UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

November 9, 2006

Tennessee Valley Authority
ATTN: Mr. K. W. Singer
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 05000259/2006008

Dear Mr. Singer:

On October 14, 2006, 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 November 6, 2006, with Mr. Masoud Bajestani 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 Unit 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 05000259,260,296/2006004, issued October 30, 2006, is the most recent Unit 2 and 3 Integrated Quarterly Report. Although that report did not contain any site inspections in these cornerstones, they will continue to be documented in ROP integrated quarterly reports such as that one.

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, a Severity Level IV violation of NRC requirements was identified resulting from two examples of inadequate modification instructions resulting in an unplanned breach of secondary containment and the unplanned loss of automatic fire pump start function. However, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy.

If you contest the NCV 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.

Overall, we primarily found only minor discrepancies, indicating that your oversight of recovery activities was generally effective. However, we will continue to monitor implementation of your corrective actions to address previously identified weaknesses in your System Return to Service process.

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 HVAC Ducts/Supports and Small Bore Pipe/Supports. 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 05000259/2006008
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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DATE	11/06/2006	11/06/2006	11/06/2006	11/06/2006	11/06/2006	11/06 /2006	11/06/2006
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Report to Karl W. Singer from Malcolm T. Widmann dated November 9, 2006

SUBJECT: BROWNS FERRY NUCLEAR PLANT UNIT 1 RECOVERY - NRC INTEGRATED INSPECTION REPORT 05000259/2006008

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-259
License No:	DPR-33
Report No:	05000259/2006008
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Unit 1
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	July 16, 2006 - October 14, 2006
Inspectors:	W. Bearden, Senior Resident Inspector, Unit 1 E. Christnot, Resident Inspector C. Stancil, Resident Inspector N. Garrett, Senior Resident Inspector, Surry (Section E1.3) D. Arnett, Resident Inspector, Surry (Section E1.3) J. Lenahan, Senior Reactor Inspector (Sections E1.7, E1.8) P. Fillion, Senior Reactor Inspector (Sections E1.11, E8.4) S. Vias, Senior Reactor Inspector (Sections E1.6, E8.1) N. Staples, Reactor Inspector (Section E1.5) R. Chou, Reactor Inspector (Section E1.9) D. Mas-Penaranda, Reactor Inspector (Section E8.3)
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 05000259/2006008

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 resident inspector inspection. 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; HVAC ducts and supports; large bore pipe and supports; long term torus integrity; small bore piping and instrument tubing; instrument sensing lines; 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. Per 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 - Engineering

- The inspector's review of four 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)

- A Severity Level IV Non-Cited Violation with two examples of inadequate modification instructions was identified during the current inspection. The inadequate instructions resulted in the unplanned breach of secondary containment and unplanned loss of the automatic fire pump start function. (Section E1.1)

- Activities associated with removal of 14 temporary alterations which affected various risk significant systems did not cause any significant impacts on the operability of equipment required to support operations of Units 2 and 3. No violations or deviations were identified. (Section E1.2)

- Activities associated with the system return to service process were being adequately implemented. System turnover walkdowns were performed in accordance with procedural guidance. System turnover plant review and acceptance boards were effective. However, inspectors will continue to review system turnover activities and observe future boards for long term effectiveness. Additionally, observation of future system turnover activities will be required to determine adequacy of corrective actions associated with previously identified weaknesses in the licensee's process. An unresolved item was identified associated with the licensee's control of duct tape pending the inspectors review of licensee resolution of this deficiency. (Section E1.3)

- System walkdowns, package reviews and interviews with the system engineer indicated the Unit 1 SLC system was adequately turned over as a functional system with pre-approved documented exceptions to operability. (Section E1.3)

- System walkdowns, package reviews and interviews with the system engineer indicated that the 250 VDC Distribution system was adequately turned over as an operable system. No exceptions or deferrals were found to be missed. No issues were found that would dispute the licensee's operability decision. (Section E1.3)

- Implementation of restart testing activities was generally acceptable. Pre-test briefs were initially not being performed in accordance with pre-job brief checklist requirements. However, discussions with licensee management improved the briefings. Only minor test deficiencies which did not effect 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 E1.4)

- Based on observations, document reviews, and discussions with engineering personnel, the inspectors determined that implementation of the subprogram for bend radius of medium voltage cable is proceeding in accordance with licensee commitments and regulatory requirements. Actions to address issues for bend radius of medium voltage cable 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 bend radius of medium voltage cable 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 no further inspections are anticipated for this subprogram. However, implementation activities associated with the Cable Separation Special Program, will need further inspections by the NRC to verify corrective actions are in accordance with licensee commitments. (Section E1.5)

- Heating Ventilation and Air Conditioning ducting and supports activities were performed in accordance with documented requirements. No issues related to this Special Program that would negatively impact restart of Unit 1 were identified. Based on this inspection, no further inspections are anticipated for this Special Program. (Section E1.6)

- Small Bore Piping and Instrument Tubing Support activities were performed in accordance with documented requirements. The inspectors determined that the licensee's program for correction of deficiencies identified in support of small bore piping, including instrument tubing, complies with the design criteria, commitments to NRC, and NRC requirements. Inspection of small bore piping supports has been completed. No further inspections of small bore piping supports are anticipated. (Section E1.7)

- The Instrument Sensing Line slope correction activities were performed in accordance with documented requirements. Additional samples of instrument sensing lines will need be inspected to verify the instrument line slope deficiencies were corrected and supports were installed in accordance with design requirements prior to closure of this Special Program. (Section E1.8)

- Based on independent walkdowns of pipe supports, as-built support drawings, and problem resolution, the inspectors determined that licensee performance was adequate in the Large Bore Pipe Support and Long Term Torus Integrity Special Programs. However, additional samples will need to be inspected prior to closure of these Special Programs. (Section E1.9)

- Modification activities associated with installation of Core Spray sparger clamps and Jet Pump aux wedges in the Unit 1 RPV were adequately implemented. The inspectors determined that the licensee's in-vessel activities had satisfied all applicable code requirements and licensing commitments. (Section E1.10)

- Electrical distribution system loading calculations were reviewed along with proposed modifications aimed at alleviating overloads predicted by the calculations. The calculations were accurate and considered all relevant system alignments and contingencies. The proposed modifications would be effective in alleviating the overloads and, at the same time, maintain the design basis. (Section E1.11)

<u>Inspection Results - Maintenance</u>

- 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)

- The licensee's functional evaluation for the planned simultaneous outages of the Unit 1 main transformers and unit station service transformers, which placed the operating units in an elevated risk condition, was adequate. Compensatory measures and equipment alignment conditions to support this condition minimized the potential for overloading the common station service transformers and 4KV start busses. (Section M1.2)

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REPORT DETAILS

Summary of Plant Status

Unit 1 has been shut down since March 19, 1985, and has remained in a long-term lay-up condition with the reactor defueled. 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, re-installation of plant equipment and structures continued. Recovery activities include ongoing replacement of small bore piping and instrument tubing in the drywell and reactor building; re-installation of balance-of-plant piping and turbine auxiliary components; installation of small and large bore pipe supports; and installation of new electrical cables, conduits, and conduit supports. The amount of restart testing and system return to service activities increased during this reporting period as the Unit 1 recovery effort continued to transition away from bulk construction work.

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 Main Steam (MS) System, Reactor Water Cleanup (RWCU) System, and Sampling and Water (S&WQ) System. 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

b.1 Review of DCN Packages

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 51235

The inspectors reviewed permanent plant modification DCN 51235, System 43,Sampling and Water Quality (S&WQ) and System 69,Reactor Water Clean Up (RWCU) Electrical and Mechanical - Reactor Building. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the S&WQ and the RWCU systems in the reactor building. The DCN consisted of seven stages and included the following:

- Replacement, relocation, and/or addition of selected related instrumentation such as the 1A and 1B suction header pressure indicators, the pre-coat tank high and low level switches, the blow down pressure control valve pressure switch, the 1A and 1B RWCU pump common vibration and temperature display unit BFR-1-XI-69-97 and monitor BFR-1-XM-69-97, the non-regenerative heat exchanger discharge temperature controller and temperature switch, the 1A and 1B pump cooling water temperature and discharge flow switches, the obsolete blow down flow transmitter, the obsolete re-generative heat exchanger inlet pressure transmitter, and the obsolete flow recorder controller

- Install a 10CFR50.49 qualified leak detection system by deleting and abandoning in place 12 non-qualified RWCU area floor drain temperature switches, install four qualified resistance temperature detectors (RTD) in the pump room 1A, install four RTD's in the pump room 1B, install four RTD's in the heat exchanger room, and an additional four RTD's in the heat exchanger room to improve high energy line break detection at that location.

During the review the inspectors observed that two Post Issuance Changes (PIC) were issued during the development of this DCN. PIC 61417 directed that the existing sample panel 1-PNL-25-09 and the associated constant temperature bath be replaced. The replacement panel, designated as BFR-1-LPNL-925-009, would also include an associated sample chiller unit, designated as BFR-1-CHR-043-2070. PIC 61417 was incorporated as Stage 3. PIC 64335 directed that, due to the original new 1A RWCU pump being removed and installed in Unit 3, a new 1A pump and associated instrumentation be installed. PIC 64335 was incorporated as Stage 7.

DCN 63005

The inspectors reviewed permanent plant modification DCN 63005, Main Steam Line EPU Data Collection Vibration Monitoring, Electrical and Mechanical - Reactor Building and Drywell, System 01. The intent of this DCN was to implement the electrical and mechanical modifications recommended for the Unit 2 main steam system in the reactor building and in the drywell. Scheduled modification activities included:

- The installation of 64 strain gauges, Type HBWAK Weldable, at two locations on each of the four main steam lines (upper and a lower). Eight strain gauges were to be installed at each location at a 45 degree angle to each other. The upper location was to be 9.5 feet from the inside of the reactor vessel wall and the lower location was to be 41.16 feet from the inside wall.

- The strain gauges were to be welded to the steam lines and were to be equipped with a cover. The strain gauges were to use a Type Varglas Viton 231 Sleeving for electrical connections.

- Additionally, separate accelerometer mounting blocks were to be installed on each of the main steam lines and the HPCI steam supply line at specified locations. This was to allow for further data acquisition and pipe response data.

- The installed vibration monitoring equipment was to be wired to a Vibration Data Acquisition System (VDAS). The VDAS will collect the data for further analysis.

The objective of the original version of the DCN was to install strain gauges, hi-speed transducer accelerometers, and data acquisition components to collect data on the Unit 2 main steam and HPCI supply piping. This was to support analysis of steam line vibration affecting steam dryer stresses and loads during EPU conditions. PIC 68112 was initiated to update DCN 63005. The PIC was used to remove the requirement to install accelerometer mounting blocks. This resulted in a final installation which would only have strain gauges for data acquisition.

<u>DCN 51211</u>

The inspectors reviewed permanent plant modification DCN 51211, Main Steam Electrical - Reactor Building, System 01. The intent of this DCN was to implement electrical modifications recommended for the main system in the reactor building. Scheduled electrical modifications included replacement of all limit switches associated with the Outboard Main Steam Isolation Valves (MSIVs) with safety related switches; replacement of cables for the MSIV solenoid valves with new class 1E and 10CFR50.49 (EQ) qualified cables and splices; replacement of cables for the MSIV open and closed L3 and L4 limit switches, respectively, with new class 1E and EQ qualified cables; removal of local main steam drain isolation valve control station; replacement of cables for the MSIV drain interlock; re-routing selected cables from a Division II Electrical Penetration Assembly (EPA) to a Division I EPA; replacement of cables for the Main Steam Relief Valves (MSRVs) with new class 1E and EQ qualified cables; modification of control switch locations to ensure required number of automatic depressurization system steam relief valves are available in case of a fire in any area of the plant; replacement of cables for the MSRV acoustic monitoring with new class 1E and EQ qualified cables; deletion and removal of selected temperature sensing switches from the main steam tunnel vault; replacement of cables for the main steam line leak detectors with new class 1E and EQ qualified cables; and replacement of conduit and install conduit supports as necessary.

DCN 51230

The inspectors reviewed permanent plant modification DCN 51230, Main Steam, Instrumentation and Control (I&C) - Reactor Building, System 01. The intent of this DCN was to implement the I&C modifications recommended for the main steam system in the reactor building. Scheduled I&C modifications included removal and replacement of each of the main steam line flow transmitters (A transmitters and B transmitters); replacement on a like-for-like basis selected main steam instrumentation; removal and replacement of each of the main steam line high flow transmitters (A transmitters and B transmitters); modification and installation of a new outboard MSIV open and close control manifold; modification, as necessary, of Panel 25-56A instrument mountings, instrument lines, and valves; and modification, as necessary, of Panel 25-56B instrument mountings, instrument lines, and valves.

b.2 Unplanned Breach in Secondary Containment

On September 18, 2006, during field walkdowns to support installation of new two inch High Pressure Coolant Injection (HPCI) piping the licensee identified an unplanned breach in the Secondary Containment. An existing two inch HPCI pipe in the Unit 1 Main Steam Tunnel in the Reactor Building and three inch HPCI steam line in Turbine Building were found to be cut. There was no isolation between the two inch line in the Reactor Building and the three inch line in the Turbine Building which constituted a Secondary Containment breach. Installation of new two inch HPCI pipe in the Reactor Building was controlled by Work Order (WO) 02-013120-010 and the three inch HPCI steam line in Turbine Building was being reworked by WO 03-020376-028. Neither WO had included a Secondary Containment breach permit to control this work activity. The licensee issued “B” level PER 110926 to address the problem. The inspectors reviewed PER 110926 and the licensee’s apparent cause determination. The licensee determined that the unplanned breach had resulted from insufficient details in the work instructions. A breach permit was approved and WO 02-013120-010 was revised to include instructions to rework the Secondary Containment penetration for replacement of the HPCI line. A plate was welded across the two inch line closing the breach until the pipe was reinstalled and Secondary Containment permanently established.

Additionally, the inspectors reviewed Functional Evaluation 41621, which addressed post operability of the secondary containment. The licensee inspected the interim piping configuration and determined that the seismic qualification of the containment seal had not been adversely affected. The licensee also determined that the affected breach size was limited to the size of the 2 inch pipe (3.36 sq. in.). The licensee also determined that the breach had most likely occurred as early as February 1, 2006. Based on review of the Secondary Containment Breach Log and comparison with known available breach margin during the period from February 1 and September 19, 2006, the licensee determined that the amount of the unplanned breach was well below the available breach margin. As such Secondary Containment was not degraded during that period and the unplanned breach had not constituted a significant safety issue.

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 February 1, 2006, modification activities resulted in an unplanned breach to Secondary Containment. This event had resulted from inadequate work instructions. 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. Although this event resulted in an unplanned breach to Secondary Containment, there was no actual loss of safety function during the affected period because sufficient breach margin had existed. A Severity Level IV Non-Cited Violation (NCV) 50-259/2006-08-01, Inadequate Modification Instructions, 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 110926.

b.3 Unplanned Loss of Automatic Fire Pump Start Function

On September 9, 2006, during performance of Surveillance Instruction 3-SI-4.11.C.1.c, Simulated Automatic Actuation of the Fire Protection Sprinkler System, operators identified that the automatic start function of the plant fire pumps had been made inoperable. The licensee's subsequent investigation determined that the problem had been due to inadequate design change work instructions. During the implementation of WO 03-021424-079 in support of Stage 5 of DCN 51368, the automatic start function associated with position indicating switches for the Unit 2 and Unit 3 Reactor Building Pre-action flow control valves, 2-FCV-026-0077 and 3-FCV-026-0077, was inadvertently defeated by lifting a cable in fire alarm panel, 1-25-311. Panel 1-25-311 was to be replaced by new panel 1-25-545. However, old panel 1-25-311 was to remain as a junction box. Cable 0FE3567 had been lifted in Panel 1-25-311 and labeled as abandoned/deleted. However, cable 0FE3567 was necessary to complete the circuit to the fire pump start circuitry and should not have been abandoned. The licensee issued "B" level PER 110479 to address the problem. Additionally, WO 03-021424-079 was revised by the licensee to add instructions to reland cable 0FE3567 to restore the automatic fire pump start function.

The inspectors reviewed PER 110479 and the licensee's apparent cause determination. The inspectors determined that this event had resulted from inadequate work instructions associated with DCN 51368. The inspectors noted that although the automatic start function was defeated, that numerous alarms and indications available to operations personnel and the fire protection staff would have led to a timely start of the fire pumps in the event of a postulated fire. Additionally, the separate automatic start logic for low system header pressure had not been affected by lifting of cable 0FE3567. 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. Although this event resulted in loss of automatic fire pump start function there was no actual loss of safety function during the affected period. Because of the diversity of the design of the fire protection system no loss of other functions occurred. This failure is a second example of NCV 50-259/2006-08-01, Inadequate Modification Instructions. This event was documented by the licensee in PER 110479.

c. Conclusions

The inspectors' review of modification design packages associated with four 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. However, based on the results of this inspection, two examples of a Severity Level IV violation of NRC requirements were identified resulting from inadequate modification instructions. These result in an unplanned breach of secondary containment and the unplanned loss of automatic fire pump start function. The NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy.

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 23, Residual Heat Removal Service Water (RHRSW); System 64, Primary Containment (PCS); System 67, Emergency Equipment Cooling Water (EECW); System 69, Reactor Water Clean Up (RWCU); System 70, Reactor Building Closed Cooling Water (RBCCW); System 85, Control Rod Drive (CRD); System 90, Radiation Monitoring (RM); System 99, Reactor Protection (RPS); System 100, Containment Penetrations; System 77, Radiological Waste Treatment (RWT); System 57-4, 480 VAC; System 111, Hoists and Cranes; and Control Room Design Review (CRDR). 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 Technical Specifications and reviewed selected completed work activities of the system to verify that installation and/or removal was 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

Historical Temporary Alterations

The inspectors reviewed and observed selected closure activities associated with seven historical temporary alterations (TACF) that had been installed in the 1984 to 1988 time frame prior to the start of the Unit 1 recovery program. These TACFs were no longer needed due to implementation of permanent modifications.
1-84-088-76

This TACF, installed in June, 1984, was initiated to address a non-qualified electrical penetration, designated as Penetration PA, that involved the Unit 1 primary containment personnel access air lock. The TACF removed from service various circuits such as air lock lighting, telephone service, indicating lights, and alarm functions. The TACF directed that jumpers be installed to return the alarm function for the air lock outer door. The TACF stated that penetrations currently unqualified will be replaced next Unit 1 outage. The inspectors verified that DCN 51189, Primary Containment Electrical and Mechanical - Reactor Building, System 64A Stage 5 was issued to replace the penetration with a qualified penetration for the Conax Corporation. The replacement activities were controlled by WO 02-016196-14.

