UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

November 8, 2004

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 05000259/2004008

Dear Mr. Singer:

On October 9, 2004, 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 October 25, 2004, with Mr. John Rupert and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations, with the commitments in your Unit 1 Recovery Program, and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Based on the results of this inspection, no findings or violations of significance were identified. Overall, only minor discrepancies were found, indicating your oversight of recovery activities was effective. However, we will continue to monitor the scope and implementation of your corrective actions to address welding program problems that our inspectors have observed and that your staff has identified in self-assessments.

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/

Stephen J. Cahill, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure: Inspection Report 05000259/2004008
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-259
License No:	DPR-33
Report No:	05000259/2004008
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 11 - October 9, 2004
Inspectors:	W. Bearden, Senior Resident Inspector, Unit 1 E. Christnot, Resident Inspector N. Merriweather, Senior Reactor Inspector (Sections E1.3, E1.4, E1.5, E1.6) W. Loo, Senior Health Physicist (Section R1.1, R8.1) J. Díaz Vélez, Health Physicist (Section R1.1) H. Gepford, Health Physicist (Section R1.1) N. Griffis, Health Physicist (Section R1.1)
Approved by:	Stephen J. Cahill, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Unit 1
NRC Inspection Report 05000259/2004-008

This integrated inspection included aspects of licensee engineering and modification activities associated with the Unit 1 recovery project. 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. The report covered a 3-month period of resident inspector inspection. In addition, NRC staff inspectors from the regional office conducted inspections of radiation protection and Unit 1 Recovery Special Programs in the areas of fuses; thermal overloads; environmental qualification; and electrical cable splices.

Inspection Results - Engineering

- Review of Unit 1 modification design packages for six modifications concluded that the design changes were appropriately developed, reviewed, and approved for implementation per procedural requirements. The packages adequately addressed changes needed for Unit 1 operation per current requirements. (Section E1.1)

- Modification installation activities associated with six permanent plant design changes were observed and found to be performed in accordance with the documented requirements. (Section E1.2)

- The licensee's Special Program to resolve previous problems with misapplication of current-limiting fuses is acceptable to support Unit 1 restart. The program is equivalent in scope to those previously applied to the restart of the other units at Browns Ferry. However, additional inspection will be conducted to verify acceptable program implementation. (Section E1.3)

- The licensee's Special Program for Unit 1 Thermal Overloads is consistent with that used for restart of Units 2/3. However, additional inspection will be necessary to verify that the DCN packages and unverified assumptions in the thermal overload calculations are adequately implemented. (Section E1.4)

- The licensee's cable splice program is consistent with the BFN Nuclear Performance Plan to ensure the adequacy of all Class 1E electrical cable splices and terminations in harsh environments. Most environmentally qualified cables and splices will be replaced prior to restart and it will be necessary to conduct further inspections after the cables and splices are installed to verify adequate implementation. (Section E1.5)

- The licensee's Special Program for the environmental qualification of electrical equipment on Unit 1 is consistent with that used for the restart of Units 2/3. However, additional inspection will be necessary to verify adequate implementation. (Section E1.6)

- Based on an initial review, the inspectors concluded that the licensee's Restart Test Program was meeting commitments established by the licensee's Regulatory Framework letters. The inspectors will continue to review the licensee's program for developing and satisfying test requirements and the resultant testing plans during future inspections. (Section E1.7)

- A review of a temporary alteration associated with the Residual Heat Removal Service Water System did not identify any significant impact on the operability of equipment required to support operations of Units 2 and 3. (Section E1.8)

- The licensee's System Return to Service (SRTS) activities continued to be performed in accordance with procedural requirements. System deficiencies were identified and appropriately addressed by the licensee's corrective action program. (Section E1.9)

- Following identification of a negative trend in welding control problems, the licensee increased management focus and oversight of the welding program. The effort has initially resulted in fewer documentation errors and an improvement in welder performance. However, inspectors will continue to evaluate the effectiveness of the licensee's long term corrective actions in this area. (Section E7.1)

<u>Inspection Results - Maintenance</u>

- Based on review of records and observation of ongoing work, the licensee's General Electric Type HFA relay replacement program was complying with the applicable requirements. (Section M1.1)

