



UNITED STATES
NUCLEAR REGULATORY COMMISSION

REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

April 30, 2007

Tennessee Valley Authority
ATTN: Mr. Preston D. Swafford, Acting
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT UNIT 1 RECOVERY - NRC INTEGRATED
INSPECTION REPORT 05000259/2007009

Dear Mr. Swafford:

On April 30, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed a quarterly inspection period associated with recovery activities at your Browns Ferry 1 reactor facility. The enclosed integrated inspection report documents the inspection results, which were discussed on April 30, 2007, with Mr. Bill Crouch and other members of your staff.

We previously informed you, in a letter dated December 29, 2004, of the transition of four Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) to be monitored under the ROP baseline inspection program. Consequently, as of January 2005, inspections for these cornerstones are integrated with Units 2 and 3 ROP baseline inspections and Integrated Quarterly Reports. They will no longer be documented in the Unit 1 Recovery Quarterly Integrated Reports such as this one. Inspection Report 05000259,260,296/2007002, issued April 30, 2007, is the most recent Units 2 and 3 Integrated Quarterly Report which contains the Unit 1 ROP inspection.

This inspection examined activities conducted under your Unit 1 license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license and also with fulfillment of Unit 1 Regulatory Framework Commitments. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. A significant portion of your engineering activities, Unit 1 Recovery Special Program implementation, and modification activities were reviewed during this inspection period and found to be effective with no significant problems identified. However, based on the results of this inspection, two Severity Level IV violations of NRC requirements were identified. The first violation involved a resulting from failure to follow equipment clearance procedure that resulted in a Core Spray pump start with no suction path. The second violation involved inadequate cable separation criteria which resulted in opposite divisional cables being routed in the same enclosure without adequate separation. However, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the NCVs in this report, 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 the Regional

Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Browns Ferry Nuclear Plant.

Based on current and previous inspections of Unit 1 Recovery activities associated with two of your Special Programs, the staff has concluded that your implementation of these Special Programs has been adequate; and, when fully implemented, should satisfy NRC regulatory requirements and commitments in your regulatory framework letter dated December 13, 2002. These Special Programs include the areas of Fire Protection Improvements and Electrical Cables Installation/Separation. We do not anticipate additional inspections for these areas.

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

Sincerely,

/RA/

Malcolm T. Widmann, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket No. 50-259
License No. DPR-33

Enclosure: Inspection Report 05000259/2007009
w/Attachment: Supplemental Information

cc w/encl: (See next page)

Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Browns Ferry Nuclear Plant.

Based on current and previous inspections of Unit 1 Recovery activities associated with two of your Special Programs, the staff has concluded that your implementation of these Special Programs has been adequate; and, when fully implemented, should satisfy NRC regulatory requirements and commitments in your regulatory framework letter dated December 13, 2002. These Special Programs include the areas of Fire Protection Improvements and Electrical Cables Installation/Separation. We do not anticipate additional inspections for these areas.

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Report to Preston Swafford from Malcolm T. Widmann dated, April 30, 2007

SUBJECT: BROWNS FERRY NUCLEAR PLANT UNIT 1 RECOVERY - NRC INTEGRATED
INSPECTION REPORT 05000259/2007009

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No: 50-259

License No: DPR-33

Report No: 05000259/2007009

Licensee: Tennessee Valley Authority (TVA)

Facility: Browns Ferry Nuclear Plant, Unit 1

Location: Corner of Shaw and Nuclear Plant Roads
Athens, AL 35611

Dates: February 4 - April 30, 2007

Inspectors: W. Bearden, Senior Resident Inspector, Unit 1
T. Ross, Senior Resident Inspector, Units 2 and 3 (Sections O8.1, E1.7, E8.4)
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C. Stancil, Resident Inspector
H. Gepford, Senior Health Physicist, (Section E1.4)
E. Riggs, Resident Inspector, Oconee (Sections E1.3, E1.4)
M. King, Resident Inspector, Harris (Section E1.3)
G. MacDonald, Senior Reactor Analyst (Sections F1.1, F1.2)
L. Mellen, Senior Project Engineer (Sections F1.1, F1.2)
D. Rich, Senior Resident Inspector Oconee, (Sections E1.3, E1.4)
S. Vias, Senior Reactor Inspector (Sections E1.8, E8.1, E8.5)
K. Korth, Project Engineer (Sections E1.3, E1.4)
N. Staples, Reactor Inspector (Section E1.6)

Approved by: Malcolm T. Widmann, Chief
Reactor Project Branch 6
Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Unit 1 NRC Inspection Report 05000259/2007009

This integrated inspection included aspects of licensee engineering and modification activities associated with the Unit 1 recovery project. This report covered a three month period of inspection by resident inspectors. In addition, NRC staff inspectors from the regional office conducted inspections of Unit 1 Recovery Special Programs in the areas of electrical cable installation/separation, fire protection improvements, and open inspection items. The inspection program for the Unit 1 Restart Program is described in NRC Inspection Manual Chapter 2509. Information regarding the Browns Ferry Unit 1 Recovery and NRC Inspections can be found at <http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/bf1-recovery.html>. Pursuant to the Partial Cornerstone Transition letter from the NRC to TVA dated December 29, 2004, four Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) are monitored under the ROP baseline inspection program as of January 2005. Consequently, inspections for these cornerstones are integrated with Unit 2 and 3 ROP baseline inspections and are no longer documented in the Unit 1 recovery quarterly integrated reports such as this one, but in the Unit 2 and 3 Integrated Quarterly Reports.

Inspection Results - Operations

- A Severity Level IV non-cited violation was identified for failure to comply with 10 CFR 50, Appendix B, Criterion V. This failure resulted in starting the Core Spray Pump 1B with no suction path. Inspectors concluded that licensee corrective actions are adequate and concurred with the licensee's event cause determination and 1B Core Spray Pump damage assessment. (Section O8.1)

Inspection Results - Engineering

- The inspector's review of nine planned modification design change packages concluded that the design changes were appropriately developed, reviewed, and approved for implementation per procedural requirements. The designs adequately addressed the changes needed to restore Unit 1 to current requirements. (Section E1.1)
- The inspectors determined that activities associated with four temporary alterations installed to support power ascension testing or extended power uprate on Unit 1 did not cause any significant impacts on the operability of equipment required to support operations of Units 2 and 3. Additionally, the inspectors reviewed the remaining five active historical temporary alterations discussed in the previous inspection report and determined that none of them affected Unit 1 restart. (Section E1.2)
- Walkdowns and licensee activities associated with the system turnover process were being adequately implemented. Increased licensee management expectations and strong ownership by the operating organization continued. Operating organization participation in turnover meetings, testing, and walkdowns was good; and systems were being turned over in a ready condition resulting in fewer open items. (Section E1.3)

- Area turnover guidance and the quality of turnover packages submitted to walkdown participants were adequate. Outstanding work and other deficiencies continue to be identified by restart area coordinators and plant management during walkdowns and subsequently punch listed in the same process for system turnover. The inspectors determined that activities associated with the Unit 1 restart area turnover process did not cause any significant impact to the operability of equipment required to support operations of Units 2 and 3. No violations or deviations were identified. (Section E1.4)
- Implementation of restart testing activities was generally acceptable. Minor test deficiencies which did not affect the results of the testing, were identified during performance of testing. Licensee processes were effective at identifying problems before components were placed in service. (Section E1.5)
- Based on observations, document reviews, discussions with engineering personnel and previously documented NRC inspections, the inspectors determined that actions completed by the licensee to address concerns with the Unit 1 Cable Installation and Cable Separation Special Programs complied with their commitments to NRC. Licensee actions to address cable issues have been performed or are being performed by the licensee. Completed or planned actions to address these issues for Unit 1 are consistent with those previously committed to and performed for Units 2 and 3. No issues related to these Special Programs that would negatively impact the restart of Unit 1 were identified as the result of the above reviews. Based on this and previously documented NRC inspections, the inspectors concluded that at this time, no further inspections are anticipated for these Special Programs. (Section E1.6)
- A Severity Level IV non-cited violation (NCV) of 10CFR50, Appendix B, Criterion III was identified for a configuration control issue in the Auxiliary Instrument Room. The inspector found that internal panel separation for the "top hat" was not adequately defined or specified in a quality standard to ensure that divisional separation for cables from opposite divisions were maintained. This resulted in opposite divisional cables being routed in the same enclosure without adequate separation. (Section E1.6)
- The licensee's corrective actions for addressing a previously identified nonconforming condition associated with a lack of assured cooling water for emergency diesel generators were adequate. Based on this inspection and a prior inspection the inspectors determined that the licensee has adequately addressed the regulatory requirements and guidance of 10CFR50.63 for Unit 1. (Section E1.7)
- Based on current and previous reviews, the inspectors determined that the licensee had properly implemented Generic Letter (GL) 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants. No further inspections are anticipated for these programs. (Section E1.8)
- Based on previous NRC inspection methodology and review of selected commitment closure documentation the inspectors concluded that the licensee had completed required corrective actions associated with Unit 1 Recovery. (Section E7.1)

Inspection Results - Maintenance

- The Maintenance organization continued to provide appropriate and comprehensive repairs to Unit 1 components which did not require design changes to support Unit 1 Restart. Work order packages included sufficient technical guidance to allow personnel to adequately perform the associated work activity. Maintenance personnel and foremen were knowledgeable of applicable requirements and appropriately documented work actually performed, as required by plant procedures. (Section M1.1)

Inspection Results - Plant Support

- Based on the review of the restart readiness of the Unit 1 fire protection systems and the final version of the three Unit Safe Shutdown Instructions the inspectors concluded that the local operator manual actions for 10CFR50 Appendix R Section III.G.2 required to achieve and maintain safe shutdown were feasible. No further inspections are planned for the fire protection special program. (Section F1.1)
- The licensee's risk evaluation of the III.G.2 operator manual actions was revised to address previous NRC staff comments. The risk evaluation documented that the risk of the operator manual actions in III.G.2 fire area/zones was of very low safety significance. (Section F1.2)

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REPORT DETAILS

Summary of Plant Status

Unit 1 had been shut down since March 19, 1985, and remained in a long-term lay-up condition with the reactor defueled until December, 2006. The licensee initiated Unit 1 recovery activities to return the unit to operational condition following the TVA Board of Directors decision on May 16, 2002. During the current inspection period, reinstallation of plant equipment and structures continued. Recovery activities included completion of replacement of components in the drywell and reactor building; reinstallation of balance-of-plant piping and turbine auxiliary components. A significant amount of restart testing, system return to service, and area turnover activities occurred during this reporting period as the Unit 1 recovery effort was completed. Additionally, the licensee returned the remaining safety related systems to service.

I. Operations

O8 Miscellaneous Operations Issues

O8.1 Core Spray Pump 1B Started with No Suction Path (37551)

a. Inspection Scope

Inspectors reviewed underlying events and subsequent licensee actions associated with the start of a Division II Core Spray Pump 1B with no suction path to verify that licensee corrective actions were adequate.

b. Observations and Findings

On January 12, 2007, the Core Spray Pump 1B was started to re-flood the reactor vessel after steam dryer testing. The control room crew observed flow and amps, but promptly tripped the pump when they observed indications of cavitation. The pump ran for approximately 45 seconds. Operations immediately investigated the problem and identified that Unit 1 valve 1-SHV-002-0705, Condensate Supply to Safety Systems, was closed when it should have been locked open. Problem Evaluation Report (PER) 117977 was issued by the licensee to address this event.

Independent inspector review of the licensee work control clearance process, tagout sheets, tagout logs, work order, and procedures indicated a human performance error during clearance tag removal resulting in a configuration control event for not following the clearance procedure. A licensee search of clearances involving 1-SHV-002-0705 indicated the last time the valve was closed was when it was tagged closed under Clearance 1-TO-2000-0001, Section 1-075-0043, Danger Tag 18914 on September 22, 2006. The clearance was hung for Work Order (WO) 06-719675-000 to clean, inspect, and refurbish valve 1-SHV-075-0031 which provided condensate suction for the 1B Core Spray Pump. Following the work, the clearance was released on September 27, 2006.

At the time the clearance was released, Unit 1 Operations personnel determined that 1-SHV-002-0705 did not need to be reopened to facilitate other valve cycling and limit switch setting. Operations personnel appeared to assume that since the Condensate

Supply to Unit 1 Emergency Core Cooling Pumps was not required for current plant conditions (valve 705 supplied only Unit 1 systems) then valve 705 did not require configuration control. Clearance release instructions stated "Valve 1-SHV-002-0705 condensate supply to safety systems will remain closed until the loop can be charged via the Operating Instruction." The danger tag was removed with the clearance tag list clearly indicating that valve 705 was left in the closed position. However, SPP 10.2, Clearance Procedure to Safely Control Energy, dictated that release of a clearance returns the equipment to an operational status.

Inspector review of operating procedures for Condensate Storage and Transfer, Condensate, and Core Spray Systems did not identify specific instructions involving 1-SHV-002-0705. Procedures also did not provide any manipulation guidance for this valve other than an open verification in the Core Spray procedure for filling the suppression chamber and the normal locked open position as required in the 0-OI-2B, Condensate Storage and Transfer System, Attachment 1A Valve Lineup Checklist. Once the 705 valve danger tag was removed and the clearance section verified released, there was no configuration control mechanism left in place for valve 1-SHV-002-0705 to be returned to the normal locked open position. As a result, the off-normal position of valve 1-SHV-002-0705 was not recognized until the loss of 1B Core Spray Pump suction event on January 12, 2007.

The licensee's immediate corrective actions included an Operations crew stand down, investigation and alignment verification of the remaining Core Spray Pumps, Residual Heat Removal, Reactor Core Isolation Cooling, and High Pressure Core Injection Systems. The 1B Core Spray Pump was also tested for vibrations, the results of which indicated favorably when compared against a previous performance of the surveillance during November 2006. A subsequent February 2007 performance of the same surveillance for rated flow and vibrations demonstrated the same results indicating that the 1B Core Spray Pump was undamaged.

The inspectors reviewed the licensee's long term corrective actions to develop a corporate program for all the nuclear plants to implement a configuration control process that will fill gaps that may occur between established configuration control programs like the clearance process, temporary modifications, work orders, and operating procedures.

10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on September 27, 2006, equipment clearance, 1-TO-2000-0001 was released without returning 1-SHV-002-0705 to an operational status as required by SPP 10.2. This event resulted in starting Core Spray Pump 1B with no suction path. Although, this event could have potentially damaged this safety related component, alert Operations personnel immediately tripped the pump when they observed indications of cavitation. Based on a review of the licensee's PER investigation results and associated corrective actions and discussions with licensee personnel, the inspectors determined that the failure was of low safety significance. A Severity Level IV Non-Cited Violation (NCV) 50-259/2007-09-01, Starting Core Spray Pump 1B with No Suction Path, was identified. This violation is being treated as an NCV, consistent with Section VI.A of the

NRC Enforcement Policy. These events were documented by the licensee in PER 117977.

c. Conclusions

A Severity Level IV NCV was identified for failure to comply with 10 CFR 50, Appendix B, Criterion V. This failure resulted in starting the Core Spray Pump 1B with no suction path. The NRC is treating this finding as a NCV consistent with Section VI.A of the NRC Enforcement Policy. Inspectors concluded that licensee corrective actions are adequate and concurred with the licensee's event cause determination and 1B Core Spray Pump damage assessment.

II. Engineering

E1 Conduct of Engineering

E1.1 Permanent Plant Modifications (71111.17, 37550, 37551)

a. Inspection Scope

In order to have some oversight of licensee recovery activities not directly limited to specific Unit Restart List Items, the inspectors reviewed planned Design Change Notice (DCN) packages associated with modifications to the Reactor Recirculation System, Main Steam (MS), Reactor Water Cleanup (RWCU), Reactor Feedwater (RFW), Reactor Pressure Vessel Vents and Drains, Standby Liquid Control (SLC) System, and Residual Heat Removal (RHR) System. Most of these modifications support the planned Extended Power Uprate (EPU) and also install additional vibration monitoring equipment needed to support EPU testing. The inspectors reviewed criteria in licensee procedures Standard Program and Process (SPP)-9.3, Plant Modifications and Engineering Change Control; SPP-7.1, Work Control Process; SPP-8.3, Post-Modification Testing; and SPP-8.1, Conduct of Testing, to verify that risk-significant plant modifications were developed, reviewed, and approved per the licensee's procedure requirements.

b. Observations and Findings

The inspectors reviewed the following DCNs associated with planned modifications on Unit 1 to verify that the packages contained adequate design information and supporting analyses to allow modifications personnel to properly implement the desired change, update plant documentation, and resolve the identified condition. In addition, the inspectors verified that the planned modifications would not adversely affect the design basis of the system or interfacing systems. Also, the inspectors verified that the planned modifications would not place either of the operating units in an unsafe condition.

DCN 51045

The inspectors reviewed Unit 1 permanent plant modification DCN 51045, Reactor Water Recirculation, Electrical and Mechanical - Drywell, System 68. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the reactor water recirculation system in the drywell. The DCN consisted of seven stages. Scheduled modification activities included removal and capping the 3/4 inch bonnet vent lines of flow control valves 1-FCV-69-01, 03, 77, and 79, recirculating pumps 1A and 1B suction and discharge valves; install conduits, junction boxes, and pulling cables to associated equipment from drywell penetrations such as CB, CA, EA, EB, EE and EF; installation of small bore pipe supports from jet pump instrument lines; and installation of EPU vibration monitoring equipment and mounting hardware for installing Hitec Products Inc. Type 2-35-125-9-2DFB-FSM strain gauges on Loop A and on Loop B piping. The strain gauges were installed on piping such as the Loop A pump discharge and suction piping and on the Loop B pump discharge and suction piping.

DCN 67898

The inspectors reviewed plant modification DCN 67898, Main Steam, Electrical and Mechanical - Drywell, System 01. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the Unit 1 main steam system in the drywell. 3 Among the scheduled modifications within the DCN was the installation of EPU vibration monitoring equipment and mounting hardware for 64 Hitec Products Inc. Type HBWAK-35-250-6-10FC strain gauges on the four System 01 lines inside the Drywell, with 8 strain gauges at two locations on each line.

DCN 51151

The inspectors reviewed Unit 1 permanent plant modification DCN 51151, Residual Heat Removal, Electrical and Mechanical - Drywell, System 74. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the RHR system in the Drywell. Scheduled electrical and mechanical modifications included replacement of the motor operator for MOV 1-FCV-74-48, shut down cooling return valve; replacement of existing cables and conduits with new conduits and EQ qualified cables; replacement of existing piping with 316 NG stainless steel; modification of additional valves such as the testable check valves, and other check valves, add decon connections for future decon activities; and the installation of EPU vibration monitoring equipment and mounting hardware for installing Endevco Piezoelectrical Type 7703A-100 accelerometers at selected location on system piping. The accelerometers were installed on the RHR Loop I discharge piping and the RHR Loop II discharge piping.

DCN 51046

The inspectors reviewed Unit 1 permanent plant modification DCN 51046, Reactor Water Cleanup, Electrical and Mechanical - Drywell, System 69. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the RWCU in the Drywell. The DCN consisted of seven stages including electrical and mechanical modifications to install piping and valves from valve 1-ISV-69-500, thru penetration X-14, and to valve 1-FCV-69-02; install conduits, junction boxes, conduit

supports, and cables for flow control valve 1-FCV-69-0; and install EPU vibration monitoring equipment and mounting hardware for installing Endevco Piezoelectrical Type 7703A-100 accelerometers on RWCU suction piping.

DCN 51136

The inspectors reviewed Unit 1 permanent plant modification DCN 51136, Main Steam, Electrical and Instrumentation and Control (I&C) - Turbine Building, System 01. The intent of this DCN was to implement the mechanical modifications recommended for the main steam system in the turbine building. The DCN consisted of three stages including mechanical modifications for support installation of the Foxboro digital feed water control system; remove and replace various pressure transmitters; refurbish and add trip units, cards, relays, signal modifiers, power supplies, fuses, selector switches, indicating lights, and internal wiring to safe shutdown panels 1-9-81 and 1-9-86; replace various flow transmitters; and install EPU vibration monitoring equipment and mounting hardware for installing Type 7703A-100 accelerometers and installing Ecker-Erhardt Co. Inc. Linear Variable Displacement Transmitters (LVDT) on selected components in the turbine building.