1-84-092-67

This TACF, installed in August, 1984, was initiated to install a non-qualified valve,1-67-237A, in the Unit 1 EECW system. The inspectors verified that DCN 51192, EECW Mechanical - Reactor Building, System 67, Stage 2 was issued and implemented to replace a series of valves in the EECW system including valve 1-67-237A. The valve replacement activities were controlled by WOs 02-013229-23, 02-013229-24, and 02-013229-25.

1-84-093-85

This TACF, installed in August, 1984, was initiated to remove Level Monitors (LM) 1-85-85A, 85B, 85C, and 85D from service. This affected the scram discharge header level instrumentation. The TACF directed that power to the LM's be disabled by removing fuses F1A and F1B located in Panel 1-PNL-25-48A and fuses F2A and F2B located in Panel 1-PNL-25-48B. The inspectors verified that DCN 51206, CRD Electrical and Mechanical - Reactor Building, System 85, Stage 2 was issued and implemented to remove and discard Panels 1-PNL-25-48A and 48B. The removal and discarding activities were controlled by WO 03-006734-07. DCN 51111, CRDR Panel 1-9-6 Electrical - Main Control Room (MCR), Stage 12 was issued to change the MCR panel affected by DCN 51206, Stage 2.

1-84-101-99

This TACF, installed in November, 1984, was initiated to install a flexible conduit in Control Panel 1-9-17 in order to re-route the electrical cable going to scram relay 5A-K14D entirely through the conduit. The TACF stated that by routing the cable through the conduit a single failure, due to a panel internal fire, would be avoided. The inspectors verified that DCN 51080, RPS Electrical - Control Bay, System 99, was issued in part to make the installation permanent. The activities involved with the permanent installation were controlled by WO 06-711189-00.

1-84-29-69

This TACF, installed in December, 1984, was initiated to bypass a thermal trip 49X relay for RWCU Pump 1B. The 49X relay was located in the compartment 8B of the 480V Shutdown Board 1B. The original 1B pump was replaced in 1978 with a pump that was not equipped with thermotectors and the thermal trip relay was no longer required. The inspectors verified that DCN 51194, RWCU Electrical and Mechanical - Reactor Building, System 69, was issued to remove and replace the RWCU piping and electrical cables. WO 02-015981-42 implemented the portion of the DCN that affected the 49X relay for the 1B pump

1-85-020-77

This TACF, installed in July, 1985, was initiated to remove the Robertshaw Model 351 flood level switches and replace them with the Model 352. The TACF stated that the Model 352 superceded the Model 351. A total of six switches were involved, 1-LS-77-25A, B, C, D, E, and F, located in the Unit 1 Reactor Building. The inspectors verified that DCN 51202, RWT Electrical - Reactor Building, System 77, was issued to upgrade the RWT system in the Unit 1 reactor building. The DCN also, in part, made the installation of the switches permanent. WO 06-710972-00 functionally tested the level switches per procedure EPI-0-077SWZ002, Functional Check of Reactor Building Flood level Switches, Rev 05.

1-88-01-90

This TACF, installed in October, 1988, was initiated to remove from service the annunciator circuits for the Unit 1 Reactor Building Closed Cooling Water (RBCCW) radiation monitor and the common radiation monitor on the RHRSW discharge of the 1A/1C RHR Heat Exchangers. It was determined in 1988 that the monitors would be removed from service and would not be needed. The TACF stated that annunciator circuit for the common radiation monitor on the RHRSW discharge of the 1B/1D RHR Heat Exchangers would remain in service. Both heat exchangers were required to support Unit 2 operations. The inspectors verified that DCN 51241, Radiation Monitoring - Reactor Building, System 90, Stage 5, was issued to restore the radiation monitors to operable status. The restoration activities for the annunciator circuits were implemented by WO 03-002070-00 and WO 03-002074-00

Unit 1 Recovery Temporary Alterations

The inspectors reviewed and observed selected closure activities associated with four TACFs that had been installed in the 2002 to 2005 time frame to support ongoing Unit 1 recovery activities. These TACFs were closed since the equipment was returned to the original configuration or due to implementation of permanent modifications.

1-02-004-77

This TACF, installed July 17, 2002, was initiated to install two portable submersible sump pumps and a level switch in the Unit 1 Turbine Building (TB) floor drain sump. Rubber hoses were connected to each of the discharges of the pumps. The hoses were routed to the Unit 1 TB condensate pit floor drain sump. The installed condensate pit floor drain sump pumps routed the discharge of the submersible pumps to the Radwaste system for treatment. The pumping system was installed to support the re-tubing of the three Unit 1 main condensers. The installation activities were controlled by WO 02-002718-00 and WO 02-002722-00. The re-tubing was completed. The inspectors verified that the system was returned to normal configuration. Restoration activities were controlled by WO 03-005916-37 and WO 03-005916-58.

1-03-01-64

This TACF, installed March 19, 2003, was initiated to complete the following work: Mechanically block open valve 1-FCV-64-29, Containment Purge Filter Inlet; replace the elements in 1-FLT-64-702, Containment Purge HEPA Filter; and mechanically block open valve 1-FCV-64-30, Containment Purge Filter Outlet. The system was modified to allow the running of the containment purge air system filter assembly in order to exhaust air from the Unit 1 drywell area. The work activities were controlled by WO 03-001120-00. The inspectors verified that DCN 51189, Primary Containment Electrical and Mechanical - Reactor Building, System 64A, Stage 3, was issued to replace valves 1-FCV-64-29 and 1-FCV-64-30 including the valve body, actuator, and solenoid valves 1-FSV-64-29 and 1-FSV-64-30. The replacement activities were controlled by WO 02-016196-00.

1-04-01-111

This TACF, installed April 12, 2004, was initiated to install a temporary 5 ton overhead crane in the Unit 1 Reactor Building, El 629', between rows R5 and R6 and between lines T and U. The installation was in accordance with Engineering Work Request (EWR) 03CEB111090. The EWR was from the Civil Engineering Branch. The installation activities were controlled by WO 04-711732-00. The purpose of the crane was support material handling for the Unit 1 restart project. The inspectors verified that DCN 66931, 5 Ton Overhead Crane - Reactor Building, System 111, was issued on June 20, 2006, which made the temporary crane a permanent installation.

1-05-001-231

This TACF, installed January 25, 2005, was initiated to install a Yokogawa recorder on breaker 1-BKR-231-0001A/3D, the normal feeder to the 1A I&C bus transformer. The recorder was located in the Unit 1 480V Shutdown Board Room 1A. The feeder breaker was spuriously tripping for no apparent reason. This caused the I&C bus to automatically transfer unnecessarily to the alternate source. The recorder was removed on June 20, 2005. The inspectors verified that the recorder was properly removed. The installation and removal activities were controlled by WO 04-722865-00.

Restoration of Primary Containment Isolation Signal (PCIS) Logic

The inspectors reviewed and observed selected closure activities associated with three TACFs that had been installed in 2004 to support ongoing Unit 1 recovery activities. The intent of these TACFs was to disable various initiation signals from Unit 1 that would impact specific systems on the operating units and on Unit 1. Installation of these TACFs had been previously reviewed and documented in Inspection Report 50-296/2004-09. These TACFs were removed and the equipment was returned to the original configuration to allow testing and return Unit 1 systems to service.

1-04-011-64D

This TACF, installed August 31, 2004, was initiated to install jumpers on specific PCIS relays located in Control Panel 1-9-15, in Panel 1-9-42, and in Panel 1-9-43. Equipment affected by these jumpers included the inboard and outboard Primary Containment Atmospheric Control trip reset seal-in control; valves 1-FCV-77-2A Inboard Drywell Floor Drain Isolation, 1-FCV-77-15A Inboard Drywell Equipment Drain Isolation, 1-FCV-77-2B Outboard Drywell Floor Drain Isolation, and 1-FCV-77-15 Outboard Drywell Equipment Drain Isolation; and Suppression Chamber Drain Valves 1-FCV-75-57 and 58. The jumper was installed to inhibit the PCIS functions. The inspectors verified proper removal of the TACF. Removal activities were controlled by WO 06-719387-00.

1-04-012-074

This TACF, installed August 31, 2004, was initiated to install a jumpers on the PCIS inboard RHR isolation relay 16A-K29, located in Control Panel 1-9-42 and on the PCIS outboard RHR isolation relay 16A-K30, located in Control Panel 1-9-42. The jumpers were installed to inhibit the PCIS function for the RHR system. The inspectors verified proper removal of the TACF. Removal activities were controlled by WO 06-720422-00.

1-04-013-069

This TACF, installed July 5, 2004, was initiated to install jumpers, lift leads, and remove fuses in Control Panel 1-9-42 and in Panel 1-9-43. The activities were performed to allow for the normal operation of RWCU valves 1-FCV-69-01, 1-FCV-69-02, and 1-FCV-69-12 with the PCIS de-energized. Revision 1 of this TACF replaced the inboard PCIS logic fuse, FU1-9-42G in order to provide instrumentation power to RWCU pumps. The inspectors verified proper removal of the TACF. Removal activities were controlled by WO 06-718242-00.

c. Conclusions

The inspectors determined that activities associated with removal of 14 temporary alterations which affected various risk significant systems did not cause any significant impacts on the operability of equipment required to support operations of Units 2 and 3. 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 continued to increase during this reporting period as the Unit 1 recovery effort continued to transition away from bulk construction work. However, only a limited number of important risk significant systems have completed SRTS activities. Specifically, System Pre-Operability Checklist (SPOC) II activities have been completed for the RHRSW, SLC, CS, and 250 VDC Systems.

The inspectors continued to evaluate the effectiveness of improvements to the licensee's SRTS process which were initiated to address weaknesses previously identified by the inspectors and by the licensee during a self assessment. NRC inspection findings related to those weaknesses were previously discussed in Inspection Report 50-259/2006-06. These improvements included increased management expectations regarding ownership by personnel from the operating organization, greater level of involvement by management (both from Unit 1 and the operating units), and creation of separate plant review and acceptance boards tasked with providing independent oversight of SPOC I and SPOC II turnover activities for each system which undergoes SRTS activities.

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 (SPAE), 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 SPAE 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 <u>SPOC I and II Boards and Walkdown Activities</u>

In addition to periodically observing daily SPOC status meetings, the inspectors observed plant system walkdowns and management review and acceptance boards. SPOC I walkdowns were observed on System 32, Control Air; System 92, Neutron Monitoring; and System 94, Traversing Incore Probes (TIP). A SPOC II walkdown was observed on System 75, Core Spray (CS), and an independent walkdown performed on System 63, Standby Liquid Control (SLC). Inspectors observed SPOC I management review boards on Control Air; System 64B, Containment Ventilation; System 64D, Primary Containment Isolation; CS System; TIP System ; and System 99, Reactor Protection (RPS). Inspectors observed SPOC II management review boards on Control Air; SLC; System 77, Radwaste; System 572, 120 VAC Instrument and Control power; System 573, 250 VDC Distribution; CS System; and System 574, 480 VAC Distribution.

The inspectors determined that SPOC walkdowns were adequately scheduled and 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. Pre-walkdown briefs were held by the restart system engineer for all participants and walkdown boundaries and guidelines were discussed. The minimum required representatives were present. Operational deficiencies and material discrepancies identified by inspectors and walkdown participants were appropriately documented and dispositioned.

During the SPOC II CS System walkdown, the inspectors identified a concern with duct tape on stainless steel sensing lines, apparently the result of previous system and component layup, demolition, and/or construction. The concern is that halogens present in tape residue may infiltrate stainless steel surfaces resulting in stress corrosion cracking and subsequent failure under high temperature and stress conditions. Whole pieces of tape and tape residue were identified on long expanses of one inch diameter sensing lines associated with 1-PDIS-75-28 and 1-PDIS-75-56. Points of impact are on unisolable sensing lines just upstream of core spray injection piping into the reactor vessel where temperatures and pressures can be close to 500 degrees F and 1000 psig respectively. Duct tape was observed on numerous other small bore piping on other systems and indicates a generic issue with control of use of duct tape. Additionally, duct tape was identified as panel edge moisture intrusion protection on numerous electrical junction boxes during a torus walkdown, an ECCS foreign material exclusion concern. The licensee placed the drywell and torus duct tape issues into their corrective action program under PER 111681 for the drywell and PER 111684 for the torus. This concern identified in the licensee's control of duct tape will need to be evaluated as a possible contributor to stress corrosion cracking and foreign material exclusion concern. Unresolved item 50-259/2006-08-02, Impact of Duct Tape on Instrument Tubing and ECCS Suction, was identified pending the inspectors review of licensee resolution of this deficiency.

b.2 System 63, Standby Liquid Control (SLC) SPOC II System Readiness Inspection

The SLC system SPOC II package was approved by the Browns Ferry Unit 1 restart organization on August 31, 2006. The SPOC II package had one exception which must be cleared and a local leak rate test must be performed prior to declaration of operability

During review of the SPOC II package, the inspectors identified a typographical error in documentation of an open item Deferral for DCN 51143. DCN 51143 installed valves 1-SHV-063-0012, 1-SHV-063-0538, 1-SHV-063-0539, and 1-CKV-063-0526 in the drywell. The first page of this deferral lists valve 1-CKV-063-0525 instead of 1-CKV-063-0526. PER 110984 was issued by the licensee to address this deficiency.

During the system walkdown the inspectors identified the following deficiencies:

- In the main control room, the inspectors noted that the red indicator light for manual isolation valve 1-SHV-063-0012 was not lit. The control room operators checked and replaced the light bulb with no affect. Further licensee investigation revealed the local position indicator had been damaged. The valves installed as part of DCN 51143, including 1-SHV-063-0012 are installed at grating level in the drywell. There is no protection installed to prevent damage to the valves or position indicator on valve 1-SHV-063-0012. PER 110715 was issued by the licensee to address this deficiency.

- Check valve 1-CKV-063-0526 installed in the drywell has a rusty allen head bolt installed in the top of the valve. The valve body is made of stainless steel. This is a new valve installed under DCN 51143. PER 110985 was issued by the licensee to address this deficiency.

- On the 621 foot level of the reactor building, a spring can is installed upstream of valves 1-SHV-063-540 and 1-SHV-063-541. The spring can has zero preload. Within a few feet of the spring can a rigid support is installed. PER 110983 was issued by the licensee to address this deficiency.

During the review of the system testing package the inspectors noted that for the SLC squib valve firing circuit, that drawing 1-729E854-1, Elementary Drawing - Standby Liquid Control, contained an error. This drawing contains the SLC control switch contract matrix for the drawing 1-729E854-2. For switch position 2, the contact matrix does not include contacts 3-3c being closed as required for the circuit to function properly. PER 110872 was issued by the licensee to address this deficiency.

b.3 System 57-3, 250 VDC Distribution SPOC II System Readiness Inspection

The 250 VDC system SPOC II package was approved by the Browns Ferry Unit 1 restart organization on September 9, 2006. The SPOC II package had no exceptions or deferrals and the system was declared operable via step 47 of 1-TI-437 at the same time the SPOC II package was approved.

During the review of system turnover documentation the inspector identified an administrative error in the documentation of operability per procedure 1-TI-437. Step 47 on pg 71 of 85 required the Shift Manager to check system operable either 'Yes or No'. Neither box was checked. A review of the logs from September 9, 2006 confirmed that System 573 was declared Operable for Unit 1. PER 111655 was issued to address this deficiency.

During the independent system walkdown the inspectors noted that each battery room has an eye wash station and sink. The inspectors questioned flooding and seismic qualification of the battery room eye wash stations and sinks. The licensee provided an adequate bounding flooding and drainage evaluation for discharge of fixed water sprinklers and hose streams.

The Inspectors reviewed system drawings to verify field accuracy and noted the following deficiencies:

Drawing 0-45E701-1:

- The circuit schedule lists "space" when in the field, it is labeled as "Future" for Breakers: 604, 605, 606, 615, 616, 721, 722, 723, 724, 725, 726, 728.
- Breaker 402 (spare) is missing the name plate.
- Breaker 711 (spare) is installed as a 30 amp breaker vice the 20 amp detailed in the drawing.
- The drawing title, "Battery Board", does not specify Unit 1 as do the Unit 2 and 3 drawings.

Drawing 0-45E702-1:

- Breaker 111 does not have 'none' listed in the Trip column of the circuit schedule as do the Unit 1 and 3 drawings.
- Breaker 716 panel 7 is not a spare, it is the ALT supply to 1-PCV-1-5, 1-30 & 1-34, and is a 20 amp vice 90 amp listed in the circuit schedule. PIC 67092 (AA-01) will resolve this issue by revising DCA's -116, 34 & 136 to show breaker 716 used instead of breaker 719.

Drawing 0-45E703-1:

- In the field, breakers 601 & 607 do not have the amperage indicated on the breaker front.

- Breaker 704 label reads "4160 V Recirc pwp trip bd 2-II Emergency FDR" and the drawing reads "4160 V Recircn pwp trip bd 2-II ALT FDR".

Unit 2 and 3 Battery Board breaker doors had signs (Plant Information Placard (PIP) 97-192) requiring thumbscrews to be tightened to prevent opening of cabinet doors. Unit 1 does not have similar signs, implying that PIP 97-192 did not apply to Unit 1.

PER 112197 was issued by the licensee to address these deficiencies.

During the review of the testing package the inspector noted that System SPOC II was signed as complete on September 9, 2006 with no exceptions or deferrals. However, operability coded item #97 (code 50) was still open on the ITEL Open Item Punch list dated September 12, 2006. Item 97 was not administratively closed until 9/12/06. Inspectors determined item 97 was discussed as a non-issue (related to other units) as part of the SPOC II signature. Item 97 closure was only administratively delayed.

c. Conclusions

Inspectors determined that activities associated with the SRTS turnover process were being adequately implemented. SPOC walkdowns were performed in accordance with procedural guidance. SPOC plant review and acceptance boards were effective. However, inspectors will continue to review system turnover activities and observe future boards for long term effectiveness. Additionally, observation of future SRTS activities will be required to determine adequacy of corrective actions associated with previously identified weaknesses in the licensee's SRTS process. An unresolved item was identified associated with the licensee's control of duct tape pending the inspectors review of licensee resolution of this deficiency.