<u>Inspection Results - Plant Support</u>

- The licensee's Radiation Protection (RP) program was being adequately maintained. Changes to the program since the last inspection were consistent with licensee commitments and NRC requirements. Based on focused RP reviews for Unit 1, inspectors did not identify any impediments to the planned transition of Unit 1 RP inspections and oversight for the Occupational and Public Radiation Safety Cornerstones to the normal Reactor Oversight Process. (Section R1.1)

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, reinstallation of plant equipment and structures continued. Recovery activities include ongoing replacement of reactor coolant system piping; reinstallation of balance-of-plant piping and turbine auxiliary components; and installation of new electrical penetrations, cable trays, and cable tray supports. Limited system return to service (SRTS) activities occurred during this reporting period.

I. Operations

O8.1 Miscellaneous Operations Issues

O8.1.1 (Closed) NRC Temporary Instruction (TI) 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants

During the previous reporting period, the inspectors completed Phase I and Phase II of Temporary Instruction 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants. Appropriate documentation of the results was provided to NRC management, as required by the TI. This completes the Region II inspection requirements for this TI for the Browns Ferry Site, including Unit 1.

O8.1.2 (Closed) NRC TI 2515/156, Offsite Power System Operational Readiness

During the previous reporting period, inspectors collected data from licensee maintenance records, event reports, corrective action documents and procedures, and through interviews of station engineering, maintenance, and operations staff, as required by TI 2515/156. Appropriate documentation of the results was provided to headquarters staff for further analysis, as required by the TI. This completes the Region II inspection requirements for this TI for the Browns Ferry Site, including Unit 1.

II. Engineering

E1 Conduct of Engineering

E1.1 Design Change Notice Package Reviews (37551)

a. Inspection Scope

The inspectors reviewed permanent plant modifications to the Reactor Protection System (RPS), Residual Heat Removal (RHR) System, Core Spray (CS) system, Reactor Vessel Level Indicating System (RVLIS), and the primary containment. The inspectors reviewed criteria in licensee procedures 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 Design Change Notice (DCN) 51080, RPS, System 099

The inspectors reviewed the Unit 1 permanent plant modification DCN 51080. The purpose of the RPS is to provide a scram mode which can be initiated manually or, depending on specific parameters, automatically. The intent of this DCN is to implement the modifications recommended for the Unit 1 RPS and to ensure the incorporation of other modifications, to additional systems, through various DCNs. Among the various DCNs were the following: DCN 51206, Control Rod Drive System (CRD), System 85; DCN 51243, Primary Containment Isolation System (PCIS), System 64D; and DCN 51477, Main Condenser Vacuum System (MCVS), System 34. Among the scheduled modifications for this DCN, in conjunction with the other DCNs, were the following:

- The main condenser low vacuum scram was deleted. The basis for the trip was to provide an anticipatory scram to reduce the reactor vessel pressure excursion caused by a turbine trip on low condenser vacuum. The licensee's accident and transient analysis does not take credit for the low condenser vacuum scram. DCN 51477 will remove the low condenser vacuum scram switches and DCN 51080 will disable this scram function logic in RPS panels 9-15 and 9-17.

- To ensure scram capability, the scram discharge instrument volume (SDIV) is monitored by redundant sets of float-type level switches. A scram is initiated on high SDIV level to insure that sufficient volume remains in the scram discharge volume (SDV) and the SDIV to accommodate the Hydraulic Control Units (HCU) water discharge volume during a scram. Due to the slow response time of the level switches, the switches could not be relied upon to provide a redundant scram function. To compensate for the slow response time, the CRD scram pilot air header pressure switches were relied upon to provide a scram function. DCN 51206 will modify the CRD system to improve the SDIV fill rate, which will improve the response time of the level switches. The DCN will also lower the level switches' scram setpoint. The low scram pilot air header pressure switches will no longer be needed to provide a redundant scram function. DCN 51080 will disable this scram function logic in the RPS panels.

- To ensure environmental qualification (EQ) Rosemont Transmitters will be installed in the reactor building and Analog Trip Units (ATU) will be installed in new ATU panels located in the auxiliary instrument room through other co-requisite DCNs, such as DCN 51243, which will install portions of the ATU system in the new ATU panels, 9-83 through 9-86. DCN 51080 will install the connecting cables between the new ATU panels and the RPS panels 9-15 and 9-17.