DCN 51143

The inspectors reviewed Unit 1 permanent plant modification DCN 51143, Main Steam and Standby Liquid Control, Electrical and Mechanical - Drywell, System 01 and System 63. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the main steam system and standby liquid control in the drywell. Scheduled electrical and mechanical modifications included modification main steam isolation valves by providing new poppet design, new larger stems, new bonnets, new bolting design, new larger actuators, and new designed limit switch mounting plates; removal and replacement of all safety related limit switches; replacement of motor operated drain isolation valve; modification and replacement of main steam relief valves, replacement of selected valves in the standby liquid control system; installation of EPU vibration monitoring equipment and mounting hardware for installing Type 7703A-100 accelerometers on selected components such as main steam stops, main steam supply valve to the RCIC system, main steam safety relief valves, and main steam supply to the HPCI system; and LVDTs on selected components.

DCN 51163

The inspectors reviewed Unit 1 permanent plant modification DCN 51163, Reactor Feedwater, Mechanical and Instrumentation and Control - Drywell, System 04. The intent of this DCN was to implement the mechanical modifications recommended for the reactor feedwater system in the drywell. Scheduled mechanical I&C modifications included replacement of the Reactor Vessel Level Indicating System (RVLIS) and sensing lines; replacement of RPV head seal leakoff reservoir line, level switch, reservoir isolation and drain valves, and associated cables; replacement of RPV head vent sensing line and flow control valves and associated cables; replacement of RPV feed water manual inboard isolation valve closed limit switches and associated cables; replacement of the double vent and drain small bore valves associated with the RPV feed water manual inboard isolation valve; and installation of EPU vibration monitoring

equipment and mounting hardware for installing Endevco Piezoelectrical Type 7703A-100 accelerometers on reactor vessel feedwater nozzles and feedwater headers.

DCN 51144

The inspectors reviewed Unit 1 permanent plant modification DCN 51144, Reactor Pressure Vessel Vents and Drains, Mechanical - Drywell, System 10. The intent of this DCN was to implement the mechanical modifications recommended for the reactor pressure vessel vents and drains system in the drywell. Scheduled mechanical modifications included removal of RPV low point drain valves due to trapping radioactive particles; replacement of obsolete RPV drain and vent valves; upgrading the main steam safety/relief vacuum breaker valves by machining the hinge shaft, replacement of cap screw and increasing the torque value, installation of a spring pin to ensure rotation of the shaft with the hinge arm, and removal of valve position indicator; and installation of EPU vibration monitoring equipment and mounting hardware for installing Endevco Piezoelectrical Type 7703A-100 accelerometers on selected main steam drain valves.

DCN 51114

The inspectors reviewed Unit 1 permanent plant modification DCN 51114, Reactor Feedwater, Mechanical - Reactor Building, System 04. The intent of this DCN was to implement the mechanical I&C modifications recommended for the reactor feedwater system in the reactor building. The DCN consisted of three stages including mechanical and I&C modifications which replace feedwater heaters A1, A2, B1, B2, C1, and C2 isolation valves; replace various mechanical components with upgraded components for EPU; replace various obsolete mechanical valves and flow control valves with newer models; various system drain valves; and install Type 7703A-10 accelerometers on selected components; and install LVDTs on selected components.

c. Conclusions

The inspector's review of modification design packages associated with nine DCNs concluded that the design changes were appropriately developed, reviewed, and approved for implementation per procedural requirements. The DCNs adequately addressed the changes needed to restore Unit 1 to current requirements.

E1.2 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed licensee procedure SPP-9.5, Temporary Alterations. The inspectors also reviewed and observed ongoing activities associated with System 01, Main Steam (MS); System 04, Reactor Feedwater (RFW); System 69, Reactor Water Cleanup (RWCU); and System 79, Fuel Handling. The inspectors verified that 10 CFR 50.59 screening and technical evaluations against the system design bases documentation, including the Final Safety Analysis Report (FSAR) and TS and reviewed selected completed work activities of the system to verify that installation and/or removal were consistent with the modification documents and the Temporary Alteration Control Form (TACF). In addition, special emphasis was placed on the potential impact of these

temporary modifications on operability of equipment required to support operations of Units 2 and 3.

b. Observations and Findings

Remaining Unit 1 Active Temporary Alterations

At the end of the previous inspection reporting period six TACFs were still open and planned for closure prior to restart of Unit 1. The inspectors' review of these TACFs was documented in Inspection Report 50-259/2006-09 and involved the Fuel Handling; Main Steam; Reactor Feed Water; Building Heating; Offgas, Recombiner, and Charcoal Filter; and Reactor Building Closed Cooling Water Systems.

TACF 1-06-008-079, System 79, Fuel Handling, dated December 16, 2006, had been initiated to install Unistrut channel assemblies on the Unit 1 refueling bridge crane. This facilitated the removal of the air hose reel from the Unit 3 refueling bridge crane and the installation of the hose reel on the Unit 1 refueling bridge crane. This TACF was required due to the Unit 3 hose reel being opposite handed to the Unit 1 hose reel. This TACF was closed by issuance of EDC 68685, System 79, Fuel Handling, dated February 20, 2007, which implemented this as a permanent design change. The inspectors reviewed the remaining five TACFs discussed in the previous inspection report and determined that none of them affected Unit 1 restart.

Temporary Alterations to Support Power Ascension Testing or Extended Power Uprate

The inspectors reviewed four additional active temporary alterations installed to support Unit 1 Power Ascension Testing or Extended Power Uprate (EPU). These temporary alterations included:

- TACF 1-04-002-01, System 01, Main Steam and System 03, Reactor Feedwater, dated March 19, 2004, was initiated to install temporary vibration monitoring and data acquisition equipment on the system 01 and system 03 piping. The TACF installation was for EPU purposes. Subsequent to the issuance of this TACF a decision was made to increase the amount of monitoring equipment and the number of systems to be monitored. This TACF was cancelled and three new TACFs, as documented below, were issued for the temporary installation.
- TACF 1-06-004-068, System 68, RWR; System 69, RWCU; and System 74, RHR, dated January 4, 2007, was initiated to install Hitec Products Inc. Type 2-35-125-9-2DFB-FSM strain gauges on System 68, Endevco Piezoelectrical Type 7703A-100 accelerometers on System 69, and Type 7703A-100 accelerometers on System 74 inside the Drywell. The installation of the instrumentation was in conjunction with the following design changes: DCN 51045, Reactor Water Recirculation, Mechanical - Drywell, System 68; DCN 51151, Residual Heat Removal, Mechanical - Drywell, System 74; and DCN 51046, Reactor Water Cleanup, Electrical and Mechanical - Drywell, System 69. This TACF was also initiated to install a temporary Data Acquisition System (DAS) which in association with the sensors will collect vibration data on system piping for further evaluation.

- TACF 1-06-005-001, System 01, MS, dated January 23, 2007, was initiated to install a total of 64 Hitec Products Inc. Type HBWAK-35-250-6-10FC strain gauges on the four System 01 lines inside the Drywell. The installation involved eight gauges at two locations on each main steam line, an upper and a lower, with each at a 45 degree angle to each other. The upper location was 9.5 feet from the inside of the reactor vessel wall and the lower was 41.16 feet from the inside wall. The installation of the instrumentation was in conjunction with design change DCN 67898 Main Steam, Electrical and Mechanical - Drywell, System 01.
- TACF 1-06-007-001, System 01, MS, and System 03, RFW, dated December 14, 2006, was initiated to install Type 7703A-100 accelerometers on System 04 in the Drywell, install Ecker-Erhardt Co. Inc. Linear Variable Displacement Transmitters (LVDT) on System 01 in the Drywell, LVDTs on System 01 in the Turbine Building, and LVDTs on System 04 in the Turbine Building. The installation of the instrumentation was in conjunction with the following design changes: DCN 51136, Main Steam, Mechanical - Turbine Building, System 01; DCN 51143, Main Steam, Electrical and Mechanical - Drywell, System 01; DCN 51163, Reactor Feedwater, Mechanical - Drywell, System 04; DCN 51144, Reactor Pressure Vessel Vents and Drains, Mechanical - Drywell, System 10; and DCN 51114, Reactor Feedwater, Mechanical - Reactor Building, System 10.

c. Conclusions

The inspectors determined that activities associated with four temporary alterations installed to support power ascension testing or extended power uprate on Unit 1 did not cause any significant impact on the operability of equipment required to support operations of Units 2 and 3. Additionally, the inspectors reviewed the remaining five historical TACFs discussed in the previous inspection report and determined that none of them affected Unit 1 restart. No violations or deviations were identified.

E1.3 System Return to Service Activities (37550, 37551)

a. Inspection Scope

The inspectors continued to review and observe portions of the licensee's ongoing System Return to Service (SRTS) activities. The SRTS activities were performed in accordance with Technical Instruction 1-TI-437, System Return to Service Turnover Process for Unit 1 Restart. The level of SRTS activities decreased as the licensee completed turnover of the remaining risk significant systems during this reporting period.

Additionally, inspectors other than the resident staff performed independent system readiness reviews on selected risk significant systems which had completed the SPOC II system turnover process. The inspectors reviewed the completed SPOC II package for their assigned System, performed a detailed independent system walkdown, and reviewed completed documentation to support the SPOC II package.

b. Observations and Findings

The SRTS process consisted of three parts: System Plant Acceptance Evaluation (SPAЕ), which consists of verification of design changes, engineering programs analysis, drawings, calculations, corrective action items, and licensing issues; SPOC I, which consists of the completion of items required for system testing; and SPOC II, which consists of the completion of system testing and the completion of items that affect operational readiness. All required system SPAЕ packages had previously been issued by the licensee prior to the start of this reporting period.

Specific SRTS activities observed by the inspectors included periodic meetings to discuss the SRTS status, which included the status of the SPOC I checklists, status of the SPOC II process, and status of outstanding work items and identified deficiencies. Documents and activities reviewed included System SPOC exceptions, deferrals, and special operating conditions; system testing requirements; temporary alterations; completed WOs; engineering calculations; SRTS open items punchlist (OIP); and various PERs associated with the SRTS process. The inspectors also held discussions with engineering and operations personnel responsible for SRTS activities and performed walkdowns of selected portions of affected systems.

b.1 SPOC I and II Boards and Walkdown Activities

In addition to periodically observing daily SPOC status meetings, the inspectors observed SPOC plant system walkdowns and management review and acceptance boards. SPOC II walkdowns were independently performed on System 71 Reactor Core Isolation Cooling (RCIC) and System 73 High Pressure Coolant Injection (HPCI). Inspectors observed SPOC II management review boards on System 64A Primary Containment, System 68 Reactor Water Recirculation, System 71 Reactor Core Isolation Cooling (RCIC), and System 73 High Pressure Coolant Injection (HPCI).

Independently performed SPOC system walkdowns by inspectors validated that licensee walkdowns were adequately conducted in accordance with Technical Instruction 1-TI-437 System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Appendix D SPOC Walkdown Instruction and Attachment 6 SPOC Walkdown. Operational deficiencies and material discrepancies identified by inspectors and licensee representatives were appropriately documented and dispositioned.

b.2 System 73, High Pressure Coolant Injection (HPCI) SPOC II System Readiness Inspection

The HPCI system SPOC II package was approved by the Browns Ferry Unit 1 restart organization on March 28, 2007. The SPOC II package had no exceptions and no deferrals. The package certified that all corrective actions and all calculations with unverified assumptions identified from the February 2006, Plant Acceptance Evaluation were resolved. The HPCI system was operated satisfactorily on March 15, 2007, with 150 psig steam supplied from the auxiliary boiler. Inspectors verified system functional requirements were met by approved surveillance instructions. Inspectors also verified that remaining system testing, such as system operation at full reactor steam pressure, and dynamic MOV testing, were captured in the open item punchlist.

During the system walkdown the inspectors identified the following deficiencies:

- Valve 1-VTV-073-524 (1-FCV-073-027 Valve Vent), had a minor leak of about two drops per minute. Operations flushed the valve and it stopped leaking.
- No label on handswitch 1-HS-073-0016C, local handswitch for valve 1-FCV-073-016. Label request TR 443407 was issued.
- Valve 1-RTV-073-0053B, (root valve for Pressure Indication 1-PI-073-53B), was not on drawing 1-47E812-1. PER 122470 was issued to correct the issue.
- Drawing 1-47E812-1 indicated that valve 1-SHV-073-0652, HPCI minimum flow shut off valve, is normally locked open. However, other locked valves were not indicated on the drawing. OPDP-6, Locked Valve Program, states locked valves and breakers are controlled by site specific procedures/instruction, and that such procedures take precedence over plant drawings. The inspectors reviewed O-GOI-300-3, Attachment 1, Locked Valve Audit, effective date 01/05/07, and found no discrepancies with installed locking devices. The licensee issued PIC 68961 to correct the drawing and PER 122510 was issued to document the issue.

The HPCI system status, outstanding design issues, and required testing were adequately captured in the SPOC II package and in the return-to-service open item punch-list.

b.3 System 71, Reactor Core Isolation Cooling System Readiness Inspection

The inspectors reviewed the SRTS-OIP and discussed with members of the TVA restart organization. The RCIC system had no exception or deferral items. The inspectors performed a review of several RCIC system test packages. Overall, the inspectors determined that the selected tests were performed in accordance with approved written procedures and properly documented. However, two minor administrative documentation errors were identified in the RCIC program test package. The licensee initiated PER 120405 to correct the errors.

The inspectors performed an in-depth system walkdown. All accessible portions of the system were inspected.

- RCIC turbine speed indication cable, 1-SE-071-0042A, was not tightly connected to the speed probe.
- RCIC Turbine Steam Supply Valve actuator, 1 MVOP-071-0008, stem cover was missing. The stem cap opening was not covered with an appropriate FME barrier, as several strips of duct tape were observed to be covering the opening on top of the actuator.
- Cable connecting 1-JBOX-071-1727 and RCIC Steam Line Outboard Drain valve actuator, 1-MVOP-071-0006B, was not securely connected at both ends.

- Cable for full open position indication for RCIC Steam Line Outboard Drain valve, 1-FCV-071-0006B, was not securely connected.
- Cable for position indicators on the RCIC Testable Check Valve, 1-FCV-071-0040, was not securely connected.
- Cable entering the actuator of the RCIC Lube Oil Cooler Cooling Water isolation valve, 1-MVOP-071-0025, was not securely connected.
- Hydraulic actuation stem of RCIC Turbine EGR Hydraulic Actuator, 1-SM-071-0010, was painted in place.
- RCIC Turbine Trip Throttle Valve Reset, 1-HS-071-0009E, label was attached in such a manner that it could interfere with the proper operation of the mechanism.
- 1-MTR-071-0009, RCIC Turbine Stop Valve actuator was missing a ground wire and one of the actuator's conduits lacks proper thread engagement.
- RCIC pump had small oil leaks on the pump's inboard and outboard bearings.
- RCIC Exhaust Rupture Disc Root valve sensing line was not securely mounted.
- Three JBOXs in the 519 elevation of the NW were not labeled.

The above system deficiencies were communicated to the licensee and PER 120325 was initiated to document and resolve the deficiencies.

RCIC turbine oil level was high, as observed on 1-LG-071-0620 (RCIC Turbine Oil Pump Level Gage) and 1-LG-071-0509 (RCIC Turbine Oil Level Gage). PER 120306 was initiated to document and resolve this deficiency.

Additionally, the inspectors noted that the following JBOXs were not adequately sealed to protect moisture intrusion in accordance with drawing O-45B891-1: 1-JBOX-071-895, -983, -3678, -3679, -3680, -3681, -1724, -1725, -1727, -1728, and JBOX-10903. The inspectors noted that corrective action 3 of PER 118020 documents that WO 07-711742-000 was previously generated to perform EPI-0-000-JBX001, Inspection and Sealing of Junction Box and Control Station, after the Unit 1 reactor building work is complete but prior to Unit 1 startup. This deficiency is being tracked by BFR-1-ITEL-071-403130167-1.

c. Conclusions

Inspectors determined that SPOC walkdowns and licensee activities associated with the SRTS turnover process were being adequately implemented. Increased licensee management expectations and strong ownership by the operating organization continued. Operating organization participation in SPOC meetings, testing, and walkdowns was good; and systems were being turned over in a ready condition resulting in fewer open items. System walkdowns, package reviews and interviews with licensee personnel indicated the above Unit 1 systems were adequately turned over as functional

and/or operable systems with exceptions to operability and deferrals adequately annotated in the SPOC II System Return to Service - Open Item Punchlist.

E1.4 Area Turnover Activities (37550, 37551)

a. Inspection Scope

The inspectors continued to review the licensee's process for turnover to the plant operations organization of Unit 1 areas after construction activities were completed. The inspectors had previously identified plant areas that contain selected risk-significant and safety-related equipment for independent NRC inspection to determine consistent program implementation and resolution of select punchlist items. The inspectors reviewed a recent revision of Business Practice BP-338, Area Turnovers from Recovery Unit 1 Restart Project. Additional document reviews included area turnover packages comprised the remaining punch listed action items, unfinished scheduled work activities, and previous walkdown items. Inspectors interviewed the program focal point of contact. Both independent plant area walkdowns and licensee walkdown observations were conducted by inspectors. Independent inspector walkdowns were performed to focus on area deficiencies. Observations of plant and restart management were performed to verify the adequacy of licensee area turnover philosophy and methodology.

b. Observations and Findings

The inspectors also performed independent area walkdowns of several areas which had completed the licensee's turnover process. During those walkdowns a number of deficiencies were identified which had not been identified by the licensee. Deficiencies identified by the inspectors included:

Torus

The inspectors performed a walkdown of the torus prior to final closeout by the licensee. Good material condition existed. Housekeeping was very good and no debris or loose items were identified which might impact the ECCS strainers. No significant deficiencies were identified.

HPCI Room

Inspectors inspected the Unit 1 HPCI room in the Reactor Building southwest quadrant. Installation of piping insulation was in progress in the area. Piping and electrical cables appeared to be in good condition. Equipment coatings were in good condition. Area civil structures and equipment mounts appeared to be in good condition. The inspectors noted a potential issue related to inconsistencies in installation and appearance of pipe hangers. Review of hanger drawings and discussions with licensee engineering personnel confirmed that all hangers were installed per design, and inconsistencies resulted from inactive equipment or hanger mounts. Aside from minor debris present due to work in progress, the room was clean, with no loose oil or debris. There was a small amount of water on the floor from a dripping valve. Licensee radiological controls

verified the water was not contaminated, and operations stopped the leak by flushing the valve.

Reactor building 593' elevation

Numerous housekeeping issues were identified in all areas of the 593' elevation, including abandoned gloves, tools, rags, barricade tape, masking/duct tape, and other miscellaneous debris. Some of these items were attributed to personnel from the Operating Unit subsequent to turnover. In addition, radiological postings that were no longer required, e.g., "contamination area" for a catch basin that had been removed, were identified. Upon identification, these issues were promptly corrected by the licensee. Handwritten notices of various types were identified throughout the elevation, including the use of masking and duct tape to identify penetrations that had not yet been stenciled or had been incorrectly stenciled with the appropriate identifier. Problem Evaluation Report (PER) 119075 was initiated to document the incorrect stenciling and the tape was subsequently removed.

A number of identified issues were appropriately addressed upon identification as "tool pouch" conditions. These included the replacement of broken drain gratings in RWCU pump rooms 1A and 1B, replacing a lens cover on panel 0-HS-067-0017B (ECCS N Header U1 Sect Valve) in the core spray mezzanine, and replacing a lens cover on panel 1-LPNL-925-0339 for RM-090-131C (RBCCW effluent radiation monitor).

The inspector performed a walkdown of the reactor water clean up (RWCU) backwash tank room and identified a number of conditions. Most of the observations involved poor housekeeping, including abandoned tools, hoses, work lights, tape, and debris. The licensee stated that the housekeeping standard for completion of construction work was not met and craft were subsequently coached on expectations. In addition, a significant leak was identified from a blind flange adjacent to valve 1-CKV-069-0742 in the overhead of the RWCU backwash tank room. This leak had resulted in significant pooling of water on the floor of the room. Work Order (WO) 07-711354-000 was initiated on January 30, 2007, to address the leak. The RWCU backwash tank room was listed as an exception on the BP-388 form because the room did not have an active radiation survey at the time of the walkdown.