System walkdowns, package reviews and interviews with the system engineer indicated the Unit 1 SLC system was adequately turned over as a functional system with pre-approved documented exceptions to operability.

System walkdowns, package reviews and interviews with the system engineer indicated that the 250V DC Distribution system was adequately turned over as an operable system. No exceptions or deferrals were found to be missed. No issues were found that would dispute the licensee's operability decision.

E1.4 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 five 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 23, Residual Heat Removal Service Water Cooling Water (RHRSW); System 57-2, 120 VAC Electrical System; System 63, Standby Liquid Control (SLC); System 57-4, 480V Electrical System; System 75, Core Spray (CS) System; and the Common Accident Signal (CAS) Logic.

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:

Residual Heat Removal Service Water (RHRSW)

Testing associated with the RHRSW System, was previously reviewed and documented in Inspection Report 50-259/2005-09. That report discussed testing performed to satisfy the requirements of the RHRSW system for Unit 1. During that reporting period all required testing of the system could not be completed due to repairs needed on the 1C RHR Heat Exchanger. Testing reviewed and observed during the current reporting period after repairs were completed included the following:

- 1-SI-3.3.13, ASME XI System Pressure Test of the RHRSW System (ASME Section III Class 3), Rev 00, verified the pressure boundary integrity of the RHRSW system, including the sample lines.

- 1-SI-4.5.C.1(3), RHRSW Pump and Header Operability and Flow Test, Rev 30, verified that the 1C RHR heat exchanger RHRSW discharge valves could not be opened unless either of the associated RHRSW pumps were running; verified that with applicable transfer switches in normal 1C RHR heat exchanger RHRSW discharge valve could be operated from the control room; verified that with applicable transfer switches in normal the RHRSW pump and swing pump could be operated from the control room; and the RHRSW pumps provided adequate flow to the 1C RHR heat exchanger.

The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements including code requirements as specified by ASME Section XI.

Common Accident Signal Logic

Additional testing requirements had been identified that involved DCN 51016, Unit 1 Common Accident Signal Logic Modifications, Stages 15 and 16, and for the C1 and C2 RHRSW Pumps. These DCN stages had not been Returned to Operations (RTO) following the previous testing activities documented in Inspection Report 50-259/2005-09. Performance of two additional PMTIs were required to satisfy the requirements of a new system Mode 23-11. This new system Mode required an additional load shed test. Inspection Report 50-259/2005-09 also documented a special test that involved the D1 and D2 RHRSW Pumps, which was performed using Technical Instruction (TI) 0-TI-517. Due to an Unverified Assumption (UVA), associated with flow profile of Unit 2 RHRSW valves, which could not be validated, the initial test was no longer acceptable. The UVA involved the flow thru the RHR heat exchangers. A new procedure, 0-TI-531, was issued to perform the special test. Testing reviewed and observed included the following:

- PMTI-51016-STG15, verified that the 4KV Load Shed Logic circuit tripped the A2 RHRSW pump upon a Channel A or Channel B Common Accident Signal initiation

- PMTI-51016-STG16, verified that the 4KV Load Shed Logic circuit tripped the C2 RHRSW pump upon a Channel A or Channel B Common Accident Signal initiation

- 0-TI-531, Simultaneous Operation of RHRSW Pumps C1 and C2, verified that RHRSW pumps C1 and C2 operated simultaneously, thru the C common header, while providing greater then 4500 gpm to the Unit 1 RHR heat exchanger 1C and greater then 4500 gpm to the Unit 2 RHR heat exchanger 2C. This requirement was to verify that during three unit operation, following a single unit accident, cooling water could be still supplied to the non-accident units by the worst case analyzed. This would allow the non-accident units to be taken to cold shutdown.

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

120V AC Power Supply and Distribution System

System acceptance testing associated with 120V AC Power Supply and Distribution reviewed and observed included:

- PMTI-51085-STG03, Functional Test of the Unit 1 Preferred Inverter/Isolimiter 1-INV-252-0001 and 1-XFA-252-001, the purpose of this test was to demonstrate the proper operation of the inverter under various load conditions by the following: Maintaining the required voltage and frequency during load bank testing; maintaining the required voltage and frequency when transferred from the normal 480V AC supply, RMOV Board 1A, to the 250V DC Battery Board 5 normal backup supply, and back to the normal supply; and maintaining the required voltage and frequency when transferred from the normal 480V AC supply to the 250V DC Battery Board 4 emergency backup supply, and back to the normal supply. Section 6.1 of the test also verified the automatic transfer of the load from the normal inverter output to the alternate Unit Preferred Regulating Transformer, XFMR TUP-1, output and back to the inverter by the static switch.

- WOs 02-013350-00 and 02-013688-00, I&C Bus Undervoltage Sensing System Bus A and Bus B, respectively, the purpose of these work orders was to verify that the Bus A and Bus B automatically transferred from their respective 480V AC shutdown board normal supply to their 480V AC alternate supply within 4 to 6 seconds, using plant procedure EPI-0-253-SWZ001.

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

<u>480 VAC Distribution</u>

System acceptance testing associated with 480 VAC Distribution reviewed and observed included:

- 0-SR-3.8.1.8(I) and 0-SR-3.8.1.8(II), 480 VAC Load Shed Logic System Functional Test (Division I) and (Division II), the purpose of these tests were to demonstrate that upon a Unit 1 accident signal, the 480 VAC distribution system would shed the required loads and sequence the required selected loads back on through the 480 VAC logic system network. This would ensure that the diesel generators would not be overloaded.

- 1-ETU-SMI-1-48SDA and 1-ETU-SMI-1-48SDB, Procedure for Relay Functional Checks on 480V Shutdown Board 1A and 1B, the purpose of these tests were to verify that upon the initiation of a undervoltage actuation, the 480 VAC distribution system would shed the required loads through the 480 VAC logic system network, and that after an extended period of time the required loads tripped. The tests also verified that the load breakers on the shutdown boards had backup controls which could be transferred from the Main Control Room (MRC) incase the MRC had to be abandoned.

The load shedding logic system functional testing determined the 480 VAC load shed logic worked in conformance with Technical Specification requirements for load block timing and emergency bus shedding. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

Standby Liquid Control (SLC)

System acceptance testing associated with SLC, reviewed and observed included:

- 1-SR-3.1.7.7, Standby Liquid Control System Functional Test, among the purposes of this test were to verify the following: Each SLC pump develops a flow rate of greater than or equal to 39 gpm at a discharge pressure of greater than or equal to 1235 psig; each SLC pump's capability to pump boron solution on recirculation to the SLC storage tank ensuring that all pipes between the tank and pump suction are unblocked; one pump's capability to inject demineralized water into the RPV; one SLC system train initiation signal provided PCIS Logic input to the RWCU System; the ASME Section XI requirements for cycling selected valves; the proper firing of the explosive Squib Valves, 1-63-08A and 1-63-08B; and the implementation of the ASME Section XI program for the SLC system.

- 1-SR-3.1.7.7, Standby Liquid Control System Enriched Sodium Pentaborate (SPB) Solution Concentration, Quantity Calculation, and ATWS Equivalency Calculation, among the purposes of this test were to verify the following: The SPB concentration by weight is within a specified value to ensure the unwanted precipitation of SPB does not occur; the minimum quantity of Boron - 10 in the SLC solution tank is greater then or equal to 203 pounds; and the minimum quantity of SLC solution is available for injection into the RPV.

- Mechanical Corrective Instruction, MCI-0-000-RLV001, Generic Instruction For Relief Valves, the purpose of this instruction was to overhaul, repair, and initially bench test SLC system relief valves 1-RFV-63-512 and 1-RFV-63-513.

- 1-SI-3.2.9, Testing of ASME Section XI Relief Valves, the purpose of this test was to verify that SLC system relief valves 1-RFV-63-512 and 1-RFV-63-513 were tested in accordance with the ASME Section II program for relief valves.

System testing determined the operability of the SLC 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.

Core Spray (CS)

System acceptance testing associated with System 75, CS, reviewed and observed included:

- 1-SR-3.6.1.3.5(CS I) and 1-SR-3.6.1.3.5(CS II), Core Spray System MOV Operability Test Loop I and Loop II, the purpose of these tests were to verify that specific System 75 valves opened and closed within a specified time frame. These tests also established a baseline for future valve testing. The tests were successful.

- 1-SR-3.5.1.6 (CS I-COMP) and 1-SR-3.5.1.6 (CS II-COMP), Core Spray Loop I and Loop II Comprehensive Pump Tests, the purpose of these tests were to verify the following: The four System 75 pumps performed to the requirements specified in the applicable technical specification surveillances; operation of the minimum flow valves; pumps and associated valves performed to requirements of the ASME Code Program; and operation of the associated equipment area coolers. The tests were successful.

- 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests, the purpose of these tests were to verify the proper operation of the CS logic system. Among the items verified were the start of the CS pumps and positioning of the applicable valves for reactor pressure vessel (RPV) injection a high drywell pressure in conjunction with a low RPV pressure and low-low-low RPV water level signals were present. The tests also verified the following: 480 VAC Distribution load shed signal and a DG start signal if a high drywell pressure in conjunction with either a low RPV pressure or a low-low-low RPV water level condition were present; low-low-low RPV water level signal to the RHR system, a start signal to the RHRSW system pumps upon a start of a CS Loop I or Loop II pump, and a RHRSW pump initiation from a simulated signal. The tests were successful.

- PMTI-51016-STG 01A, Division I Core Spray Response to Unit 2 Accident Signal, and PMTI-51016-STG 02A, Division II Core Spray Response to Unit 2 Accident Signal, these tests were part of the ESF common accident signal system. The purpose of these tests were to verify that System 75 Division I pumps 1A and 1C, and Division II pumps 1B and 1D, responded as designed to an accident logic signal from Unit 2. The tests were successful.

- The inspectors reviewed and/or partially observed additional tests such as the following: 1-SR-3.3.3.2.1(75 I) and (75 II), Backup Control Panel Testing Loop I and Loop II; 0-TI-492, ASME Pump Curve Data Acquisition; 1-SI-3.1.8, CS Loop I and CS Loop II Baseline Data Evaluation; and Operate CS Division I and Division I in accordance with operating procedure 1-OI-75, Core Spray System.

CS System Logic Functional Tests determined the operability of the system in conformance with Technical Specification requirements for initiation logic associated with pump operation, reactor vessel low level and pressure, and high drywell pressure. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

Throughout the performance of the above test activities deficiencies were identified and documented as Test Exceptions (TE). Examples of TEs included an indicating light not coming on or going off when required, an alarm not functioning as required, and a relay not energizing or de-energizing when required. All TEs were documented and addressed in accordance with the licensee’s RTP process. Additionally, the inspectors had noted that pre-test briefs were initially not being performed by the test directors in accordance with pre-job brief checklist requirements. Discussions with Unit 1 management improved the briefing process which were effective at identifying problems before components were placed in service

b.2 Test Summary Reports (TSRs)

The TSR's were developed, written, approved, and issued to document the results of testing 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. They were used to establish for each system Mode specific test requirements to verify all safe shutdown functions. During this reporting period the inspectors reviewed TSRs issued for testing performed on the following systems: System 23, Residual Heat Removal Service Water (RHRSW); System 57-2, 120V Distribution; System 57-3, 250V DC Distribution; System 57-4, 480V Distribution; System 57-6, Plant Offsite Power and Miscellaneous Distribution System; System 63, Standby Liquid Control (SLC); and System 75, Core Spray (CS) System. Specific TSRs reviewed included the following:

RHRSW, TSR 1-BFN-BTRD-023

A partial TSR had been previously reviewed and documented in Inspection Report (IR) 50-259/2005-09, which listed the tests performed to satisfy the requirements of system Mode 23-01 and system Mode 23-08. The partial TSR had been issued at that time due to the condition of the 1C heat exchanger. Testing of Unit 1 RHRSW system Loop C had not been performed due to tube leakage on the 1C RHR heat exchanger. Test Exception (TE) PL-05-1600 was initiated and documented the leakage. The TE also including applicable test procedures and work documents that were required to be performed. The applicable test procedures were placed on the Unit 1 recovery schedule for performance after repairs were completed on the 1C. Tubing repairs were completed successfully and testing of the heat exchanger resumed. The tests performed involving the 1C RHR heat exchanger were similar to those documented in the previous IR.

The RHRSW System consisted of eight BTRD Modes as follows:

- Mode 23-01, Provide cooling water to the RHR , System 74, heat exchangers of at least 4500 gpm from the respective RHRSW pump and the dedicated swing pump. Flow tests, system alignment, and valve tests were performed as required.

- Mode 23-03, Provide cooling water to the EECW , System 67, upon the start of the RHRSW pumps given the EECW valve position interlock signals. This is a shared system between all three units and Test 2-BFN-RTP-023, Test Results Package - Residual Heat Removal Service Water System, was performed during Unit 2 recovery and was applicable to Unit 1. No further testing of System 23 was required for Unit 1 recovery to verify this Mode.

- Mode 23-04, Provide secondary containment boundary. The boundary was tested during Unit 2 and Unit 3 recovery and has been maintained operable to support Unit 2 and Unit 3 operations. No further testing of System 23 was required for Unit 1 recovery to verify this Mode.

- Mode 23-06, Provide Wheeler Lake level alarm at elevation 564 feet and rising. This is a shared function between all three units and was tested during Unit 2 recovery. No further testing of System 23 was required for Unit 1 recovery to verify this Mode.

- Mode 23-08, Provide manual RHRSW system operation from outside the Main Control Room (MRC) to supply cooling water to the RHR heat exchangers. Testing for this Mode was performed using PMTI's and surveillance tests.

- Mode 23-09, Provide sump pump operation capability for the RHRSW pump compartments located at the intake structure. This is a shared function between all three units. This Mode was tested during Unit 2 recovery and was applicable to Unit 1. No further testing of System 23 was required for Unit 1 recovery to verify this Mode.

- Mode 23-10, Provide for the operation of the RHRSW pumps from outside the MCR to supply water to the EECW system given the EECW valve position interlock signals. This is a shared system between all three units and Test 2-BFN-RTP-023, Test Results Package - Residual Heat Removal Service Water System, was performed during Unit 2 recovery and was applicable to Unit 1. No further testing of System 23 was required for Unit 1 recovery to verify this Mode.

- Mode 23-11, Provide for the tripping of RHRSW pump A2 and pump C2 to prevent overloading 4KV Distribution, System 57-5. PMTI-51016-STG15 and PMTI-51016-STG16 were performed to verify this function.

The inspectors reviewed the TSR and verified that the above RHRSW system modes were satisfactorily tested during the ongoing testing activities.

<u>120 VAC Distribution, TSR 1-BFN-BTRD-572</u>

System 57-2, 120V AC Distribution system consisted of four BTRD Modes as follows:

- Mode 572-01, Provide 120/208V Instrumentation and Control (I&C) bus power distribution. The I&C buses A and B for Units 1, 2, and 3 are equipped with a normal and alternate feeds from their respective unit 480V AC shutdown board systems through regulating transformers. WO's were issued and tests were performed to verify this mode.

- Mode 572-02, Provide Unit Preferred Power distribution. PMTI-51085-STG03, Functional Test of the Unit 1 Preferred Inverter and Isolimiter 1-INV-252-0001 and 1-XFA-252-001, respectively, was performed to verify this mode.

- Mode 572-03, Provide 120V AC power to the Reactor Protective System (RPS), System 99, and the ability to de-energize the RPS from outside the MRC. The tests required to verify this mode were transferred to 1-BFN-BTRD-099, RPS

- Mode 572-04, Provide control of the 120V AC power for the RPS system due to overvoltage, undervoltage, and underfrequency. The Unit 1 RPS power system is required to support Unit 2 operations. The power system is equipped with two physically independent Class 1E circuit protectors placed in series with each source. The circuit protectors are periodically tested by the performance of surveillance instructions, and the performance verified this mode.

DCN 51085 replaced the Unit Preferred DC Motor-AC Motor-AC Generator (MMG) set for Unit 1 with a rectifier/inverter Uninterruptible Power Supply (UPS). The new UPS system includes a regulating transformer (TUP-1), a 35KVA rectifier-inverter, and an automatic static transfer switch. The normal feed for the UPS is from the 480 VAC RMOV Board 1A. Two alternative 250 VDC sources from Main Battery Boards 4 and 5 are provided via a manual transfer switch to the inverter. The new DC source of power is normally floating and will automatically supply power to the inverter upon loss of the normal 480V AC power or loss of the rectifier. Additionally, power to the Unit Preferred Bus is transferred automatically to the TUP-1 transformer via the automatic static transfer switch upon loss of the rectifier-inverter UPS system. The inspectors reviewed the TSR and verified that the above 120 VAC system modes were satisfactorily tested during the ongoing testing activities.

<u>250 VDC, TSR 1-BFN-BTRD-573</u>

System 57-3, 250 VDC Distribution system consisted of five BTRD Modes as follows:

- Mode 573-01, Provide control and logic power to the 4KV and 480V plant switchgear

- Mode 573-02, Provide the 500KV switchyard and the 161KV switchyard with relay and tripping power

- Mode 573-03, Provide motive power and logic power to various equipment such as DC powered MOV's and the HPCI system

- Mode 573-04, Provide a distribution point for various electrical systems such as emergency lighting

- Mode 573-05, Provide logic power to the 480V load shed logic network

System 57-3 testing requirements to support safe shutdown were previously satisfied by the Unit 2 and Unit 3 RTP's. The system had remained in service and operable to support operation of Units 2 and 3. In order to support three unit operations, DCN 66071A was issued, which revised the discharge profiles for the Unit 1 Main Bank

Battery, the Unit 2 Main Bank Battery, and the Unit 3 Main Bank Battery. The DCN also revised the discharge profiles for the A Shutdown Board Battery, the B Shutdown Board Battery, the C Shutdown Board Battery, and the D Shutdown Board Battery. The inspectors determined that the changes resulting from the revised profile for these shutdown board batteries were minor. The latest test data for the performance of the batteries indicated adequate capacity to meet the revised discharge profile. The remaining 3EB Shutdown Board Battery did not require a discharge profile change. The following tests were performed to the new discharge profiles:

- 1-SR-3.8.4.3(MB-1), Main Bank 1 Battery Service Test
- 2-SR-3.8.4.3(MB-2), Main Bank 2 Battery Service Test
- 3-SR-3.8.4.3(MB-3), Main Bank 3 Battery Service Test

The inspectors reviewed the TSR and verified that the above 250 VDC system modes were satisfactorily tested during the ongoing testing activities. The five Modes required to support safe shutdown had been tested during the previous Unit 2 RTP using procedure 2-BFN-RTP-57-3, Browns Ferry Nuclear Plant, Unit 2 Restart Test Program Test Instructions, 250V DC Distribution System, Rev 0. This previous testing satisfied the Unit 1 RTP requirements to support safe shutdown, with the exception of the above mentioned new discharge profiles.

