 1A RHR pump to restore shutdown cooling flow. The Loop II of RHR was OOS for repairs. Approximately three hours later, operators secured the 1A RHR pump for outage work and declared the ADHR system as the TS required system for core cooling.

The 1C RHR pump had been in-service for shutdown cooling for approximately 94 hours prior to experiencing a catastrophic failure of the motor on October 27. Total service time for the 1C RHR pump since November 2007 was approximately 350 hours. The mission time of the 1C RHR pump to perform its intended safety functions was 30 days (i.e., 720 hours). Consequently, the 1C RHR pump had been incapable of meeting its required mission time, and thereby considered inoperable, since at least November 2007.

The inspectors found that as part of the Unit 1 recovery project, the 1A and 1C RHR Loop I pump motors were sent offsite to the licensee's Power Service Shop (PSS) in June 2004 to be refurbished. In March of 2005, the refurbished and reassembled 1C RHR pump motor experienced excessive vibration during no-load run testing by PSS. In August 2005, the motor was disassembled, inspected, bearings replaced, reassembled and no-load tested again but vibration readings remained unacceptably high. In September 2005, the 1C RHR pump motor was field balanced, no-load tested acceptably, and returned to Browns Ferry. During uncoupled and coupled runs of the 1C RHR pump motor in September to October 2006, the licensee identified elevated iron content in the lower motor bearing oil reservoir which was indicative of internal motor wear (e.g., rubbing between stationary and rotating elements). This reservoir was subsequently flushed on five separate occasions over a six week period due to persistently elevated iron content in the oil which turned the oil completely black. Almost immediately upon return to service (RTS) in 2007, the IC RHR pump motor exhibited an increasing trend of high vibration as determined by the Predictive Maintenance Program. Unit 1 was restarted on May 17, 2007.

After the Unit 1 restart, until October 2010, the 1C RHR pump motor continued to exhibit an ever increasing trend of elevated radial and axial vibrations, and iron content in the lower bearing oil reservoir. The inspectors concluded that these persistent symptoms were indicative of internal wear that went undiagnosed by the licensee. From March 2009 through August 2010, four PERs and two WOs were initiated to specifically address and correct the degraded equipment conditions associated with high motor vibrations. The licensee's initial diagnosis concluded the 1C RHR pump motor was unbalanced and needed to be re-balanced. However, all four PERs were closed to two WOs (initiated in March and August 2009) which were never worked. Both WOs were removed and/or rejected from the daily work week schedule and the most recent U1R8 outage.

Subsequent disassembly, inspection, and root cause evaluation determined that the rotor of the 1C RHR pump motor had come into physical contact with the stator which resulted in mechanical seizure of the motor. The direct cause of the motor seizure was due to a dynamic physical bow in the rotor shaft, compounded by the field balance weights, which resulted in a significant loss of air gap between the rotor and stator when the motor was in operation. This led to internal rubbing over approximately four years which resulted in catastrophic mechanical failure of the motor. The licensee attributed the root cause of this failure to a misdiagnosis of the dynamic rotor bow that was treated as a rotor imbalance problem during the PSS motor refurbishment in 2005.

The inspectors identified that the 1C RHR pump motor performance over the past four years provided evidence that the rotating elements of the motor (i.e., rotor assembly) had been rubbing against the stationary elements (i.e., stator, upper/lower bearing air and oil seals, and lower bearing). The inspectors concluded that the licensee's predictive maintenance and corrective action programs failed to adequately recognize, evaluate and/or understand an adverse trend in elevated iron content of the lower bearing oil reservoir and increased axial and radial vibrations that exceeded their alert levels for the 1C RHR pump.

Analysis: The inspector's determined that the licensee's misdiagnosis and failure to correct a dynamic physical bow in the 1C RHR pump motor rotor constituted a performance deficiency that resulted in a degraded condition which directly led to mechanical failure of the 1C RHR motor. This performance deficiency was considered greater than minor because it was associated with the Mitigating Systems cornerstone and adversely affected the equipment performance objective to ensure the availability and capability of the RHR system to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the 1C RHR subsystem was degraded to the point that it was incapable of performing its intended safety functions for the required mission time. Since the 1C RHR motor failure occurred during Mode 5 shutdown conditions after a significant period of shutdown cooling operation, the finding was evaluated according to IMC 609, Appendix G, Shutdown Operations SDP, Attachment 1, Phase 1 Operational Checklists, Checklist 7, Refueling Operation with Reactor Coolant Level Above 23'. Accordingly, the finding was determined to be of very low safety significance (Green) because the 1A RHR pump and the ADHR system were available, when only one RHR pump was needed per Section I.C of Checklist 7.

The cause of this finding was directly related to the cross cutting aspect of Thorough Evaluation of Identified Problems in the Corrective Action Program component of the Problem Identification and Resolution area, because the licensee did not adequately evaluate the precursors related to the degraded 1C RHR pump motor performance and properly prioritize the resolution of a known condition adverse to quality in time to preclude motor failure [P.1(c)].

Enforcement: The RHR TS LCO 3.6.2.3, Suppression Pool Cooling, in part, required that four RHR suppression pool cooling subsystems shall be OPERABLE in Modes 1, 2 and 3, with an allowed outage time of 30 days, or place the unit in Hot Shutdown (Mode 3) within 12 hours and Cold Shutdown (Mode 4) within 36 hours. Contrary to the above, between November 2007 and October 2010, the 1C RHR suppression pool cooling subsystem was inoperable without the licensee taking the required TS LCO actions. However, because the finding was determined to be of very low safety significance (Green) and has been entered into the licensee's CAP as PER 274840, this violation is being treated as an NCV consistent with the Enforcement Policy. This NCV is identified as NCV 05000259/2010005-02, Degraded 1C RHR Pump Motor Rendered One RHR Subsystem Inoperable Beyond the Technical Specifications Allowable Outage Time.

.2 Unit 3 Forced Shutdown Due To Main Generator Exciter High Bearing Vibrations

a. Inspection Scope

On December 26, 2010, Unit 3 commenced a forced shutdown due to high vibrations on the main generator/exciter bearings. The main control room received an alarm for high vibrations and noticed two locations (bearings #11 and #12) had experienced a sudden step change in vibrations that exceeded the turbine trip setpoint. The operators initiated a manual reactor scram, followed by a trip of the main turbine, as required by their operating procedures. The licensee initiated necessary repairs to the affected bearings and the main generator exciter. The licensee determined the cause of the high vibrations was due to a high temperature difference between the 3A and 3B exciter coolers that resulted in reduced clearances between the exciter casing and bearing housings. Unit 3 remained shutdown through the end of the report period. During this short notice forced outage, the inspectors examined the conduct of critical outage activities pursuant to TS, applicable procedures, and the licensee's outage risk assessment and outage management plans. The more significant outage activities witnessed, monitored, examined and/or reviewed by the inspectors were as follows:

- Shutdown and cooldown of Unit 3 in accordance with general operating instruction (GOI) 3-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations, and 3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring

- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 3 forced outage and verified that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following five 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:

- 2-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure

Routine Surveillance Tests:

- 0-SR-3.8.4.4 (SB-D), Shutdown Board D Battery Modified Performance Test
- 0-SR-3.7.3.2 (HEPA), Control Room Emergency Ventilation System In Place Leak Test
- 1-SI-4.7.A.2.a-f, Primary Containment Integrated Leak Rate Test

Reactor Coolant System Leak Detection Tests:

- 3-SR-3.4.5.3, Drywell Floor Drain Sump Flow Integrator Calibration

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP7 Emergency Exercise Evaluation

a. Inspection Scope

On December 14, the inspectors observed the Emergency Preparedness (EP) portion of a site exercise consistent with the requirements of NRC Inspection Procedure 711114.07. The inspectors observed emergency response operations in the simulated control room to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Classification Procedure and other applicable Emergency Plan Implementing Procedures. The inspectors also attended the licensee's critique of the drill to verify any inspector observed weaknesses were also identified by the licensee.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Cornerstone: Initiating Events

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the Performance Indicators (PIs) listed below, including procedure NPG-SPP-02.2, Performance Indicator Program. The inspectors examined the licensee's PI data for the specific PIs listed below for the fourth quarter of 2009 through the third quarter of 2010. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC for the third quarter 2010 PI report to verify that the data was correctly reflected in the report. Additionally, 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. 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, Regulatory Assessment Performance Indicator Guideline, 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 Service Request (SR) report summaries, and periodically attending Corrective Action Review Board (CARB) and PER Screening Committee (PSC) meetings.