Inspectors performed independent area walkdowns of the 593' elevation that identified the following additional issues beyond what the licensee identified:

- The RWCU backwash transfer pump had an oil leak and a minimal quantity of oil was observed in the oiler. In addition, the conduit protective jacket was not complete to the fitting. Maintenance personnel investigated the observations and determined that the oil level in the oiler was low and the pump was leaking. All observed conditions were corrected. However, subsequent inspection determined that the oil leak was still present and WO 07-711663-000 was initiated.
- The locks on the doors to the RWCU backwash transfer pump room and RWCU backwash tank room were very sticky. Radiation Control (RadCon) technicians had difficulty opening both locks. These locks, under RadCon control, are used

for Locked High Radiation Area control. The locks were lubricated by Maintenance personnel and determined to be acceptable by RadCon and Operations.

- A conditional release tag dated September 23, 2004, was identified on the 1A RWCU pump motor. Review by the licensee determined that the conditional release had been cleared on August 25, 2005, but the tag had not been removed as required by SPP-4.1. PER 123238 was initiated and the tag was removed.
- Pressure indicator gauge 1-PI-070-0055 for RBCCW inlet to HX 1A was rapidly fluctuating +/- 5 psi, whereas indicators to 1B and spare HX indicated constant pressure. U1 recovery AUO's inspected the condition and determined the gauge deflection was normal and acceptable in the interim. WO 07-712015-000 was initiated for instrument maintenance to troubleshoot, repair/replace the snubber, and calibrate the pressure indicator as required.
- 1-JBOX-069-1105 (RWCU pump 1B) and 1-JBOX-069-1102 (RWCU pump 1A) had no indicator lights lit and no indication of current knob setting (off/on/auto). The bulbs were subsequently replaced. WO 07-711529-000 was written to label start/stop indications at 1-HS-069-0004B-B and 1-HS-069-0004A-B.
- Fire Protection Panel 1-039-5660 had no bulbs in the sockets for X-line ground fault and Y-line ground fault, and the system power available light was not on. The licensee determined that light bulbs were removed from the panel during U1 alarm upgrades. WO 07-715619-000 was initiated to cover the open holes with blanks.
- Elbowlet conduit for 1-JBOX-068-6111 cover gasket was broken, resulting in an incomplete seal. Maintenance personnel installed a new cover gasket. 1-JBOX-244-9467 was missing a screw. Maintenance personnel corrected the condition.
- At the R4.5-P line, 1-JBOX-256-6431 (fire seal R15931208) pull box had no visual evidence of a gasket and the cover was not flush with pull box. Inspection by the licensee determined the fire seal was intact; however, the cover gasket for the conduit elbowlet was missing and the cover was not flush. The conditions were corrected by Maintenance personnel.
- Junction boxes 1-JBOX-069-11142, 41, 40, and 39 were found latched closed with only one of six latching mechanisms and the latch painted closed. The licensee performed a review and determined no work had been performed after the turnover walkdown. PERs 117822 and 118020, written previously for problems discovered with junction boxes, will require reinspection of all junction boxes.
- Cables were identified outside of an overhead cable tray at R3-Q. The cables were inspected and returned to the tray by Modifications Electrical.

- A support for 1" conduit in the southwest corner of the RHR HX Room A/C was broken. Maintenance personnel installed a new clamp on the conduit. It was determined that the conduit was abandoned and did not contain any cables.

Reactor building 565 elevation

The inspectors performed an independent walkdown of the 565' elevation of the Unit 1 Reactor Building, including the RHR Heat exchanger rooms and the Transversing In-Core Probe Room. Some work activities were in progress in the area, including CRD Hydraulic Control Unit work, Purge Valve local leak rate testing and insulation installation activities.

In general, piping and electrical cables appeared to be in good condition. Equipment coatings were in good condition. Area civil structures and equipment mounts appeared to be in good condition, with one exception noted below. The inspector noted some deficiencies in control of temporary equipment, inconsistencies in the administration of the Locked Valve Program and some general housekeeping issues. Aside from minor debris present due to work in progress, the room was clean, with no loose oil or debris. The inspector performed an independent area walkdown of the area and identified the following issues beyond what the licensee identified:

During the ongoing walkdown the inspectors noted temporary equipment not always meeting requirements of SPP-10.7 and/or O-TI-471. These deficiencies included:

- Modication's rolling ladder and several bottle carts were not restrained/chocked.
- Mechanics Tool boxes staged and unattended with no SPP 10.7 tag.
- LLRT Carts not tagged or restrained.
- Temporary power transformer and gas bottles staged, no SPP 10.7 tag.

The inspectors verified that the above tags were added as required.

Various deficiencies associated with implementation of locked valve program per GOI-300-3 were identified. These deficiencies included:

- High point vent on x-tie (74-0604) is locked, not listed as locked in GOI or OI-74.
- Several fire valves locked, not listed as locked in GOI or OI-26 (26-1639, 26-1641, 26-1638).
- Valves 67-0847 and 67-0848 have Green locked closed tags, valves are not locked and are not in the GOI. OI lists them as closed and capped.
- Pass valve 043-158A is locked, no Red locked open tag, not listed in GOI. The Pass TI indicates the valve should be open. The LLRT procedure states it should be locked open.

- Valve 1-SHV-032-2529 is locked, no red/green tag, not listed in GOI or OI.
- Valves 85-0082 and 85-0082A, scram discharge volume vents, have their restraining devices locked, no lock was called for in GOI or OI.

Licensee initiated PER 123103 to address the locked valve issues.

The inspectors noted that although work appeared to be complete, the associated work sites were not restored, or general housekeeping issues existed. These deficiencies included:

- Red hoses hanging down from vent valves on D RHR HX vents. (Removed)
- Several scaffolds erected with no apparent work in progress. (Removed those not in use)

Service hose connected and not in use or tagged. (Removed)

- Tygon drain line run from 8585-623/4203 Vent with no hose clamp. (Removed)
- FME Bag installed downstream of 33-2225. (Removed bag and installed cap)
- Lights burned out in both RHR HX Rooms and West HCU area. (Added to Light list)
- Tools, cords and yellow poly near 74-067 and work appears to be complete. (Removed material and cleaned area)
- Drip catches installed not meeting Radcon/Maintenance practices (missing WO Tags and/or Radcon tags). (Removed)
- RHR x-tie telltale vent has an unmarked bucket under it. Should be a radcon container with appropriate tygon hose attached. (Removed bucket)
- Wood and paper in a cable tray. (Removed)
- Ladder used to access area above Steam Tunnel has no scaffold tag and radcon tag out of date. (Removed)

The inspectors verified that the licensee took action to correct the above deficiencies as necessary.

Additionally, during the ongoing walkdown the inspectors identified other miscellaneous deficiencies. These deficiencies included:

- Electrical outlets shown on the fire pre-plan at the east HCU area and on the east wall are all abandoned. (PER 117818 previously written to address inconsistencies between FPR pre-plan and the "as built" U1 configurations)

- Welding outlet cap missing. (Cap replaced)
- TIP Room area radiation Monitor is disconnected, both in the room and on the outside wall. (Work in progress, WO 07-712480-000)
- Two holes located above CRD filters on the west wall are not marked with penetration numbers. Unable to verify they are sealed. (PER 123129 written to address issue)
- Tubing support has one of two bolts missing. (Bolt replaced)
- RB Heater piping (near SW Stairs) needs preservation and lagging. (WO 07-715534-000 issued for work)
- Coax cable burnt and hanger broken behind 480V Motor Cont Bd 1C. (WO 07-715533-000 issued for work)
- TCV-024-0080A Local Valve position indicating plate missing. (WO 07-715535-000 issued for work)
- Valve 67-0051 Local Valve position indicating plate missing. (WO 07-715536-000 issued for work)

The inspectors noted that the licensee issued WOs or PERs to address the other above issues.

c. Conclusions

The inspectors determined that area turnover process was adequate given the ongoing work in progress. Outstanding work and other deficiencies continue to be identified by restart area coordinators and plant management during walkdowns. The inspector determined that additional deficiencies identified did not cause any significant impact to the operability of equipment required to support operations of Units 2 and 3. No violations or findings were identified.

E1.5 System Restart Testing Program Activities (37551, 35301, 70304, 70315)

a. Inspection Scope

The inspectors reviewed and observed on-going Restart Test Program (RTP) activities associated with system acceptance testing for seven risk significant systems to ensure activities were in compliance with design basis requirements.

Additionally, the inspectors reviewed the activities associated with the RTP Test Summary Reports (TSR) for six risk significant systems. The reviews were performed to verify that the individual systems would be capable of supporting safe down and maintain shutdown of the Unit 1 reactor.

b. Observations and Findings

b.1 System Acceptance Testing Activities

Restart testing activities reviewed and observed consisted of system acceptance testing performed on System 64D, Primary Containment Isolation System (PCIS); System 64A, Primary Containment (PCS); System 68, Reactor Water Recirculation (RWR); System 71, Reactor Core Isolation Cooling (RCIC); System 73, High Pressure Coolant Injection (HPCI); and System 85, Control Rod Drive (CRD);

Test procedures consisted of Post Modification Test Instructions (PMTIs) issued to test portions of applicable DCNs, Technical Instructions (TIs), and Surveillance Instructions (SIs) and Surveillance Requirements (SRs). The inspectors verified that pre-test briefings were held, assignments made, and communications were established prior to performance of testing. The inspectors also attended various meetings where testing activities, test planning, testing status, test exceptions, and test results were discussed. The inspectors observed portions of the ongoing testing, reviewed selected completed test packages, and verified acceptance criteria for testing were satisfied. Specific system acceptance testing activities reviewed and observed included the following:

PCIS

System testing reviewed and partially observed for PCIS included:

- 1-SR-3.3.6.1.6 (GRP 2, 3, & 8), Groups 2, 3, and 8 Primary Containment Isolation System Logic, the purpose of this test was to demonstrate that the PCIS logic functioned as required for the following: The Group 2 isolation of the RHR System, the drywell sump drains, and the reactor building, refueling floor, and the drywell vent and purge; The Group 3 isolation for the reactor water cleanup system; and the Group 8 isolation for the transverse in-core probe system.
- 1-SR-3.3.6.1.6 (SDC), Functional Testing of RHR Shutdown Cooling Suction Valve Isolation Logic, the purpose of this test was to demonstrate that the PCIS logic functioned as required for the automatic closure of shutdown cooling suction return valves, 1-FCV-74-47 and 48, from Loop I of System 68 to System 74 upon a Group 2 PCIS signal.
- 1-SR-3.3.5.1.6 (CS I) and (CS II), Functional Test of RHR Loop I (Loop II) Valve Logic and Interlock, the purpose of these tests was to demonstrate that the PCIS logic functioned as required for the automatic closure of shutdown cooling supply valves as follows: Closure of supply valve 1-FCV-74-53, from System 74 to Loop I of System 68 upon a Group 2 PCIS signal; and closure of supply valve 1-FCV-74-67, from System 74 to Loop II of System 68 upon a Group 2 PCIS signal.
- 1-SR-3.3.1.1.13 (4A), Reactor Protection and Primary Containment Isolation Systems Low Reactor Water Level Instrument Channel A1 Calibration, the purpose of this test, and other similar tests, were to demonstrate that RPV water level instrumentation, such as Level Transmitters 1-LT-03-0203 A, B, C, and D,

transmit an electronic signal corresponding to a RPV level to the associated Analog Trip Unit (ATU) level indicating switches, such as 1-LIS-03-0203 A, B, C, and D. The testing demonstrated that the ATU's tripped at the RPV Level 3 set point and transmitted a trip signal to System 64D, PCIS, and System 99, RPS.

Primary Containment

System testing reviewed and partially observed for Primary Containment included:

- 1-SR-3.3.1.1.13/6A, B, C, and D, Reactor Protection and Primary Containment isolation Systems High Drywell Pressure Instrument Channel Calibration, the purpose of these tests was to demonstrate that the high drywell pressure indicating instrumentation was within calibration requirements.
- 1-SR-3.3.5.1.5 DWP A, B, C, and D ECCS, Core and Containment Cooling Systems HPCI, LPCI, and Core Spray High Drywell Pressure Instrumentation Calibration, the purpose of these tests was to demonstrate that the high drywell pressure instrumentation, such as Pressure Transmitters 1-PT-64-0058 A, B, C, and D, transmit an electronic signal corresponding to a drywell pressure to the associated Analog Trip Unit (ATU) pressure indicating switches, such as 1-PIS-64-0058 A, B, C, and D. The tests also demonstrate that the ATU's tripped at a drywell pressure set point of 2.45 psig and transmitted a permissive start signal to System 73 HPCI, System 74 RHR, and System 75 Core Spray.
- PMTI-51189-STG03, the purpose of this test was to demonstrate that no more than 210 lbs. of vertical force was required to open the drywell vacuum breaker discs in order to prevent a vacuum from forming.
- 1-SR-3.6.1.5.2 the purpose of this test was to demonstrate that the check valves, 1-CKV-64-800 and 801, for the Reactor Building to Suppression Pool vacuum breakers functioned as required.

Reactor Recirculation

System testing reviewed and partially observed for Reactor Recirculation included:

- 1-SR-3.3.5.1.4 (A), (B), (C) and (D), Core and Containment Cooling systems Reactor Low Pressure Instrument Channel Calibration the purpose of these tests was to demonstrate that the RPV pressure instrumentation, such as Pressure Transmitters 1-PT-68-0095 and 0096, transmit an electronic signal corresponding to a RPV pressure to the associated ATU pressure indicating switches, such as 1-PIS-68-0095 and 0096. The tests also demonstrate that the ATU's tripped at a RPV pressure set point of 251 psig and transmitted a low RPV pressure injection permissive and ECCS initiation signals, as well as a low RPV recirculation discharge valve permissive, to the applicable system logic networks.

- 1-SR-3.3.1.1.14 (8 I) and (8 II), Turbine Stop Valve Closure - RPS Trip and Recirc Pump Trip Logic System Functional Test. the purpose of these tests was to demonstrate that Turbine Stop Valve Closure and the RPS trip function performed as required. The tests also demonstrated that the end-of-cycle Recirc Pump Trip Logic performed as required.
- 1-SR-3.5.1.5, the purpose of this test was to demonstrate that the Recirc Pump Loop I discharge valve 1-FCV-68-03 and Loop II discharge valve 1-FCV-68-77 met the required valve closure function. This test was also used in part to implement the ASME Code Program requirements.
- 1-SR-3.3.6.1.5 (SDC A) and (SDC B), Reactor High Pressure Calibration 1-PS-68-93 and 94, the purpose of these tests was to demonstrate that the System 74, RHR, shutdown cooling outboard isolation valve 1-FCV-74-47 and the inboard isolation valve 1-FCV-74-48 automatically close at the RPV high pressure setpoint.

RCIC

System testing reviewed and partially observed for RCIC included:

- 1-SR-3.6.1.3.5 (RCIC) the purpose of this test was to demonstrate that the isolation times, closure times, of the following power operated valves, steam line inboard isolation 1-FCV- 71-02, and the RCIC turbine steam supply outboard isolation 1-FCV-71-03 were within requirements. The test also demonstrated that stroke times for various other valves were within the requirements of the ASME Code inservice testing program.
- 1-SR-3.3.6.1.2 (4C), Reactor Core Isolation System Turbine Exhaust Rupture Disc High Pressure Functional Test, the purpose of this test was to demonstrate that when the four pressure switches, 1-PS-71-0011A, B, C, and D, connected in a one-out-of-two-taken-twice logic, contacts closed the steam supply valves, 1-FCV-71-002 and 003, automatically closed.
- 1-SR-3.3.3.2.1 (71), Backup Control Panel Testing, the purpose of this test was to demonstrate that selected control circuits and transfer switches for System 71 were manipulated in order to operate the system from outside the MCR. This test also demonstrated that should the MCR become inaccessible the plant can be placed and maintained in MODE 3 from the Backup Control Panel and the local control stations.
- 1-SR-3.3.6.1.2 (4B) Reactor Core Isolation Cooling System Steam Supply Pressure Low Functional Test, the purpose of this test was to demonstrate that the when the four pressure switches, 1-PS-71-0001A, B, C, and D, connected in a one-out-of-two-taken-twice logic, contacts closed the steam supply valves, 1-FCV-71-002 and 003, automatically closed.
- 1-SR-3.3.5.2.4 (FT), RCIC System Logic Functional Test, among the purposes of this test was to demonstrate that the system logic performed the following:

Initiated RCIC on low RPV water level; isolated RCIC on steam line space high temperature; isolated on steam line high flow from high differential pressure; isolated on steam supply pressure low; isolated on a high RPV water level; manual isolated on high rupture disc pressure with low RPV water level signal present; tripped turbine on exhaust pressure high; tripped the turbine on a pump suction pressure low isolation signal; performed the proper function for turbine automatic restart following a high RPV water level turbine isolation; the proper function for the condensate storage tank suction valve and suppression pool suction valve interlocks; the proper function for logic bus failure; the proper function for the vacuum tank level; and the proper function for low bearing oil pressure. The procedures also verified the proper function of the flow control valve 1-FCV-71-0034, RCIC pump minimum flow valve.

- PMTI-51243-ST01 and 02, the purpose of these tests was to demonstrate that power for the System 71 250V DC power system supplied power to the Division I Analog Trip Units (ATU) and the Division II ATU's. The tests were performed after completion of DCN 51243, Reactor Core Isolation Cooling, Instrumentation and Control (I&C) - Control Bay, Stage 1 and Stage 2, System 71.

HPIC

System testing reviewed and partially observed for HPCI included:

- 1-SR-3.3.6.1.2 (3C), HPCI System Turbine Exhaust Rupture Disc High Pressure Functional Test, the purpose of this test was to demonstrate that when the four Turbine Exhaust Rupture Disc pressure switches, 1-PS-71-0020A, B, C, and D, connected in a one-out-of-two-taken-twice logic, contacts closed on high pressure the inboard steam supply valve 1-FCV-73-0002, the outboard steam supply valve 1-FCV-73-0003, the steam line warmup valve 1-FCV-73-081, and HPCI suction valves 1-FCV-73-0026 and 0027 automatically closed.
- 1-SR-3.3.5.1.3 (E), HPCI Suppression Chamber High Level Calibration and Functional Test, the purpose of this test was to demonstrate that the Suppression Chamber high level switches 1-LS-73-0057A and 0057B trip settings were calibrated. This test also demonstrated that the trip logic sent an open signal to the HPCI suction valves, 1-FCV-73-0026 and 0027, to open on a high water level signal, and to transfer the HPCI pump suction from the condensate header to the Suppression Chamber.
- 1-SR-3.3.6.1.2 (3B), HPCI Steam Supply Low Pressure Functional Test the purpose of this test was to demonstrate that when the four HPCI Steam Supply pressure switches, 1-PS-71-0001A, B, C, and D, connected in a one-out-of-two-taken-twice logic, contacts closed on low pressure the inboard steam supply valve 1-FCV-73-0002, the outboard steam supply valve 1-FCV-73-0003, the steam line warmup valve 1-FCV-73-081, and HPCI suction valves 1-FCV-73-0026 and 0027 automatically closed and initiated a turbine trip.
- 1-SR-3.6.1.3.5 (HPCI), the purpose of this test was to demonstrate that the isolation time, closure time, of selected motor operated valves were within

acceptable limits. Among these valves were the following: 1-FCV-73-0002, inboard steam supply isolation valve, 1-FCV-73-0003, the outboard steam supply isolation valve, 1-FCV-73-0016, the steam supply valve, 1-FCV-73-0081 the steam line warmup valve, 1-FCV-73-0034, pump discharge valve to the feedwater system, and HPCI suction valves 1-FCV-73-0026 and 0027.