<u>480 VAC, TSR 1-BFN-BTRD-574</u>

System 57-4, 480 VAC Distribution system consisted of five BTRD Modes as follows:

- Mode 574-01, Provide 480 VAC switchgear distribution to various boards that the 1A and 1B 480 VAC Shutdown Boards feed. The shutdown boards are currently normally energized to support Unit 2 operations. This demonstrated their ability to provide power distribution. No further testing of System 57-4 was required for Unit 1 recovery to verify this Mode.

- Mode 574-02, Provide 480 VAC Motor Control Center (MCC) distribution power to the Reactor Motor Operated Valve (RMOV) boards 1A, 1B, 1C, and 1D; to the Diesel Auxiliary Boards 1A and 1B; and to the Control Bay Ventilation Board A. These boards are currently normally energized to support Unit 2 operations. This demonstrated their ability to provide MCC power distribution. No further testing of System 57-4 was required for Unit 1 recovery to verify this Mode.

- Mode 574-03, Provide logic and perform 480 VAC load shed based on an accident signal from System 75, Core Spray, and the Diesel Generator available signal from the System 57-5, 4 KV. 480 VAC load shed logic system functional tests for Division I and Division II were performed, as required, to verify this Mode.

- Mode 574-04, Provide 480 VAC switchgear distribution backup control. Testing was performed on the 480 VAC system backup controls during the Unit 2 recovery and the testing was accepted for Unit 1 operations. No further testing of System 57-4 was required for Unit 1 recovery to verify this Mode.

- Mode 574-05, Provide 480 VAC switchgear load shed logic on a degraded voltage condition. 480V system relay functional tests were performed, as required, to verify this Mode.

The inspectors reviewed the TSR and verified that the above 480 VAC system modes were satisfactorily tested during the ongoing testing activities.

<u>500 KV, 161KV, and Misc Electrical Distribution, TSR 1-BFN-BTRD-576</u>

System 57-6, Plant Offsite Power and Miscellaneous Distribution System consisted of three BTRD Modes as follows:

- Mode 576-01, Provide offsite power to the 4 KV Distribution system. The 500 KV and 161 KV systems are the primary and secondary offsite source of power, respectively for the 4 KV distribution system. The 500 KV system normally provides power to the applicable unit station service transformers (USST) A and B. The applicable A USST's provide power to the shutdown busses 1 and 2, through the 4KV unit boards. The 161 KV system normally provides power to the cooling tower transformers (CTT) 1 and 2 and the common station service transformers (CSST) A and B. The CSST's provide power to the start busses 1A, 1B, 2A, and 2B through the 4 KV start boards 1 and 2. For a Unit 1 shutdown the Unit 1 main generator output breaker is the only breaker required to open. When the output breaker opens the 1A and 1B USST's are then energized through a backfeed from the Unit 1 main transformer. The output breaker was refurbished. No testing for the 500 KV was required. The only breakers required to close to provide offsite power from the 161 KV system are the individual 4 KV unit board breakers. These breakers are not part of the 161 KV system. No testing for the 161 KV was required. In all cases the DG's would be available in case of a loss of all offsite power. No further testing of System 57-6 was required for Unit 1 recovery to verify this Mode.

- Mode 576-02, Provide 24 VDC power to the Neutron Monitoring system. The 24 VDC system provides power primarily to the System 92, Neutron Monitoring, for all modes of operation. Testing of the system was not required. The system is not safety-related, a complete loss of the system does not have unacceptable results, and a loss would not prevent safe shutdown of the plant. No further testing of System 57-6 was required for Unit 1 recovery to verify this Mode.

- Mode 576-03, Provide 48 VDC power to the Annunciator system The 48 VDC system provides power to the plant communications and annunciator system, for all modes of operation. The 48 VDC system is not safety-related and supplies power to non-safety related loads. Testing of the system was not required. One battery and the associated charger are for the communication system. The other two batteries and the associated chargers are for the annunciator system. The fourth charger is a spare and may be switched to any one of the 48 VDC buses. The digital annunciators, System 55, for Unit 1 has two independent channels 1A and 1B. A Loss power to one of channels will be annunciated and will not affect the operation of the other channel. No further testing of System 57-6 was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and concurred with the licensee's conclusion that no further testing had been required.

<u>SLC System, TSR 1-BFN-BTRD-63</u>

System 63, SLC System consisted of 4 BTRD Modes. The four Modes were tested as follows:

- Mode 01, Provide for the manual inject of the Boron solution into the RPV upon an indication of an incomplete insertion of control rod from the CRD System and the reactor not being in a subcritical condition from the Neutron Monitoring (NMS), System 92. The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.1.7.3, Standby Liquid Control System Enriched Sodium Pentaborate (SPB) Solution Concentration, Quantity Calculation, and ATWS Equivalency Calculation; 1-SR-3.1.7.7. Standby Liquid Control Functional Test; and 1-SI-3.2.9, Testing of ASME Section XI Relief Valves.

- Mode 02, Provide a SLC initiation signal to the Reactor Water Clean Up (RWCU), System 69, for the isolation of the RWCU from the RPV during a SWLC injection to prevent a loss of Boron solution. Test procedure 1-SR-3.1.7.7, Standby Liquid Control Functional Test, was performed to verify this Mode.

- Mode 03, Provide a reactor coolant pressure boundary. Testing for this Mode was satisfied by 1-BFN-BTRD-68, Reactor Recirculation, System 68.

- Mode 04, Provide a primary containment boundary. Testing for this Mode was satisfied by 1-BFN-BTRD-64A, Primary Containment, System 64A.

The inspectors reviewed the TSR and verified that the above SLC system modes were satisfactorily tested during the ongoing testing activities.

<u>CS System, TSR 1-BFN-BTRD-75</u>

System 75, CS System consisted of 15 BTRD Modes. Four of the Modes were not tested as follows:

- Mode 04, Provide reactor coolant pressure boundary. The testing required for this Mode was satisfied by 1-BFN-BTRD-068, Reactor Recirculation, System 68.

- Mode 05, Provide primary containment boundary. The testing required for this Mode was satisfied by 1-BFN-BTRD-064A, Primary Containment, System 64A.

- Mode 09, Provide CS System piping flow path from suppression pool to Reactor Core Isolation Cooling (RCIC), System 71, pump suction piping for operation of RCIC System. The testing required for this Mode did not use the RCIC pump. The CS System, Division I comprehensive pump testing verified this Mode.

- Mode 13, Provide secondary containment boundary. Testing for this Mode was not required. The secondary containment boundary has been operable to support the operation of Units 2 and 3 and has remained operable .

The CS System initiates logic relay signals to other logic network systems, such as the logic networks in the RHR, HPCI, and Primary Containment Isolation System (PCIS) systems. These initiation signals into the CS network come from various applicable parameters such as reactor low pressure, high drywell pressure, and reactor low water level. Several overlap tests were not performed due to the conditions existing in the other logic network systems. The initiating relays within the CS logic network were tested and required overlap testing was placed on individual Punchlist (PL) as open testing items. Outstanding PL items included PL-06-3379, RHR System Low Pressure Coolant Injection (LPCI) mode of actuation overlap test was assigned to an applicable RHR logic network system test; PL-06-3380, HPCI system actuation on high drywell pressure overlap test was assigned to an applicable HPCI logic network system test; and PL-06-3383, the LPCI mode of RHR actuation on low reactor water level was assigned to an applicable RHR logic network system test. Eleven of the 15 modes were tested as follows:

- Mode 01, Supply CS cooling water to the reactor on automatic initiation. The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.6.1.3.5(CS I) and 1-SR-3.6.1.3.5(CS II), Core Spray System MOV Operability Test Loop I and Loop II; 1-SR-3.5.1.6 (CS I-COMP) and 1-SR-3.5.1.6 (CS II-COMP), Core Spray Loop I and Loop II Comprehensive Pump Tests; and 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests.

- Mode 03, Provide CS cooling water from controls located outside the Main Control Room (MCR), with the controls in the MCR disconnected, through manual operation. Procedures 1-SR-3.3.3.2.1(75 I) and 1-SR-3.3.3.2.1(75 II), Backup Control Panel Testing Loop I and Loop II were among the test procedures performed to verify this Mode.

- Mode 07, Provide a start signal to the Diesel Generators (DG), System 82, on high drywell pressure or low reactor water level, and provide an accident signal to the 4KV AC Distribution, System 57-5, logic on either a reactor low level or drywell high pressure coincident with reactor low pressure. Procedures 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests were among the test procedures performed to verify this Mode.

- Mode 08, Provide high drywell pressure signal for HPCI, System 73, automatic operation, Procedure 1-SR-3.3.5.1.6 (FT), Functional Test of Automatic Initiation Logic, was among the test procedures performed to verify this Mode.

- Mode 10, Provide signals that the CS pumps are running to the Main Steam, System 01, Automatic Depressurization System (ADS). The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.3.5.1.3 (ADS A/CS), Core Spray System Pump Discharge Pressure ADS Permissive Channel A; 1-SR-3.3.5.1.3 (ADS B/CS), Core Spray System Pump Discharge Pressure ADS Permissive Channel B; 1-SR-3.3.5.1.6 (ADS A) Core Spray ADS Logic Permissive Channel A; and 1-SR-3.3.5.1.6 (ADS B); Core Spray ADS Logic Permissive Channel B.

- Mode 11, Provide logic initiation signals for the LPCI mode of RHR actuation on low reactor water level. Procedures 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests were among the test procedures performed to verify this Mode.

- Mode 12, Provide logic initiation signals for the LPCI mode of RHR actuation on low reactor pressure The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.3.5.1.6 (CS I) Core Spray System Logic Functional Loop I; 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop II; 1-SR-3.3.5.1.6 (A I), Functional Test of Loop I Automatic Initiation Logic; and 1-SR-3.3.5.1.6 (A II),Functional Test of Loop II Automatic Initiation Logic.

- Mode 14, Provide for the closure of the PSC head tank pump suction valves on reactor low level or drywell high pressure. The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.6.1.3.5(CS I), Core Spray System MOV Operability Test Loop I.

- Mode 15, Provide for the common accident Loss of Coolant Accident (LOCA) signal from Unit 1 to inhibit (separately by divisional) the operation of Unit 2 Division I Core Spray System. Procedures 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests were among the test procedures performed to verify this Mode.

- Mode 16, Provide for the common accident LOCA signal from Unit 2 to inhibit divisionally the operation of Unit 1 Division II Core Spray System. The following procedures were among the test procedures performed to verify this Mode: 1-SR-3.3.5.1.6 (CS I) Core Spray System Logic Functional Loop I; 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop II; PMTI-51016-STG07, Common Accident Signal Logic; and PMTI-51016-STG08, Common Accident Signal Logic.

- Mode 17, Provide a load shed signal to the 480 VAC Distribution, System 57-4, logic on either a reactor low level or drywell high pressure coincident with reactor low pressure. Procedures 1-SR-3.3.5.1.6 (CS I) and 1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop I and Loop II Tests were among the test procedures performed to verify this Mode.

The inspectors reviewed the TSR and verified that, except for open items associated with required overlap testing, the above CS system modes were satisfactorily tested during the ongoing testing activities

c. Conclusions

Implementation of restart testing activities was generally acceptable. Pre-test briefs were initially not being performed in accordance with pre-job brief checklist requirements. Discussions with licensee management improved the briefings. Only minor test deficiencies which did not effect 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.

E1.5 Special Program Activities - Cable Installation and Cable Separation (37550, 37551)

a. Inspection Scope

This inspection focused on the corrective actions that were being implemented by TVA to resolve the cable separations concerns for Unit 1 Recovery. This inspection included a review of issues addressed in calculations EDQ 0999-910078 for external separation. The inspection was conducted by reviewing work order records, design basis documents, corrective actions, exceptions, drawings, and conducting walkdown inspections of methods used for achieving divisional separation or functional redundancy for Unit 1.

b. Observations

Internal Separation

The inspectors reviewed criteria for spacial separation, connection details, and other construction requirements to verify that as-built configurations were consistent with standards and requirements for wires and separation for cable routing inside panels. The inspectors reviewed examples of punchlist walkdowns, DCAs (Design Change Authorization), and PICs (Post Issuance Change) used to modify DCNs (Design Change Notice). The DCAs selected for the review were: 51080-124, 51094-715, and 51105-029. The inspectors performed independent review of punchlist packages of closed stages that had been walked down by staff for return to operations. The inspectors verified that field installations met divisional separation or functional redundancy separation.

External Separation

This inspection consisted of review of walkdowns of areas in the control room and the cable vault and tunnel focusing on external cable separations. The inspectors selected completed blocks of DCN 51768. The inspectors reviewed criteria for spacial separation to verify that as-built configurations were consistent with standards and requirements for cables, cable routes, and cable trays. The inspectors verified the use of cable tray covers and performed walk-downs of existing trays and new cable trays. In addition, the inspectors reviewed criteria used to calculate cable tray loading and performed walk downs of cable trays to verify that installed cables were within the limits of cable tray fill located in the control room and in the cable spreading room.

Bend Radius of Medium Voltage Cable

On a previous inspection, the inspectors reviewed exceptions that resulted from TVA-Okonite engineering evaluations to relax the pulling radius and training radius for medium voltage cables. This relaxation was requested because some cables will exist in embedded concrete. On this inspection, the inspectors verified licensee actions for accomplishing medium voltage cable replacement by reviewing targeted cables, calculations, drawings, and physical arrangement. The inspectors reviewed excerpts of walkdown packages and performed walkdowns of motor cables for Core Spray Pumps “A” and “C”, and RHR Pump “A” and “C” installed in the Unit 1 reactor building. Transformer Feeder Cable for the 480V shutdown board 1A Normal Supply and Transformer Incoming Cable for the 480V shutdown board 1A and 1B were also walked down. The inspectors used drawings to verify that physical arrangement of cables were consistent with requirements used for proper bend radius. The inspectors selected the following cables to perform a walkdown of: 1ES5408I, 1ES5404I, 0ES173I, 0ES125I, 1PP9857IA, and 0PP626IB. The inspectors observed that power cables from Unit 2 were routed in the same cable tray as Unit 1 power cables. Although, cables for Unit 1 were routed correctly per the requirements, the inspectors noted that Unit 2 power cables were not routed in the triangular configuration, bound with tie wraps as stated in design requirements. The licensee issued PER 111322 to arrange U2 cables in a grouped configuration in accordance with General Engineering Specification G-38.

Corrective Actions

The inspectors identified no significant examples in which the corrective action program has not been effective at identification and resolution of issues related to cable separation issues. The inspectors reviewed the resolution related to PER 109403 that involved the “Top Hat” region of panels in the Control Room where Division I and II cables share chimneys. The top hat region of panels and associated divisional and non-divisional cables were inspected and reviewed for compliance with the requirements of BFN-50-728. The inspectors verified that the top hat region maintains compliance of raceway criteria as defined for the cable trays. The inspectors also reviewed the resolution related to PERs: 105303 which involved V3 cables mixed with V4 cables at a node and 107318 which involved cable bend radius concerns. In this regard, the corrective action program has been effective. As a result of the inspection, the licensee generated the following PERs: 111322, 111281, and 111167.

c. Conclusions

Based on observations, document reviews, and discussions with engineering personnel, the inspectors determined that implementation of the subprogram for bend radius of medium voltage cable is proceeding in accordance with licensee commitments and regulatory requirements. Actions to address issues for bend radius of medium voltage cable 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 bend radius of medium voltage cable 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 subprogram. Overall, inspectors found minor discrepancies, indicating that the oversight of recovery activities was generally effective. However, inspectors will continue to monitor implementation of corrective actions to address implementation deficiencies associated with cable separations for internal and external issues.

E1.6 Special Program Activities - HVAC Ducting and Duct Supports (37551)

a. Inspection Scope

The inspectors reviewed the Browns Ferry Unit 1 HVAC Ducting and Duct Supports activities as detailed below to ensure these activities were in compliance with regulatory requirements and licensee commitments.

b. Observations and Findings

On October 18, 1988, with all 3 units defueled, a review of open condition adverse to quality reports identified several discrepancies involving the design and seismic qualification of heating, ventilation, and air conditioning (HVAC) ductwork. The HVAC ductwork had discrepancies between design assumptions, duct test results and/or design standards. These conditions could adversely affect all Class 1 HVAC ducts, their supports, and their anchorages in class 1 structures. Class 1 duct systems are required to remain functional during and after a seismic event. As a result, the licensee developed this Special Program to resolve the concerns.

The inspectors held discussions with licensee personnel and reviewed documentation covering the scope and resolution of this matter. The inspectors reviewed the central document, DCN 51520, that details the issues previously identified in the area of seismic HVAC ducts and supports. The basis for the acceptance of the HVAC ducts and supports in question are covered in Design Criteria BFN-50-C-7104, Design of Structural Supports, Rev. 12. The DCN only covers areas, HVAC ducts and supports that were not previously identified and corrected for the Units 2 & 3 restarts. The areas that were found to be deficient, are where the heat is generated by the Core Spray (CS) and Residual Heat Removal (RHR) pump motors and heat is removed by air cooling units through HVAC ductwork. These pumps are located in Unit 1 four corner rooms (northwest, northeast, northwest and southeast quadrants) of the Reactor Building. The licensee performed detailed walkdowns of these ducts and supports to obtain the as-built conditions. (Any defect and/or deficiencies were identified in the walkdown packages.)