.2 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 2010 through December 2010, although some PER database and WO searches expanded beyond these dates. The inspectors reviewed the licensee's integrated trend review (ITR) program and the quarterly implementation of the process as documented in licensee procedure NPG-SPP-02.8, Integrated Trend Review, Rev. 01. 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 new procedures, NPG-SPP-02.8, Integrated Trend Review, Rev. 01 and NPG-SPP-02.7 PER Trending, Rev. 01 issued during this period.

b. Findings and Observations

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

The purpose of the licensee's integrated trend review process was to identify the top issues (gaps to excellence) requiring management attention. Other objectives of the ITR program 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. The inspectors determined that the new guidance provided in NPG-SPP-02.8 was adequate to meet the purpose and objectives of the ITR program. The inspectors also reviewed the two most recent Integrated Trend (IT) reports. The licensee had identified certain departments that did not submit their reports on time which contributed to the site report being issued after its required due date. The inspectors noted that SRs were written for each occurrence. The inspectors also noted that the new procedures improved the consistency of trend discussions and the report format across departments.

The inspectors also identified several other observations related to the licensee's implementation of the ITR program. The licensee initiated PER 302232 for these observations.

The inspectors conducted an independent review to identify potential adverse trends, and identified several notable trends which were either verified to be in the licensee's CAP and/or referred to the licensee who entered them into their CAP. The potential adverse trends were as follows:

- During the Unit 1 refueling outage (RFO) U1R8, the inspectors noted four service requests (SR) were written to document foreign material in the Unit 1 spent fuel pool (SFP). The licensee initiated SR 281642 and PER 282539 to address several additional examples of foreign material in the SFP and reactor vessel. The license initiated PER 277764 to document the adverse trend in foreign material during the U1R8 RFO. As foreign material issues were discovered, SRs were initiated and appropriate corrective actions taken to remove the foreign material and provide personnel coaching where appropriate. Additional actions to review and/or improve the implementation of the site's foreign material exclusion (FME) program were planned, but not completed by the end of this inspection period.

- PER 213116 was generated to address the licensee's actions to address an inspector identified trend, concerning the adequacy of post maintenance testing (PMT), which has been previously documented in multiple inspection reports, but is yet to be adequately addressed by the corrective action program. The licensee developed another corrective action plan including actions to develop a PMT team with a team charter. The inspectors reviewed the charter which included additional actions for the team. However, due dates for those actions were not provided. The PER was closed on July 22, 2010, upon development of the team charter. The licensee identified the corrective actions from PER 213116 were not effective and initiated PER 246534 on Aug. 25, 2010. This PER was assigned a higher level in accordance with licensee procedure NPG-SPP-02.8. None of the corrective actions were completed by the end of this inspection period. On Dec. 17, 2010, the inspectors observed the PMT associated with the U2 HPCI system. It was discovered that two additional work orders (WO) for the HPCI system did not have PMTs assigned. The licensee captured this issue in their CAP as PER 299877.

- The inspectors identified a potential adverse trend regarding inaccuracy and incomplete information contained in LERs. During the review of LERs from 2009 through 2010, inspectors identified seven examples where LERs contained inaccurate statements, incomplete descriptions and details, and other technical and editorial errors. The licensee had previously initiated the following PERs to resolve the issues identified by the inspectors: PERs 215479, 205308, 201410, and 163176. Additionally, as documented in report Section 4OA3.1 below, the inspectors identified two violations associated with inadequate and incomplete information in Unit 3 LER 2009-003. The licensee initiated SR 314177 to address this apparent adverse trend.

- Over the past operating cycle, Units 2 and 3 have developed a large number of control rod Rod Position Indication System (RPIS) component problems. Unit 2 had outstanding WO's on about 25 different control rods with RPIS related problems, and Unit 3 had about 15 control rods with WO's. These problems involved incorrect back lighting, intermittent drift alarms, and primarily inaccurate rod position indication at one or more positions. The licensee initiated SRs 313460 and 313465 to address this adverse trend.

.3 Annual Sample: Review of Cross Cutting Aspect H.2.c

a. Inspection Scope

The inspectors reviewed the cause analysis and specific corrective actions associated with PER 228347, Emerging Trend in Human Performance Cross-Cutting Area. This PER was initiated to evaluate an overall adverse trend in NRC findings and licensee events attributed to human performance issues associated with the "Resources" component area (i.e., H.2) defined by Inspection Manual Chapter (IMC) 0310, Components Within The Cross Cutting Areas. During this inspection, the inspectors focused primarily upon the cross-cutting aspect (CCA) of H.2.c. In IMC 310, this CCA is described as the licensee ensures that personnel, equipment, procedures, and other resources are available to assure nuclear safety, specifically, those necessary for complete, accurate, and up-to-date design documentation, procedures, and work packages, and correct labeling of components. Within the preceding 12 months, the NRC has cited three violations with a cross-cutting aspect of H.2.c that were included as part of PER 228347. The violations for which the CCA is cited include: Failure to perform an adequate risk assessment during severe weather conditions (PER 171402); Inadequate operating procedures cause partial loss of reactor feedwater, which results in Unit 2 manual reactor scram (PER 203538); and Inadequate surveillance procedure to ensure all relevant RPV metal temperatures were monitored during leak testing (PERs 223539 and 224778). The licensee also included an additional 57 PERs for review in the common cause analysis of this PER. The inspectors reviewed the events and analysis of the events, the extent of condition, previous similar events, root and contributing causes, the licensee's safety culture evaluation, and corrective actions taken or planned for this PER.

b. Findings and Observations

No findings were identified. Inspectors determined that, in general, the licensee's root cause analysis (RCA) of the human performance cross cutting implications of the NRC findings associated with the H.2.c CCA was technically accurate, of sufficient depth, and consistent with the licensee's process. The RCA was determined to have adequately addressed operability, reportability, common cause, generic concerns, extent-of-condition, and extent-of-cause. The inspectors also determined that the licensee had appropriately identified and prioritized corrective actions. Furthermore, in general, the corrective actions to prevent recurrence (CAPRs) and additional corrective actions implemented to date, or scheduled to be implemented, are considered reasonable to address the root cause. However, the inspectors identified the following observations which were discussed with the licensee:

Not all of the licensee's corrective actions were completed. As part of the licensee's corrective actions, various communication methods of management expectations have been ongoing. Training teams were formed or forming, and industry benchmarking was in progress. The plant procedure upgrade was also in progress and lists of the most difficult procedures for each department have been generated. However, after these more difficult procedures were identified it was unclear as to what actions the licensee was taking to ensure personnel and management were taking any compensatory actions regarding future use of these procedures until the planned improvements were implemented. In response to the inspectors' observations, PER 302263 was initiated to evaluate whether some form of compensatory measures should be established when working with these procedures.