Other issues addressed by DCN 51080 include: Removal of applicable inputs to the plant computer and the plant annunciator system; upgrading of diodes associated with the reactor recirculating pump trip (RPT) circuitry; replacement of obsolete RPS motor-generator set circuit breakers; replacement of scram relay contactor coils with coils that have a higher nominal voltage rating; and installation of key-lock test switches for the scram discharge volume vent and drain valve closure test, for both Channel A and Channel B.

b.2 DCN 51152, CS Cooling - Drywell, System 075

The inspectors reviewed the Unit 1 permanent plant modification DCN 51152. The intent of this DCN is to implement the mechanical modifications recommended for the CS system in the drywell. Consistent with the applicable requirements of Design Criteria Document BFN-50-7075, the scheduled modifications for this DCN were the following:

- IGSCC-susceptible Type 304 stainless steel piping in both loops will be replaced with carbon steel, which is a non-susceptible material. The replacement would be from the Reactor Pressure Vessel (RPV), including the RPV vessel nozzles' safe ends, up to the primary containment penetrations 1-X-16A and -16B.

- The testable check valves will be replaced with standard tilting disc-type check valves. The replacement valves do not require air actuators, air supply lines back to the nearest supply valve, pilot solenoid valves, actuator limit switches, and magnetic proximity switches that were used for testing. The DCN directed the corresponding determination and removal of applicable cabling, raceway, conduits, and junction boxes up to the drywell penetrations. A separate DCN directed the removal of related hand switches, relays, and indicating lights in the Main Control Room panel.

- Replacement of existing instrumentation cabling between position-indicating instruments and the drywell penetrations will be with cabling meeting standards consistent with the criteria of Class 1E and 10CFR50.49 qualified cables.

- The two manually-operated isolation valves, one per loop, will be modified to qualify them to conditions of 1250 psig at 575 degrees F. The valves were originally rated for 1146 psig at 575 degrees F.

b.3 <u>DCN 51189, Primary Containment System (PCS), System 064A, and Primary Containment Isolation System (PCIS), System 64D</u>

The inspectors reviewed the Unit 1 permanent plant modification DCN 51189. The intent of this DCN is to implement the modifications recommended for the PCS and PCIS inside the Reactor Building and the Torus. The DCN consists of multiple stages. Modifications activities included:

- The 18-inch drywell vacuum breakers 1-FCV-64-28A through 64-28M hinge arms, bushings, hinge pins, and other parts will be modified to improve the strength and reliability of the valves. Stops will be added inside each vacuum breaker air cylinder to limit the stroke on the opening cycle; the air solenoid valves and limit switches will be replaced; the air cylinder mounting arrangement will be modified, conduits associated with the limit switches will be rerouted and/or replaced in accordance with applicable drawings; control air tubing will be rerouted and supported in accordance with applicable drawings; and the torus temperature elements 1-TE-64-100 thru 64-105, which are no longer used, will be removed.

- New 14-inch piping will be installed between the 20-inch reactor building to torus vacuum relief piping to the existing capped 14-inch Hardened Wet Well Vent (HWWV) system piping. The existing 14-inch piping is capped inside the Unit 1 portion of the Reactor Building. The cap is located upstream of the existing shutoff valve, 1-SHV-64-737, located in the plant yard. This valve is currently locked closed and upon completion of DCN 51189, the valve will changed to locked open. Two new in-series PCIS valves, 1-FCV-64-221 and -64-222, equipped with air operators, pilot solenoid valves 1-FSV-64-221 and -64-222, and position indicating switches will be installed in the new 14-inch piping.

- Nine 18-inch and 20-inch air-operated PCIS butterfly valves will be replaced. Among these valves were 1-FCV-64-18, Cooling/Purge Air to Containment; 1-FCV-64-19, Cooling/Purge Air to Suppression Chamber; 1-FCV-64-29, Drywell Exhaust; and 1-FCV-64-32, Torus Exhaust. The associated air solenoid valves and position switches will also be replaced. All electrical components switches, solenoids, and cabling will meet EQ requirements.