To provide an insight of the issues identified and the corrective actions taken, the inspectors performed a walkdown of all the areas that contained HVAC supports that were part of this scoped work. The scoped packaged covered: roughly 290 ft of ducting and 34 supports in the Reactor Building corner rooms and approximately 18 ft of 18" round duct and 2 supports at EL. 621'-3", Drywell Purge and Vent in the Reactor Building. The typical modification consisted of adding splice plates, adding new welds, repairing existing welds, and modifying support members and/or connections, however, two new supports were also installed.

The inspectors also reviewed the stress analysis and evaluations for the areas of concern. The computer program TPIPE was utilized for the stress evaluations and support load generation. Supports were evaluated by the licensee using the GTSTRUDL computer program and hand calculations, documented in the calculations reviewed by the inspectors and listed in the “Documents Reviewed” section of this report.

c. Conclusions

Based on field walkdowns and observations, document reviews, and discussions by the inspectors with engineering personnel, the inspectors determined that TVA has developed an adequate program for Class 1 HVAC Ducting and Duct Supports Program on Unit 1. Licensee actions to address issues for Class 1 HVAC Ducting and Duct Supports Program have been performed by the licensee and are completed. Completed 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 Class 1 HVAC Ducting and Duct Supports Program that would negatively impact restart of Unit 1 were identified as the result of the above review. Based on this inspection, the inspectors concluded that at this time, no further inspections are anticipated for the Class 1 HVAC Ducting and Duct Supports Program and that inspection activities are complete for Unit 1.

No violations or deviations were identified during this review of the licensee's Class 1 HVAC Ducting and Duct Supports Program for Unit 1.

E1.7 Special Program Activities - Small Bore Piping and Instrument Tubing (37550)

a. Inspection Scope

The small bore piping (less than 2.5 inch diameter) program was developed by the licensee to address concerns identified with application of design criteria, incomplete support details, questions regarding seismic qualification, and lack of design calculations. The small bore piping includes instrument tubing, but does not include piping which had been rigorously analyzed, such as the control rod drive (CRD) piping. The licensee's program to resolve the concerns involve identification of the small bore piping and instrument tubing systems; performance of walkdown inspections to identify inadequately supported piping and tubing, missing supports, and missing hardware from existing supports; preparation of as-built drawings; completion of design calculations to qualify the small bore piping and tubing; issuing DCNs to correct discrepancies; and implementation of the DCNs.

The licensee's commitments for resolution of issues associated with the small bore piping and instrument tubing 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. Design criteria for design and seismic qualification were submitted to the NRC in TVA letters dated February 27, 1991, Subject: Action Plan to Disposition Concerns Related to Units 1 and 3 Small Bore Piping; February 27, 1991, Subject: Action Plan to Disposition Concerns Related to Units 1 and 3 Instrument Tubing; and December 12, 1991; February 27, 1991, Subject: Small Bore Piping, Tubing, and Conduit Support Plan for Units 1 and 3 - Additional information. Acceptance of the licensee's program for resolution of the small bore piping and instrument tubing concerns by the NRC is documented in Safety Evaluation Reports dated October 24, 1989, and January 23, 1991. Previous NRC inspections of the small bore pipe support program are documented in Inspection Report numbers 50-259/2005-008, 50-259/2006-006, and 50-259/2006-007.

b. Observations and Findings

The inspectors walked down selected small bore piping and instrument tubing systems, and examined completed modifications. These systems included the main steam, System 1, primary containment isolation, System 64, and portions of CRD piping which were not rigorously analyzed, System 85.

The inspectors walked down portions of the instrumentation tubing and small bore piping listed below to verify that the design changes were implemented in accordance with the design documents. Attributes examined were support location, configuration, including member size and type, weld size, and hardware for attachment of piping/tubing to supports, and support attachment to building structure. The inspectors also examined supports which were identified with missing or incorrect hardware to verify the correct type hardware was installed as specified in the DCN design drawings.

Supports examined were as follows:

- Main steam (System 1) support numbers 1-47B400-268, 1-47B400-269, 1-47B400-270, and 1-47B400-272

- CRD (System 85) support numbers 1-47B466-5502, 1-47B466-5504, 1-47B466-5506, 1-47B466-5507, and 1-47B466-5515

- Containment Isolation (System 64) support numbers 1-47B600-5432-15, -17, & -35; 1-47B600-5502 through 1-47B600-5508; 1-47B600-5515; 1-47B600-5438 through -5442; 1-47B600-5416-36 & -37; 1-47B600-5428-01 through -04; 1-47B600-5426-01 through -04; and 1-47B600-5430-01 through -04

- Small bore supports for instrument line numbers N1-164-80R and N1-164-81R which are attached to large bore support numbers 1-47B920-1289, and for instrument line number N1-164-52R, which is attached to large bore support number 1-47B920-1282.

The inspectors also reviewed work orders and quality control inspection records documenting support installation. Records examined were weld maps, records of completed welding activities, weld visual inspection records, installation records for clamps attaching small bore piping and tubing to supports, and concrete expansion anchor installation records.

c. Conclusions

During the walkdown inspection, the inspectors verified the following attributes complied with the requirements shown on the design drawings: support locations, support member sizes and configuration, weld sizes, type, and length, connection details, and verification of correct type of hardware for attachment of small bore piping/ tubing to supports. The inspectors determined that the licensee's program for correction of deficiencies identified in support of small bore piping and instrument tubing complies with the design criteria, commitments to the NRC, and NRC requirements. 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 small bore piping and instrument supports complied with their commitments to the NRC.

Based on this inspection and previous NRC inspections documented in Inspection Report numbers 50-259/2005-008, 50-259/2006-006, and 50-259/2006-007, no further inspections are anticipated for this Special Program. No findings of significance were identified.

E1.8 Special Program Activities - Instrument Sensing Lines (37550)

a. Inspection Scope

The instrument line program was developed for restart of Browns Ferry Unit 2 to address issues regarding installation of instrument sensing lines. The issues concerned potential violation of three basic design requirements: physical separation of redundant components; provision of sensing line slope; and specification of material quality requirements. TVA submitted the corrective action program for Unit 2 to address these concerns in a letter dated August 14, 1989. The Unit 2 scope and common instrument scope were based on evaluations of system calculations, the FSAR Chapter 14 safety analysis, emergency operating instructions, review of instrument related maintenance problems, and the master component equipment list. TVA concluded after completion of the instrument line evaluations that problems were limited to instrument slope. No cases were identified of inadequate physical separation of redundant components, and no cases were identified of inadequate material quality. The Unit 2 instrument sensing line program was reviewed and approved by the NRC, as documented in Section 3.4 of NUREG-1232, Volume 3, Supplement 2. In letters dated February 13 and November 8, 1991, TVA submitted their action plan to resolve concerns related to instrument sensing lines for Browns Ferry Units 1 and 3. The approach was to use the same methodology used for Unit 2. The NRC accepted the TVA action plan in a Safety Evaluation Report dated December 10, 1991.

Eliminated from this Special Program were vendor supplied instruments, instruments with a process pressure greater the 100 psig, totally sealed capillary tubing, and instruments without sense lines. Previous inspections of the Unit 1 Instrument Sensing Line Program are documented in NRC Inspection Report number 50-259/2006-007.

b. Observations and Findings

The inspectors reviewed walkdown procedures and results of walkdown inspections performed by licensee engineering personnel. The inspectors also examined DCNs which specify corrective actions to address instrument sensing line slope deficiencies, reviewed construction procedures and walked down the core spray cooling system instrument sensing lines to examine completed modifications. The inspectors also examined calculation number CDQ1-075-2003-2294 which evaluated portions of the existing core spray cooling instrument lines and determined support loads.

The inspectors walked down portions of the core spray cooling system instrumentation tubing in the Unit 1 reactor building between the root valves installed in the core spray cooling system pump discharge piping at Elevation 554 to Instrument Panel 25-1 on Elevation 524 to verify that the design changes were implemented in accordance with the design documents. The inspectors independently measured instrument line slope at numerous locations using a level engineer plumber to verify the modified instrument tubing met the slope specified on the DCN drawings.

The inspectors examined new instrument line tubing supports installed to support the core spray cooling system instrument sensing lines discussed above. The following supports were inspected: numbers numbers 1-47B600-5473-01 through -12, and 1-47B600-5475-01 through -10, 1-47B458-930 through -935. During the walkdown inspection, the inspectors examined the following attributes and compared the instrument lines and installed supports with the requirements shown on the design drawings: instrument line slope, support locations, support member sizes and configuration, weld sizes, type, and length, connection details, and verification of correct type of hardware for attachment of instrument tubing to supports. Acceptance criteria utilized by the inspector were critical specific in Modification and Addition Instruction MAI-4.2A, Piping/Tubing Supports, Revision 19 and MAI-4.4a, Instrument Line Installation, Revision 16.

The inspectors also examined instrument panel numbers which were repaired under DCN 51243 in the Unit 1 reactor building. Instrument panels examined were numbers 25-57B, 25-306, & 25-307. These panels support System 64, containment isolation, instruments. Severe corrosion of the original instrument panel number 25-306 was identified in 2003, documented in PER 54186. This panel was replaced under DCN 51243. Instrument panels 25-57B and 25-307 were refurbished. In most cases instruments and some valves were reused. The original copper tubing was replaced with stainless steel tubing, except for two short pieces (4 inches long) on panel 25-307 which were re-used. The licensee's process requires re-calibration of the instruments prior to restart. In addition, the inspectors walked down the turbine building on Elevations 586 and 617 and examined panel numbers 25-100A, 25-100B, 25-100C, 25-110, 25-111, 25-113, 25-120, and 25-131 which support various steam line instruments. The panels either had been refurbished under DCN 51236, or work was in progress under DCN 51236. Work on panel number 25-120, which is a complete change out of the panel, was in progress.

The inspectors also reviewed Post Issue Changes (PIC) which document changes from construction details shown on the design drawings. Final review of the PICs are being conducted by engineering. The drawings are scheduled to be revised to incorporate the approved PICs. In the case when a PIC is not approved, a work order is required to be issued to perform additional field work to make any changes necessary so the affected supports meet design criteria. PICs reviewed by the inspectors were as follows: 67849, deviations from instrument line slope, 63624, minor revisions to installation details for various instrument panels.

c. Conclusions

The inspectors determined that the licensee's program for correction of instrument tubing slope issues complies with the design criteria, commitments to the NRC, and NRC requirements. Instrumentation line supports were installed in accordance with the design drawing requirements. However, additional samples of instrument tubing installed in Unit 1 will need to be inspected prior to closure of this Special Program. No findings of significance were identified.

E1.9 Special Program Activities - Long Term Torus Integrity Program & Large Bore Piping and Supports (IP 50090)

a. Inspection Scope

The inspectors reviewed Design Criteria BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems - Piping and Instrument Tubing, Rev. 5, BFN-50-C-7100, Design of Civil Structures, Attachment A - General Design Criteria for the Torus Integrity Long Term Program, Rev. 16, and BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7. The inspectors selected and performed independent walkdown inspections for 10 pipe supports in Primary Containment, Residual Heat Removal (RHR), Reactor Core Isolation Cooling (RCIC), and Core Spray (CS) systems for the Long Term Torus Integrity Program and 10 pipe supports in Reactor Feedwater and Reactor Building Closed Cooling Water (RBCCW) systems for the Large Bore Piping and Support Program to verify the field installed conditions as compared to as-built drawings. The inspectors reviewed one DCN and one WO Package in order to verify the adequacy of the design or modification, inspection, and implementation associated with the pipe supports. The independent support walkdown and document review of the DCN and WO were to verify adequacy and compliance with the design criteria, drawings, IE Bulletin 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors, and IE Bulletin 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems. Additionally, the inspectors reviewed Problem Evaluation Requests (PERs) to verify adequacy of problem identification, resolution, corrective actions, and extent of condition review.

b. Observations and Findings

The inspectors walked down 20 supports with licensee Quality Control (QC) examiners and engineers. The inspections were performed to evaluate the effectiveness of the licensee's walkdown, modifications, and repairs. The elements inspected included dimensions, sizes, diameters, symbols, identifications, spacing, and clearances for members, anchor bolts, base plates, standard components, and welds. The supports walked down are listed below:

Long Term Torus Integrity

Primary Containment (403), RHR (452), RCIC (456), and Core Spray (458) Systems

Support No.	Drawing Revision Nos.
1-47B403-1	Sheet 1&2, Rev. 002. 003
1-47B403-5	001
1-47B452-91	001
1-47B452-3006	001
1-47B452-3008	001
1-47B456-58	002
1-47B458-434	Sheet 1, Rev. 002 & Sheet 2, Rev. 001
1-47B458-614	002
1-47B458-615	001
1-47B458-624	002

Large Bore Piping and Supports

Feedwater (415) and RBCCW (464) Systems

Support No.	Drawing Revision Nos.
1-47B415-21	002
1-47B415-25	001
1-47B415-47	Sheet 1, Rev. 003 & Sheets 2 & 3, Rev.002
1-47B464-424	002
1-47B464-425	003
1-47B464-433	002
1-47B464-456	004
1-47B464-464	003
1-47B464-466	Sheet 1, Rev. 001 & Sheet 2, Rev. 000
1-47B464-467	001

One problem identified was a pin hole enlarged in a standard component which was not evaluated. PER 109890 was issued by the licensee to correct the drawing and to request an evaluation for the enlarged pin hole. The licensee completed the drawing change and revised the support calculation to add the evaluation for the enlarged pin hole before the end of the inspection.

The inspectors reviewed DCN 51349 and WO 03-010982, System 75 Core Spray for the Long Term Torus Integrity Program. The inspectors reviewed the DCN for the scope, design, modification, or repair drawings, 50.59 screening review, procedures or calculations required to be revised or generated, and test or inspection requirements. The inspectors reviewed the WO for installation, material, welder and weld data records, inspection records, and non destructive examination records such as magnetic particle, liquid penetrant, or visual examination records.

c. Conclusions

Based on independent walkdowns of 20 pipe supports; one completed DCN; one completed WO; as-built support drawings; and problem resolution the inspectors determined that licensee performance was adequate in the in the Long Term Torus Integrity and Large Bore Piping and Support Programs. However, additional samples will need to be inspected prior to closure of these Special Programs.

E1.10 Reactor Vessel Internals Activities - (37551)

a. Inspection Scope

The inspectors reviewed and observed selected portions of ongoing licensee activities associated with modifications in the Unit 1 Reactor Pressure Vessel (RPV). The inspectors also evaluated the adequacy of licensee efforts to maintain cleanliness, limit introduction of foreign material (FME) while working on RPV internals, and for removal of any FME identified during the ongoing activities. Additionally, the inspectors reviewed any issues which were identified during the ongoing work activities to assess whether the issues were processes in accordance with the licensee's corrective action program.

b. Observations and Findings

The inspectors had previously reviewed the licensee' program for completion of Boiling Water Reactor Vessel Internals Program (BWRVIP) to determine status of completion of BWRVIP requirements. That review is documented in Inspection Reports 50-259/2005-09 and 50-259-2006-06. During the previous review the inspectors concluded that the licensee had satisfied all in-vessel BWRVIP inspection requirements. However, it would be necessary for General Electric personnel to return to the site for the purpose of performing several in-vessel repairs based on the results of those inspections. Required work was to include installation of a Core Spray sparger clamp and Jet Pump aux wedges along with dryer repairs. Installation of Core Spray sparger clamps and Jet Pump aux wedges was completed during this reporting period. Dryer repairs are scheduled to be performed during October - November 2006. During the current inspection period the inspectors reviewed and observed selected portions of ongoing modification activities in the RPV. Additionally, the inspectors reviewed selected NDE examination procedures and qualification records for the GE and TVA visual examination personnel. The inspectors reviewed and observed selected portions of the following activities:

DCN 51193

DCN 51193, Stage 3, Reactor Vessel Internals Modifications - System 68, involved the installation of Jet Pump Auxiliary Spring Wedges. This work activity was implemented by WO 02-016506-017. The inspectors noted that a total of nine wedges were installed on vessel side of Jet pumps JP-2, JP-3, JP-4, JP-6, JP-7, JP-8, JP-12, JP-14, and shroud side of JP-10. The inspectors noted that the original scope of DCN 51193 had only included addition of wedges to eight jet pumps. However, PIC 67527 had added JP-10 to scope. A VT-3 visual inspection of all installed spring wedges was performed by Level III NDE examiner.

<u>WO 02-016506-018</u>

WO 02-016506-018 was issued by licensee to install Core Spray Sparger T-Box Clamps. The inspectors noted that VT-3 visual inspection of all installed CS sparger clamps performed by Level III NDE examiner.

<u>WO 05-725146-000</u>

The inspectors reviewed completed WO 05-725146-000, Repair Locking Tab for Core Plate Plug at Location 32-41 North. During the previous GE IVVI examination of lower head region performed in 2005, it was noted that the locking tab for Core Plate Plug at location 32-41 North was not properly engaged. This problem had been documented by the licensee in PER 93956. During the present reporting period GE removed the old plug which was placed in container in the Unit 1 fuel storage pool and replaced with new plug. GE Extended Life Plug Exchange Procedure, BFN-PI-CPP-002 used to obtain proper engagement of plug.

<u>WO 06-719495-000</u>

Minor maintenance WO 06-719495-000 was issued by licensee in support of WOs 02-016506-018 and 02-016506-017 to document measurements taken by GE during CS T-Box repairs and Jet Pump Auxiliary Wedge Installation.

The inspectors evaluated the licensee’s program for maintaining cleanliness in the RPV. The inspectors observed ongoing cleanliness inspections of RPV internals and verified that licensee procedures required that any FME identified during these inspections was to be removed. The inspectors reviewed the licensee’s FME log for the RPV activities and verified that the licensee retrieved any items which were dropped into the vessel during this work period. The inspectors concluded that the licensee program for cleanliness in the RPV was adequate. Additionally, the inspectors reviewed various corrective action documents issued by the licensee during the ongoing work activities. The documented problems were of minor significance and adequately addressed by the licensee. A list of the PERs reviewed is included in the attachment.

c. <u>Conclusions</u>

Ongoing modifications activities associated with installation of a Core Spray sparger clamp and Jet Pump aux wedges in the Unit 1 RPV were adequately implemented. The inspectors determined that the licensee's in-vessel activities had satisfied all applicable code requirements and licensing commitments.