In addition, the licensee had identified prior similar events related to human performance through self assessments, benchmarking and QA assessments. However, previous corrective actions related to these prior events had failed to provide sustainable resolution of the issues in the past. Since the licensee's corrective actions for the H.2 adverse trend were still ongoing, a final effectiveness review of these actions has not been accomplished. The inspector noted that in the interim, since the licensee identified this adverse trend, and began taking corrective actions; there have been no new NRC findings or violations with a CCA of H.2.c.

.4 Annual Follow-up of Selected Issues – Assessment of Progress in Addressing the Substantive Cross-Cutting Issue (SCCI)

a. Inspection Scope

The inspectors reviewed the licensee's progress on the development and implementation of corrective actions to address the SCCI identified in the NRC Annual Assessment Letter for the period of January – December 2009. The SCCI was identified in the problem identification and resolution area, in the aspect of thorough evaluation of identified problems (P.1 (c)). The SCCI was subsequently held open in NRC Mid-Cycle Performance Review Letter for the period January – July 2010 in order to give the licensee time to develop and schedule a corrective action plan. This PI&R inspection was the first opportunity to review the licensee's actions to address the open SCCI.

The inspectors conducted a detailed review of the licensee's common cause and root cause analysis (PER 223536) related to the open SCCI to assess the adequacy of the licensee's evaluation of the problems identified. The inspectors reviewed these evaluations against the guidance in licensee procedure NPG-SPP-03.1.6, "Root Cause Analysis" and the performance attributes of NRC Inspection Procedure 71152. The inspectors assessed if the licensee had adequately determined the cause(s) of identified problems, and had adequately addressed operability, reportability, common cause, generic concerns, extent-of-condition, and extent-of-cause. The review also assessed if the licensee had appropriately identified and prioritized corrective actions to prevent recurrence. Inspectors also reviewed a sample of completed corrective actions (twenty-five of fifty-two total corrective actions were complete at the time of the inspection) to independently verify that the corrective actions were implemented as intended.

The inspectors also noted that the licensee had identified a trend of findings in the problem identification and resolution area, in the aspect of timely corrective actions (P.1 (d)) which they included in their root cause analysis and corrective actions to address the open SCCI. Because of the inclusion of both cross cutting areas in their root cause analysis and corrective actions, the observations of the inspectors reflect the licensee's progress in addressing both areas. Documents reviewed are listed in the Attachment.

b. Assessment

Inspectors determined that, in general, the licensee's evaluation of the SCCI was technically accurate and of sufficient depth to address the issue. The analysis was determined to have adequately addressed operability, reportability, common cause, generic concerns, extent-of-condition, and extent-of-cause. The inspectors also determined that the licensee had appropriately identified and prioritized corrective actions. However, the inspectors did make the following observations regarding the licensee's evaluation of the SCCI (for which the licensee initiated PER 311304):

- Inspectors noted that many of the actions identified to address the open SCCI were similar to previous corrective actions to address weaknesses in the Problem Identification and Resolution area (PERs 151140, 153438 and 136489) that had proven to be ineffective over the long term. Inspectors also noted that previous corrective actions (CA) included the actions taken to address weaknesses in the area of timeliness of corrective actions for the P.1(d) SCCI closed out in NRC Mid-Cycle Performance Review Letter for the period January – July 2009. The licensee's discussion of previous similar events included in the root cause report noted that previous corrective actions had been unsuccessful at ensuring sustainable improvements. However, a rigorous evaluation of why previous actions were ineffective was not included.

- Inspectors noted that clearly defined success measures were not defined for the critical aspects of all of the corrective actions to prevent recurrence (CAPRs) identified in the root cause as required by licensee procedure PIDP-6, "Root Cause Analysis". Most notably, no success measures were defined in the root cause to measure the critical aspect of sustainability of the CAPR's. Inspectors concluded that, given the history of unsustainable corrective actions to address weaknesses in the Problem Identification and Resolution area noted in the root cause, additional success measures and effectiveness review actions were warranted to ensure sustainable and effective corrective actions.

Inspectors determined that, in general, the corrective actions implemented to date or scheduled to be implemented to address the SCCI were appropriate. The licensee initiated CAPRs and additional corrective actions to address the three common causes identified. The inspectors were able to evaluate the implementation of a sample of the twenty-five completed corrective actions. During the review of selected records, the inspectors identified two corrective actions which were not completely implemented as intended, as follows:

- CA 223536-039 was created as an Interim Corrective Action to address the Extent of Cause (EOC) for the root cause. This action directed the CARB to reevaluate all open root cause PERs to determine if the following were adequately addressed: plant risk significance, timeliness of actions, and sufficiently detailed and timely interim actions. The action was closed to a previously completed action from a different PER, CA 214592-010, which was completed five months earlier. However, inspectors identified that the scope of the completed action only included PERs greater than one year old. The licensee initiated SR 294998 to address this issue.

- CA 223536-023 directed a backwards assessment of RCAs and ACEs for systems important to safety for the previous two years to verify the adequacy of the previous evaluations and CAs. The CA also directed an increase in sample size if necessary. A contractor conducted the backwards assessment for the licensee and provided the results in a report dated September 2, 2010. The licensee subsequently marked the CA as complete. Inspectors reviewed the report and noted that it documented eleven separate issues for "immediate follow-up" out of a sample of seven RCEs and thirty-one ACEs reviewed. However, at the time of the inspection, 3 months after the report was completed, the issues had not been evaluated and no consideration was given to increasing the sample size based on the number issues identified. The licensee initiated SR 295007 to address this issue.

Inspectors were unable to assess the effectiveness of the completed and open corrective actions due to the number of open corrective actions and the limited time since implementation of completed corrective actions.

c. <u>Findings</u>

No findings were identified.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Reports (LERs) 05000296/2009-003-01 and -02, Reactor Core Isolation Cooling System Inoperable Longer Than Allowed By the Technical Specifications

a. Inspection Scope

The original LER 50-296/2009-003-00 dated May 24, 2010, and applicable PERs 200183,119628 and 246527, including cause determination and corrective action plans, were reviewed by the inspectors and documented in Section 4OA3.2 of NRC inspection report (IR) 05000296/2010003. As a result of this prior review, two violations of NRC requirements were identified: NCV 05000296/2010003-02, Unit 3 RCIC System Inoperable beyond the Technical Specifications Allowed Outage Time; and NCV 05000296/2010003-03, Failure to Provide Complete and Accurate Information in LER 0500296/2009-003-00. The NCV 05000296/2010003-03 was the result of the review of the original LER, when the inspectors determined that, contrary to 10 CFR 50.9, LER 0500296/2009-003-00 was not accurate or complete in all material aspects for which the licensee initiated PER 246527. Specifically, the LER inaccurately reported the duration of system inoperability, inaccurately reported the availability of HPCI while the RCIC was inoperable, and did not report a previous event that occurred on the same unit with the same cause as required by 10 CFR 50.73(b)(5).

As part of the PER 246527 corrective actions, the licensee issued a revised LER 0500296/2009-003-01 on July 15, 2010. The principal intent of this LER revision was to establish the date that began the period of RCIC inoperability as March 22, 2006, and to notify the NRC that additional time was needed to complete a determination of any concurrent HPCI system inoperability. The licensee revised their commitment to supplement the LER to September 30, 2010. Subsequently, the licensee issued their second revised LER 0500296/2009-003-02 on August 31, 2010. This LER was revised by the licensee to correct and update the LER narrative with an expanded timeline and results from their efforts to retrieve high speed computer data regarding actual RCIC pump performance. This second revision was also intended to address and correct any missing or inaccurate information identified by the inspectors in the original LER. This revised LER included changes to the Abstract, Description of Event, Cause of the Event, Analysis of the Event, and Corrective Actions.