- 1-SR-3.3.5.1.3 (D), HPCI Condensate Header Low Level Calibration and Functional Test, the purpose of this test was to demonstrate that the condensate header level switches 1-LS-73-0056A and 0056B trip settings were calibrated on low level. This test also demonstrated that the logic sent an open signal to the HPCI suction valves, 1-FCV-73-0026 and 0027, to open on a low water level signal, and to transfer the HPCI pump suction from the condensate header to the Suppression Chamber.
- 1-SR-3.3.5.2.4 (FT), HPCI System Logic Functional Test, among the purposes of this test was to demonstrate that the system logic performed the following: Initiated HPCI on low RPV water level; Initiated HPCI on high drywell pressure; isolated HPCI and suppression pool suction valves on steam line space high temperature; isolated on steam line high flow from high differential pressure; isolated on steam supply pressure low; isolated on a high RPV water level; isolated on high rupture disc pressure; and manually isolated following an automatic initiation; tripped turbine on exhaust pressure high; tripped the turbine on a HPCI booster pump suction pressure low signal; tripped the turbine on a high RPV water level; tripped the turbine on steam supply pressure low; steam supply pressure low PCIS signal; tripped the turbine manually from the MCR; performed the proper function for turbine automatic restart following a high RPV water level turbine isolation; the proper function for the condensate storage tank suction valve and suppression pool suction valve interlocks on high suppression pool water level and low CST water level; the proper function for logic bus power failure annunciation; the proper function for 120V AC control power failure annunciation; and the proper function for supervisory annunciation to alert MCR operators to potential damaging conditions. The procedures also verified the proper function of selected flow control valves upon a PCIS Group 4 signal and of the flow control valve 1-FCV-73-0050, HPCI pump minimum flow valve.
- PMTI-51094-ST10, Functional Test of Miscellaneous HPCI System Electrical Components, the purpose of this test was to demonstrate the functional performance of various HPCI electrical components that were relocated. The electrical components that were relocated were on MCR control panel 1-9-03. Among the components were the following: Hand Switch (HS) 1-HS-73-02, HPCI Steam Supply Inboard Isolation Valve; switch 1-HS-73-03, HPCI Steam Supply Outboard Isolation Valve; Switch 1-HS-73-10A, HPCI Gland Seal Condenser Blower; switch 1-HS-73-16, HPCI Steam Supply Valve; switch 1-HS-73-30A, HPCI Minimum Flow Valve; switch 1-HS-73-18A, HPCI Turbine Trip; and switch 1-HS-73-18B, HPCI Turbine Trip RPV Level High Reset. The test was performed after completion of DCN 51094, Control Room Design Review (CRDR) Main Control Room, Panel 1-9-03-Control Bay, Stage 10, System 71.

- 1-SR-3.5.1.8, HPIC Main and Booster Pump Set Developed Head and Flow Rate Test at 150 psig Reactor Pressure verified that the High Pressure Coolant Injection (HPCI) System is capable of pumping 5000 gpm into the Reactor Pressure Vessel (RPV) against a system head corresponding to a nominal RPV steam dome pressure of 150 psig. The test determined the operability of the HPCI turbine, pump, and auxiliaries in conformance with Technical Specification requirements for rated flow and pressure at auxiliary boiler steam pressure (150-165 psig).

The inspectors observed licensee preparations for testing, selected portions of ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

CRD

System acceptance testing associated with CRD reviewed and observed included:

- Test Instruction 0-TI-20, Control Rod Drive System Testing and Troubleshooting, the purpose of this TI was to manipulate and exercise control rods, verify rod status board indications, and to determine the work activities need to bring the system to a functional status for further testing.
- 0-SR-3.1.4.1, Scram Insertion Times
- 0-SR-3.9.5.1, Mode 5 Control Rod Drive Rod Exercise
- 1-SR-3.1.3.5 (A), Control Rod Drive Coupling,
- 1-SR-3.10.7, Verification of Surveillance Requirements for Control Rod Testing

System acceptance test activities for this system were previously reviewed and documented in Inspection Report 50-259/2006-09. Testing reviewed involved post modification testing of electrical, and instrumentation and control equipment. Additional CRD testing activities reviewed included the following:

- WOs from 07-710775-00 to 07-710783-00 to perform various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components.
- Post maintenance testing associated with the above WO's to verify that repair activities were completed and tested.
- Post modification testing involved with DCN 51080, Reactor Protective System, relay replacement and calibration.
- Post modification testing involved with DCN 51240, Control Rod Drive, electrical and Mechanical - Reactor Building, System 85, for the replacement of electrical cables, fuses, components attached to hydraulic control units, and various types of instrumentation.

- Post modification testing involved with DCN 51085, 120V AC Control Bay distribution for the replacement of circuit breakers.
- PMTI-51082-STG02, post modification testing to verify that System 85 computer points, both analog and digital, communicate adequately with System 261, Plant Computer

Additional acceptance testing activities for System 85 are on the RTP schedule to be performed following reactor startup during power operations. This planned testing includes Test Instruction 0-TI-253, Rod Block Monitoring System. This TI cannot be performed until the reactor has reached 30% power.

System testing determined the operability of the CRD System was in conformance with Technical Specification requirements for pump performance, flowpath verification, piping integrity, initiation logic, and ASME inservice testing. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

b.2 Integrated System Testing

RPV ASME Section XI System Leakage Test

1-SI-3.3.1.A, ASME Section XI System Leakage Test of the Reactor Pressure Vessel and Associated Piping (ASME Section III, Class I and II), was performed to satisfy the ASME Section XI system pressure test requirements (IWB-5210/Table IWB-2500-1 Category B-P and IWB-5000 of the ASME Boiler and Pressure Vessel Code, Section XI, 1995 Edition, 1996 Addenda). The testing consists of a system leakage test of the ASME Class I equivalent and portions of Class II CRD piping and components, including scram discharge volume, and Class II lines in the drywell. This testing also satisfied the Class I ten year test requirements of IWB-5222(b). The inspectors observed test preparations, system lineups, attended licensee just-in-time training, senior management briefs, and pre-test briefing prior to performance of testing. The inspectors also observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements. Additionally, the inspectors reviewed the qualification records for the NDE examination personnel that performed the VT-2 visual exams during the ongoing testing.

Marotta Valve Testing

The instrument line excess flow check valves (Marotta valves) were tested to satisfy requirements for the high flow closure function defined in TS 3.6.1.3. A total of 67 Marotta valves are installed on various instrument lines associated with 13 Unit 1 instrument panels. Testing of these valves was performed in accordance with Surveillance Instructions 1-SR-3.6.1.3.8(1), 1-SR-3.6.1.3.8(2), 1-SR-3.6.1.3.8(3), 1-SR-3.6.1.3.8(4), 1-SR-3.6.1.3.8(5), Instrument Line Excess Flow Check Valve Operability Testing. The licensee functionally tested all 67 Marotta valves on sensing lines related to reactor water level, reactor pressure, jet pump flow, recirculation pump discharge flow, recirculation pump differential pressure, recirculation pump seal pressures, main

steam line high flow, core plate differential pressure, core spray sparger break, main steam line flows, CRD drive water header differential pressure, CRD cooling water differential pressure, and HPCI/RCIC steam line flows. Testing was performed at elevated pressure (500 psig) in conjunction with ASME Section XI RPV system leakage testing by establishing a flow path from the RPV through the individual Marotta valves to be tested and the local instrument panel valves into an appropriate receptacle. Observance of an initial surge of flow followed by restricted flow confirmed by measured flow consistent with Marotta valve design flow (.2 to .7 gpm) demonstrated proper operation. The inspectors observed test preparations and pre-test briefing prior to performance of testing. The inspectors also observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

Containment Integrated Leak Rate Test

1-SI-4.7.A.2.a-f, Primary Containment Integrated Leak Rate Test (ILRT) verified that the overall leak rate of the Primary Containment was within allowable leakage limits as required by TS 3.6.1.1.1 and TS 5.5.12. Testing was accomplished by installation of temporary air compressors to maintain a stable pressure of approximately 49.6 psig in the Primary Containment and computing the leakage rate using a mass flow method in accordance with ANSI/ANSI 56.8-1994 American national Standard, Containment Air Leakage Testing Requirements. The maximum allowed calculated leak rate corresponded to 2% of the primary containment free-air volume per 24 hours at 49.6 psig (1093.12 SCFM). The containment design pressure of 56 psig was not to be exceeded during the testing.

During the ongoing ILRT the licensee performed a general visual examination of the primary containment as required by 10 CFR 50, Appendix J and ASME Section XI, Subsection IWE. The licensee also performed visual VT-2 inspection of the ASME Code MC pressure retaining boundary during the ILRT as required by 0-TI-376, ASME Section XI Containment Inservice Inspection Program. The inspectors observed test preparations, system lineups, management briefing, and pre-test briefing prior to performance of testing. The inspectors also observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements. Additionally, the inspectors reviewed the qualification records for the NDE examination personnel that performed the VT-2 visual exams during the ongoing testing.

Recirculation Flow Control Testing

1-TI-132, Recirculation Flow Control, was performed to verify the Recirculation Flow Control System performed as designed. Portions of 1-TI-132 testing performed included exercising system controls including the Foxboro Flow Controls and the Variable Frequency Drives (VFDs) were tested and tuned at elevated pressure in conjunction with ASME Section XI RPV system leakage testing. Additional testing utilizing 1-TI-132 will be performed later at power after restart. During the ongoing testing both recirculation pumps were operated from 480 to 1080 RPM. The inspectors observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

b.3 Test Summary Reports (TSRs)

The TSR's were developed, written, approved, and issued to document the results of tests performed on the listed systems. The tests verified that the system performed adequately to the specified design functions. The tests were based on the system Baseline Test Requirement Documents (BTRD) Modes. The system BTRD's were based on the safe shutdown analysis (SSA) and were used to establish test requirements (by system mode) to verify all safe shutdown functions. During this reporting period the inspectors reviewed TSR's on tests performed on System 64A, Primary Containment; System 64D, Primary Containment Isolation System (PCIS); System 68 / 96, Reactor Water Recirculation / Recirculation Flow Control (RWR / RFC); System 71, Reactor Core Isolation Cooling (RCIC); and System 73, High Pressure Coolant Injection. Specific TSRs reviewed included the following:

Primary Containment Isolation System (PCIS), 1-BFN-BTRD-64D

The System 64D Primary Containment Isolation System (PCIS) consisted of five BTRD Modes as follows:

- Mode 64D-01, provides a signal to close Group 1 PCIS valves in System 01, Main Steam (MS), and valves in System 43, Sample and Water Quality (S&WQ). Testing requirements for this Mode was transferred to 1-BFN-BTRD-01, Main Steam.
- Mode 64D-02, provides a signal to close Group 2 PCIS valves in System 74, RHR, valves in System 75, Core Spray, and valves in System 77, Radwaste (RWS). Testing for this Mode was performed and documented during the Unit 1 recovery by the following: Verified that a Group 2 isolation signal was provided by the PCIS isolation logic and was sealed in from System 64A thru System 99 on drywell high pressure; verified that a Group 2 signal was provided from System 03 thru System 99 on a RPV water level low (Level 3); and verified that a Group 2 isolation signal was provided to the isolation valves for the Core Spray drain pumps, the drywell equipment and floor drains, the control circuits for the RHR shutdown cooling supply, and the control circuits for the LPCI injection. The testing involved the use of various procedures including 1-SR-3.6.1.5.3(A) and (B), 1-SR-3.3.6.1.6(GRP 2, 3, & 8), 1-SR-3.3.6.1.6 (SDC), 1-SR-3.3.5.1.6(AI) and (AII), 1-SR-3.3.5.1.6(CS I) and (CS II), 1-SR-3.3.1.1.13(4A), (4B), (4C), and (4D), and 1-SR-3.3.1.1.13(6A), (6B), (6C), and (6D). No further testing of System 64D was required for Unit 1 recovery to verify this Mode.
- Mode 64D-03, provides a signal to close Group 3 PCIS valves in System 69, RWCU. Testing for this Mode was performed and documented during the Unit 1 recovery by the following: Verified that a Group 3 isolation signal was provided by the PCIS isolation logic and was sealed in from RWCU trench drain high temperature; verified that a Group 3 isolation signal was provided by the PCIS isolation logic on RWCU space high temperature; verified that a Group 3 signal was provided from System 03 thru System 99 on a RPV water level low (Level 3); and a Group 3 signal was provided to the control circuitry of the RWCU isolation valves. The testing involved the use of various procedures such as the

following: 1-SR-3.3.6.1.6 (GRP 2, 3, & 8), 1-SR-3.3.1.1.13 (4A), (4B), (4C), and (4D), and 1-SR-3.3.6.1.4 (GRP3/A1), (GRP3/A2), (GRP3/B1), and (GRP3/B2). No further testing of System 64D was required for Unit 1 recovery to verify this Mode.

- Mode 64D-04, provides a signal to close Group 6 PCIS valves in System 43, S&WQ, valves in System 64B, Containment Purge, valves in System 76, Containment Inerting, valves in System 84, Containment Air Dilution, and valves in System 90, Radiation Monitoring. The Mode 64D-04 was also to provide the following: Send a signal to Isolate the System 31, Control Bay HVAC, Main Control Room (MCR) ventilation ducts; send a signal to initiate emergency pressurization of the MCR; send a signal to trip fans and position dampers in System 64B, Reactor Building Ventilation; and send a signal to initiate System 65, Standby Gas Treatment System. Testing for this Mode was performed and documented during the Unit 1 recovery by the following: Verified that a Group 6 isolation signal was provided by the PCIS isolation logic and was sealed in from System 90 on a refuel zone exhaust high radiation; verified that a Group 6 isolation signal was provided from System 90 on a reactor zone exhaust high radiation; verified that a Group 6 isolation signal was provided from system 99 on a drywell high pressure; verified that a Group 6 isolation signal was provided from System 03 thru System 99 on a RPV water level low (Level 3); verified that a Group 6 isolation was provided to the control circuits of the isolation valves for Systems 64A, 76, 84, 90, and 43. The testing involved the use of various procedures such as the following: 1-SR-3.3.1.1.13 (6A), (6B), (6C), and (6D), 1-SR-3.3.1.1.13 (4A), (4B), (4C), 1-SR-3.3.6.1.6 (GRP 2, 3, & 8), and 1-SR-3.3.6.2.4 (GRP 6). No further testing of System 64D was required for Unit 1 recovery to verify this Mode.
- Mode 64D-05, provides a signal to close Group 8 PCIS valves in System 94, Transversing Incore Probe. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying that a Group 8 isolation signal was provided by the PCIS isolation logic and was sealed in from System 99 on a drywell high pressure signal, and verified that a Group 8 isolation signal was provided by a RPV water low level (Level 3) from System 03. The testing involved the use of various procedures such as the following: 1-SR-3.3.1.1.13 (6A), (6B), (6C), and (6D), 1-SR-3.3.1.1.13 (4A), (4B), (4C), and 1-SR-3.3.6.1.6 (GRP 2, 3, & 8). No further testing of System 64D was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and verified that the above PCIS system modes were satisfactorily tested during the ongoing testing activities. For Mode 64D-01 where the licensee had relied on testing performed for the Main Steam System, the inspectors concurred that no further testing of System 64D was required for Unit 1 recovery.

Primary Containment System, TSR 1-BFN-BTRD-64A

System 64A Primary Containment System consisted of 19 BTRD Modes as follows:

- Mode 64A-06, provides a primary containment boundary. Testing for this Mode was performed and documented during the Unit 1 recovery by the testing of various systems containing primary containment pressure boundary valves. Among these systems were the following: System 01, Main Steam; System 03, Reactor Feed Water; System 12, Auxiliary Boilers; System 32, Control Air, Emergency Control Air, and Drywell Control Air; System 68, Reactor Water Recirculation; System 73, HPCI, System 74, RHR; and System 75, Core Spray. All functional tests of the PCIS logic were addressed by 1-BFN-BTRD-64D. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-08, provides a high drywell pressure trip signal to System 99, RPS. Testing for this Mode was performed and documented during the Unit 1 recovery by testing pressure transmitters 1-PT-64-0056A, B, C, and D, and pressure indicating switches 1-PIS-64-0056A, B, C, and D. The testing involved the use of surveillance procedures 1-SR-3.3.1.1.13/6A, B, C, and D. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-09, provides a high drywell pressure signal to the following: System 74, RHR, for low pressure coolant injection (LPCI) logic; signal to System 75, Core Spray, for initiation logic; signal to System 57-4, 480V AC Distribution, for load shed logic; signal to System 57-5, 4KV AC Distribution, for diesel generator start logic; and signal to System 74, HPCI, for initiation logic. Testing for this Mode was performed and documented during the Unit 1 recovery by testing pressure transmitters 1-PT-64-0058A, B, C, and D, and pressure indicating switches 1-PIS-64-0058A, B, C, and D. The testing involved the use of surveillance procedures 1-SR-3.3.5.1.5 DWPA, B, C, and D ECCS. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-10, provides a vacuum relief system, through vacuum breaker valves to prevent drywell or suppression chamber negative pressure from damaging the containment structure and provide air-operated reclosure of the reactor building to torus vacuum breakers. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various equipment such as the following; Vacuum breaker valves 1-FCV-64-0020 and 0021 for vacuum relief from reactor building the torus; verified that the vacuum breaker discs 1-CKV-64-0800 and 0801 move freely, that the disc closure magnets secured the discs upon closure, that the discs seated against the bodies, and that no more than 210 pounds of vertical force was required to open the discs. The testing also involved vacuum relief from the torus to the drywell by verifying that the eight vacuum breaker valves 1-FCV-64-0028A thru M opened within specified requirements. The testing involved the use of various procedures including 1-SR-3.6.1.5.3(A) and (B), PMTI-51189-STG03, 1-SR-3.6.1.5.2, 1-SR-3.6.1.6.2, and 1-SR-3.6.1.6.3. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.

- Mode 64A-11, provides a drywell temperature indication in the MCR for the full scale of the required temperature range in support of System 70, RBCCW, drywell cooling and System 74, RHR, drywell containment spray cooling mode. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various temperature instruments such as the following: Temperature elements 1-TE-64-0052A and C, temperature indicators 1-TI-64-0052AA and AB, temperature monitors 1-TM-64-0052AA and CA, and temperature switch 1-TS-64-0052A. The testing involved the use of procedures 1-SR-3.3.3.1.4(9B) and (9A). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-12, provides a torus temperature indication in the MCR for the full scale of the required temperature range in support of System 74, RHR, torus cooling and torus spray containment cooling, System 01, Main Steam, manual RPV depressurization, and System 99, RPS, manual scram. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various temperature instruments including temperature elements 1-TE-64-0161A thru H, temperature elements 1-TE-64-0162A thru H, temperature indicators 1-TI-64-0161 and 0162, temperature monitors 1-TM-64-0161A thru M, temperature monitors 1-TM-64-0162A thru M, temperature recorders 1-TR-64-0161 and 0162, and temperature switches 1-TS-64-0161A thru H. The testing involved the use of procedures 1-SR-3.3.3.1.4(8B) and (8A). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-13, provides a torus level indication in the MCR in support of System 74, RHR, containment cooling, and System 01, Main Steam, manual RPV depressurization. And also to provide for System 73, HPCI, pressure boundary integrity. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various level instruments including level indicators 1-LI-64-0054A, 0066, and 0159A, level transmitters 1-LT-64-0054, 0066, 0159A, and 0159B, level switch 1-LS-064-0054A, and recorder 1-XR-64-0159. The testing involved the use of procedures 1-SR-3.3.3.1.4(3B) and (3A), and 1-SR-3.6.2.2 (A) and (B). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-14, provides a drywell pressure indication in the MCR in support of System 74, RHR, drywell / torus spray containment cooling mode and System 84, Containment Atmosphere Dilution, for containment venting after a LOCA. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various pressure instruments including pressure indicators 1-PI-64-0050, 0067B, and 0160A, pressure transmitters 1-PT-64-0050, 0067, and 016, recorders 1-XR-64-0050 and 0159, and pressure switch 1-PS-64-0067B. The testing involved the use of procedures 1-SR-3.3.3.1.4(4 NRB) and (4 NRA), and 1-SR-3.3.3.1.4(4 WRA) and (4 WRB).
- Mode 64A-15, provides a drywell temperature indication outside the MCR, at the backup control panel, for the full range of the required temperature range in support of System 70, RBCCW, drywell cooling and System 74, RHR, operation from outside the MCR. Testing for this Mode was performed and documented

during the Unit 1 recovery by testing various temperature instruments including temperature element 1-TE-64-0052A, temperature transmitter switch 1-XS-64-0052AA and temperature indicating switch 1-TIS-64-0052AA. The testing involved the use of procedure 1-SR-3.3.3.1.4(9B). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.