E1.11 Review of Electrical Distribution System Loading Analysis (37551)

a. Inspection Scope

Inspectors reviewed the licensee's load flow calculations on the electrical distribution system. These calculations modeled the loads (ie. megawatts and megavars) throughout the system for combined three unit operation. The calculations included loads that would appear on the system should the applied-for unit power uprates be approved and implemented. Prior to the inspection, the inspectors were aware that these calculations predicted that overloads would occur on portions of the system if remedies were not taken to offset the overloads. Each of these overload cases were reviewed regarding how, when and where the overload occurs and the estimated amount of overload. The resolution of the overload conditions were reviewed along with the associated safety evaluations. The criteria applied to this review was that the electrical distribution system be highly reliable and that the basic requirements of one immediately available offsite source, one delayed offsite source and an onsite source of power would remain available from a design perspective in light of any proposed modifications.

b. Observations and Findings

The load flow calculations determined there were about ten cases where the system would be overloaded if modifications were not implemented to alleviate the overload. In some cases the system was limited by voltage considerations and in some cases the system was limited by the ampacity of a bus or cable. Some calculated overload cases were resolved by revising a procedure. These procedural resolutions took one of two forms: (1) certain alignments would require that certain automatic transfers be blocked by placing a selector switch in the control room in the manual position, or (2) cautions and guidance were inserted into operating procedures to cause the operator to manage the load at certain points in the system by removing non-essential loads when necessary. These operational procedure changes were either in draft form or not yet started at the time of the inspection. However, the inspectors reviewed the calculation and DCN developed by engineering which summarized the required operational procedure changes. Also, the inspectors toured the control boards to confirm the selector switches and ammeters referenced in the design documents were installed.

Some calculated overload cases were resolved by revising the control logic to automatically shed non-essential load when certain conditions existed, such as accident signal. These changes had already been implemented, and the inspectors reviewed the elementary diagrams and the post-modification test records to confirm the logic changes had been correctly implemented.

The inspectors found the loading calculations and associated DCNs dictated by the calculations were detailed, accurate, and all inclusive with regard to system alignments evaluated. Engineers responsible for the calculations were able to readily answer all questions posed by the inspectors during the review.

One PER (112237) was generated as a result of the inspection related to the proposed FSAR wording change contained in DCN 66071B describing which conditions initiated a fast dead bus transfer of the unit boards from the 500 kV source to the 161 kV source. This PER was of minor safety significance because no actual logic change for the transfer was being implemented, but rather the licensee was proposing to describe the already existing transfer in more detail than the current version of the FSAR. The FSAR change had not yet been submitted to the NRC.

Documents reviewed are listed in the Attachment.

c. Conclusions

Electrical distribution system loading calculations were reviewed along with proposed modifications aimed at alleviating overloads predicted by the calculations. The calculations were accurate and considered all relevant system alignments and contingencies. The proposed modifications would be effective in alleviating the overloads and, at the same time, maintain the design basis.

E7 Quality Assurance in Engineering Activities

E7.1 Licensee Oversight of Work Scope reduction (37550, 71152)

a. Inspection Scope

The inspectors evaluated the adequacy of ongoing licensee efforts to identify work scope reduction associated with previously planned design changes, modification WOs and maintenance WOs from the original work scope as communicated to the NRC as part of the Unit 1 restart regulatory framework. Additionally, the inspectors evaluated the adequacy of the licensee's documented basis for any identified deleted work activities. The inspectors reviewed selected corrective action documents and held discussions with TVA and Stone & Webster Engineering Corporation (SWEC) management personnel, Nuclear Assurance (NA) personnel, and craft personnel. The inspectors evaluated of the effectiveness of self-assessments in this area, and corrective actions associated with documented deficiencies.

b. Observations and Findings

The licensee had initiated a series of ongoing monthly NA assessments in January 2006 based on previous concerns which the inspectors had regarding work scope reduction. The inspectors reviewed the completed assessment reports and observation reports associated with these NA oversight activities and discussed the results of those assessments with the assigned NA assessors. A list of assessment reports and observation reports reviewed by the inspectors is included in the attachment. Additionally, the inspectors discussed the work scope reduction process with the Unit 1

Engineering Manager and Unit 1 Maintenance and Modifications Manager. The inspectors determined that some level of work scope reduction had occurred in the form of cancelled DCNs, deletion of selected work activities from DCNs, and cancelled WOs. A large amount of the identified work scope reduction effort was associated with non safety-related modifications. Additionally, the licensee's monthly assessment reports included numerous examples of original work scope for safety-related components which had been deleted from DCNs. However, in each case the licensee had provided a valid justification for removal of that work scope from the original DCNs. Examples of safety related components included cables previously planned for replacement for EQ considerations where adequate documentation was subsequently identified which satisfied the requirements of 10 CFR 50.49, valves which originally were to be replaced which subsequently were determined to only require maintenance, and supports which were no longer needed due to re-routing piping or instrument lines. During the ongoing reviews the licensee NA oversight personnel had selected various recently closed DCNs and all related Post Issuance Changes (PICs). The NA personnel had also determined which WOs had been cancelled during each monthly assessment period and evaluated the basis for cancellation. The inspectors noted that some examples of inadequate documentation of the licensee's basis for scope reduction had occurred. Each example was documented in the licensee's correction action program and an adequate justification was added to the work document. Various PERs which documented these errors were reviewed by the inspectors and listed in the attachment. In all cases the NA assessors had determined that all examples of DCN or WO work scope reduction were appropriate and technically justified. The inspectors also reviewed the licensee's design change process and determined that design engineering was required to evaluate any reduction in DCN work scope. Specifically any examples of DCN work scope reduction would involve issuance of a PIC and require specific approval by the Unit 1 Engineering Manager. Closure of these PICs and revision of DCN to represent actual work scope was required prior to closure of each DCN.

c. Conclusions

The licensee's evaluation of work scope reduction was acceptable. The inspectors determined that any examples of work scope had been adequately evaluated and technically justified. No violations or deviations were identified.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) Licensee Event Report (LER) 88-37, Inadequate Design Control Procedures Discrepancies in HVAC Ductwork.

In October 1988 a review of open non-conformance reports identified several discrepancies involving the design and seismic qualification of HVAC ductwork. This LER was previously reviewed and closed for Unit 2 in NRC inspection report 50-259,260,296/1991-006 and for Unit 3 in 50-259,260,296/1995-052. The inspectors performed a review to identify Class 1 HVAC ductwork for Unit 1 that was not previously reviewed for either the Unit 2 and/or Unit 3 restart. Modifications reviewed were discussed in paragraph E1.6 of this inspection report. Based on this NRC inspection, the inspectors concluded that at this time, no further NRC actions are required associated with this LER for Unit 1. This issue is closed for Unit 1.

E8.2 (Closed) Bulletin (IEB) 93-02 (and Supplement 1), Debris Plugging of ECCS Strainers

This bulletin notified licensees of a previously unrecognized contributor to the potential loss of net positive suction head (NPSH) for emergency core cooling systems (ECCS) during a loss of coolant accident (LOCA). Subsequent to this the NRC issued Bulletin 93-02, Supplement 1, dated February 18, 1994 to inform licensees of additional information related to the vulnerability of ECCS suction strainers at boiling water reactors. Additionally, licensees were required to provide a response describing actions taken associated with the bulletin. This item was previously reviewed by NRC as documented in Inspection Report 50-259/06-06. At that time final closure of this item was deferred until the Office of Nuclear Reactor Regulation (NRR) completed their review in this area and any safety evaluation reports (SERs), if required, were issued. Subsequently, NRR completed their review in this area as documented in SER issued on July 26, 2006. Based on that review the staff concluded that the licensee's supplemental response to Bulletin 93-02 for Unit 1 was in compliance with the staff's position on debris plugging of ECCS suction strainers. The inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.3 (Closed) Bulletin 80-06, Engineered Safety Feature (ESF) Reset Controls

The inspectors reviewed licensee actions to address Bulletin 80-06. The subject bulletin was issued March 13, 1980 and requested licensees to review Engineered Safety Features (ESF) systems and determine if resetting of Engineered Safety Features Actuation Signals (ESFAS) allowed the changing of components from their safety or emergency mode to their normal mode. The licensee had previously determined that the only modifications required as a result of their review was to prevent energizing the TIP withdrawal enable circuit upon reset of a containment isolation signal. In response to this bulletin, the licensee committed to modify the transversing incore probe (TIP) design on all three Browns Ferry units. This commitment was documented in TVA letter dated April 28, 1988. These modifications, which installed a pushbutton switch, seal in relay, and associated wiring, were previously implemented for Unit 2 with ECN P0469 and DCN W17185 for Unit 3. Previous NRC review of these TIP modifications was documented in Inspection Reports 259,260,296/95-22 for Unit 2 and 259,260,296/90-40 for Unit 3. The inspector reviewed DCN 51079 , which included the design details of the TIP modifications for Unit 1. Specifically, this DCN includes the installation of a TIP Isolation Reset Hand Switch and a new relay for isolation seal-in for primary containment Isolation (PCIS) logic to Panel 9-13 that prevents the TIP isolation valve from automatically opening if a PCIS signal were reset. The inspectors determined that this would appropriately address the issue for Unit 1. Therefore, because this item is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.4 (Closed) Temporary Instruction (TI) 2515/111, Electrical Distribution System Followup Inspection

The Electrical Distribution System Functional Inspection (EDSFI), performed according to TI 2515/107, was completed at Browns Ferry on May 22, 1992 (Refer to NRC Inspection Report 50-259, 260, 296/92-15). The report contained eleven findings, one of which was a Severity Level IV violation. In April 1993, the NRC staff performed an inspection to follow-up on these findings pursuant to TI 2515/111, and all but one of the findings were closed (Refer to NRC Inspection Report 50-259, 260, 296/93-14). That item, Finding 5, was closed in NRC Inspection Report 50-259, 260, 296/93-45. During the current inspection period, the inspectors reviewed these findings to ascertain whether any might contain an item indicating the need for specific action prior to startup of Unit 1, and inspectors found there was none. Nevertheless, the inspectors performed some inspection activity related to the EDSFI findings. First, the inspectors reviewed the calibration results from the last two calibrations performed on the degraded grid protection relays at 4 KV shutdown board C. Second, the inspectors followed-up on five PERs related to the direct current (DC) system (75471, 75494, 75497, 75575 and 75599). The resolution of these PERs, which had been initiated in early 2005, was adequate. Documents reviewed are listed in the Attachment. The inspectors determined that no further actions were required for Unit 1. This issue is closed for Unit 1.

E8.5 (Closed) Generic Letter (GL) 98-04, Potential For Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

This GL notified licensees of the potential for degradation of ECCS because of containment coatings deficiencies and foreign material in the containment. Additionally, licensees were requested to provide a response describing plant-specific program or programs implemented to ensure that Service Level 1 protective coatings used inside the containment were in compliance with applicable regulatory requirements. By letter dated November 10, 1998, the licensee had responded to GL 98-04 for Browns Ferry Units 2 and 3. At the time that Unit 1 was shut down in an extended outage. In their GL 98-04 response for Units 2 and 3, TVA committed to address GL 98-04 prior to restart of Unit 1. By letter dated May 11, 2004, TVA submitted to the NRC a response to GL 98-04 for Unit 1. On September 7, 2006, TVA submitted additional information as requested by the NRC staff.

This item was previously reviewed by NRC as documented in Inspection Report 50-259/06-06. At that time final closure of this item was deferred until NRR completes their review in this area and any SERs, if required, were issued. Subsequently, NRR completed their review in this area as documented in SER issued on September 27, 2006. Based on that review the staff concluded that the licensee's coatings program for Unit 1 is consistent with that previously approved for Units 2 and 3. Based on the extensive remediation of coatings in both the torus and the drywell, the 100 percent visual inspection of the containment coatings, and the supplemental physical testing performed, the staff finds that proper maintenance of the containment coatings is being performed prior to the restart of Unit 1. The inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

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 74, Residual Heat Removal (RHR); and System 75, Core Spray, (CS).

b. Observations and Findings

Licensee maintenance activities reviewed or observed by the inspectors during this report period were associated with the return to service of the RHR and CS Systems. These activities included support for system testing. Specific maintenance activities reviewed or observed included the following:

- WOs 02-012506-00, 02-012499-00, 02-012504-00, and 02-012501-00 for the bump for rotation of the 1A, 1B, 1C, and 1D CS Pump Motors, and the four hour temperature stabilization operation of the uncoupled motors from the Main Control Room (MCR) and in the Reactor Building.

- WOs 05-725260-00, 05-000997-00, 05-725261-00, and 05-725260-00 for the bump for rotation of the 1A, 1B, 1C, and 1D RHR Pump Motors, and the four hour temperature stabilization operation of the uncoupled motors from the Shutdown Board A, using the emergency switch, and in the Reactor Building. The emergency switch was used due to on going work on the pump suction valves 1-FCV-74-01, 1-FCV-74-24, 1-FCV-74-12, and 1-FCV-74-35.

- WO 04-724879-12, removal and replacement of the 1C RHR Heat Exchanger floating head and the overall work involved with the heat exchanger was documented in previous inspection reports. The reports documented that Eddy-Current Testing (ET) indicated a significant number of tubes were degraded. As a result of the ET it was decided to replace 450 tubes. The licensee completed replacing the heat exchanger tubes during this report period, re-assembled the heat exchanger, performed a pressure test, and resumed testing. The inspectors observed portions of the final tube replacement activities. Additionally, the inspectors reviewed the licensee's ET examination report associated with the newly installed tubes.

- 1-TI-526, Core Spray Valve Differential Pressure Testing Loop I, was performed in conjunction with the Core Spray Loop I comprehensive pump test. The purpose of this Differential Pressure (dp) test was to configure the system to achieve the flows and pressures required for dp testing of the Division I valve 1-FCV-75-09, Minimum Flow Valve, and Division I Valve 1-FCV-75-22, Test Valve. The dp test was performed to satisfy Generic Letter (GL) 89-10 Program testing requirements.

- 1-TI-527, Core Spray Valve Differential Pressure Testing Loop II was performed in conjunction with the Core Spray Loop II comprehensive pump test. The purpose of this Differential Pressure (dp) test was to configure the system to achieve the flows and pressures required for dp testing of the Division II valve 1-FCV-75-37, Minimum Flow Valve, and Division II Valve 1-FCV-75-50, Test Valve. The dp test was performed to satisfy GL 89-10 Program testing requirements.

The inspectors reviewed the applicable WO packages and observed selected portions of the ongoing maintenance activities. The inspectors determined that WO packages included sufficient guidance to allow maintenance personnel to adequately perform the associated work activity. Maintenance personnel and foreman were knowledgeable of applicable requirements and appropriately documented work actually performed, as required by plant procedures.

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.

M1.2 Functional Evaluation Associated with Electrical Transformer Outage

a. Inspection Scope

The inspectors reviewed the licensee's functional evaluation associated with a planned outage of the Unit 1 Main Bank Transformers 1A, 1B and 1C. The evaluation also included the simultaneous outages of Unit Station Service Transformers (USST) 1A and 1B.

b. Observations and Findings

The inspectors reviewed the licensee's functional evaluation, 41589, Rev 0, that addressed a planned outage of the Unit 1 Main Bank Transformers 1A, 1B and 1C. The evaluation also included the simultaneous outages of Unit Station Service Transformers (USST) 1A and 1B. The inspectors had previously reviewed a Unit 1 main bank outage which had occurred in December 2005 as documented in Inspection Report 50-259/2005-09. During the previous review of the 2005 transformer outage the inspectors had identified that the licensee's evaluation had not addressed the Units 1 and 2 4KV Common Boards. During the review of Functional Evaluation 41589 during the current reporting period the inspectors verified that the current evaluation stated the Procedure 0-O-57A was revised to require an evaluation anytime a 4KV Common Board was placed on the alternate power source. The licensee's functional evaluation was performed in accordance with procedure NEDP - 22, Functional Evaluation, Rev 2. The current functional evaluation determined that specific compensatory measures were needed for the main bank outage. Those compensatory measures were the same as had been required for the 2005 outage. The main bank outage occurred September 11 to 25, 2006.

The equipment affected by this outage were the following:

- The Unit 2 4 KV Unit Board 2C switch 43, AUTO/MAN transfer, to be in the manual position and aligned the Unit Station Service Transformer (USST) 2A, the normal power supply

- The Unit 3 4 KV Unit Board 3C switch 43, AUTO/MAN transfer, to be in the manual position and aligned the Unit Station Service Transformer (USST) 3A, the normal power supply

- The 4 KV Shutdown Bus 1 to be aligned to the 4 KV Unit Board 2B, the alternate power supply, by closing breaker 1622 and opening breaker 1612

- The 4 KV Shutdown Bus 2 to be aligned to the 4 KV Unit Board 2A, the normal power supply, by ensuring that breaker 1722 remains closed and breaker 1712 remains opened

The inspectors observed these activities helped to minimized the potential of an overload condition on the Common Station Service Transformers (CSST) A and B, and the 4 KV Start Busses 1A and 1B during any scenario that included a design basis accident on either Unit 2 or Unit 3; an outage of the Unit 1 main bank transformers and the USSTs 1A and 1B; and a loss of the 500 KV to circuits between the offsite transmission network and the Unit 2 USSTs and/or the Unit 3 USSTs. The inspectors also observed that the evaluation did mention the 4 KV Common Boards A and B which supply electrical loads to Units 1 and 2. The Common Board A receives normal power from USST 1A and alternate power from

CSST A. The Common Board B receives normal power from USST 2A and alternate power from CSST B.

During this outage, unlike the previous outage in December, 2005, testing of the Unit 1 Core Spray and RHR pumps would be occurring. The design Electrical Engineering Branch (EEB) issued two Engineering Work Requests (EWR) which justified the operation of the Unit 1 pumps for testing purposes. The EWR's, 06EEB074218 and 06EEB075217, from the EEB also listed the restrictions for testing the Unit 1 pumps. Specific restrictions included verification the pumps would trip upon receiving an accident signal from Unit 2. The inspectors observed and reviewed the verification tests. The signal was initiated from the common accident signal logic system.

c. Conclusions

No deficiencies were identified during the review of the ongoing planned main transformer outage activities. The licensee's functional evaluation for the simultaneous outages of the Unit 1 Main Bank Transformers 1A, 1B and 1C and USSTs 1A and 1B was adequate. Compensatory measures and equipment alignment conditions to support this condition minimized the potential for overloading the CSSTs and 4 KV Start Busses.