- Components from Drywell Delta-P Air Compressor, 1-CMP-64-142, were previously removed to support Unit 2 and Unit 3 operations. The compressor will be replaced with a similar compressor, including a new motor and after cooler. Cooling water to the compressor and the after cooler will be rerouted, and seismic supports will be installed as necessary.

b.4 DCN 51199, RHR - Reactor Building, System 74

The inspectors reviewed the Unit 1 permanent plant modification DCN 51199. The intent of this DCN is to implement the mechanical modifications recommended for the RHR system in the reactor building. Stage 1 of the DCN will implement changes associated with Loop 1, which will include RHR Pump A and Pump C. Stage 2 of the DCN will implement changes associated with Loop 2, which will include RHR Pump B and Pump D. Stage 2 will also implement changes associated with the common areas between RHR Loop 1 and RHR Loop 2. Stage 3 of the DCN will implement all non-physical work associated with the DCN, such as updating the Master Equipment List (MEL), drawing changes as a result of the modifications, changes to reflect the MEL, and drawing discrepancies. Among the scheduled modifications for this DCN are the following:

- Changes to components which fail to meet environmental or safety-related qualification requirements; changes to obsolete, damaged, or inadequate instruments; and verification that instrument line slope meets requirements. Components being changed include flow switches, pressure switches, flow transmitters, and pressure transmitters.

- Changes to valves which fail to meet Appendix J, Local Leak Rate Test (LLRT) requirements; changes to damaged, leaking, or obsolete valves; changes to valves which fail to reflect current industry standards and technology; and improvements, as necessary, in valve packing performance. This included changes to 27 valves due to EQ and GL 89-10 requirements and three valves which were downgraded and removed from the EQ list.

- Implementation of pump performance enhancements, repair heat exchanger seal leakage, and perform system labeling. Among these changes are installation of bypass valves and valves between pumps and heat exchangers to allow for servicing the heat exchangers without removing the pumps from service; replacement of the current head sealing gaskets on the heat exchangers 1A and 1C with a silver-plated, solid stainless steel ring gasket to stop leakage due to relaxation of the old gasket after fit-up; and revision of specific equipment unique-identifiers to reflect operational expectations.

- Changes as a result of PERs, Punch List items, and other outstanding previously identified items. These items were documented as part of the corrective action program in effect at the time of the Unit 1 shutdown in 1985.

b.5 DCN 51163, RVLIS - Drywell, System 3

The inspectors reviewed the Unit 1 permanent plant modification DCN 51163. The intent of this DCN is to implement the modification to replace the RVLIS sensing lines to provide a more reliable level measurement system in accordance with GL-84-23 and NUREG-0737, Three Mile Island Action Item II.F.2. The DCN reroutes the sensing lines and installs new condensate pots on the reference legs to reduce the effects of the drywell environment. The DCN also provides for the replacement of the reactor head seal leakoff reservoir line, level switch, isolation and drain valves, reactor head vent sensing line and flow control valves, main feedwater inboard isolation valve closed limit switches, vibration monitoring mounting hardware, and vent and drain valves associated with the main feedwater inboard isolation valves.

b.6 DCN 51231, RVLIS -Reactor Building, System 3

The inspectors reviewed the Unit 1 permanent plant modification DCN 51231. The intent of this DCN is to implement the modification to correct RVLIS sensing line slope, separation, and orientation concerns associated with the Unit 1 Recovery Sensing Lines Special Program. Various sensing lines will be replaced in the reactor building and rerouted to meet requirements of General Electric Specification N1E-003, Instrument Line Installation and Inspection. The modification also involved drilling new drywell penetrations, capping old penetrations, removal of obsolete Barksdale and GE transmitters, installation of new Rosemount and Foxboro transmitters, and refurbishment of various panels in the reactor building.

c. Conclusions

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

E1.2 Implementation of Permanent Plant Modifications (71111.17, 37550, 37551)

a. Inspection Scope

The inspectors reviewed permanent plant modifications for the Unit 1 common accident signal logic, Unit 2 common accident signal logic, Core Spray (CS) System, RHR System, Reactor Building Closed Cooling Water (RBCCW), and the new Unit 1 digital annunciator system. The inspectors evaluated the adequacy of the modification and observed field work to verify that the design basis, licensing basis, and TS-required systems had not been degraded as a result of the modifications.

b. Observations and Findings

b.1. DCN 51016, Unit 1 Emergency Core Cooling System (ECCS) Accident Signal Logic

The inspectors reviewed permanent plant modification activities associated with DCN 51016 to restore the Unit 1 common accident signal logic.