- Mode 64A-16, provides a torus cooling temperature indication outside the MCR, at the backup control panel, for the full scale of the required temperature range in support of System 74, RHR, operation, and System 01, Main Steam, manual RPV depressurization. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various temperature instruments including temperature elements 1-TE-64-0055 E and F, temperature indicator 1-TI-64-0055B, and temperature transmitter switch 1-XS-64-0055B. The testing involved the use of procedure 1-SR-3.3.3.2.3(3). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-17, provides a torus level indication outside the MCR, at the backup control panel, in support of System 74, RHR, operation, System 01, Main Steam, manual RPV depressurization, and System 71, RCIC, operation. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various level instruments including level indicator 1-LI-64-0054B, level transmitter 1-LT-64-0054, level switch 1-LS-064-0054B, and transfer switch 1-XS-64-0054. The testing involved the use of procedure 1-SR-3.6.2.2 (A). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-18, provides a torus pressure indication outside the MCR, at the backup control panel, in support of System 74, RHR, operation. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various pressure instruments including pressure indicator 1-PI-64- 0050, pressure transmitters 1-PT-64-0050, and transfer switch 1-XS-64-0050. The testing involved the use of procedure 1-SR-3.3.3.1.4(4 NRA). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-20, provides a pressure suppression by cooling/condensation of safety relief valves (SRVs) steam from System 10, Boiler Drains and Vents, System 71, RCIC, turbine exhaust steam, System 73, HPCI, turbine steam exhaust, and accept RCIC and HPCI pump flow. Testing for this Mode was performed and documented during the Unit 1 recovery by baseline testing of the affected individual systems. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-24, provides a water supply to System 71, RCIC, System 73, HPCI, System 75, Core Spray, and/or System 74, RHR. Testing for this Mode was performed and documented during the Unit 1 recovery by baseline testing of the affected individual systems. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-25, provides a high drywell pressure signal to System 01, Main Steam, for Automatic Depressurization System (ADS) logic. Testing for this

Mode was performed and documented during the Unit 1 recovery by testing various pressure instruments including pressure transmitters 1-PT-64-0057A thru D, and pressure indicating switches 1-PIS-64-0057A thru D. The testing involved the use of procedures 1-SR-3.3.5.1.5(DWP A - ADS), (DWP B - ADS), (DWP C - ADS) and (DWP D - ADS). No further testing of System 64A was required for Unit 1 recovery to verify this Mode.

- Mode 64A-26 provides a structural support for System 85, CRD, rod drive housings. This Mode involves structures which only provide a passive function. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64A-27, provides a drywell permissive signal to support System 74, RHR, drywell / torus spray mode of operation. Testing for this Mode was performed and documented during the Unit 1 recovery by testing various pressure instruments such as pressure transmitters 1-PT-64-0058E thru H, and pressure indicating switches 1-PIS-64-0058E thru H. The testing involved the use of procedures 1-SI-4.2.B-4 A, B, C and D. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 64B-27, Close selected primary containment ventilation system isolation valves on a System 64D, PCIS, Group 6 isolation signal. Testing for this Mode was performed during the Unit 1 recovery which verified that selected Reactor Building ventilation valves/dampers closed upon a Group 6 PCIS signal and remained closed upon resetting or clearing of the Group 6 initiation signal; verified that the PCIS Group 6 isolation signal could not be overridden by operator action, except as provided for in post-accident mitigation manual override circuitry; verified that the selected Reactor Building ventilation valves/dampers closed within their individual time requirements; verified that selected Reactor Building ventilation valves/dampers closed upon a loss of control air and the backup nitrogen supply as applicable; and verified that upon a loss of 120V AC power to the selected solenoid valves, the selected Reactor Building ventilation valves/dampers closed. The testing involved the use of procedures 1-SR-3.3.6.2.4(GRP 6), 1-SR-3.6.1.3.5(OC), 1-SR-3.6.1.3.5, PMTI-51189-STG03, and PMTI-51189-STG4. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.
- Mode 32-09, provides a System 84, Containment Atmosphere Dilution (CAD), flow integrity for the supply of nitrogen to the torus vacuum breaker valves. This Mode also provided a CAD flow for nitrogen to the reactor building to torus vacuum breaker butterfly valves. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying actuation of the torus vacuum breaker valves 1-FCV-64-20 and 21 by the CAD nitrogen system thru solenoid valves 1-FSV-64-20 and 21 when normal control air was not available. The testing involved the use of procedure PMTI-51189-STG03. No further testing of System 64A was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and verified that the above Primary Containment System modes were satisfactorily tested during the ongoing testing activities. For Mode

64A-06 where the licensee had relied on testing performed for the PCIS System the inspectors concurred that no further testing of System 64A was required for Unit 1 recovery.

Reactor Water Recirculation System and Recirculation Control System, TSR 1-BFN-BTRD-68/96

System 68, Reactor Water Recirculation System and System 96 Recirculation Control System consisted of 9 BTRD Modes as follows:

- Mode 68-01, Close recirculation pump discharge valves upon a System 74, RHR, automatic LPCI mode initiation signal. Testing for this Mode was performed and documented during the Unit 1 recovery by the following: Verified that a low pressure signal was sent to System 74; and verified that with a simulated accident signal the DIV I LPCI signal closed the 1B pump discharge valve; the DIV II LPCI signal closed the 1A pump discharge valve; and the discharge valves closed within 33 seconds. The testing involved the use of procedures 1-SR-3.3.5.1.4(C) and (D), 1-SR-3.5.1.9(RHR I) and (RHR II), 1-SR-3.3.5.1.6(CI) and (CII), and 1-SR-3.5.1.5. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-02, Open recirculation pump motor breakers open on a System 99, RPS, signal due to main turbine first stage pressure < 30%, with either main turbine control valve (TCV) fast closure or main turbine stop valve (TSV) > 90% open (end of cycle function), and provided adequate coast down inertia. Testing for this Mode was performed and documented during the Unit 1 recovery which verified that the motor breakers tripped open upon RPS TSV trip signal; verified that the motor breakers tripped open upon RPS TCV trip signal; and verified that upon a breaker trip the coast down due to pump motor inertia was < 3.5 seconds. The testing involved the use of procedures 1-SR-3.3.1.1.8(8), 1-SR-3.3.1.1.14(8 I) and (8 II), 1-SR-3.3.4.1.4, and 1-SR-3.3.1.1.8 (9). No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-03, Close Recirculating pump discharge valves manually in support of manually initiated System 74, RHR, shutdown cooling mode and LPCI mode from the MCR and from outside the MCR. Testing for this Mode was performed and documented during the Unit 1 recovery which verified that when transfer switch 1-XS-68-03 was in the EMERGENCY position, at the backup control station, valve 1-FCV-68-03 could only be closed by the operation of switch 1-HS-68-03C, and that valve 1-FCV-68-03 could not be operated from the MCR; verified that when transfer switch 1-XS-68-03, was in the NORMAL position valve 1-FCV-68-03 could not be operated at the backup control station, and that valve 1-FCV-68-03 could only be operated from the MCR; and verified that valve 1-FCV-68-79 could be closed by operation of hand switch 1-HS-68-79A in the MRC. The testing involved the use of procedures 1-SR-3.3.3.2.1(74), 1-SR-3.5.1.5, and 1-SI-3.2.10.D. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.

- Mode 68-04, provides a reactor coolant pressure boundary. Testing for this Mode was performed and documented during the Unit 1 recovery by performing a system pressure test and verifying that excess flow check valves closed on a simulated line break. The testing involved the use of procedures 1-SI-3.3.1.A and 1-SR-3.6.1.3.8 (1), (2), (3) and (4). No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-05, provides a low reactor pressure permissive signal to System 74, RHR, and to System 75, Core Spray. Testing for this Mode was performed and documented during the Unit 1 recovery which verified that with pressure sensed by pressure switches 1-PS-68-93 and 94 was above the shutdown pressure setpoint signals sent to System 74 to initiate closure and inhibit opening of the shut down cooling suction isolation valves; verified that with pressure sensed by pressure switches 1-PS-68-93 and 94 was below the shutdown pressure setpoint signals were sent to System 74 to remove the inhibit of opening the shutdown cooling suction isolation valves; and verified that pressure switches 1-PS-68-95 and 95 sent corresponding permissive signals to system 75. The testing involved the use of procedures 1-SR-3.3.6.1.5 (SDC A) and (SDC B), and 1-SR-3.3.5.1.4 (C) and (D). No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-06, Open recirculation pump motor breakers upon on a high reactor pressure or a low water level (L2). Testing for this Mode was performed and documented during the Unit 1 recovery which verified that the pump motor breakers tripped on a RPV high pressure signal, and verified that the breakers tripped on and RPV low water level signal. The testing involved the use of procedure 1-SR-3.3.4.2.4. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-08, provides a Primary Containment pressure boundary. Testing for this Mode of providing primary containment pressure boundary was transferred to the System 64A, Primary Containment, BTRD. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-09, Assures that the reactor recirculation pump motor speed changes stay within the analyzed limits. Testing for this Mode was performed and documented during the Unit 1 recovery which verified that the pump motor maximum acceleration was no more than 25% of full speed per second, and verified the maximum flow at 100% rated power. The testing involved the use of procedures PMTI-51219, and 1-TI-174. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 68-10, Verify that Plant Technical Specifications (TS) and procedures require a warm-up of the recirculation loops prior to the start of the recirculation pump motors. This Mode is a statement of fact. TS 3.4.9, RCS Pressure and Temperature (P/T) Limits, stated that RCS Pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation pump starting temperature requirements shall be maintained within the limits. No baseline testing is required to support this statement.

The inspectors reviewed the TSR and verified that the above Reactor Recirculation System modes were satisfactorily tested during the ongoing testing activities. For Mode 68-08 where the licensee had relied on testing performed for the Primary Containment System the inspectors concurred that no further testing of System 68 was required for Unit 1 recovery.

RCIC, TSR 1-BFN-BTRD-71

System 71, RCIC, consisted of 11 BTRD Modes as follows:

- Mode 71-01, Provide an automatic operation for initiation of System 71 on a RPV low water level (Level 2); shutoff of System 73, if operating, on a RPV high water level (Level 8); and transfer, if needed, the pump suction from the Condensate Storage Tank (CST) to the suppression pool on low condensate storage tank level or high suppression pool level. Testing for this Mode was performed and during the Unit 1 recovery which verified that the selected components responded to an initiation from the system in the standby mode to the injection mode; verified that the selected components responded to an initiation from the system in the pump test mode to the injection mode; verified that the steam line drain valves closed when the turbine steam supply valve was opened; verified that the steam line drain valves opened when the turbine steam supply valve was closed; verified that the CST suction valve opened when the suppression pool suction valves were not fully closed, and the annunciation for these valves indicated the appropriate position in the MCR. The testing involved the use of various procedures. Among the procedures used were the following: 1-SR-3.5.3.4; 1-SR-3.6.1.3.5 (RCIC); and 1-SR-3.3.5.2.4 (FT). Further testing of System 71 was required for Unit 1 recovery to verify this Mode for the following; Verification that the RCIC system delivers a minimum flow rate of 600 gpm within 30 seconds upon receipt of an initiation signal; and verification that the minimum flow valve functions properly. To ensure that these verifications occur during reactor startup, Punch List (PL) items, PL-06-3567 and 3569, and procedures 1-SR-3.5.3.3 and 1-TI-428 were issued.
- Mode 71-02, Provide manual initiation and trip to control level in a non-LOCA unit, and transfer, if needed, the pump suction from the CST to the suppression pool on low condensate storage tank level or high suppression pool level. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying that selected components were manually operated from the MCR. The testing involved the use of procedure 1-SR-3.6.1.3.5 (RCIC). No further testing of System 71 was required for Unit 1 recovery to verify this Mode.
- Mode 71-03, Close RCIC system supply line isolation valves on a Group 5 isolation signals from the following: High steam line differential pressure, high steam line space temperature, low steam line pressure, or high HPCI turbine exhaust diaphragm pressure. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying that a Group 4 isolation signal was provided to the HPCI Divisions I and II isolation logic and sealed in from the following: High steam supply differential pressure from instruments 1-

PDIS-71-0001A and 0001B in a one-out-of-two logic; high steam line space temperature from instruments 1-TS-71-0002A thru D, E thru H, J thru M, and 1-TS-71-002N, P, R and S, with the temperature switches connected in a one-out-of-four logic feeding relays connected in a one-out-of-two, taken twice logic; high turbine exhaust diaphragm from instruments 1-PS-71-0011A thru D connected in a one-out-of-two, taken twice logic; low steam supply line pressure from instruments 1-PS-71-0001A thru D connected in a one-out-of-two, taken twice logic; and verified that selected components did not reset when the Group 5 isolation signal was reset. The testing involved the use of various procedures including 1-SR-3.3.6.1.5 (4C/A), (4C/B), (4C/C), and (4C/D); 1-SR-3.3.6.1.5 (4B/A), (4B/B), (4BC/C), and (4B/D); 1-SR-3.3.6.1.5 (4A/A), and (4A/B); 1-SR-3.6.1.3.5 (RCIC); and 1-SR-3.3.5.2.4 (FT). No further testing of System 71 was required for Unit 1 recovery to verify this Mode.

- Mode 71-04, Manually close RCIC system supply line isolation valves on a low RPV pressure. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying that selected RCIC valves were manually closed from the MCR. No further testing of System 71 was required for Unit 1 recovery to verify this Mode.
- Mode 71-05, Provide a Reactor Coolant pressure boundary. Testing for this Mode of providing reactor coolant pressure boundary was transferred to the System 68, Reactor Water Recirculation, BTRD. No further testing of System 71 was required for Unit 1 recovery to verify this Mode.
- Mode 71-07, Provide Primary Containment pressure boundary. Testing for this Mode of providing primary containment pressure boundary was transferred to the System 64A, Primary Containment, BTRD. No further testing of System 68 was required for Unit 1 recovery to verify this Mode.
- Mode 71-08, Provide system pressure boundary in support of System 74 containment or torus cooling mode. Testing for this Mode of verifying system pressure boundary was deferred. To ensure that the verification occurs during reactor startup, a Punch List (PL) item, PL-06-3841, and procedure 1-SI-4.7.A.2.G-3/71 were issued.
- Mode 71-09, Provide for manual operation outside the MCR to maintain normal RPV water inventory while the RPV pressure is above 100 psig, and transfer, if needed, the pump suction from the CST to the suppression pool on low condensate storage tank level or high suppression pool level. Testing for this Mode was performed which verified that with respective transfer switches in the EMERGENCY position selected components were operated from the respective RMOV Board, and that the selected components could not be operated from the MCR; and verified that with respective transfer switches in the NORMAL position selected components could not be operated from the respective RMOV Board, and that the selected components were operated from the MCR. The testing involved the use of procedure 1-SR-3.3.3.2.1 (71). Further testing of System 71 was required for Unit 1 recovery to verify this Mode for the following; Verification that the RCIC system delivers a minimum flow rate of 600 gpm from the backup

control panel using flow indicating controller 1-FIC-71-036B; and verify that transfer switch 1-XS-71-036B is in the EMERGENCY position. To ensure that these verifications occur during reactor startup, a Punch List (PL) item, PL-07-3569, and procedure 1-TI-428 were issued.

- Mode 71-10, Provide 250V DC power to Emergency Core Cooling System (ECCS) Division I and II Analog Trip Units (ATU), from the 250V DC Reactor Motor Operated Valve (RMOV) board, in System 03, System 64A, System 68, System 71, and System 73. Testing for this Mode was performed during the Unit 1 recovery which verified that the ATU power supplies 1-PX-71-60-1 and 1A for ECCS Division I and 1-PX-71-60-2 and 2A for ECCS Division II are fed from the RMOV board per DCN 51085; and verified that power supplies provide power to the proper ATU's per DCN 51243. The testing involved the use of procedures PMTI-51085 STG01 and STG02, and PMTI-51243 STG01 and STG02. Further testing of System 71 was required for Unit 1 recovery to verify this Mode for ensuring that the power supplies provided power to the proper ATUs per DCN 51243. To ensure that this verification occurs during reactor startup Punch List (PL) items, PL-06-3296 and 3297, and procedures PMTI-51243 STG01 and STG02 were issued.
- Mode 71-11, Provide Secondary Containment pressure boundary. Testing for this Mode of providing secondary containment pressure boundary was transferred to the System 64C, Secondary Containment, BTRD. No further testing of System 71 was required for Unit 1 recovery to verify this Mode.
- Mode 71-12, Establish a MSIV leakage pathway to the main condenser. Testing for this Mode of providing a leakage pathway to the main condenser was not required. This Mode of operation is a passive function and no physical action was required of System 71 to establish a leakage pathway.

The inspectors reviewed the TSR and verified that the above RCIC System modes, except for open items associated with above punchlist items, were satisfactorily tested during the ongoing testing activities. For Modes 71-05, 71-07, and 71-11 where the licensee had relied on testing performed for other systems the inspectors concurred that no further testing of System 68 was required for Unit 1 recovery.

HPCI, TSR 1-BFN-BTRD-73

System 73 HPCI consisted of 14 BTRD Modes as follows:

- Mode 73-01, Provide an automatic operation for the following: Initiation of System 73 on a System 03 RPV low water level (Level 2), or System 64A high drywell pressure; shutoff of System 73, if operating, on a System 03 RPV high water level (Level 8); and transfer, if needed, the pump suction from the Condensate Storage Tank (CST) to the suppression pool on low condensate storage tank level or high suppression pool level. Testing for this Mode was performed during the Unit 1 recovery which verified that the selected components responded to an initiation from the system in the standby mode to the injection mode; verified that the selected components responded to an

initiation from the system in the pump test mode to the injection mode; verified that the steam line drain valves closed when the turbine steam supply valve was opened; verified that the steam line drain valves opened when the turbine steam supply valve was closed; verified that the CST suction valve opened when the suppression pool suction valves were not fully closed, and the annunciation for these valves indicated the appropriate position in the MCR; verified that the suppression pool suction valves automatically open and the CST suction valve closes upon a CST low level and on a high suppression pool level the CST suction valve started closing when the suppression pool suction valves were fully open; and verified that the CST and suppression pool instrumentation provided signals when the levels reached the appropriate setpoints, and proper annunciation was provided to the MCR. The testing involved the use of various procedures. Among the procedures used were the following: 1-SR-3.3.6.5.1.5 (DWP A-ECCS), (DWP B-ECCS), (DWP C-ECCS), and (DWP D-ECCS); 1-SR-3.3.5.1.2 (ATU A), (ATU B), (ATU C); 1-SR-3.3.5.1.5 (RWL A), (RWL B), (RWL C), and (RWL D); 1-SR-3.3.5.1.5 (HPCI), (HPCI B), and (HPCI D); and 1-SR-3.3.5.1.6 (FT). Further testing of System 73 was required for Unit 1 recovery to verify this Mode for the following; Verification that the HPCI system delivers a minimum flow rate of 5000 gpm within 30 seconds upon receipt of an automatic initiation signal; and verification that the minimum flow valve functions properly. To ensure that these verifications occur during reactor startup, a Punch List (PL) item, PL-07-4140, and procedures 1-SR-3.5.1.7 (COMP) and 1-TI-429 were issued.

- Mode 73-02, Provide indication in the MCR of HPCI pump suction transfer on low condensate tank level to suppression pool. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying proper indication in the MCR during the tests involved with Mode 73-01. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-03, Close HPCI system supply line isolation valves on a Group 4 isolation signals from the following: High steam line differential pressure, high steam line space temperature, low steam line pressure, or high HPCI turbine exhaust diaphragm pressure. Testing for this Mode was performed during the Unit 1 recovery by verifying that a Group 4 isolation signal was provided to the HPCI Divisions I and II isolation logic and sealed in from the following: High steam supply differential pressure from instruments 1-PDIS-73-0001A and 0001B in a one-out-of-two logic; high steam line space temperature from instruments 1-TS-73-0002A thru D, E thru H, J thru M, and 1-TS-73-002N, P, R and S, with the temperature switches connected in a one-out-of-four logic feeding relays connected in a one-out-of-two, taken twice logic; high turbine exhaust diaphragm from instruments 1-PS-73-0020A thru D connected in a one-out-of-two, taken twice logic; low steam supply line pressure from instruments 1-PS-73-0001A thru D connected in a one-out-of-two, taken twice logic; and verified that selected components did not reset when the Group 4 isolation signal was reset. The testing involved the use of various procedures including 1-SR-3.3.6.1.5 (3C/A), (3C/B), (3C/C), and (3C/D); 1-SR-3.3.6.1.5 (3B/A), (3B/B), (3B/C), and (3B/D); 1-SR-3.3.6.1.2 (3B), and (3C); and 1-SR-3.3.5.1.6

(FT). No further testing of System 73 was required for Unit 1 recovery to verify this Mode.