V. Management Meetings

X1 Exit Meeting Summary

On November 6, 2006, the resident inspectors presented the inspection results to Mr. Masoud Bajestani 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
B. Hargrove, Radcon Manager, Unit 1
K. Hess, SWEC Project Director
R. Jackson, Bechtel
R. Jones, General Manager of Site Operations
D. Kehoe, Nuclear Assurance, Unit 1
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
J. Schlessel, Maintenance Manager, Unit 1
J. Symonds, Modifications 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 70301	Preoperational Test Procedure Review
IP 70315	Preoperational Test Witness
IP 71111.08	Inservice Inspection Activities
IP 71111.17	Permanent Plant Modifications
IP 71111.23	Temporary Plant Modifications
IP 71152	Identification and Resolution of Problems
IP 92701	Follow-up
IP 50090	Pipe Support and Restraint Systems

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

259/2006-08-01	NCV	Inadequate Modification Instructions (Section E1.1)
259/2006-08-02	URI	Impact of Duct Tape on Instrument Tubing and ECCS Suction (Section E1.3)

Closed

88-37	LER	Inadequate Design Control Procedures Discrepancies in HVAC Ductwork (Section E8.1)
93-02	BUL	Debris Plugging of Emergency Core Cooling Suction Strainers (Section E8.2)
80-06	BUL	Engineered Safety Feature (ESF) Reset Controls (Section E8.3)
2515/111	TI	Electrical Distribution System Followup Inspection (Section E8.4)
98-04	GL	Potential For Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment (Section E8.5)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section E1.1: Plant Modifications

Procedures and Standards

SPP-9.3, Plant Modifications and Engineering Change Control, Rev. 9
MAI-4.2B, Piping, Rev. 20
G-94, Piping Installation, Modification, and Maintenance, Rev. 2
1-POI-64-2, MSIV Secondary Containment System, Rev. 0

DCNs

DCN 51235, System 43,Sampling and Water Quality and System 69, RWCU Electrical and Mechanical - Reactor Building
DCN 63005, Main Steam Line EPU Data Collection Vibration Monitoring, Electrical and Mechanical - Reactor Building and Drywell, System 01.
DCN 51211, Main Steam Electrical - Reactor Building, System 01.
DCN 51230, Main Steam, Instrumentation and Control (I&C) - Reactor Building, System 01
DCN 51368, Fire Protection System

Work Orders

02-013120-010 ,Installation of new two inch HPCI pipe in the Reactor Building
03-020376-028. rework three inch HPCI steam line in Turbine Building
03-021424-079, fire protection modification activities in support of Stage 5 of DCN 51368

Problem Evaluation Report (PERs)

PER 110926, unplanned breach in secondary containment
PER 110479, defeating automatic fire pump start circuits

Misc Documents

Functional Evaluation 41621, post operability of the secondary containment.

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

1-84-088-76, Unit 1 primary containment personnel access air lock
1-84-092-67, install a non-qualified valve,1-67-237A, in the Unit 1 EECW system

1-84-093-85, remove Level Monitors (LM) 1-85-85A, 85B, 85C, and 85D from service
1-84-101-99, install flexible conduit in Control Panel 1-9-17
1-84-29-69, bypass a thermal trip 49X relay for RWCU Pump 1B
1-85-020-77, remove the Robertshaw Model 351 flood level switches
1-88-01-90, remove from service the annunciator circuits for the Unit 1 RBCCW radiation monitor and the common radiation monitor on the RHRSW discharge of the 1A/1C RHR Heat Exchangers
1-02-004-77, install two portable submersible sump pumps and a level switch in the Unit 1 Turbine Building floor drain sump
1-03-01-64, activities to support DCN 51189, Primary Containment Electrical and Mechanical - Reactor Building, System 64A
1-04-01-111, install a temporary 5 ton overhead crane in the Unit 1 Reactor Building, El 629'
1-05-001-231, install a Yokogawa recorder on breaker 1-BKR-231-0001A/3D
1-04-011-64D, install jumpers on specific PCIS relays located in Control Panel 1-9-15, in Panel 1-9-42, and in Panel 1-9-43
1-04-012-074, install jumpers on the PCIS inboard RHR isolation relay 16A-K29
1-04-013-069, install jumpers, lift leads, and remove fuses in Control Panel 1-9-42 and in Panel 1-9-43

Section E1.3: System Return to Service Activities

Procedures, Guidance Documents, and Manuals

1-SR-3.1.7.3, Standby Liquid Control System Enriched Sodium Pentaborate (SPB) Solution Concentration, Quality Calculation, and ATWS Equivalency, Revision 14
1-SR-3.1.7.7, Standby Liquid Control System Functional Test, Revision 0
1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Revisions 16 and 17
1-TI-439, ITEL (Integration Task Equipment List), Revision 10
0-TI-404, Unit one Separation and Recovery, Revision 10

Design Change Notices

51211

Calculations

NDQ0999910033, Safe Shutdown Analysis, Revision 22
ED-Q2000-870050, 24V D.C. System Voltage Calculations, Revision 5

Drawings

1-47E854-1, Flow Diagram Standby Liquid Control, Revision 11
1-4E610-63-1, Mechanical Control Diagram Standby Liquid Control System, Revision 5
1-729E854-1, Elementary Drawing Standby Liquid Control, Revision 9
1-729E854-2, Elementary Drawing Standby Liquid Control, Revision 7
1-45E779-3, Wiring Diagram 480V Shutdown Auxiliary Power Schematic Diagram, Revision 22
1-730E927-13, Elementary Drawing Primary Cntmt Isol System, Revision 12

Problem Evaluation Report (PERs)

111681 Drywell Stainless Steel Duct Tape Issue
111684 Torus Electrical Junction Box Duct Tape Issue
56773 Damaged Heat Trace Cable on Piping to SLC
84151 Label Replacement/Removal Left Holes in Electrical Panels
86030 Cable Replacement required for DCN 51081 and 51190
83383 No Design Drawings to Validate Components
90637 Final QC As-Built Verification Rejected
90928 Final As-Built Verification Walkdown
86054 Gouges in SLC System Piping
87002 Pipe Support Discrepancies
87082 Final As-Built Verification: Support 1-47B462-98
88278 Final As-Built Pipe Verification/Inspection
88961 Final As-Built Verification: Support 1-47B462-101
109447 Items Identified in NA Review of SRTSOIP for System 63
109591 SLC Flow Diagram 1-47E854-1 Drawing Discrepancy
110320, Main Bank Battery Service Tests do not contain sufficient acceptance criteria
110316, Calculation errors were made during the performance of 2-SR-3.8.4.3

<u>Miscellaneous Documents</u>

Integration Task Equipment List (ITEL) System Scoping Milestone Reports for Systems 70, 80, and 57-4.
BFN-50-7063, Design Criteria Document, Standby Liquid Control System, Revision 12
System Plant Acceptance Evaluation Package, System 63, Standby Liquid Control, March 17, 2006
System Pre Operability Checklist (SPOC II) - System 063, Standby Liquid Control, August 31, 2006
Restart Test Program Tests Results Package, 1-BFN-BTRD-063, Standby Liquid Control, August 31, 2006
System Return to Service - Open Item Punchlist, September 7, 2006
Updated Final Safety Analysis Report Section 3.8 Standby Liquid Control System, Revision
Unit 1 Technical Specifications 3.1.7 SLC System and Bases B 3.1.7
System Return to Service - Open Item Punchlist (SRTS-OIP) SE-ITEL-410 for system 573
SRTS-OIP SE-ITEL-210c for system 574
SRTS-OIP SE-ITEL-410 for system 094
System Plant Acceptance Evaluation package for the 250V DC Distribution system Revision 3. RIMS Number: W82-060327-001
FSAR section 8.6 250-V DC Power Supply and Distribution
BFN-50-7200C - 250 V DC Power Distribution System Revision 7
1-BFN-BTRD-573, Revision 4 Baseline Test Requirements Document for 250V DC distribution (System 573)
Operator Logs for 9/09/06

Section E1.4: 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.

Restart Test Procedures

PMTI-51016-STG15, 4KV Load Shed Logic
PMTI-51016-STG16, 4KV Load Shed Logic
PMTI-51085-STG03, Functional Test of the Unit 1 Preferred Inverter/Isolimiter 1-INV-252-0001 and 1-XFA-252-001
PMTI-51016-STG 01A, Division I Core Spray Response to Unit 2 Accident Signal
PMTI-51016-STG 02A, Division II Core Spray Response to Unit 2 Accident Signal

Test Summary Reports:

1-BFN-BTRD-023,RHRSW
1-BFN-BTRD-572, 120 VAC Distribution
1-BFN-BTRD-573, 250 VDC
1-BFN-BTRD-574, 480 VAC
1-BFN-BTRD-576, 500 KV, 161KV, and Misc Electrical Distribution
1-BFN-BTRD-63, SLC System
1-BFN-BTRD-75, CS System

Surveillance Instructions

1-SI-3.3.13, ASME XI System Pressure Test of the RHRSW System (ASME Section III Class 3)
1-SI-4.5.C.1(3), RHRSW Pump and Header Operability and Flow Test
0-SR-3.8.1.8(I), 480V Load Shed Logic System Functional Test (Division I)
0-SR-3.8.1.8(II), 480V Load Shed Logic System Functional Test (Division II)
1-ETU-SMI-1-48SDA, Procedure for Relay Functional Checks on 480V Shutdown Board 1A
1-ETU-SMI-1-48SDB, Procedure for Relay Functional Checks on 480V Shutdown Board 1B
1-SR-3.1.7.7, Standby Liquid Control System Functional Test
1-SR-3.1.7.3, Standby Liquid Control System Enriched Sodium Pentaborate (SPB) Solution Concentration, Quantity Calculation, and ATWS Equivalency Calculation
1-SI-3.2.9, Testing of ASME Section XI Relief Valves
1-SR-3.6.1.3.5(CS I), Core Spray System MOV Operability Test Loop I
1-SR-3.6.1.3.5(CS II), Core Spray System MOV Operability Test Loop II
1-SR-3.5.1.6 (CS I-COMP), Core Spray Loop I Comprehensive Pump Test
1-SR-3.5.1.6 (CS II-COMP), Core Spray Loop II Comprehensive Pump Test
1-SR-3.3.5.1.6 (CS I), Core Spray System Logic Functional Loop I Test
1-SR-3.3.5.1.6 (CS II), Core Spray System Logic Functional Loop II Tests
1-SR-3.3.3.2.1(75 I), Backup Control Panel Testing Loop I
1-SR-3.3.3.2.1(75 II), Backup Control Panel Testing Loop II
1-SI-3.1.8, CS Loop Baseline Data Evaluation

1-SR-3.8.4.3(MB-1), Main Bank 1 Battery Service Test
2-SR-3.8.4.3(MB-2), Main Bank 2 Battery Service Test
3-SR-3.8.4.3(MB-3), Main Bank 3 Battery Service Test

Work Orders

02-013350-00, I&C Bus Undervoltage Sensing System Bus A
02-013688-00, I&C Bus Undervoltage Sensing System Bus B

Miscellaneous Documents

Mechanical Corrective Instruction, MCI-0-000-RLV001, Generic Instruction For Relief Valves
0-TI-531, Simultaneous Operation of RHRSW Pumps C1 and C2
0-TI-492, ASME Pump Curve Data Acquisition

Section E1.5: 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
G-40, Installation, Modification and Maintenance of Electrical Conduit, Cable Trays, Boxes, Containment Electrical Penetrations, Electric Conductor Seal Assemblies, Lighting and Miscellaneous Systems, Rev. 15
MAI-3.2, Cable Pulling for Insulated Cables Rated up to 15KV Units 1, 2, and 3, Rev. 41

DCNs

51177, U1 Reactor Building Mechanical Lead System-023
51194, U1 Cables with Wrong DCN Number
51217, Minor Corrections to DCN
51222, 480V RMOV BD 1B, System-074

Walkdown Packages Reviewed

LSWDP-BFN-1-ELEC-312, Verify Internal Separation of Cables 1RP426-IIIB & 1RP209-IIIA in PNL 9-16, Rev. 0
LSWDP-BFN-1-ELEC-358, Verify Internal Wiring Installation in 1-PNLA-009-0054, For Division Separation, Rev. 0
LSWDP-BFN-1-ELEC-363, Verify Fuse Block & Fuse Installation in 1-PNLA-009-0003 For Division Separation, Rev. 0
WDP-BFN-1-EEB-074-VCD-01, Walkdown Data for RHR “B” Pump motor cable ES2625-II, Rev. 4

PICs Reviewed

61167, Cable 1ES6011I
61068, Cable 1PP9857
60227, Cable 1ES5404I
63623, Cable 0ES173I
63713, Cable 0ES125I
61002, Cable 0PP626IB

Problem Evaluation Reports Reviewed

105303, Cable in Incorrect Cable Tray
109403, Div-I/Div-II Separation Control Room Ceiling
107318, Violation Training Radius of Cables

Problem Evaluation Reports Generated

111281, Free air cables in violation of 4'-0" requirement
111167, Additional free air cables in violation of 4'-0" requirement
111322, Medium Voltage Cable in violation of G-38 Section 8.6.3.2

Drawings

0-45N804-18, Conduit & Grounding Floor EL 593.0 Ceiling Plan, Rev. 0
0-45W832-2, Conduit & Grounding Cable Tray Single Lines, Rev. 0
0-45E830-6, Conduit & Grounding Cable Tray Plan EL 586 & 593, Rev. 1
0-55N627-1, Wiring Diagram Diesel Generators C & D Main Control Board Panel 8 DCA 51090-654, Rev. 06
0-45N802-23, DCA 51223-018, Rev. 000
1-45E676-1, DCA 51105-029, Rev. 005
1-45E812-16, DCA 51223-207, Rev. 004
1-45E812-16, DCA 51223-208, Rev. 006
1-45N1641-6 DCA 51083-003, Rev. 2
1-45N1641-6 DCA 51221-050, Rev. 2
1-45N1641-6 DCA 51081-184, Rev. 2 CC
1-45N1668-6 DCA 51081-136, Rev. 0 CC
1-45N1686-5 DCA 51076-092, Rev. 7
1-45N1671-3 DCA 51076-094, Rev. 001
1-45N1671-3 DCA 51083-003, Rev. 001
1-45W832-4, Conduit & Grounding Cable Tray Single Lines, Rev. 0
1-45E830-38, Conduit & Grounding Cable Tray Plan Elev. 621'-0" and Sections, Rev. 8
1-45W834-8, Conduit & Grounding Cable Trays Node Diagram Plan Elevation 593, Rev. 6
1-45W830-32, Conduit & Grounding Cable Trays Elevation 593, Rev. 6
1-47W1392-602, DCA 51223-205, Rev. 002
1-45N812-1, DCA 51223-206, Rev. RF
1-45E802-33, DCA 51222-308, Rev. R2
1-791E246-12, DCA 51094-715 Rev. RO
1-828E469RE, DCA 51105-075, Rev. 003
45N1641, DCA 51080-124, Rev. RA
45N1641-6, Wiring Diagrams Unit Control Boards Panel 9-3 Sh. 6, Rev. 22
45N814-1, DCA 51216-374, Rev. RD

45N812-2, Conduit & Grounding Floor EL 621.25 Ceiling Plan, Rev. 15
45N812-7, Conduit & Grounding Floor EL 621.25 Details, Sh. 1, Rev. J
45N804-2, Conduit & Grounding Floor EL 593.0 Ceiling Plan, Rev. H
45N800-15, DCA 51222-266, Rev. RH
45N800-02, DCA 51222-257, Rev. RC
45N800-04, DCA 51222-256, Rev. RE
45N800-15, DCA 51222-266, Rev. RH

Section E1.6 Special Program Activities - HVAC Ducting and Duct Supports

Procedures and Design Criteria

WI-BFN-0-CEB-04,	Seismic Verification Walkdown Instruction for USI A-46 and Seismic IPEEE, Rev, 0
WI-BFN-0-GEN-01	Walkdown Instructions, Rev. 1
BFN-50-C-7104	Design of Structural Supports, Rev. 12

Isometric Drawings:

1-SWHVAC-109-00-0	Unit 1 Core Spray Pump Motor 1B-1D Cooling System (NE Quadrant) [8 supports] (5 no mods)
1-SWHVAC-108-00-0	Unit 1 Core Spray Pump Motor 1A-1C Cooling System (NW Quadrant) [8 supports] (3 no mods)
1-SWHVAC-110-00-0	Unit 1 RHR Pump Motor 1-D Cooling System (SE Quadrant) [4 supports] (3 no mods)
1-SWHVAC-111-00-0	Unit 1 RHR Pump Motor 1-B Cooling System (SE Quadrant) [6 supports] (2 no mods)
1-SWHVAC-112-00-0	Unit 1 RHR Pump Motor 1-C Cooling System (SW Quadrant) [4 supports] (3 no mods)
1-SWHVAC-113-00-0	Unit 1 RHR Pump Motor 1-A Cooling System (SW Quadrant) [4 supports] (3 no mods)

Support Drawings: (calcs reviewed and field walkdown) [13/34 - 38%]

1-SWHVAC-109-03-0 (47B923-53)
1-SWHVAC-109-08-0 (47B923-43)
1-SWHVAC-108-01-0 (47B923-20)
1-SWHVAC-108-02-0 (47B923-54)
1-SWHVAC-108-07-0 (47B923-56)
1-SWHVAC-108-09-0 (47B923-21-1)
1-SWHVAC-108-09-0 (47B923-21-2)
1-SWHVAC-111-03-0 (47B923-29)
1-SWHVAC-111-06-0 (47B923-32)
1-SWHVAC-112-01-0 (47B923-62)
1-SWHVAC-112-04-0 (47B923-33)
1-SWHVAC-112-03-0 (47B923-64)
1-SWHVAC-113-02-0 (47B923-65)
1-SWHVAC-113-04-0 (47B923-45)

Calculations:

CDQ1 031 2003 1946, Seismic Evaluation of Class 1 HVAC Ducting and Supports in the Reactor Building, North-East Corner Room El. 519 Ft. And 541.5 Ft.
CDQ1 031 2003 1947, Seismic Evaluation of Class 1 HVAC Ducting and Supports in the Reactor Building, South-East Corner, Room El. 519 Ft. And 541.5 Ft.
CDQ1 031 2003 1948, Seismic Evaluation of Class 1 HVAC Ducting and Supports in the Reactor Building, South-West Corner, Room El. 519 Ft. And 541.5 Ft.
CDQ1 031 2003 1950, Seismic Evaluation of Class 1 HVAC Ducting and Supports in the Reactor Building, North-West Corner Room El. 519 Ft. And 541.5 Ft.
CDQ1 031 2003 2405, Qualification of Class 1 HVAC Duct Support No. 1-47B923-21, 1-47B923-40, 1-47B923-42, 1-47B923-43, and Modified Supports at Corner Rooms

Walkdown Packages:

BFN1-CEB-HVAC-SE, HVAC Ducting and Supports, South-East Corner Room
BFN1-CEB-HVAC-NE, HVAC Ducting and Supports, North-East Corner Room
BFN1-CEB-HVAC-SW, HVAC Ducting and Supports, South-West Corner Room
BFN1-CEB-HVAC-NW, HVAC Ducting and Supports, North-West Corner Room

Design Change Notices (DCN):

51520 Reactor Building Miscellaneous Supports

Plant Evaluation Reports (PER):

102750, Discrepancies on HVAC Supports
100221, Insufficient Weld size and Length
106195, Existing Anchors in Ceiling and Flame Cut Holes in Supports (HVAC Supports)
107391, A Walkdown of HVAC Supports Found the Following Discrepancies Between DCA & Field Configurations

Section E1.7 Special Program Activities - Small Bore Piping and Instrument Tubing

Specifications & Procedures

TVA General Engineering Specification G-43, Installation, Modification, and Maintenance of Pipe Supports and Pipe Rupture Mitigative Devices, Rev. 13
TVA General Engineering Specification G-32, Bolt Anchors set in Hardened Concrete, Rev. 21
TVA General Engineering Specification G-29A, PS 0.C.1.2, Specification for Welding of Structures Fabricated in Accordance with AISC Requirements for Buildings and Inspected to the Criteria of NCIG-01
TVA General Engineering Specification G-29-S01, PS 4.M.4.4, ASME Section III and Non-ASME (Including AISC, ANSI B31.1 and ANSI B31.5)
Procedure No. N-VT-6, Visual Examination of Structural Welds Using the Criteria of NCIG-01, Rev 6
MAI-4.2A, TVA-BFNP Piping/Tubing Supports, Rev. 33

Drawings

Drawing number 0-47B435-1 through -21, Mechanical General Notes, Pipe Supports
Drawing numbers 1-47B400–260 through -270, -272-1, -2, Mechanical Main Steam System Pipe Support
Drawing numbers 1-47B600-5438 through - 5442, 1-47B600-5502, -5504, -5506, -5507, & -5515, 1-47B600-5413, -5414-2, -5415-1, -5415-2, -5415, -5416-3, and -5425 through -5430, Mechanical Primary Containment System Pipe Support
Drawing number 1-47B600-5431, 1-47B600-5432-1, -5432-2, and -5432-3, Mechanical CRD System Pipe Support
Drawing numbers 1-46B600-1282-1, 1282-2, -1289-1 & -1289-2, Mechanical PCI System pipe Support

Problem Evaluation Reports (PER)

96004, Missing Support On System 71 Instrument Line
106420, Incorrect Unistrut Channel Installed on Support Number 1-47B600-5440

Miscellaneous Documents

DCN 51413, Install Small Bore Supports for RCIC System (System 71) in Unit1 Reactor Building
DCN 51418, Install Small Bore Supports for Primary Containment System Isolation (System 64) in Unit1 Reactor Building
Engineering Change Control Documents, Post Issue Change (PIC) numbers 65455 and quality control inspection records documenting inspections pertaining to changes documented on PIC 65455, Work Order 03-014817-011
Work Order numbers 03-006884-002, -004, -006 and 03-019416-003 and quality control inspection records for Main Steam system instrument sensing lines (System 23)

Section E1.8 Special Program Activities - Instrument Sensing Lines

Specifications & Procedures

TVA Engineering Specification N1E-003, Instrument and Instrument Line Installation and Inspection, Rev. 1
MAI-4.2A, TVA-BFNP Piping/Tubing Supports, Rev. 33
MAI-4.4A, TVA-BFNP Instrument Line Installation, Rev. 16
MMDP-10, Controlling Welding, Brazing, and Soldering Processes, Rev. 4, dated 1/15/03
WI-BFN-1-GEN-01, General Requirements for Walkdowns, Rev. 4
WI-BFN-1-MEB-01, Walkdown Instruction for Mechanical and Instrumentation and Control Systems, Rev. 0

Drawings

Drawing number 0-47B435-1 through -21, Mechanical General Notes, Pipe Supports
Drawing number 1-47E600-2629 and -2630, Mechanical Instrumentation and Controls, Sensing Line Isometrics
Drawing numbers 1-47B600-5472 through -5476, I and C, Core Spray Cooling System, Pipe Support
Drawing numbers 1-47B458-930 through -935, I and C, Core Spray Cooling System, Pipe Support
Drawing number 0-47E600-8, Mechanical Instruments and Controls

Drawing number 1-47W1600-7, Mechanical Instruments and Controls

Calculations

Calculation number CDQ1-075-2003-2294, Rev. 5, Pipe stress analysis of Problem N1-175-58R, -61R, -62R, -65R, -66R, -67R, -69R, and -71

Problem Evaluation Reports (PER)

54186, Instrument Panel 25-306 at Floor Elevation is Severely Corroded
105959, Installation of Inlet and Outlet piping from RWCU Panel to Cooler in Reverse Order
109165, System 74 Instrument Line Discrepancies, Various Locations, Incorrect Slope
109452, Sections of Instrument Line BFR-1-PI-074-0003 with Inadequate Slope
109453, Sections of Instrument Line BFR-1-PI-074-0008 with Inadequate Slope
109454, Sections of Instrument Line BFR-1-PI-074-0014 with Inadequate Slope
109505, Sections of Instrument Line BFR-1-PS-074-0019A, -0019B, & -0019 with Inadequate Slope
109774, Sections of Instrument Line BFR-1-LS-073-0057 A & B with Inadequate Slope
109869, Sections of Instrument Line BFR-1-PS-073-0020A, -0020B, -0020c, & -0020D with Inadequate Slope and Root Valve BFR-1-RTV-073-0205A Installed with Valve Stem in Incorrect Position
109877, Sections of Instrument Line BFR-1-PS-073-0022A with Inadequate Slope and Root Valve BFR-1-RTV-073-0207A Installed with Valve Stem in Incorrect Position
109888, Sections of Instrument Line BFR-1-PS-073-0022B with Inadequate Slope and Root Valve BFR-1-RTV-073-0208A Installed with Valve Stem in Incorrect Position
109895, Sections of Instrument Line BFR-1-PS-073-0029 and -0029-1 with Inadequate Slope and Root Valve BFR-1-RTV-073-0210A Installed with Valve Stem in Incorrect Position
110008, Portions of System 84, Containment Air Dilution, QC Inspection of CAD Line to 1-FE-084-19, Drawing 1-47E600-2638, Did Not Meet Minimum Sensing Line Slope
110177, HPCI Instrument Line - Slope Discrepancies Various Locations Between Instrument Panel 25-63 and Root Valve 1-73-208A
110186, Inconsistencies in As-Built Drawing
110235, System 73 Sensing Line Installed with Incorrect Slope to Root Valve 1-73-210A
110253, HPCI Instrument Line - Slope Discrepancies Various Locations Between Instrument Panel 25-63 and Root Valve 1-73-205A
110318, RHR System Instrument Line with Slope Discrepancies BRF-1-PS-074-0093 and Root Valve BFR-1-RTV-074-0219A Installed with Valve Stem in Incorrect Position
110390, HPCI Instrument Line Shown on Drawing 1-47E600-2572 - Slope Discrepancies Various Locations

Miscellaneous Documents

General Design Criteria Document BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems (Piping and Instrument Tubing), Rev. 5, dated 9/9/91
General Design Criteria Document BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7, dated 4/6/94
General Design Standard DS-C1.2.6, General Pipe Support Design Manual, Rev. 0
Small Bore Piping Evaluation CDQ1-075-2002-0822
TVA Nuclear Engineering Civil Design Standard DS-C1.7.1, General Anchorage to Concrete, Rev 9, dated 8/25/99
DCN 51236, Modifications to Turbine Building Main Steam (System 1) Instrumentation

DCN 51238, Modifications to Instrument Line Slope, Core Spray Cooling System, and Exception Number EX-NE1E-003-65, Rev. 1
DCN 51243, Modifications to Instrument Line Slope, System 64, Containment isolation

Section E1.9 Special Program Activities - Large Bore Piping and Supports

Procedures and Design Criteria

Procedure No., WI-BFN-0-CEB-01, Walkdown Instruction for Piping and Pipe Supports
Design Criteria BFN-50-C-7100, Design of Civil Structures, Attachment A - General Design Criteria for the Torus Integrity Long Term Program, Rev. 16
Design Criteria BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7
Design Criteria BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems (Piping and Instrument Tubing), Attachment A, Rigorous Piping Analysis and Attachment E, Analysis of Torus Attached Piping (Long Term Torus Integrity Program)

Other Documents

Pipe Support Drawing No. 1- 47B403-1, Sheet 1, Rev. R002 & Sheet 2, Rev. 003
Pipe Support Drawing No. 1- 47B403-5, Rev. 001
Pipe Support Drawing No. 1- 47B452-91, Rev. 001
Pipe Support Drawing No. 1- 47B452-3006, Rev. 001
Pipe Support Drawing No. 1- 47B452-3008, Rev. 001
Pipe Support Drawing No. 1- 47B456-58, Rev. 002
Pipe Support Drawing No. 1- 47B458-434, Sheet 1, Rev. 002 & Sheet 2, Rev. 001
Pipe Support Drawing No. 1- 47B458-614, Rev. 002
Pipe Support Drawing No. 1- 47B458-615, Rev. 001
Pipe Support Drawing No. 1- 47B458-624, Rev. 002
Pipe Support Drawing No. 1- 47B415-21, Rev. 002
Pipe Support Drawing No. 1- 47B415-25, Rev. 001
Pipe Support Drawing No. 1- 47B415-47, Sheet 1, Rev. 003 & Sheets 2 & 3, Rev. 002
Pipe Support Drawing No. 1- 47B464-424, Rev. 002
Pipe Support Drawing No. 1- 47B464-425, Rev. 003
Pipe Support Drawing No. 1- 47B464-433, Rev. 002
Pipe Support Drawing No. 1- 47B464-456, Rev. 004
Pipe Support Drawing No. 1- 47B464-464, Rev. 003
Pipe Support Drawing No. 1- 47B464-466, Sheet 1, Rev. 001 & Sheet 2, Rev. 000
Pipe Support Drawing No. 1- 47B464-467, Rev. 001
DCN 51349, Core Spray System Large Bore for Long Term Torus Integrity Program for Bulletins 70-02/79-14
Work Order (WO) 03-010982 for DCN 51349
PER 109890, NRC Inspection for Billing Material Missing in the Drawing and Pin Hole Diameter Change
Drawings for DCA No. 51343-089 to 093
Isometric Drawings CDQ1-003-2002-0352 Sheet 8 & 0353 Sheet 7 for Piping Stress Problem N1-103-1RA & 1RB
Isometric Drawings CDQ1-070-2002-0356 & 0357 for Piping Stress Problem N1-170-1R &2R

Section E1.10: Reactor Vessel Internals Activities

Procedures

GE Procedure GE-VT-204, procedure for Invessel Visual Inspections (IVVI) of BWR4 Internals, Rev 8
GE Procedure BFN-CSC-INST-001, Rev 2, Core Spray Sparger Clamp Setup/Machining/Installation
GE procedure BFN-ASW-001 Rev 2, Jet Pump Auxiliary Spring Wedge Measurement/Installation/Removal
BFN-ASW-Traveler-001, Rev 1, Jet Pump Auxiliary Spring Wedge installation specs
BFN-ASW-INST-WPC-001, Rev 1, Core Spray Sparger Clamp installation specs

Design Change Notices

DCN 51193, Stage 3, Reactor Vessel Internals Modifications - System 68

Work Orders

02-016506-017, installation of Jet Pump Auxiliary Spring Wedges
02-016506-018, Install Core Spray Sparger T-Box Clamps
06-719495-000 Document measurements taken by GE during CS T-Box repairs and Jet Pump Auxiliary Wedge Installation

PERs

107324, camera head dropped in Unit 1 annulus area (noted that all was later retrieved)
107367, Unit 1 refuel bridge power cord damage
93956, During IVVI examination of Unit 1 RPV bottom head noted that locking tab for core plate location 32-41 not properly engaged

Section E1.11: Review of Electrical Distribution System Loading Analysis

Drawings

PIP-02-03, One Line Diagram - Electrical Distribution System, Rev. 3/15/06
1-45E765-4, Schematic Diagram Raw Cooling Water Pump 1D, Rev. 15
0-731E761, Sheet 15, Elementary Diagram Emergency Equipment, Rev. 14
2-45E765-7, Schematic Diagram Fire Pump A, Rev. 30
0-45E765-5, Schematic Diagram RHR Service Water Pump A2, Rev. 39
1-45E779-3, Control Circuit for Drywell Blowers, Rev.22
0-45E763-1, Schematic Diagram 4160 V Unit Board Normal and Emergency Feeder Breakers, Rev. 25
0-45E769-9, Schematic Diagram Chill Water Pump, Rev.

DCNs

66071B, Revise Single Lines to Remove /Revise Load Limitations and Breaker Closure Restrictions

Calculation

EDQ0-057-2004-0026, AC and DC Load Limitations for Units 1, 2 and 3 Operating, Rev. 6

Operating Instructions

0-OI-57B, 480V/240V AC Electrical System, Rev. 155, effective 9/16/06

Post-Modification Test Instructions

PMTI-51016, Stage 13, 4 kV Load shed Logic Signal Initiation Division I, performed 6/13/06
PMTI-51016, Stage 14, 4 kV Load shed Logic Signal Initiation Division II, performed 6/22/06
PMTI-51016, Stage 15, Functional Test of RHRSW Pump A2 Load Shed, performed 6/27/06
PMTI-51016, Stage 16, Functional Test of RHRSW Pump C2 Load Shed, performed 6/29/06
PMTI-51016, Stage 17, Raw Cooling Ware pump 1D Load Shed, performed 7/21/06
PMTI-51016, Stage 18, Fire Pump A Load Shed Logic, performed 7/7/06
PMTI-51016, Stage 19, Fire Pump B Load Shed Logic, performed 7/14/06
PMTI-51016, Stage 20, Fire Pump C Load Shed Logic, performed 7/21/06

PER

112237, Incorrect UFSAR description of 4 kV unit board transfer

Section E7.1 Licensee Oversight of Work Scope reduction

NA Assessment and Observation Reports

NA Assessment Report, DCN and Work Order review of work scope reduction, January 9, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, February 9, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, March 10, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, April 10, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, May 8, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, June 6, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, July 6, 2006
NA Assessment Report Attachment B, Voided DCNs, July 6, 2006
NA Assessment Report, DCN and Work Order review of work scope reduction, August 6, 2006
NA Observation 38443, 12/1-12/31/2005 work scope reduction review
NA Observation 38846, 1/1-1/31/2006 work scope reduction review
NA Observation 39173, 2/1-2/28/2006 work scope reduction review
NA Observation 39452, 3/1-3/31/2006 work scope reduction review
NA Observation 39765, 4/1-4/30/2006 work scope reduction review
NA Observation 40043, 5/1-5/31/2006 work scope reduction review
NA Observation 40262, 6/1-6/30/2006 work scope reduction review

NA Observation 40516, 7/1-8/31/2006 work scope reduction review
NA Observation 40571, Voided DCN review

Problem Evaluation Reports

106360, failure to document valid reason for cancellation of four workorders
108908, inadequate justification for cancellation of work order
110498, inadequate justification for cancellation of two work orders
109160, additional justification needed for 19 voided DCNs

Section E8.4: Temporary Instruction 2515/111, Electrical Distribution System Followup Inspection

Surveillance Procedures

0-SR-3.3.8.1.1 ©, 4 kV Shutdown Board C Degraded Voltage Relay Calibration and Functional Test, performed on 9/13/05
0-SR-3.3.8.1.1 ©, 4 kV Shutdown Board C Degraded Voltage Relay Calibration and Functional Test, performed on 4/25/06
2-SR-3.8.4.3(MB-2), Main Bank 2 Battery Service Test, performed 8/23/06

PERs

75471, Basis for the set point of the 250 V battery board ground detection relay not documented
75494, Battery rack steel blocks ability to visually inspect for cell sediment
75497, Evaluate need for PM on battery board filter capacitor
75575, Minimum required voltages in calculation 87041 need to be clarified
75599, Unit 2&3 DC voltage calculation appears to conflict with new computer program being used for Unit 1, 2 & 3 calculation

Section M1: Conduct of Maintenance

Procedures and Standards

1-TI-526, Core Spray Valve Differential Pressure Testing Loop I
1-TI-527, Core Spray Valve Differential Pressure Testing Loop II

Work Orders

02-012506-00, bump for rotation of the 1A CS Pump Motor
02-012499-00, bump for rotation of the 1B CS Pump Motor
02-012504-00, bump for rotation of the 1C CS Pump Motor
02-012501-00, bump for rotation of the 1D CS Pump Motor
05-725260-00, bump for rotation of the 1A RHR Pump Motor
05-000997-00, bump for rotation of the 1B RHR Pump Motor
05-725261-00, bump for rotation of the 1C RHR Pump Motor
05-725260-00, bump for rotation of the 1D RHR Pump Motor
04-724879-12, removal and replacement of the 1C RHR Heat Exchanger floating head

Miscellaneous Documents

EWR 06EEB074218, restrictions for testing the Unit 1 pumps
EWR 06EEB075217, restrictions for testing the Unit 1 pumps
Functional evaluation, 41589, rev 0, that addressed a planned outage of the Unit 1 Main Bank Transformers 1A, 1B and 1C