The second revision of the LER did specifically report a more accurate duration of system inoperability, including when the nonconforming turbine electric governor-remote (EG-R) had been installed; a discussion of concurrent HPCI unavailability while RCIC was inoperable; and a discussion of the previous event on February 9, 2007 that occurred on the same unit with the same cause. The inspectors reviewed the revisions 1 and 2 of the LERs, and verified the root causes and previously identified corrective actions for the RCIC flow instabilities were not substantially different, except for the additional clarifying information provided.

b. Findings

This LER is considered closed with one NRC identified finding related to the LER itself.

Introduction: A Severity Level IV, cited violation (VIO) of 10 CFR 50.9, Completeness and Accuracy of Information, was identified by the inspectors for the licensee's repeat failure to provide complete and accurate information regarding the licensee's LER 0500296/2009-003-02, Reactor Core Isolation Cooling System Inoperable Longer than Allowed by Technical Specifications.

Description: Following the Unit 3 reactor scram on August 24, 2009, the RCIC system auto-initiated as designed and injected into the reactor pressure vessel (RPV) restoring reactor water level. Subsequent review of RCIC system operating parameters revealed an unexpected level of instability in system flow and turbine control system response. The RCIC system flowrate was discovered to have oscillated between approximately 300 gpm to 900 gpm. On September 12, 2009, Unit 3 conducted a shutdown for unrelated maintenance and the RCIC EG-R hydraulic actuator was replaced. The licensee had the EG-R vendor conduct testing and inspection of the original EG-R to determine the cause of the oscillations. The vendor determined that the cause of the oscillations was due to a missing buffer piston and buffer spring in the EG-R. These components were essential in providing the smoothing and/or dampening function of the controller, without which resulted the observed flow oscillations. It was determined that the EG-R was missing these components since original installation in 2006. On March 25, 2010, the licensee determined that the installation of this EG-R had rendered the Unit 3 RCIC system inoperable which represented a condition prohibited by TS since RCIC had been inoperable beyond the AOT of TS LCO 3.5.3. In addition, Unit 1 had changed modes of operation without evaluating the impact on risk as required by TS 3.0.4.

On May 24, 2010, the licensee submitted LER 05000296/2009-003-00. The LER attributed the root cause for the RCIC flow oscillations to be the missing EG-R components. However, the LER did not mention when the faulty EG-R had been installed. Also, this LER inaccurately stated that RCIC had been inoperable from August 26, 2009, to September 12, 2009, and that HPCI was operable during this time period. Furthermore, the LER failed to identify and describe the reactor scram event on February 9, 2007 when the Unit 3 RCIC flow oscillations were first recognized, and did not describe the subsequent corrective actions. The corrective actions following this event included maintenance on a control system wiring terminal lug, EG-R needle valve adjustment and turbine governor valve replacement. However, the subsequent post maintenance testing was conducted using the routine quarterly surveillance procedure which operated RCIC in a condensate storage tank (CST) recirculation mode, rather than aligned for RPV injection. Since no RCIC oscillations were identified during the surveillance test, the licensee erroneously concluded that the flow oscillations had been corrected. Unbeknownst to the licensee the faulty EG-R only became a factor when RCIC was actually injecting against the dynamic pressure head of the RPV. The inspectors determined that, contrary to 10 CFR 50.9, the initial LER 0500296/2009-003-00 was not accurate or complete in all material aspects for the reasons mentioned above. The licensee then initiated PERs 232668 and 246527 and the NRC documented a non-cited violation (i.e., NCV 05000296/2010003-03).

Subsequently, the licensee issued revised LERs 05000296/2009-003-01 on July 15, 2010, and 05000296/2009-003-02 on August 31, 2010. The inspectors reviewed the revised LERs, and identified incomplete and inaccurate information in LER 0500296/2009-003-02. The inspector identified issues are detailed below:

- Section 5 Event Date was incorrectly documented as August 26, 2009. The event date was March 22, 2006, following the replacement of the RCIC EG-R as documented by the licensee in the cover letter of the first LER revision.

- Section I referenced time is not specific for when the licensee had actually determined the RCIC had been previously inoperable which was March 25, 2010, significantly distanced from the event date.

- The narrative, Sections II, IV and VI, discussed the previous RCIC instability event on February 9, 2007, but failed to describe the corrective actions taken to address the RCIC oscillations (i.e., maintenance activities and post maintenance testing) that proved unsuccessful but led the licensee to conclude via a functional evaluation that the RCIC system was operable. Furthermore, the narrative did not describe why these repairs and subsequent post maintenance testing did not resolve the RCIC instabilities. The licensee’s business procedure BP-213, Managing TVA’s Interface With NRC, established the required guidance for writing and submitting LERs. This guidance directed the licensee to utilize NUREG-1022, Event Reporting Guidelines 10 CFR 50.72 and 50.73. Section 5.2.5, Previous Occurrences, of NUREG-1022 states that if any earlier events, in retrospect, were significant in relation to the subject event to discuss why prior corrective action did not prevent recurrence. This same omission by the licensee, and the specific NUREG-1022 guidance, was documented in detail as part of NCV 05000296/2010003-03.

- The narrative, Section IV, Analysis of the Event, incorrectly referenced oscillations that occurred on February 9, 2007 as occurring on February 13, 2007.

- The narrative, Section V, Assessment of Safety Consequences, while discussing periods of coincident HPCI unavailability with RCIC being inoperable, did not address the resultant TS impacts to Unit 3.

- The narrative, Section VII.B, Previous LERs on Similar Events, indicated no similar events. However, NUREG 1022 states that previous similar events are not necessarily limited to events reported in LERs.

- The narrative, Section VII.C, Additional Information, referenced the two PERs for the two separate RCIC flow oscillation events, but does not reference a PER for the previous 10CFR50.9 NCV for incomplete and inaccurate LER information.

- The corrective actions established by PERs 232668 and 246527 to develop and submit another LER revision that would address the inaccurate and incomplete information, specifically documented in IR 05000296/2010003 for NCV 05000296/2010003-03, were not effective.

The licensee initiated PER 304722 to determine the cause of the inaccurate and incomplete information contained in revised LER 0500296/2009-003-02, and to evaluate if the LER should be further supplemented. The licensee's guidance for corresponding with the NRC required multiple levels of supervisory and management review and concurrence on submittals, including LERs. Despite these multiple levels of review and previous NRC identification of incomplete or inaccurate information for the original LER documented in IR 05000296/2010-003, the licensee's CAP and LER review process did not prevent LER revision 2 from again containing inaccurate and incomplete information. Based on extensive NRC involvement on the issue and previously completed NRC regulatory action, the inspectors determined that the licensee's failure to provide complete and accurate information in the LER was not a willful attempt to withhold information, but rather a break down in the CAP, and LER submittal review and approval process.

<u>Analysis</u>: Because violations of 10 CFR 50.9 are considered to potentially impede or impact the regulatory process, they are dispositioned using the traditional enforcement process. The inspectors concluded that the licensee had reasonable opportunity to foresee and correct the incomplete/inaccurate information prior to the information being submitted to the NRC. As a result, this issue was considered a performance deficiency. The performance deficiency was ultimately considered to be more than minor per the NRC Enforcement Manual, Section 2.10.F, since adequate corrective action was not taken to ensure complete and accurate information was provided in LER revision 2, and this finding was identified by the NRC. Furthermore, because the violation was NRC identified and repetitive, this violation was dispositioned as a cited violation in accordance with Section 2.3 of the NRC Enforcement Policy and Section 3.1.2 of the NRC Enforcement Manual, and determined to be of Level IV significance based on Section 6.9 of the NRC Enforcement Policy. No cross cutting aspect was assigned because the ROP was not applicable.