- Mode 73-04, Manually close HPCI system supply line isolation valves on a low RPV pressure. Testing for this Mode was performed and documented during the Unit 1 recovery by verifying that selected HPCI valves were manually closed from the MCR. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-05, Provide a Reactor Coolant pressure boundary during HPCI System standby. Testing for this Mode of providing reactor coolant pressure boundary was transferred to the System 68, Reactor Water Recirculation, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-06, Provide a Reactor Coolant pressure boundary during HPCI System operation. Testing for this Mode of providing reactor coolant pressure boundary was transferred to the System 68, Reactor Water Recirculation, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-07, Provide a Reactor Coolant pressure boundary during HPCI System standby. Testing for this Mode of providing primary containment pressure boundary was transferred to the System 64A, Primary Containment, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-08, Provide a Reactor Coolant pressure boundary during HPCI System operation. Testing for this Mode of providing primary containment pressure boundary was transferred to the System 64A, Primary Containment, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-09, Provide for the manually tripping of the HPCI from outside the MCR to prevent RPV overfill. Testing for this Mode was performed and documented during the Unit 1 recovery which verified that with transfer switch 1-XS-73-0016, located in the Shutdown Board 1A at 480V RMOV Board 1A, was in the EMERGENCY position the HPCI steam supply valve was closed when hand switch 1-HS-73-0016C, located at the RMOV board, was operated, and that the hand switch 1-HS-73-0016A, located in the MCR, did not affect the operation of the steam supply valve; and verified that with the transfer switch in the NORMAL position the steam supply valve did not close when switch 1-HS-73-0016C was operated. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.
- Mode 73-10, Limit the loss of coolant through a HPCI system steam supply line break. Testing for this Mode of providing for a limited loss of coolant was not required. A flow element was installed in the steam supply piping to operate as a flow limiter. This Mode of operation is a passive function and no physical action was required of System 73 to limit the flow.
- Mode 73-11, Provide Secondary Containment pressure boundary. Testing for this Mode of providing secondary containment pressure boundary was

transferred to the System 64C, Secondary Containment, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.

- Mode 73-12, Provide power to system 64A drywell pressure indicators in support of System 74 drywell/torus spray mode and System 84 post LOCA containment venting mode. Testing for this Mode of providing power was not required. The testing requirements for this Mode were deleted by MDQ099920050010, Mini-Calculation for Safe Shutdown Analysis.
- Mode 73-13, Establish a MSIV leakage pathway to the main condenser. Testing for this Mode of providing a leakage pathway to the main condenser was not required. This Mode of operation is a passive function and no physical action was required of System 73 to establish a leakage pathway.
- Mode 01-28, Establish a MSIV leakage pathway to the main condenser. Testing for this Mode of providing a leakage pathway was transferred to the System 01, Main Steam, BTRD. No further testing of System 73 was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and verified that the above HPCI System modes, except for open items associated with above punchlist items, were satisfactorily tested during the ongoing testing activities. For Modes 73-05, 73-06, 73-07, 73-08, 73-11 and 01-28 where the licensee had relied on testing performed for other systems the inspectors concurred that no further testing of System 73 was required for Unit 1 recovery.

c. Conclusions

Implementation of restart testing activities was generally acceptable. Only minor test deficiencies which did not affect the results of the testing, were identified during performance of testing. Licensee processes were effective at identifying problems before components were placed in service. Based on the above review and observations, the inspectors determined that testing was conducted according to applicable licensee procedures and emergent issues during the testing were adequately addressed by the licensee.

E1.6 Special Program Activities - Cable Installation and Cable Separation (37550, 37551)

a. Inspection Scope

The programs for investigating and resolving the issues of cable installation and cable separation are described in TVA letter to the NRC dated May 10, 1991. This letter describes programs as essentially the same as described in the Browns Ferry Nuclear Performance Plan which outlined the corrective actions to be implemented before restart of Unit 2, and repeated for restart of Unit 3. NRC Inspection Manual MC 2509, Browns Ferry Unit 1 Restart Project Inspection Program, endorses the special programs utilized on Units 2 and 3 as sufficient to address corresponding issues on Unit 1 if implemented in the same manner.

b. Observations

The inspector reviewed the licensee's corrective actions and extent of condition (EOC) for the previous examples of cable separation violations. Those corrective actions were found to be adequate, the reestablishment of the 95/95 confidence level was conservative, and the extent of condition was comprehensive. The inspector reviewed examples of punch list walkdowns, Design Change Authorizations (DCAs), and Post Issuance Changes (PICs) used to modify DCNs. The inspector performed an independent review of closed stages that had been walked down by staff for return to operations (RTO).

b.1 Cable Installation

TVA letter dated December 13, 2002, "Browns Ferry Nuclear Plant - Unit 1- Regulatory Framework for the Restart of Unit 1," provided TVA's proposed regulatory framework for restart of Unit 1. The licensee stated that TVA's plan for the restart of Unit 1 was based on regulatory requirements, special programs, commitments, technical specification improvements, and TVA-identified deficiencies and concerns that were resolved prior to Units 2 and 3 restarts.

The licensee's commitments for resolution of Cable Installation issues are documented in TVA letter dated December 13, 2002, Subject: Browns Ferry Nuclear Plant - Unit 1 - Regulatory Framework for the Restart of Unit 1. The letter references previous commitments for restart of Units 1 and 3 stated in a letter dated July 10, 1991, Subject: Regulatory Framework for the Restart of Units 1 and 3, and NRC approval of the licensee's plans in a letter dated April 1, 1992. Acceptance of the licensee's program for resolution of the Cable Installations concerns by NRC is documented in Safety Evaluation Report dated April 8, 1992. Previous NRC reviews of the licensee's cable installation activities are documented in inspection reports (IR) 50-259/2004-07, 50-259/2004-09, 50-259/2005-08, 50-259/2005-09, and 50-259/2006-06.

Based on observations, document reviews, and discussions with engineering personnel, the inspectors determined that actions completed by the licensee to address concerns with the Unit 1 Cable Installation complied with their commitments to NRC. Licensee actions to address issues for cable installations have been performed or are being performed by the licensee. Completed or planned actions to address these issues for Unit 1 are consistent with those previously committed to and performed for Units 2 and 3. No issues related to the Cable Installation Special Program that would negatively impact the restart of Unit 1 were identified as the result of the above review. Based on this and previously documented NRC inspections the inspectors concluded that at this time, no further inspections are anticipated for this Special Program.

b.2 Cable Separation:

TVA identified instances where the electrical separation requirements have not been met at BFN. These discrepancies were discovered while implementing design changes and conducting reviews as part of the BFN Unit 2 restart effort and have been documented by the issuance of Licensee Event Report No. 88-032, dated October 21, 1988, and subsequent condition adverse to quality reports. This inspection focused on

the corrective actions that were being implemented by TVA to resolve the cable separations concern for Unit 1 Restart. This inspection included a review of external and internal separations issues addressed in calculations EDQ 0999-910078 for external separation, EDQA 19992-003061 Internal Cable Separation Analysis for internal separation, and the criteria, methods, and exceptions identified in Design Criteria Document (DCD) BFN 50-728, Physical Independence of Electrical Systems. The inspection was conducted by reviewing work order records, design basis documents, and conducting walkdown inspections of methods used for achieving divisional separation or functional redundancy on Unit 1. The inspectors reviewed the Browns Ferry Unit 1 Cable Separation activities as detailed below to ensure that these activities were in compliance with regulatory requirements and licensee commitments. See NRC IRs: 50-259/2005-08, 50-259/2006-07, 50-259/2006-09, 50-259/2006-12 for previous inspections in this area. The inspectors also reviewed Unresolved Item (URI) 50-259/200609-03, Criteria Was not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained.

During the current reporting period, the inspectors identified a violation of 10 CFR 50 Appendix B, Criterion III, Design Control, located in the Unit 1 Auxiliary Instrument Room while conducting walkdowns during the week of January 8-12, 2007. During the walkdown inspections of enclosures, it was discovered that the "top hat" was not analyzed nor defined for divisional cable separation or functional redundancy in accordance with the criteria in DCD BFN-50-728.

The "top hat" is an enclosure that is physically attached, but separated by barriers, to panels in the Unit 1 Auxiliary Instrument Room. The "top hat" is closed on three sides with a removable face plate on the front. There are no barriers inside of the enclosure. Divisional and non-divisional cables are routed within the enclosure. The licensee could not determine whether divisional cables inside of the "top hat" were properly analyzed to meet the requirements for divisional separation or functional redundancy as defined in DCD BFN-50-728. As a result, divisional cables were routed inside "top hats" without divisional separation being met.

In prior discussions, TVA indicated to NRC staff that the area was not clearly identified as meeting "external" or "internal" separation criteria, and that requirements for the "top hat" currently should be addressed as "internal." The licensee's position was that compliance for the "top hat" region meets the same separation criteria defined for panels. This position could not be supported by any requirements or the DCDs. Subsequently, the licensee conducted additional reviews and concluded that the area was internal to the panel and should be considered intra-panel therefore meeting requirements for internal separation as defined in DCD BFN-50-728. The "top hat" area was determined to be internal to the panel after additional discussions between NRC staff and TVA staff. TVA staff conducted walkdowns of the safety-related divisional cables routed within "top hats" and other enclosures. Twenty-two noncompliances of TVA requirements were identified.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to ensure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are

specified and included in design document and that deviations from such standards are controlled. FSAR Section 8.9.4 states that "No single control panel, local panel, or instrument rack includes wiring essential to the protective function of both redundant systems, which are backups for each other (Division I and Division II)." TVA General DCD BFN-50-728, Rev.16, was issued August 3, 1987, as a product of the U2 restart activities under the Design Baseline and Verification Program which was reviewed and accepted by the NRC in NUREG-1232. DCD BFN-50-728 states that installation activities will "as a minimum requirement, satisfy the single failure criteria" as described in IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," which states in part concerning the application of the single failure criteria, "complete isolation and/or separation of the components of the redundant system shall be provided." Contrary to the above, these requirements were not met as of January 12, 2007, in that the area identified as "top hat" located in the Unit 1 Auxiliary Instrument Room, was not adequately defined nor specified in a quality standard to ensure that divisional separation of cables from opposite divisions were maintained. This violation was characterized at Severity Level IV in accordance with the guidance contained in the NRC Enforcement Policy, Supplement II, Facility Construction. In addition, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, this violation will be tracked as NCV 50-259/2007-09-02, Criteria Was Not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained. TVA generated PER 117921 to document these noncompliances in the corrective action program.

Based on observations, document reviews, and discussions with engineering personnel, the inspectors determined that actions completed by the licensee to address concerns with the Unit 1 Cable Separations complied with their commitments to NRC. Licensee actions to address issues for cable separations have been performed or are being performed by the licensee. Completed or planned actions to address these issues for Unit 1 are consistent with those previously committed to and performed for Units 2 and 3. No issues related to the Cable Separations Special Program that would negatively impact the restart of Unit 1 were identified as the result of the above review. Based on this and previously documented NRC inspections the inspectors concluded that at this time, no further inspections are anticipated for this Special Program.

c. Conclusions

A Severity Level IV NCV was identified for failure to comply with 10 CFR 50, Appendix B, Criterion III, in that, measures were not adequately defined nor specified in a quality standard to ensure that divisional separation of cables from opposite divisions were maintained in the Unit 1 Auxiliary Instrument Room.

Based on observations, document reviews, discussions with engineering personnel and previously documented NRC inspections, the inspectors determined that actions completed by the licensee to address concerns with the Unit 1 Cable Installation and Cable Separation Special Programs complied with their commitments to NRC. Licensee actions to address issues for cable issues have been performed or are being performed by the licensee. Completed or planned actions to address these issues for Unit 1 are consistent with those previously committed to and performed for Units 2 and 3. No issues related to these Special Programs that would negatively impact the restart of Unit

1 were identified as the result of the above reviews. Based on this and previously documented NRC inspections, the inspectors concluded that at this time, no further inspections are anticipated for these Special Programs.

E1.7 Station Blackout (71152)

a. Inspection Scope

In Inspection Report 05000259/2006009, Section E1.13, the inspectors documented their review of the licensee's activities related to USI A-44, Station Blackout, including compliance with 10CFR50.63, Loss of All AC Power, for Unit 1. As documented in this report, the inspector's concluded that Unit 1 conformed with the regulatory requirements and guidance associated with USI-A44 and the Station Blackout (SBO) rule (i.e., 10CFR50.63), except for one nonconforming condition. This nonconforming condition was identified as NCV 05000259/2006009-06, Lack of Assured Cooling Water for Emergency Diesel Generators. Consequently, USI-A44 and the SBO Rule would remain open pending completion of the licensee's corrective actions. The licensee entered this finding into their corrective action program as PERs 114913 and 114967.

In order to close this issue related to USI-A44, and SBO Rule, for Unit 1, the inspectors reviewed the corrective actions associated with PERs 114913 and 114967, including Functional Evaluations #41702 and #41706. As part of this focused inspection, the inspectors reviewed Revisions 65 through 69 of 0-AOI-57-1A, Loss of Offsite Power (161 and 500KV)/Station Blackout, and examined licensed operator training on the newly developed SBO mitigation strategies. The inspectors also conducted walkdowns to verify and validate the AOI-57-1A revisions, and witnessed two separate dual-unit simulator demonstrations of the revised AOI-57-1A mitigation strategies with actual operating crews on January 23 and February 14, 2007. Furthermore, the inspectors met with the Operations Superintendent and Training supervision to discuss and critique the results of these successful simulator demonstrations.

b. Observations and Findings

The inspector identified deficiencies with the SBO design calculations and operating procedures (e.g., AOI-57-1A), documented in Inspection Report 50-259/2006-09, were adequately addressed by the licensee's corrective actions for Unit 1. In particular, AOI-57-1A was revised to improve the operator's ability to restore cooling water to the operating emergency diesel generators (EDG) during the worst case SBO event(s). Several revisions of AOI-57-1A were issued as the licensee systematically refined, simplified and streamlined their mitigation strategies in order to ensure adequate emergency equipment cooling water (EECW) would be supplied to the running EDGs (on the non-SBO units) in a timely manner. Based on the licensee's engineering analysis, for the worst case licensing-basis scenarios, the remaining three EDGs in operation would overheat in approximately seven minutes without cooling water. The licensee revised AOI-57-1A to incorporate the newly developed SBO mitigation strategies, and associated lessons learned, to provide operators with the necessary guidance to restore EECW before the operating EDGs on the non-SBO units overheated. Although the simulator demonstrations were unsuccessful for Unit 2 (see IR 05000260/2007002) due to unit specific differences, the licensee was able to demonstrate and verify successful

mitigation of the worst case loss of EECW SBO event on either Unit 1 or 3. The Unit 2 issue will be dispositioned in the referenced inspection report. The latest revision of AOI-57-1A, Revision 69, along with associated operator training and other applicable procedures, were determined by the inspectors to be sufficient for restoring cooling water to the operating EDGs in a timely manner for an SBO event, with loss of EECW, on Unit 1.

c. Conclusions

The inspectors concluded the licensee's corrective actions for addressing the nonconforming condition identified by NCV 05000259/2006009-06, Lack of Assured Cooling Water for Emergency Diesel Generators, were adequate. Based on this inspection, and the prior inspection documented in IR 05000259/2006009, Section E1.13, the inspectors have determined that the licensee has adequately addressed the regulatory requirements and guidance of 10CFR50.63 for Unit 1. No findings of significance were identified.

E1.8 Verification of Seismic Adequacy of Mechanical and Electrical Equipment

a. Inspection Scope

The inspectors reviewed the Browns Ferry Unit 1 Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors and Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants activities to ensure that these activities were in compliance with regulatory requirements and licensee commitments. This issue was implemented in GL 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors and Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants.

b. Observations and Findings

USI A-46 and GL 87-02 were previously reviewed by the NRC as documented in Inspection Reports 50-259/2004-06 and 50-259/2006-06. During the current reporting period the inspectors reviewed the documents discussed below to assess the licensee's evaluation and resolution of the remaining issues related to USI A-46 for BFN Unit 1. To accomplish this review, the inspectors reviewed Report No. TVA/BFN-01-R-004, Browns Ferry Nuclear Plant Unit 1 USI A-46 Seismic Evaluation Report, Revision 1, dated February 2007. The report provided updated information supporting the resolution of the remaining issues relative to USI A-46 for BFN-1.

The areas revised included in this update were: 1) the documentation of the review by the BFN-1 Operations group for consistency with BFN-1 plant operating procedures of the safe shutdown equipment list (SSEL) and 2) documentation of the closure of outliers that required walkdown verification.

The inspectors assessed the detail of the review performed by the Operations department review of the SSEL identified under USI A-46. The inspectors reviewed the equipment list for equipment needed by Operations to support the mission for bringing the plant to a safe shutdown condition following a Design Basis Earthquake (DBE) event

and maintain that condition for a minimum of 72 hours with the assumption that this occurs with a loss of off-site power. Four functions were identified that must be accomplished to achieve and maintain safe shutdown following a DBE; Reactivity Control, Reactor Coolant System Pressure Control, Reactor Coolant System Inventory Control, and Decay Heat Removal. The inspectors reviewed procedures and EOI Flowcharts, as listed in the Documents Reviewed Section of this report, to verify their inclusion in the SSEL.

The inspectors held discussions with the licensee's staff about the items listed in a February 10, 2007, "Record of Meeting" of their USI A-46 SSEL review. All items listed were successfully addressed as documented in Document: CDQ1 999 2003 0654 Revision 004. No outstanding issues remain and no additions or deletion of components to the SSEL were made.

To verify completion of issues identified previously as "Open" in Appendix H, "Area Turnover Walkdown Punch List," of the Browns Ferry Nuclear Plant Unit 1 USI A-46 Seismic Evaluation Report, Report No. TVA/BFN-01-R-004, Revision 1, February 2007, the inspectors reviewed the final punch list close-out as documented in calculation CDQ1 999 2006 0149, USI A-46 Seismic Verification of Punch List Items and General Turnover Walk-by Confirmation, Rev. 1, to verify that no new potential seismic interaction concerns remained.

By letter to the NRC dated December 4, 2006, the licensee documented that License Condition 2.C(15) of the Renewed Facility Operating License, issued May 4, 2006, has been met. The license condition states, "The licensee is required to confirm that the conclusions made in TVA's letter dated September 17, 2004, for the turbine building remain acceptable using seismic demand accelerations based on dynamic seismic analysis prior to restart of Unit 1." In the Safety Evaluation, dated September 27, 2004, the NRC staff found that the methods and assumptions for calculating seismic capacity and demands of the turbine building were approximate and reasonable. Also, based on the information contained in the licensee letter dated December 4, 2006, the tests and analyses required for meeting License Condition 2.C(15) have been performed and this license condition has been satisfied and is documented in an NRC letter to the licensee dated December 22, 2006.

c. Conclusions

Based on this and previously documented NRC inspections in the seismic area, the inspectors concluded that no further actions were required for Unit 1. No further NRC inspection in this area is anticipated.

E7 Quality Assurance in Engineering Activities

E7.1 Verification of Licensee Corrective Actions (37550, 71152)

a. Inspection Scope

The inspectors reviewed the status of licensee corrective actions associated with NRC inspection items and Unit 1 Recovery Special Programs to verify that associated licensee corrective actions were completed. The inspectors selected various items from the NRC Unit 1 Inspection Plan and Schedule (IP&S) related to the Mitigating Systems, Initiating Events, and Barrier Integrity Reactor Oversight Process (ROP) Cornerstones to verify completion of associated licensee corrective actions.

b. Observations and Findings

NRC letter dated December 29, 2004, informed the licensee of the transition of four ROP Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) associated with Unit 1 would be monitored under the ROP baseline inspection program. However, the remaining ROP cornerstones (Mitigating Systems, Initiating Events, and Barrier Integrity) continued to be monitored under the special Unit 1 Restart Inspection Program as defined in NRC Manual Chapter (MC) 2509. The NRC Browns Ferry Unit 1 Restart IP&S lists all NRC inspection open items and licensee Special Programs which required NRC inspection. The inspectors selected various items from the IP&S related to those remaining cornerstones to verify completion of associated licensee corrective actions.

Recovery Special Programs

IP&S lists 30 licensee Special Programs associated with Unit 1 Recovery. All but two were required to be closed prior to restart. Licensee actions associated with those Special Programs (Restart Test Program and Probabilistic Risk Assessment) will be completed after restart. The Restart Test Program (RTP) was previously reviewed and documented in Inspection Report 50-259/2006-09. Although, NRC observation and review of RTP activities would continue throughout the remainder of system acceptance testing and power ascension testing programs the inspectors concluded that the existing RTP provided adequate assurance that safety systems would fulfill their safe shutdown functional requirements and support the safe return to operation on Unit 1 and no further program inspections were required. For the Probabilistic Risk Assessment (PSA) the NRC Restart Oversight Panel reviewed the status of previously licensee actions during Unit 3 Recovery and determined that this Special Program was not a Unit 1 restart issue.

The remaining 28 licensee Special Programs were required to be completed prior to restart. Each of these Special Programs was inspected by the NRC prior to restart of Unit 1. NRC final review of two of those Special Programs (Fire Protection and Electrical Cables Installation/Separation) are documented in Sections E1.6 and F1.1 of this inspection report. NRC final review of the other 26 Special Programs was previously documented in various other Unit 1 integrated inspection reports. Based on NRC inspection methodology associated with each of these Special Program, which involved a

detailed review of implemented design changes and other corrective actions, no additional review of corrective actions associated with Unit 1 Recovery Special Programs is needed. Therefore, the inspectors determined that verification of corrective actions had previously occurred as part of the ongoing NRC inspections associated with the licensee's Unit 1 Recovery Special Programs.

Historical Open Inspection Items

The inspectors conducted an audit of NRC open items for Unit 1 to identify any possible open NRC inspection items (violations, LERS, URIs, IFIs) which would require further review prior to the restart of Unit 1. That audit was documented in Inspection Report 50-259/2003-10. Existing inspection open item databases were compared against open item reviews documented in NRC inspection reports issued since 1984. The purpose for this review was to identify NRC open and closed items which needed to be addressed prior to Unit 1 restart. As the result of this review, various open items were identified which required further review. These NRC open items, along with previously identified generic issues (NRC bulletins, generic letters, TMI action items) required additional NRC review prior to the restart of Unit 1 and were included in IP&S. The inspectors noted that although MC 2509 allowed administrative closure of open items that did not warrant inspection resources, no historical open items were actually administratively closed.

The inspectors determined that the NRC inspection methodology associated with each of these historical open items had involved review of selected licensee corrective actions. In most cases, the review consisted of verification of implementation of licensee corrective actions. Those corrective actions usually involving planned design changes which were similar to those previously performed during Units 2 and 3 recoveries. However, some open items were closed by the NRC based on review of issued/approved design changes which had not yet been implemented.

The inspectors had previously reviewed an ongoing licensee effort associated with work scope reduction associated with previously planned design changes from the original Unit 1 Recovery work scope. Additionally, the inspectors evaluated the adequacy of the licensee's documented basis for any identified deleted work activities. That review was documented in Inspection Report 50-259/2006-08. During that review the inspectors determined that any examples of work scope reduction had been adequately evaluated and technically justified. No examples of cancelled design changes associated with previously closed open items were identified. That previous NRC review would have verified that the licensee had not cancelled planned design changes which might have involved required corrective actions. Additionally, the inspectors selected five generic issues previously closed by the NRC based on planned licensee corrective actions which had not then been implemented. These generic items included:

- Bulletin 86-02, Static O-Ring Differential Pressure Switches
- GL 83-08, Modification of Vacuum Breakers on mark 1 Containments
- GL 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning
- GL 89-16, Installation of a Hardened Wetwell Vent

- GL 96-05, Periodic Verification of Design Basis Capability of Motor Operated Valves

During the current reporting period the inspectors reviewed the licensee's commitment closure packages associated with the above five generic items. This review verified that all planned design changes associated with those generic items had been completed.

Unit 1 Recovery Inspection Open Items

During the ongoing Unit 1 Recovery process from May 1, 2002, until the completion of the current reporting period a number of new non-cited violations and one Severity level III violation were identified by the NRC. The Severity level III violation was documented in Inspection Report 50-259/2004-11. Corrective actions associated with this violation were subsequently verified by the inspectors and documented in Inspection Report 50-259/2004-07. One of the non-cited violations was associated with radiation protection which was subsequently placed under the ROP. The inspectors verified that any corrective actions for each of the other non-cited violations associated with the three remaining cornerstones were verified as part of followup inspections for the associated Unit 1 Recovery Special Programs.

c. Conclusions

Based on previous NRC inspection methodology and review of selected commitment closure documentation the inspectors concluded that the licensee had completed required corrective actions associated with Unit 1 Recovery.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) Generic Letter (GL) 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors

This item is discussed further in Section E1.8 of this report. During that review, the inspectors reviewed various documents to assess the licensee's evaluation and resolution of the remaining issues related to GL 87-02. Based on that review the inspectors concluded that no further actions were required for Unit 1. This item is closed.

E8.2 (CLOSED) TMI Action Item II E.4.2.1-4, Containment Isolation Dependability

The inspectors performed a review of the licensee's activities associated with this item. This item was previously reviewed for Unit 3 and documented in Inspection Report 50-259,260,296/95-60. The inspector also reviewed the applicable Safety Evaluation Report issued by the NRC on January 5, 1995. This SER contained an evaluation of information provided in response to NUREG-0737, Item II.E.4.2. The report evaluated the design of the containment isolation systems for BFN Units 1 and 3 and compared them to the previously evaluated Unit 2 design. The report concluded that the containment isolation systems for Units 1 and 3 were acceptable and that no differences in Appendix J, Primary Reactor Containment Leakage Testing were identified between the units. Subsequently, the licensee provided supplemental information regarding Unit 1

conformance with Item II.E.4.2 as documented in TVA letter dated June 24, 2004. The inspector reviewed this supplemental information provided by TVA concerning additional differences between Units 1 and 2 and noted that final NRC acceptance of the Unit 1 system configuration was granted in a letter dated March 7, 2007. Based on the above reviews, the inspectors determined that the licensee has satisfactorily completed all requirements associated with this commitment. This item is closed.

E8.3 (Closed) URI 50-259/2006-09-03 Criteria Was not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained

The licensee's resolution of this issue is discussed further in Section E1.6 of this report. This item is closed.

E8.4 (Closed) Unresolved Safety Issue (USI) A-44, Station Blackout (SBO)

This item is discussed further in Section E1.7 of this report. Based on this review, and the prior inspection documented in IR 05000259/2006009, the inspectors have determined that the licensee has adequately addressed the regulatory requirements and guidance of USI-A44 and 10CFR50.63 for Unit 1. This item is closed.

E8.5 (Closed) USI A-46, Seismic Qualification of Equipment in Operating Plants

This item is discussed further in Section E1.8 of this report. During that review the inspectors reviewed various documents to assess the licensee's evaluation and resolution of the remaining issues related to USI A-46. Based on that review the inspectors concluded that no further actions were required for Unit 1. This item is closed.

E8.6 (Closed) GL 03-01, Control Room Habitability

This GL alerted licensees of findings at reactor facilities suggesting that the control room habitability licensing and design bases and applicable regulatory requirements may not be met, and that existing Technical Specification (TS) Surveillance Requirements (SRs) may not be adequate. Licensees were requested to submit information that demonstrated that the control room at each of their respective facilities complied with the current licensing and design bases, and applicable regulatory requirements, and that suitable design, maintenance and testing control measures are in place for maintaining compliance.

The inspectors reviewed the licensee's response to GL 03-01, which was documented in a TVA letter dated December 8, 2003. In their response, TVA stated that the Units 1, 2, and 3 design basis and licensing basis were in compliance with applicable regulatory requirements. The licensee stated that the plant was constructed and maintained in accordance with its design, and the testing performed was in accordance with the applicable TS, and their basis was adequate to demonstrate compliance and material condition. The licensee described the results of additional testing performed in November 2003 which confirmed that the in-leakage testing which had been periodically performed on the common control room habitability zone (CRHZ) since 1991 had been adequate to detect degradation in the CRHZ envelope. That testing used an American Society for Testing and Materials (ASTM) tracer gas methodology on the CRHZ for

quantification of unfiltered in-leakage. The licensee's testing determined that the unfiltered in-leakage into the CRHZ was less than 600 CFM. The quantity was approximately 16% of the 3717 CFM assumed in the Browns Ferry design and licensing bases. The licensee further stated that the potential harmful effects of a toxic gas release near the site and the potential for migration of smoke into the CRHZ from a fire were also evaluated and found not to be a safety concern and that the licensee believed that no TS changes were required. Subsequently the licensee submitted a regulatory commitment to submit a proposed license amendment request based on TS Task Force Traveler 448 (TSTF-448) by March 1, 2008. This commitment was documented in licensee letter dated February 8, 2007.

The licensee's responses to the GL was reviewed by the Office of Nuclear Reactor Regulation (NRR). The staff determined that the licensee's responses and commitment to submit a license amendment request based on TSTF-448 were acceptable for purpose of closing out this GL. This GL is closed.

III. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Program

a. Inspection Scope

The inspectors continued to observe and/or review ongoing licensee maintenance program activities. Maintenance work activities were controlled by approved procedures and work orders. Specific maintenance activities reviewed and observed included selected portions of ongoing system testing support activities associated with return to service of System 01, Main Steam; System 71, RCIC; and System 73, HPCI.

b. Observations and Findings

The inspectors reviewed and observed selected maintenance activities for ongoing SRTS activities for the Main Steam, RCIC, and HPCI Systems. These activities also included support for system testing. Maintenance activities observed and reviewed included the following work orders:

- 05-720239-00 for the setting and adjusting of the outboard Main Steam Stop Valve (MSIV) limit switches using procedure 1-SR-3.3.1.1.13 (OUTBD) for verification and replacement of the switches as part of DCN 51211.
- 05-720247-00 for the setting and adjusting of the inboard MSIV limit switches using procedure 1-SR-3.3.1.1.13 (INBD) for verification and replacement of the switches as part of DCN 51143.
- 06-726199-05 for the calibration and setting of the inboard MSIV slow speed adjustment for the purpose of testing the inboard MSIVs during power operations.

- 06-726199-06 for the calibration and setting of the outboard MSIV slow speed adjustment for the purpose testing the outboard MSIVs during power operations.
- 06-725330-09 thru 12 the purpose of these WO's was to provide support to the vendor for the replacement of the outboard MSIV yoke rods, one WO per MSIV, on a like-for-like basis.
- 06-725330-13 thru 16 the purpose of these WO's was to provide support to the vendor for the replacement of the outboard MSIV yoke rods, one WO per MSIV, on a like-for-like basis.
- 06-722879-35, RCIC System, for the testing support of the Emergency Core Cooling System (ECCS) Analog Trip Units (ATU) using procedure 1-SR-3.3.5.1.2 (ATU A), Core and Containment Cooling Systems Analog Trip Unit Functional Test.
- 06-722879-38, RCIC System, for the testing support of the ECCS ATUs using procedure 1-SR-3.3.5.1.2 (ATU B), Core and Containment Cooling Systems Analog Trip Unit Functional Test.
- 05-720521-00 for the purpose of performing the static MOVATS testing on flow control valve 1-FCV-73-040, HPCI Condensate Storage Tank Suction Valve.
- 06-722879-33, HPCI System, for the testing support of the ECCS ATUs using procedure 1-SR-3.3.5.1.2 (ATU C), Core and Containment Cooling Systems Analog Trip Unit Functional Test.
- 06-722879-36, HPCI System, for the testing support of the ECCS ATUs using procedure 1-SR-3.3.5.1.2 (ATU D), Core and Containment Cooling Systems Analog Trip Unit Functional Test.
- 06-718119-00 for the purpose of performing the static MOVATS testing on flow control valve 1-FCV-73-016, HPCI Steam Supply Valve.
- 06-712675-00 for the purpose of using Steps 1 thru 10 of the WO to perform the HPCI Turbine over speed test with the Auxiliary Boiler System supply the necessary steam flow.

c. Conclusions

No deficiencies were identified during the review of the ongoing maintenance activities. The Maintenance organization continued to provide appropriate and comprehensive repairs to Unit 1 components which do not require design changes to support Unit 1 Restart. Maintenance WO packages included sufficient technical guidance to allow maintenance personnel to adequately perform the associated work activity. Maintenance personnel and foremen were knowledgeable of applicable requirements and appropriately documented work actually performed, as required by plant procedures.

IV. Plant Support

F1 Fire Protection

F1.1 Special Program Activities - Fire Protection Improvements (37550)

a. Inspection Scope

The inspectors reviewed a sample of the approved three unit Safe Shutdown Instructions (SSIs) to determine if the procedures were adequate to achieve and maintain safe shutdown (SSD). This review included a feasibility assessment of the 10CFR50 Appendix R Section III.G.2 local operator manual actions (OMAs) for fire areas/fire zones 1-1 and 1-5. The inspectors reviewed all local OMAs with completion time of 30 minutes or less for fire areas/fire zones 1-1, 1-5, 16, and 20. The SSI verification and validation (V&V) packages were also reviewed. Additionally, the testing of the fire protection communications F2 and F4 radio systems and the Unit 1 backup control panel post-modification testing were reviewed.

b. Observations and Findings

The inspectors performed walkdowns of the selected SSI's to assess the feasibility of the 10CFR50 Appendix R Section III.G.2 local OMAs. The inspectors found that the local OMA's for the III.G.2 areas reviewed were feasible. Additionally, the inspectors walked down all OMAs with completion time of 30 minutes or less in SSI's in 0-SSI-1-1, 0-SSI-1-5, 0-SSI-16, and 0-SSI-20 and found that all OMAs were feasible.

In June 2006, and again in January 2007, the NRC notified TVA that the Browns Ferry SSI V&V packages were not a complete auditable record proving the capability to achieve and maintain three unit safe shutdown (SSD). The V&V packages were not consistent in time recording, did not completely explain environmental effects, and did not include the details regarding SCBA use, 480V Breaker racking, and acceptability of lighting and communications. Additional work remains to clearly demonstrate that the three unit SSIs can satisfactorily achieve and maintain three unit SSDs given the large number of local OMAs to be successfully coordinated within the time constraints of the design basis. TVA provided NRC a copy of the revised SSIs and revised V&V packages on March 27, 2007. On March 29, 2007, the NRC determined that the licensee's V&V for the three unit SSIs had not adequately addressed the identified deficiencies. The licensee revised all 40 SSI's to incorporate NRC comments. On April 2, 2007, the NRC determined that the licensee, had not appropriately addressed all V&V discrepancies. On April 3, 2007, the NRC was informed that the licensee planned to reissue some V&V packages and revised additional SSI's to correct identified deficiencies. The licensee also issued PERs to determine extent of condition of the procedural problems. The inspectors reviewed a sample of the revised V&V packages and revised SSIs and found that the local OMA's were feasible. The inspectors determined that the licensee's revised V&V packages for the selected SSIs documented that the revised SSIs could achieve and maintain safe shutdown. This was accomplished within the time requirements of the design basis OMA calculation and met the criteria in NRC inspection procedure 71111.05T regarding OMAs.

The inspectors reviewed testing on portions of the Backup Control Panel instrumentation and controls for selected systems required for safe shutdown. The instrumentation and controls reviewed included the RCIC, RHR system, control rod drive system, core spray system, reactor water cleanup system, and reactor recirculation isolation system, suppression pool temperature, RHR flow, RCIC flow, and RCIC turbine speed. The tests demonstrated that there was adequate isolation of system controls and acceptable calibration of instrumentation.

The inspectors reviewed the testing of the fire protection communications F2 and F4 radio systems. In January 2007, the inspectors identified that the licensee's post installation testing of the modified F2 and F4 radio systems did not include verification of communication with the radios on the backup power supply (UPS) as would be the case under the design basis fire conditions. The initial tests of the radio systems failed to provide adequate communications to some areas of the plant required for 10CFR50 Appendix R safe shutdowns. The licensee has issued a PER for resolution of the SSI communications.

c. Conclusions

On January 22 - 26, 2007, NRC reviewed the TVA BFNP Unit 1 fire protection special program for closure. The intent was to inspect the restart readiness of the Unit 1 fire protection systems and the final version of the three Unit SSIs. The NRC continued their review on April 2, 2007. By April 5, 2007, the licensee had re-issued the V&V packages and revised SSIs to adequately address all NRC comments. The NRC determined that the local OMA's for 10CFR50 Appendix R Section III.G.2 required to achieve and maintain safe shutdown were feasible.

The inspectors also concluded that the testing for Fire Protection communications F2 and F4 radio systems were essentially complete. The remaining issues were adequately addressed by PER 122853. Additionally, the inspectors concluded that the testing for the Unit 1 backup control panel PMT was adequate.

No further inspections are planned for the fire protection special program. The Fire Protection Special Program is closed. No violations or deviations were identified.

F1.2 Review of BFNP 10CFR50 Appendix R Section III.G.2 Operator Manual Action Risk Evaluation (37550)

a. Inspection Scope

The inspectors reviewed the licensee's Significance Determination Process (SDP) Evaluation of Fire Scenarios for Appendix R III.G.2 Areas Browns Ferry Nuclear Plant Units 1, 2 and 3 Revision 2 to determine if the evaluation incorporated comments from NRC inspection report 05000259/2006012.

b. Observations and Findings

Inspection Report 05000259/2006012 documented a previous NRC review of the risk assessment which TVA performed for the BFNP Appendix R Section III.G.2 operator

manual actions (OMAs). TVA committed to perform this review in a letter dated April 24, 2006. The IR documented that the risk assessment of the III.G.2 OMAs was incomplete and listed several items which needed to be completed to finalize the assessment. TVA initiated problem evaluation report PER 104418 to track resolution of the NRC comments. The inspectors reviewed the PER and verified that it contained all the items described in Inspection Report 05000259/2006012. TVA revised its risk assessment several times to incorporate the NRC comments. The inspectors reviewed revision 2 of the assessment which was provided by TVA via Email on March 5, 2007 and verified that the assessment had been revised to address the identified issues. The overall results of the assessment did not change as a result of addressing the comments. The assessment concluded that the risk of the III.G.2 OMAs remained of very low safety significance.

c. Conclusion

The BFNP SDP risk evaluation of the III.G.2 OMAs was revised to address comments from IR 05000259/2006012 and the evaluation's conclusions were not changed. The risk evaluation documented that the risk of the OMAs in III.G.2 fire area/zones was still of very low safety significance.