<u>Enforcement</u>: 10 CFR 50.9, Completeness and Accuracy of Information, required, in part, that information provided to the Commission by a licensee shall be complete and accurate in all material respects. Contrary to the above, on August 31, 2010, the licensee submitted a revised LER, as corrective action for a previous 10 CFR 50.9 violation involving the inoperability of the Unit 3 RCIC system, which was not complete and accurate in all material respects. Specifically, the revised LER did not report the correct event date, did not discuss prior corrective actions (e.g., maintenance and testing) for a previous event, and why these corrective actions did not prevent recurrence (as specifically documented in IR 05000296/2010003). This violation was determined to be a Severity Level IV violation and was entered into the licensee's corrective action program as PER 304722. This is a violation of 10 CFR 50.9 and is identified as VIO 05000296/2010005-03, Repeated Failure to Provide Complete and Accurate Information in LER 0500296/2009-003-02. A notice of violation is attached.

.2 <u>(Closed) LER 05000260/2010-003-00, Reactor Scram Due to Closure of the Main Steam Isolation Valves and Subsequent Invalid RPS Scram from the Intermediate Range Monitoring System</u>

a. <u>Inspection Scope</u>

On June 9, 2010, Unit 2 experienced an automatic reactor scram from full power due to an unexpected closure of the main steam isolation valves (MSIV) from a Primary Containment Isolation Signal (PCIS) Group 1 actuation. The inspectors' initial event followup and evaluation of this event were documented in Section 4OA3.1 of IR 05000260/2010003. Since then, the inspectors reviewed the associated LER dated August 9, 2010. Following completion of the root cause analysis, the licensee was unable to determine a definitive cause for this event. However, two possible causes were identified: 1) Foreign material from the control air system might have caused the 2A (MSIV) direct current (DC) solenoid valve to bind; or 2) Intermittent electrical fault in the DC power system. Although neither of these possible causes were confirmed, the licensee developed corrective actions to address both of them.

b. <u>Findings</u>

No findings were identified. This LER is considered closed.

.3 <u>(Closed) LER 05000260/2010-001-00, Condition Prohibited By Technical Specifications When Two Emergency Core Cooling Systems, Loops I and II of the Residual Heat Removal System Low Pressure Coolant Injection System, Became Inoperable</u>

a. <u>Inspection Scope</u>

The inspectors reviewed LER 50-260/2010-001, dated April 26, 2010, and the applicable PER 218493, including associated apparent cause determination and corrective action plans.

On February 25, 2010, operators determined that Unit 2 had entered TS Limiting Condition of Operation (LCO) 3.0.3 when both loops of RHR were declared inoperable. Within an hour of entering TS LCO 3.0.3, operators began reducing reactor power to shutdown Unit 2 as required by TS. However, once operators realigned the ECCS keep fill system to increase RHR Loop II system pressure, they were able to declare RHR Loop II operable again. At which point, TS LCO 3.0.3 was exited and reactor power was returned to 100 percent the same day. Unit 2 had entered TS LCO 3.0.3 for approximately 80 minutes due to both loops of RHR being inoperable. The conditions that led up to both loops of RHR being declared inoperable are described below.

On December 18, 2009, Operational Decision Making Issue (ODMI) 210437 was issued to address RHR system Loop II discharge piping elevated temperatures due to reactor coolant seat leakage past the RHR Loop II injection line discharge check valve and gate valve. This ODMI established monitoring guidelines and specific temperature thresholds for ensuring RHR Loop II discharge piping remained sub-cooled to preclude steam voiding. On February 24, 2010, RHR system Loop I was removed from service for planned maintenance. Then on February 25, operators recognized that RHR Loop II discharge temperature had increased to 264° Fahrenheit (F) which exceeded the ODMI trigger value (i.e., 260°F) for ensuring operability. However, per the ODMI instructions, operators were able to promptly lineup an alternate keep fill source that increased RHR Loop II discharge pressure which restored sub-cooled conditions.

Subsequent engineering evaluation by the licensee, determined that the actual ODMI trigger value was indeed conservative for the actual RHR Loop II discharge piping temperatures and keep fill pressure. This evaluation was able to conclude that the elevated RHR Loop II discharge temperatures of February 25 had not reached steam saturation conditions. Furthermore, an ultrasonic testing (UT) examination of the RHR Loop II discharge piping on February 26 confirmed the absence of any steam voiding. Based on the licensee's evaluation, and UT exam, the RHR system Loop II was fully operable and capable of performing its intended safety functions on February 25, 2010.

b. Findings

No findings were identified. This LER is considered closed.

.4 Unit 3 Manual Reactor Scram

a. Inspection Scope

On December 26, 2010, Unit 3 was manually scrammed from approximately 90% power due to high vibrations on the main generator exciter bearings that exceeded the required threshold for tripping the main turbine. Upon notification by the shift manager, the inspector responded to the control room and verified that the unit was stable in Mode 3 (Hot Shutdown), and confirmed that all safety-related mitigating systems had operated properly. The inspector evaluated safety equipment and operator performance before and after the event by examining existing plant parameters, strip charts, plant computer historical data displays, operator logs, and the critical parameter trend charts in the reactor scram report. The inspector also interviewed available onshift Operations personnel, examined the implementation of the applicable ARPs and AOIs, including 3-AOI-100-1, Reactor Scram, and reviewed the written notification made in accordance with 10 CFR 50.72. The inspector discussed the preliminary cause of the bearing high vibrations with responsible Operations personnel.

b. Findings

No findings were identified during the initial event followup.

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) Unresolved Item (URI) 05000259, 260 and 296/2010004-01, Uncontrolled Materials Adversely Impacted the Capability of the EDG Building Emergency Drainage System to Mitigate an Internal Flooding Event

a. Inspection Scope

This URI 05000259, 260 and 296/2010004-01 was opened pending additional information from the licensee and subsequent review by the inspectors. The licensee initiated PER 256390 to remove the temporary equipment from the Unit 1/2, and Unit 3, EDG building lower corridors. The inspectors reviewed the licensee’s actions and conducted tours of the EDG buildings to verify whether all temporary equipment was removed or properly restrained per the licensee’s procedural requirements. Additionally, the inspectors reviewed the results of WOs 111530751 and 111530754 to verify the as-found condition of the EDG building floor drain sumps were operable, and whether the building sump high level alarm would alert the main control room. The licensee also initiated PER 268624 to perform a past operability evaluation of the EDG building emergency drain function which considered the potential adverse impacts of the specific items left in the EDG building lower corridors. Furthermore, the inspectors reviewed the licensee’s annunciator response procedures (ARP) for a high water level in the DG building sump to verify whether required operator actions would be timely and sufficient to prevent an adverse impact to the EDGs from an internal flooding event.

b. Findings

No findings were identified. However the inspectors identified a minor violation of TS 5.4.1.a because the licensee failed to implement the requirements of licensee procedure 0-TI-471, Temporary Equipment Control, Rev. 04 in the common U1/2 EDG building and U3 EDG building. TS 5.4.1.a required, in part, that written procedures shall be established, implemented, and maintained covering the activities and procedures recommended in Regulatory Guide (RG) 1.33, Rev. 2, Appendix A. Section 1c, of RG 1.33, Rev. 2, Appendix A required the licensee to have a procedure for Equipment Control. Licensee procedure, 0-TI-471, Temporary Equipment Control, section 7.1.1 required temporary equipment to be removed from plant areas; or, attended, restrained or stored. Contrary to the above requirements, the inspectors identified unattended and loose materials in the EDG building lower corridors that included potential licensing basis internal flooding sources (e.g., the EECW North and South supply header piping). This failure to comply with TS 5.4.1.a constitutes a violation of minor significance that is not subject to enforcement action in accordance with the NRC's Enforcement Policy.

.3 (Closed) Notice of Violation (VIO) 07200052/2010-003-01 (EA-10-215), Repeated Failure to Control Transient Combustibles in Proximity of the Independent Spent Fuel Storage Facility (ISFSI)

a. Inspection Scope

The inspectors reviewed the licensee's response to VIO 07200052/2010-003-01 (EA-10-215) dated November 29, 2010. The licensee's corrective actions included establishment of an ISFSI Pad Escort Zone (i.e., fenced in area of the ISFSI pad) with appropriate posted signage and gate locks to preclude unattended vehicles from being parked on the pad and to require Operations escort for any access to the ISFSI pad. The licensee also established an ISFSI Pad Exclusion Zone (i.e., an area 150 feet from any point on the ISFSI pad) that would be routinely monitored by Operations to ensure transient combustibles were maintained at least 150 feet from the ISFSI pad.

The inspectors conducted a tour of the ISFSI Pad Escort Zone and ISFSI Pad Exclusion Zone to verify the licensee's controls were in place and were being effectively applied. The inspectors also reviewed the ISFSI Pad Protection Plan instructions and briefing sheet guidance contained in the latest BFN Operation's Daily Instructions (ODI) dated December 15, 2010. Furthermore, the inspectors reviewed the latest revision (revision 210) of 0-GOI-300-1, Operator Round Logs, Attachment 12, Outside Operator Round Log, Sections 6.0, Steps (23) and (24), that define and verify the ISFSI Pad and Exclusion Zones are clear of uncontrolled transient combustibles.

b. Findings

No findings were identified. This VIO is considered closed.

.4 Follow-up On Alternative Dispute Resolution Confirmatory Orders (IP 92702)

a. Inspection Scope

During the inspection period the inspectors completed a review of TVA's completion of Confirmatory Order for Office of Investigation Report Nos. 2-2006-025 & 2-2009-003, item numbers 2, 5, 7, 8, and 9. These individual items are considered closed.

2. By no later than seven (7) calendar days after the issuance of this Confirmatory Order, a member of TVA's executive management responsible for the licensee's

nuclear power plant fleet will, in writing, communicate TVA's policy, and the expectations of management, regarding the employees' rights to raise concerns without fear of retaliation in the context of this Confirmatory Order.

5. By no later than sixty (60) calendar days after the issuance of this Confirmatory Order, representatives from the TVA's OGC and Human Resources shall conduct a lessons learned training session

7. TVA shall incorporate a discussion of NRC's employee protection rule in the next revision of the "One Team, One Fleet, One TVA" booklet. The next revision will be completed by no later than December 31, 2010.

8. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall modify its contractor in-processing program to ensure that a TVA representative provides a presentation regarding the CRP program and the TVA's SCWE policy during the contractor in-processing sessions.

9. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall revise its training program for new supervisors to incorporate a classroom discussion of the NRC's employee protection rule and the Company's policy on SCWE.

The inspectors also performed a follow-up review of TVA's implementation of Confirmatory Order for Office of Investigation Report Nos. 2-2006-025 & 2-2009-003, item numbers 1, 6, and 10. These items are not closed.

1. By no later than ninety (90) calendar days after the issuance of this Confirmatory Order, TVA shall implement a process to review proposed licensee adverse employment actions at TVA's nuclear plant sites before actions are taken to determine whether the proposed action comports with employee protection regulations, and whether the proposed actions could negatively impact the SCWE.

6. Through calendar year 2013, TVA shall conduct "Town Hall"-type meetings at least annually at its nuclear power plants and corporate office with TVA and contractor employees which address topics of interest, including a discussion on TVA's policy regarding fostering a SCWE.

10. TVA's annual online computer-based training course initiative, which discusses the components of a nuclear safety culture, what is meant by a SCWE, and the avenues available to raise concerns, shall be maintained through calendar year 2013.

b. Findings and Observations

No findings were identified.

The inspectors raised a concern during the inspection of item #1 about the content of TVA's Adverse Employment Action Procedure - TVA-SPP-11.10. TVA staff understood the concern and were in the process of incorporating modifications to the procedure with an expected completion of late February or early March 2011.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On January 11, 2011, the senior resident inspector presented the inspection results to Mr. Keith Polson and other members of the site'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.

An exit meeting was conducted on October 15, 2010, to discuss the findings of the 71111.11B inspection. The inspectors confirmed that no proprietary information was reviewed during this inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Albright, Simulator Manager
S. Austin, Licensing
W. Baker, Operations Support Superintendent
S. Bono, Maintenance Manager
J. Boyer, System Engineering Manager
O. Brooks, Operations LOR Supervisor
W. Byrne, Site Security Manager
P. Chase, Site Nuclear Assurance Manager
J. Colvin, Engineering Programs Manager
P. Donahue, Assistant Engineering Director
G. Doyle, Assistant to the Site Vice President
M. Durr, Director of Engineering
M. Ellet, Maintenance Rule Coordinator
J. Emens, Licensing Manager
B. Evans, Instrumentation and Controls Superintendent
A. Feltman, Emergency Preparedness Manager
N. Gannon, Plant General Manager
K. Gregory, Director Projects
K. Groom, Mechanical Design Engineering Supervisor
B. Jones, Mechanical Maintenance Superintendent
J. Keck, Reactor Engineering Manager
S. Kelly, Assistant Work Control Manager
R. King, Design Engineering Manager
D. Malinowski, Operations Training Manager
T. Marlow, Director of Safety and Licensing
M. McAndrew, Assistant Operations Manager
O. Miller, Operations Manager
J. Morris, Director Training
R. Norris, Radiation Protection Manager
W. Nurnberger, Work Control Manager
W. Pearce, Performance Improvement Manager
K. Polson, Site Vice President
M. Rasmussen, Operations Superintendent
T. Smith, Component Engineering Manager
J. Underwood, Chemistry Manager
S. Walton, Electrical Maintenance Superintendent
D. Zielinski, Operations Training

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000259/2010005-01	AV	RHR Subsystem Inoperable Beyond the TS Allowed Outage Time (Section 1R20.1(1))
05000296/2010005-03	VIO	Repeated Failure to Provide Complete and Accurate Information in LER 0500296/2009-003-02 (Section 4OA3.1)

Opened and Closed

05000259/2010005-02	NCV	Degraded 1C RHR Motor Rendered One RHR Subsystem Inoperable Beyond the TS Allowed Outage Time (Section 1R20.1(2))

Closed

07200052/2010-003-01	VIO	Repeated Failure to Control Transient Combustibles in Proximity of the Independent Spent Fuel Storage Facility (Section 4OA5.3)
05000296/2009-003-01	LER	Reactor Core Isolation Cooling System Inoperable Longer Than Allowed By the Technical Specifications (Section 4OA3.1)
05000296/2009-003-02	LER	Reactor Core Isolation Cooling System Inoperable Longer Than Allowed By the Technical Specifications (Section 4OA3.1)
05000260/2010-003-00	LER	Reactor Scram Due to Closure of the Main Steam Isolation Valves and Subsequent Invalid RPS Scram from the Intermediate Range Monitoring System (section 4OA3.2)
05000260/2010-001-00	LER	Condition Prohibited By Technical Specifications When Two Emergency Core Cooling Systems, Loops I and II of the Residual Heat Removal System Low Pressure Coolant Injection System, Became Inoperable (section 4OA3.3)
05000259, 260, 296/2010004-01	URI	Uncontrolled Materials Adversely Impacted the Capability of the EDG Building Emergency Drainage System to Mitigate an Internal Flooding Event (Section 4OA5.2)

05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 2 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 5 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 7 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 8 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 9 (Section 4OA5.4)

Discussed

05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 1 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 6 (Section 4OA5.4)
05000259, 260, 296- 00	ORD	12/29/2009 Confirmatory Order Action 10 (Section 4OA5.4)