V. Management Meetings

X1 Exit Meeting Summary

On April 30, 2007, the resident inspectors presented the inspection results to Mr. Bill Crouch and other members of his staff, who acknowledged the findings. Although some proprietary information may have been reviewed during the inspection, no proprietary information will be identified in the final inspection report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

M. Bajestani, Vice President, Unit 1 Restart
R. Baron, Nuclear Assurance Manager, Unit 1
M. Bennett, QC Manager, Unit 1
D. Burrell, Electrical Engineer, Unit 1
P. Byron, Licensing Engineer
J. Corey, Radiological and Chemistry Control Manager, Unit 1
W. Crouch, Nuclear Site Licensing & Industry Affairs Manager
R. Cutsinger, Civil/Structural Engineering Manager, Unit 1
J. Dizon, Facility Risk Consultants
S. Eder, Facility Risk Consultants
B. Hargrove, Radcon Manager, Unit 1
K. Hess, SWEC Project Director
R. Jackson, Bechtel
R. Jones, General Manager of Site Operations
J. Lewis, Integration Manager
G. Little, Restart Manager, Unit 1
J. McCarthy, Licensing Supervisor, Unit 1
R. Moll, Mechanical Engineering and Systems Engineering Manager, Unit 1
B. O'Grady, Site Vice President
J. Schlessel, Maintenance Manager, Unit 1
J. Valente, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 35301	QA of Preoperational Test Program
IP 37550	Onsite Engineering
IP 37551	Engineering
IP 51053	Electrical Components and Systems - Work Observation
IP 50090	Pipe Support and Restraint Systems
IP 60705	Preparations for Refueling
IP 62706	Maintenance
IP 70301	Preoperational Test Procedure Review
IP 70315	Preoperational Test Witness
IP 71111.08	Inservice Inspection Activities
IP 71111.17	Permanent Plant Modifications
IP 71111.20	Refueling and other Outage Activities
IP 71111.23	Temporary Plant Modifications
IP 71152	Identification and Resolution of Problems
IP 72500B	Initial Fuel Loading Procedure
IP 92701	Follow-up

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSEDOpened and Closed

259/2007-09-01	NCV	Starting Core Spray Pump 1B with No Suction Path (Section O8.1)
259/2007-09-02	NCV	Criteria Was not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained (Section E1.6)

Closed

87-02	GL	Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46 (Sections E1.8, E8.1)
II.E.4.2.1-4	TMI	Containment Isolation Dependability - Implement Diverse Isolation (Section E8.2)
259/2006-09-03	URI	Criteria Was not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained (Section E1.3)
A-44	USI	Station Blackout (Sections E1.7, E8.4)
A-46	USI	Seismic Qualification of Equipment in Operating Plants (Sections E1.8, E8.5)
03-01	GL	Control Room Habitability (Section E8.6)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section O8.1: 1B Core Spray Pump Started with No Suction Path

Procedures and Standards

SPP 10.2, Clearance Procedure to Safely Control Energy, Rev. 9
 0-OI-2B, Condensate Storage and Transfer System, Rev. 60
 1-OI-2, Condensate System, Rev. 6
 1-OI-75, Core Spray System, Rev. 3
 1-SR-3.5.1.6 (CSII), Core Spray Flow Rate Loop II, Rev. 2
 1-SR-3.5.1.6 (CSII), Core Spray Flow Rate Loop II, Rev. 4

Drawings

1-47E814-1, Core Spray System Flow Diagram, Rev. 23
 1-47E818-1, Condensate System Flow Diagram, Rev. 27

Problem Evaluation Report (PERs)

117977, 1-SHV-002-0705 Found in the Closed Position

Misc Documents

Clearance Tagout 1-TO-2000-0001, Section 1-075-0043, 09/27/06
 Operations Logs dated 01/12-13/07
 Management Brief/White Paper, Phillip Chadwell, Operations Superintendent, 01/12/07

Section E1.1: Permanent Plant Modifications

DCNs

51045, Reactor Water Recirculation, Electrical and Mechanical - Drywell, System 68
 67898, Main Steam, Electrical and Mechanical - Drywell, System 01
 51151, Residual Heat Removal, Electrical and Mechanical - Drywell, System 74
 51046, Reactor Water Cleanup, Electrical and Mechanical - Drywell, System 69
 51136, Main Steam, Electrical and Instrumentation and Control - Turbine Building, System 01
 51143, Main Steam and Standby Liquid Control, Electrical and Mechanical - Drywell, System 01 and System 63
 51163, Reactor Feedwater, Mechanical and Instrumentation and Control - Drywell, System 04
 51144, Reactor Pressure Vessel Vents and Drains, Mechanical - Drywell, System 10.
 51114, Reactor Feedwater, Mechanical - Reactor Building, System 04

Section E1.2: Temporary Modifications

Procedures, Guidance Documents, and Manuals

0-TI-405, Plant Modifications and Design Change Control, Rev. 0
 0-TI-410, Design Change Control, Rev. 1

SPP-9.5, Temporary Alterations, Rev. 6

TACFs

1-06-008-079, System 79, Fuel Handling
 1-04-002-01, System 01, Main Steam and System 03, Reactor Feedwater
 1-06-004-068, System 68, RWR; System 69, RWCU; and System 74, RHR
 1-06-005-001, System 01, Main Steam
 1-06-007-001, System 01, Main Steam and System 03, Reactor Feedwater

Section E1.3: System Return to Service Activities

Procedures, Guidance Documents, and Manuals

1-TI-437, System Return to Service Turnover Process for Unit 1 Restart, Rev. 22
 1-TI-452, Restart Test Program Test Requirements, Rev. 5
 Brown's Ferry Unit 1 Final Safety Analysis Report, Section 6
 Brown's Ferry Unit 1 Technical Specifications and Bases
 BFN-50-7073, General Design Criteria, High Pressure Coolant Injection System, Rev. 18
 1-BFN-BTRD-073, Baseline Test Requirements Document, HPCI System, Rev. 3
 SPOC II package, dated March 28, 2006, including 1-TI-437-1 SRTS Turnover Boundary, and
 System Plant Acceptance Evaluation package, Unit 1, System 73, 02/02/2006, Rev. 0,
 with attachments A - M
 SE-ITEL-410, System Return to Service Open Item Punch-list, 03/27/07
 1-TI-437, Attachment 6, HPCI SPOC Walkdown, 03/21/2007

Drawings

1-47E812-1, Flow Diagram HPCI System, Rev. 26
 1-47E610-73-1, Mechanical Control Diagram HPCI System, Rev. 17
 1-47E812-2, Flow Diagram HPCI Oil System, Rev. 3
 1-47B455- 2196, Mechanical HPCI System Pipe Support, Rev. 1
 1-47B455-730, Mechanical HPCI System Pipe Support, Rev. 1
 1-47B455-728, Mechanical HPCI System Pipe Support Rev. 1
 1-47B455-3252, Mechanical HPCI System Pipe Support, Rev. 0
 1-47B455-2191, Mechanical HPCI System Pipe Support, Rev. 1

Surveillance Procedures

1-SR-3.5.1.8, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at
 150 psig Reactor Pressure, Rev. 0000, performed Mar 15, 2007
 1-SR-3.3.5.1.6 (FT), HPCI System Logic Functional Test, Rev. 1
 1-SR-3.3.5.1.5 (HPCI B), Core & Containment Cooling Systems Reactor High Water Level
 HPCI, RFPT, & Main Turbine Trip Instrument Channel Cal 1-L-3-208B, Rev. 2

Operating Instructions

1-OI-73, High Pressure Coolant Injection System, Rev. 4
 OPDP-6, Locked Valve/Breaker Program, Rev. 1

Section E1.4 Area Turnover Activities

Procedures

BP-388, Area Turnovers from Recovery Unit 1 Restart Project, Rev. 3 and Rev. 4
 0-SI-4.11.G.2, Semiannual Fire Door Inspection, Rev. 21
 FP-0-260-INS001, Inspection and Maintenance of Architectural Doors, Rev. 19
 GOI-300-3, General Valve Operations, Rev. 128
 GOI-300-3/Attachment 1, General Valve Operations Locked Valve Audit, Rev. 128
 0-TI-471, Temporary Equipment Control, Rev. 2
 SPP-10.7, Housekeeping/Temporary Equipment Control, Rev. 2

PERs

119033, NRC Walkdown of U1 Reactor Elevation 593
 119075, Penetration Numbers Incorrect
 123047, Missed Opportunity - NRC Walkdown Identified Issues
 119798, CS&S Pipe Supports Unit 1 RB 565 Elevation
 117818, Pre-fire Plan Upgrades

Miscellaneous Documents

BFNP FSAR Figure 1.6-5, Equipment Plans Elevations 593 and 586, Amendment 21
 Fire Protection Report Vol. 2, Pre-plan No. RX1-593
 P3 schedule of outstanding work items
 WO 02-013115-001, DCN 51208, Stage 2, replacement of fire door BFR-1-DOOR-260-0490
 Area Turnover / Walkdown Acceptance Checklist: Unit 1 Reactor Bldg Elevation 565
 FPR-Volume 2, Pre-Plan No. RX1-565, Reactor Building Unit 1 Elevation 563'

Section E1.5: Restart Test Program

Procedures and Standards

Technical Instruction 1-TI-469, Baseline Test Requirements, Rev. 1
 SSP-3.1, Corrective Action Program, Rev. 9
 SPP-8.1, Conduct of Testing, Rev. 3
 SPP-8.3, Post Modification Testing, Rev. 6
 SSP-9.5, Temporary Alterations, Rev. 7
 SSP-10.3, Verification Program, Rev. 1
 SPP-10.2, Clearance Procedure to Safely Control Energy, Rev. 9
 0-TI-360, Containment Leak Rate Programs, Rev. 21
 0-TI-376, AMSE Section XI Containment Inservice Inspection Program, Rev. 5
 0-TI-20, Control Rod Drive System Testing and Troubleshooting, Rev. 1
 1-TI-179, CILRT Data Acquisition System Setup, Rev. 0
 1-TI-173, Primary Containment Inspection, Rev. 0
 1-TI-132, Recirculation Flow Control, Rev. 0

Test Summary Reports:

1-BFN-BTRD-64D, PCIS
 1-BFN-BTRD-64A, Primary Containment
 1-BFN-BTRD-68/96, Reactor Water Recirculation System and Recirculation Control System
 1-BFN-BTRD-71, RCIC
 1-BFN-BTRD-73, HPCI

Surveillance Instructions

1-SR-3.5.1.8, HPIC Main and Booster Pump Set Developed Developed Head and Flow Rate Test at 150 psig Reactor Pressure, Rev. 0
 1-SI-4.7.A.2.a-f, Primary Containment Integrated Leak Rate Test, Rev. 1
 1-SR-3.6.1.3.8(1), Instrument Line Excess Flow Check Valve Operability Testing, Rev. 1
 1-SR-3.6.1.3.8(2), Instrument Line Excess Flow Check Valve Operability Testing, Rev. 1
 1-SR-3.6.1.3.8(3), Instrument Line Excess Flow Check Valve Operability Testing, Rev. 2
 1-SR-3.6.1.3.8(4), Instrument Line Excess Flow Check Valve Operability Testing, Rev. 1
 1-SR-3.6.1.3.8(5), Instrument Line Excess Flow Check Valve Operability Testing, Rev. 1
 1-SI-3.3.1.A, ASME Section XI System Leakage Test of the Reactor Pressure Vessel and Associated Piping (ASME Section III, Class I and II), Rev. 2
 1-SR-3.3.6.1.6 (GRP 2, 3, & 8), Groups 2,3, and 8 Primary Containment Isolation System Logic, Rev. 1
 1-SR-3.3.6.1.6 (SDC), Functional Testing Of RHR Shutdown Cooling Suction Valve Isolation Logic, Rev. 1
 1-SR-3.3.5.1.6 (CS I) and (CS II), Functional Test of RHR Loop I (Loop II) Valve Logic and Interlock, Rev. 1
 1-SR-3.3.1.1.13 (4A), Reactor Protection and Primary Containment Isolation Systems Low Reactor Water Level Instrument Channel A1 Calibration, Rev. 1
 1-SR-3.3.1.1.13/6A, B, C, and D, Reactor Protection and Primary Containment isolation Systems High drywell Pressure Instrument Channel Calibration, Rev. 1
 1-SR-3.3.5.1.5 DWP A, B, C, and D ECCS, Core and Containment Cooling Systems HPCI, LPCI, and Core Spray High Drywell Pressure Instrumentation Calibration, Rev. 1
 1-SR-3.6.1.5.2, Check Valves, 1-CKV-64-800 and 801, for the Reactor Building to Suppression Pool vacuum breakers, Rev. 1
 1-SR-3.3.5.1.4 (A), Core and Containment Cooling systems Reactor Low Pressure Instrument Channel Calibration, Rev. 1
 1-SR-3.3.5.1.4 (B), Core and Containment Cooling systems Reactor Low Pressure Instrument Channel Calibration
 1-SR-3.3.5.1.4 (C), Core and Containment Cooling systems Reactor Low Pressure Instrument Channel Calibration
 1-SR-3.3.5.1.4 (D), Core and Containment Cooling systems Reactor Low Pressure Instrument Channel Calibration, Rev. 1
 1-SR-3.3.1.1.14(8 I), Turbine Stop Valve Closure - RPS Trip and Recirc Pump Trip Logic System Functional Test, Rev. 1
 1-SR-3.3.1.1.14(8 II), Turbine Stop Valve Closure - RPS Trip and Recirc Pump Trip Logic System Functional Test, Rev. 1
 1-SR-3.5.1.5, Recirc Pump Loop I discharge valve 1- FCV-68-03 and Loop II discharge valve 1-FCV-68-77, Rev. 1
 1-SR-3.3.6.1.5(SDC A), Reactor High Pressure Calibration 1-PS-68-93, Rev. 1

1-SR-3.3.6.1.5(SDC B), Reactor High Pressure Calibration 1-PS-68-94, Rev. 1
 1-SR-3.6.1.3.5, Steam line inboard Rev. 1
 1-SR-3.3.6.1.2 (4C), Reactor Core Isolation System Turbine Exhaust Rupture Disc High Pressure Functional Test, Rev. 1
 1-SR-3.3.3.2.1 (71), Backup Control Panel Testing, Rev. 1
 1-SR-3.3.6.1.2 (4B) Reactor Core Isolation Cooling System Steam Supply Pressure Low Functional Test, Rev. 1
 1-SR-3.3.5.2.4 (FT), RCIC System Logic Functional Test, Rev. 1
 1-SR-3.3.6.1.2 (3C), HPCI System Turbine Exhaust Rupture Disc High Pressure Functional Test, Rev. 1
 1-SR-3.3.5.1.3(E), HPCI Suppression Chamber High Level Calibration and Functional Test, Rev. 1
 1-SR-3.3.6.1.2 (3B), HPCI Steam Supply Low Pressure Functional Test, Rev. 1
 1-SR-3.6.1.3.5, HPCI motor operated valves, Rev. 1
 1-SR-3.3.5.1.3(D), HPCI Condensate Header Low Level Calibration and Functional Test, Rev. 1
 1-SR-3.3.5.2.4 (FT), HPCI System Logic Functional Test, Rev. 1
 0-SR-3.1.4.1, Scram Insertion Times, Rev. 0
 0-SR-3.9.5.1, Mode 5 Control Rod Drive Rod Exercise, Rev. 0
 1-SR-3.1.3.5.(A), Control Rod Drive Coupling, Rev. 1
 1-SR-3.10.7, Verification of Surveillance Requirements for Control Rod Testing, Rev. 1

Work Orders

07-710775-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710776-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710777-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710778-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710779-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710780-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710781-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710782-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components
 07-710783-00, various work activities identified through 0-TI-20 to the Rod Position Indicating System (PCIS) and other CRD components

PMTIs

PMTI-51189-STG03, demonstrate that no more than 210 lbs of vertical force was required to open the drywell vacuum breaker discs
 PMTI-51243-ST01, System 71 250V DC power system supplied power to the Division I ATUs
 PMTI-51243-ST02, System 71 250V DC power system supplied power to the Division I ATUs
 PMTI-51094-ST10, functional test of miscellaneous HPCI system electrical components

PMTI-51082-STG02, post modification testing to verify that system 85 computer points

Other

ANSI/ANSI 56.8-1994 American national Standard, Containment Air Leakage Testing Requirements

N-VT-4 ASME Section XI VT-2 Visual Examination Reports, System Leakage Test of the Reactor Pressure Vessel and Associated Piping

Section E1.6: Special Program Activities - Cable Installation and Cable Separation

Procedures and Standards

BFN-50-728, DCD Physical Independence of Electrical Systems, Rev. 16

BFN-50-758, Power, Control, and Signal Cables for Use in Class 1 Structures, Rev. 15

G-38, Installation, Modification and Maintenance of Insulated Cables Rated up to 15,000 Volts, Rev. 20

IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations

IEEE 384-1974, IEEE Trial-Use Standard Criteria for Separation of Class IE Equipment and Circuits

Section E1.7: Station Blackout

Procedures and Standards

0-AOI-57-1A, Loss of Offsite Power (161 and 500KV)/Station Blackout Revs. 65 through 69

PERs:

114913, LOOP/SBO procedure did not adequately address potential loss of all EECW

114967, SBO calculation did not adequately consider potential loss of all EECW

Functional Evaluations

41702

41706

Section E1.8: Seismic Qualification of Equipment in Operating Plants

Procedures:

1-AOI-100-1, Reactor Scam

0-AOI-57-1A, Loss of Off Site Power (161 & 500kv) Station Blackout

0-AOI-100-5, Earthquake

Flow Charts

EOI-1, RPV/Control

EOI-3, Primary Containment Control

EOI-4, Reactivity Release Control
 C-1, Alternate Level Control
 C-2, Emergency RPV Depressurization
 C-4, RPV Flooding
 C-5, Level/Power Control

Calculations

CDQ1 999 2003 0654, Composite SSEL for USI A-46 and Seismic IPEEE Programs, Rev. 4
 CDQ1 999 2006 0149, USI A-46 Seismic Verification of Punch List Items and General Turnover
 Walk-by Confirmation, Rev. 1

Reports

Browns Ferry Unit 1 USI A-46 Seismic Evaluation Report, February 2007, Rev. 1

Section E7.1: Verification of Licensee Corrective Actions

Commitment Closure Packages

NCO870212002
 NCO840226002
 NCO890245002
 NCO970027001
 NCO930185051
 NCO930042001
 NCO040006040

Section M1: Conduct of Maintenance

Work Orders

05-720239-00, adjusting of the outboard MSIV limit switches
 05-720247-00, adjusting of the inboard MSIV limit switches
 06-726199-05, calibration of the inboard MSIV slow speed adjustment
 06-726199-06, calibration of the outboard MSIV slow speed adjustment
 06-725330-09, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis.
 06-725330-10, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis.
 06-725330-11, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis.
 06-725330-12, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis.
 06-725330-13, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis rods on a like-for-like basis
 06-725330-15, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis

06-725330-16, provide support to the vendor for the replacement of the outboard MSIV yoke rods on a like-for-like basis

06-722879-35, testing support of the ECCS ATUs using procedure 1-SR-3.3.5.1.2 (ATU A), Core and Containment Cooling Systems Analog Trip Unit Functional Test

06-722879-38, testing support of the ECCS ATU's using procedure 1-SR-3.3.5.1.2 (ATU B), Core and Containment Cooling Systems Analog Trip Unit Functional Test

05-720521-00, performing the static MOVATS testing on flow control valve 1-FCV-73-040, HPCI Condensate Storage Tank Suction Valve

06-722879-33, testing support of the ECCS ATU's using procedure 1-SR-3.3.5.1.2 (ATU C), Core and Containment Cooling Systems Analog Trip Unit Functional Test

06-722879-36, HPCI System, for the testing support of the ECCS ATU's using procedure 1-SR-3.3.5.1.2 (ATU D), Core and Containment Cooling Systems Analog Trip Unit Functional Test

06-718119-00, performing the static MOVATS testing on flow control valve 1-FCV-73-016, HPCI Steam Supply Valve

06-712675-00, perform the HPCI Turbine over speed test with the Auxiliary Boiler System supply the necessary steam flow

Section F1.1: Restart Special Program - Fire Protection Improvements

Procedures and Standards

0-SSI-001; Safe Shutdown Instructions, Rev. 0

0-SSI-1-1; Unit 1 Reactor Building Fire EL 519' through 565' West of Column Line R4, Rev. 0

0-SSI-1-5; Unit 1 Reactor Building Fire EL 621' and 639' North of Column R, Rev. 0

0-SSI-16; Control Building Fire EL 593' through 617', Rev. 0

0-SSI-20; Unit 1 & 2 Diesel Generator Building, Rev. 0

Drawings

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-01, Rev. 4

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-02, Rev. 5

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-03, Rev. 7

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-04, Rev. 2

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-05, Rev. 3

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-06, Rev. 3

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-07, Rev. 6

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-08, Rev. 4

Appendix R Emergency LTG Ingress/Egress Routes & Major Shutdown Equipment, 0-45W400-RW-11, Rev. 2

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Key Diagram of Normal Auxiliary Power System, 0-15E500-2, Rev. 24
 Key Diagram of Normal and Standby Auxiliary Power System, 3-15E500-3, Rev. 43

PERs

PER 122853, 0-SSI-16 (App R radio communications)
 PER 122729, SSI Verification and Validation
 PER 122854, 0-SSI-16 Walkdowns

V&V Packages

V&V Appendix R Manual Action SSI Number: 0-SSI-1-1
 V&V Appendix R Manual Action SSI Number: 0-SSI-1-5
 V&V Appendix R Manual Action SSI Number: 0-SSI-16
 V&V Appendix R Manual Action SSI Number: 0-SSI-20

Miscellaneous Documents

0-SR-3.3.3.2.1(43) Backup Control Panel Testing, Rev. 0
 0-SR-3.3.3.2.1(69) Backup Control Panel Testing, Rev. 0
 0-SR-3.3.3.2.1(71) Backup Control Panel Testing, Rev. 0
 0-SR-3.3.3.2.1(71) Backup Control Panel Testing, Rev. 1
 0-SR-3.3.3.2.1(74) Backup Control Panel Testing, Rev. 3
 0-SR-3.3.3.2.1(75) Backup Control Panel Testing, Rev. 0
 0-SR-3.3.3.2.1(85) Backup Control Panel Testing, Rev. 0
 1-SR-3.3.3.2.3(03) Backup Control System Suppression Pool Temperature Indication Calibration, Rev. 0
 1-SR-3.3.3.2.3(06) Backup Control System RHR System II Total Flow Indication Calibration, Rev. 0
 1-SR-3.3.3.2.3(7) Reactor Core Isolation Cooling System Backup Control Panel Flow Indication and Control Calibration, Rev. 1
 1-SR-3.3.3.2.3(8) Reactor Core Isolation Cooling System Backup Control Panel Turbine Speed Indication and Control Calibration, Rev. 1