LIST OF DOCUMENTS REVIEWED

<u>Section 1R01: Adverse Weather Protection</u>

0-GOI-200-1, Freeze Protection Inspection, Rev. 66
Operating Logs
0-AOI-100-3, Flood Above Elevation 558', Rev. 33
MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev. 38
MPI-0-000-INS001, Inspection of Flood Protection Devices, Rev. 12
SPP-10.14, Freeze Protection, Rev. 0
0-GOI-200-1, Freeze Protection Inspection, Revs. 64, 65, 66
SR 271672
PER 272691
SR 288551
PER 289066
WO 110821237 – Perform Inspection of the Diesel Bldg Flood Protection Portable Bulkheads
WO 06-714206-000 – Perform Inspection of the Diesel Bldg Flood Protection Portable Bulkheads
WO 08-713109-000 – Perform Inspection of the Diesel Bldg Flood Protection Portable Bulkheads
FPDQ (Freeze Protection Report), RFP-NWM117, dated 11/2/2010
WO # 01-011443-001, Generate Report
WO # 05-725438, Duct Heater
WO # 08-710085-000, D/G Heaters
WO # 09-725938-000, D/G Space Heater
WO # 09-726137-000, Strip Heater
WO # 110980907, RCW A Drain Valve
WO # 111300432, Expansion Tank Safety Valve
WO # 111361895, ADHR Instrumentation Heaters
WO # 111537776, RHRSW Pump B1
WO # 111581385, EECW Strainer Valve
SR # 271610, EECW Strainer Valve
SR # 277461, Freeze Protection GOI
SR # 277480, RHRSW Tunnel Doors
SR # 277481, Cancel WO
PER # 277476, Freeze Protection GOI
PER # 277482, RHRSW Tunnel Doors
PER # 277484, Cancel WO
BFN Operations Log, 11/6/2010 Midnight Shift, 11/7/2010 Day Shift
44N267, Diesel Generator Building Personnel Access Doors Portable Bulkhead, Rev. A
3-47W587-1, Standby Diesel Gen Bldg Unit 3, Mechanical Drains & Embedded Piping, Rev. 3
3-47W587-2, Standby Diesel Gen Bldg Unit 3, Mechanical Drains & Embedded Piping, Rev. 2
0-47E851-4, Flow Diagram Drainage, Rev. 13

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

0-OI-72, Auxiliary Decay Heat Removal System, Rev. 48
0-OI-72, ADHR System, Attachment 1, Valve Lineup Checklist, Eff. Date 11-10-2009
0-OI-72, ADHR System, Attachment 2, Panel Lineup Checklist, Eff. Date 7-14-2006
0-OI-72, ADHR System, Attachment 3, Electrical Lineup Checklist, Eff. Date 5-04-2010
0-OI-72, ADHR System, Attachment 2, Instrument Inspection Checklist, Eff. Date 11-12-2007

FSAR 10.22 Auxiliary Decay Heat Removal System (ADHR)
3-OI-82, Standby Diesel Generator System, Rev. 99
3-OI-82/ATT-1D, Standby Diesel Generator 3D Valve Lineup Checklist, Rev. 96
3-OI-82/ATT-2D, Standby Diesel Generator 3D Panel Lineup Checklist, Rev. 96
3-OI-82/ATT-3D, Standby Diesel Generator 3D Electrical Lineup Checklist, Rev. 95
3-OI-82/ATT-4D, Standby Diesel Generator 3D Instrument Inspection Checklist, Rev. 96
FSAR 8.5 Standby AC Power Supply and Distribution
3-OI-75, Core Spray System, Rev. 50
3-OI-75, Attachment 1, Core Spray System Valve Lineup Checklist, Eff. Date 8-28-09
3-OI-75, Attachment 2, Core Spray System Panel Lineup Checklist, Eff. Date 4-08-08
3-OI-75, Attachment 3, Core Spray System Electrical Lineup Checklist, Eff. Date 8-28-09
3-47E814-1, Core Spray System Flow Diagram, Rev. 34
0-47E873-1, -2, Flow Diagram Aux Decay Heat Removal System, Sheet 1 & 2, Date 7-12-97
0-47E610-72-1, -2, Control Diagram Aux Decay Heat Removal System, Sheet 1 & 2, Date 7-12-97
0-15E900-1, Electrical Instrument Details, Date 8-6-97
0-15E740-1, Single-Line Diagram ADHR Service Entrance and MCC, Date 7-12-97

Section 1R05: Fire Protection
Fire Protection Report, Volume 1, Fire Protection Plan, Units1/2/3, Rev. 8
Fire Protection Report, Volume 1, Fire Hazards Analysis, Units1/2/3, Rev. 8
Fire Protection Report, Volume 2, Sections IV.7, Pre-Plan No. RX3-519, Rev. 7
Fire Protection Report, Volume 2, Sections IV.8, Pre-Plan No. RX3-519, Rev. 7
Fire Protection Report, Volume 2, Sections IV.8, Pre-Plan No. RX3-565, Rev. 7
Fire Protection Impairment Permit #'s; 09-1920
Fire Watch Route/Coverage Sheet: Permit/Route #: Reactor Bldg. & Turbine Bldg, 10/16/10 to 10/18/10
TVAN Fire Watch Briefing and Turnover Form: Permit/Route #: U1, 2, &3 RX/TB Bldg, Multiple Sheets from 10/16/10 to 10/18/10
SR 268995
SR267561
SR267696
SR267624
SR267677
SR267630
Fire Protection Report, Volume 2, Sections IV.13, Pre-Plan No. DG3-565, Revision 8
Fire Protection Report, Volume 2, Sections IV.13, Pre-Plan No. DG3-583, Revision 8
Fire Protection Report, Volume 1, Fire Hazards Analysis, Units1/2/3, Rev. 8
Fire Protection Report, Volume 1, Fire Protection Plan, Units1/2/3, Rev. 8

Section 1R08: Inservice Inspection Activities
GE-UT-511, Procedure for the Automated Examination of Core Spray Piping Welds Contained within the Reactor Pressure Vessel, Revision 7
N-PT-9, Liquid Penetrant Examination of ASME and ANSI Code Components and Welds, Revision 0034
N-UT-64, Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds, Revision 0011

N-UT-66, Generic Procedure for the Ultrasonic Examination of Weld Overlay Austenitic Pipe Weld, Revision 0006
N-UT-76, Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds, Revision 0007
NETP-112, BWR Reactor Pressure Vessel Internals Inspections (RPVII), Revision 0000
54-ISI-363-05, Remote Underwater In-Vessel Visual Inspection of Reactor Pressure Vessel Internals, Components, and Associated Repairs in Boiling Water Reactors, Revision 10/21/2008
54-ISI-850-007, Manual Ultrasonic Examination of BWR Reactor Vessel Nozzle Inner Radius Regions and Nozzle to Shell Welds (inner 15%), Revision 9/7/2010
PDI-UT-6, Generic Procedure for Ultrasonic Examination of Reactor Pressure Vessel Welds, Revision 3/17/2009
Problem Evaluation Report (PER) 156982, U1C7 Jet Pump Restrainer Bracket Indication
PER 275955, Indications found on Core Spray Downcomer A, Weld P4a
PER 275958, Lost Quals after being requalified
PER 277618, U1R8 Jet Pump Wedge Wear and Set Screw Gaps/Indications
Report #: 0801464.401.R0, BFNP Unit 1 Cracked Jet Pump Set Screw Tack Welds Evaluation
Report #: BFN1-01-JLCJ2, Browns Ferry Nuclear Power Station- Unit 1 Core Spray Piping Ultrasonic Examination

Section 1R11: Licensed Operator Requalification

TRN-11.4, Continuing Training for Licensed Personnel, Rev. 16
SPP-10.0, Plant Operations, Rev. 05
OPDP-1, Conduct of Operations, Rev. 18

Benchmark Tests:
Unit 2 PLU Trip from 100% power 7/8/04
Unit 2 Scram(RFP 2A/2B trip) at 100% power 8/5/05
Unit 3 Power Level Imbalance 12/31/07

Design Changes:
DCR B 1538 (SDCR B1538) "Replace Unit 2 Main Generator Circuit Brown Boveri DR Air Blast breaker with new ABB SF6 HEC-7 type

General Items Reviewed:
License Reactivation Packages (5).
LORP Training Attendance records (15).
Medical Files (20).
Remedial Training Records (15).
Remedial Training Examinations (15).
Feedback Summaries (50).

License Event Reports (LER):
LER 50-259/2009-001-00, Turbine Trip and Reactor Scram Due to Power Load Unbalance Signal on Main Generator (2/18/2009)
LER 50-259/2009-002-00, Unexpected Logic Lockout Of The Loop II Residual Heat Removal System Pumps (3/21/2009)

LER 50-259/2009-003-00, A Train Standby Gas Treatment System Inoperable Longer Than Allowed by The Technical Specification (6/19/2009)
LER 50-259/2009-004-00, High Pressure Core Injection Found Inoperable During Compensate Header Level Switch Calibration and Functional Test (7/24/2009)
LER 50-260/2009-001-00, Manual Reactor Scram following Stator Cooling Water Equipment Failure (2/16/2009)
LER 50-260/2009-007, “Manual Scram During Removal of a Reactor Feedwater Pump from Service”
LER 50-260/2009-002-01, Leak In An ASME Class 1 Code Reactor Pressure Boundary Pipe (05/21/2009
LER 50-260/2009-003-00, Main Steam Relief Valve As found Setpoint Exceeded Technical Specification Lift Pressure (6/9/2009)
LER 50-260/2010-003, Reactor Scram Due to Closure of the Main Steam Isolation Valves and Subsequent Invalid RPS Scram From the Intermediate Range Monitoring System (6/9/2010)
LER 50-260/2010-001, Condition Prohibited by Technical Specifications, (2/25/2010)
LER 50-260/2010-002, Failure to Meet the Requirement of Technical Specification Limiting Condition for Operation Due to Inoperable Primary containment Isolation Instrumentation
LER 50-260/2010-004, HPCI Isolation During Time Delay Relay Calibration (6/16/2010)
LER 50-260/2010-005, High Pressure Coolant Injection System Isolation Experienced During Performance of High Pressure Coolant Isolation Steam Supply Low Pressure Functional Test (7/12/2010)
LER 50-269/2010-001, Safety relief Valves As-Found Setpoints Exceeded Technical Specification Lift Pressure Values (4/20/1010)
LER 50-269/2010-002-00, A Subsystem of the Standby Liquid Control System was Inoperable Longer than Allowed by the Plant’s Technical Specification (4/20/2010)
LER 50-269/2010-003-01, Multiple Test Failures of Excess Flow Check Valves (3/26/2010)

Malfunction Tests:
Condensate Pump Trip (FW01) completed 9/4/09
Loss of Condenser Vacuum (OG02) Completed 9/18/09
RCIC Low Suction Pressure Turbine Trip (RC03 Completed 9/27/09)

JPM Packages:
JPM 231 “Operator 1 Manual Actions 0-SSI-16”
JPM 249 “Control Room Abandonment Attachment 4 Part A”
JPM 224 “Transfer of 480V HVAC Board B Power Supplies”
JPM 238 “Operator 3 Manual Actions 0-SSI-1-1”

Unit 2 Simulator Information:
Transient #1 Manual Scram Completed 8/26/09
Transient #2 Simultaneous Trip of all Feed Pumps Completed 8/26/09
Transient #3 Simultaneous Closure of all MSIVs Completed 8/26/09
Transient #4 Simultaneous Trip of all Recirc Pumps Completed 8/26/09
Transient #5 Single Recirc Pump Trip Completed 8/26/09
Transient #6 Turbine Trip < 30% Power Completed 8/26/09
Transient #7 Manual Rate Power Ramp Completed 8/26/09
Transient #8 Max Size LOCA with LOOP Completed 8/26/09
Transient #9 Max Size Unisolable Main Steam Line Rupture Completed 8/26/09

Transient #10 MSIV Isolation and Relief Valve Failure Completed 8/26/09
100% Steady State Test Completed 8/26/09
75% Steady State Test Completed 8/26/09
50% Steady State Test Completed 8/26/09
Stability Test (Drift) Completed 8/26/09
Real Time Test Completed 8/26/09

Written Examination Reviewed:
Requal Written SRO exams for weeks 2 and 5 of 2009.

Section 1R12: Maintenance Effectiveness
Cause Determination Evaluation (CDE) 750, CS System I Logic Power Functional Failure
CDE 823, 1B CS Room Cooler Fan Functional Failure
CDE 867, 1B CS Room Cooler Low EECW Flow 1/28/09
CDE 864, 1B CS Room Cooler Low EECW Flow 2/09/09
CDE 862, 1B CS Room Cooler Low EECW Flow 9/13/09
CDE 852, 1B CS Room Cooler Low EECW Flow 11/19/09
CDE 897, 1B CS Room Cooler Low EECW Flow 2/17/10
CDE 925, 1B CS Room Cooler Functional Failure Due to Low EECW Flow
CDE 835, Unit 2 CS I Unavailable Due to Elevated Fluid Temperature 10/05/09
CDE 863, 2B CS Room Cooler Low EECW Flow
CDE 880, 2D CS Pump Breaker Functional Failure
CDE 881, Unit 2 CS I Unavailable Due to Elevated Fluid Temperature 1/10/10
CDE 836, 3EA Shutdown Board Loss of Control Power Functional Failure
FSAR Section 6.4.3 Core Spray System, BFN-23.3
OPL171.045 License Operator Training, Core Spray System, Rev. 11
PER 209302, Core Spray Venting
PER 219100, 3A CS and 3A RHR Room Cooling Coils Not Meet Original Specifications
PER 221650, U3 Core Spray Piping Indications Re-Inspection
PER 227894, Re-Status of CS Systems to (a)(1)
PER 236909, 1B CS Room Cooler Failed
PER 238523, CS II Room Cooler Testing Weekly
Technical Specifications and Bases 3.5.1 ECCS-Operating, Amendment 249 and Rev. 50 respectively
Units 1, 2, and 3 Function 75-B Core Spray (a)(1) Plan, Rev 0, Effective Date 6/29/10
WO 10569918, Replacement of Unit 1 Testable Check Valve 75-26
WO 10569919, Replacement of Unit 3 Testable Check Valve 75-26
WO 110717766, 3A CS Pump Oil Change Due to ISO Particle Count
WO 110714652, 3C CS Pump Oil Change Due to ISO Particle Count
WO 110874232, CS 75-53 Metal Particles in Motor Clutch Housing
WO 110900580, 3A CS Pump Cyclone Separator Tubing Against Pedestal
BFPER940777, Recirculation Pump 2B Discharge Valve Failure to Close
BWROG-TP-09-005, Inspection of Motor Operated Valve Limitorque AC Motors with Magnesium Rotors, Rev. 0
Flowserve Technical Update 06-01, Reliance Motors/Magnesium Rotors, dated December 26, 2006
Flowserve Technical Update 08-01, Reliance Motors/Magnesium Rotors, dated December 19, 2008

GE SIL 425, EQ Test Anomalies of Reliance Motors in Limitorque Valve Operators, Rev. 1
NRC Information Notice 86-02: Failure of Valve Operator Motor During Environmental Qualification Testing, dated November 20, 2006
NRC Information Notice 2006-26: Failure of Magnesium Rotors in Motor-Operated Valve Actuators, dated November 20, 2006
PER 95431, Failure of 3-MVOP-68-77
PER 95610, PM Program for Magnesium Rotor Motors
PER 95611, Motor Start Attempts
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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