The inspectors observed portions of the permanent plant modification which involved determing electrical cables in control panels 1-9-32, 0-LPNL-925-0046C, 3-BDAA-211-03EA, and 1-9-33, per Work Order (WO) 02-011715-01. These activities were performed to facilitate the installation of the common accident signal logic system on Unit 1, which is required for three-unit operation. Terminating the electrical cables in the control panels would allow Unit 1 modification activities to proceed without the possibility of any initiating logic system signals. Initiating logic system signals would result in the inadvertent operation of Unit 1 and/or Unit 2 safety-related equipment. The inspectors also observed activities involving WO-011715-16, remove Agastat relays from control panel 1-9-32, and WO-011715-22, remove Agastat relays from control panel 1-9-33.

b.2. DCN 51018, Unit 2 ECCS Accident Signal Logic

The inspectors reviewed permanent plant modification activities associated with DCN 51018 to restore the Unit 2 common accident signal logic for three unit operation.

The inspectors observed portions of the permanent plant modification to determinate electrical cables in control panels 2-9-32, 0-LPNL-925-0045A, 3-BDAA-211-03EC, and 2-JBOX-074-11542, per WO 02-011715-02. These activities were performed to facilitate the installation of the common accident signal logic system on Unit 1 which is required for three-unit operation. Terminating the electrical cables in the control panels would allow Unit 1 modification activities to proceed without the possibility of initiating logic system signals. The initiating logic system signals would result in the inadvertent operation of Unit 1 and/or Unit 2 safety-related equipment.

b.3. DCN 51107, Control Annunciator Upgrade, System 55

The inspectors reviewed permanent plant modification activities associated with DCN 51107.

The inspectors observed portions of the permanent plant modification in the Unit 1 Control Room panels. The work observed was the removal and replacement of the Automatic Bus Transfer (ABT) system which provided a breaker-type dual-power source to the Unit 1 analog annunciator system. The ABT was replaced with a fused-type two-power source for the new Unit 1 digital annunciator system. During the removal and replacement the power for the annunciator system was placed on a temporary power system. While the power for the annunciator system was on the temporary power system the licensee initiated applicable Limiting Conditions for Operation (LCOs) involving the Offsite Dose Calculation Manual (ODCM) and the Technical Requirements Manual (TRM). The LCOs remained in effect until the annunciator system was on the new power system. The LCO entries lasted for approximately 50 hours, which was within their allowable time. When the annunciators were down-powered per procedure 1-SOI-55-1, Unit 1 Annunciator Compensatory Measures During DCN 51107 Implementation, position indication only was lost on valve 0-HS-33-1, Service Air Isolation Valve. The valve remained capable of its design function to open on low control air pressure. The licensee documented this discrepancy in PER 68705.

b.4. DCN 51199, RHR, System 74

The inspectors reviewed permanent plant modification activities associated with DCN 51199. Specifically, the inspectors reviewed licensee activities related to removal of a normally-open manual valve in each of the suction lines from the ECCS ring header. These valves were being replaced with newly qualified suction pipe segments (spool pieces). The inspectors observed replacement spool piece construction activities and internal cleanliness conditions for portions of the ECCS ring header and RHR suction piping prior to installation. The inspectors also reviewed actions to address licensee concerns related to minimum wall thickness of portions of system piping.

b.5. DCN 51200, CS, System 75

The inspectors reviewed permanent plant modification activities associated with DCN 51200. Specifically, the inspectors reviewed licensee activities related to removal of a normally open manual valve in each of the suction lines from the ECCS ring header. These valves were being replaced with newly qualified suction pipe segments (spool pieces). The inspectors observed replacement spool piece construction activities and reviewed actions to address licensee concerns related to minimum wall thickness of portions of system piping.

b.6. DCN 51195, RBCCW, System 70

The inspectors reviewed permanent plant modification activities associated with DCN 51195. Specifically, the inspectors reviewed circumstances associated with installation activities for RBCCW Heat Exchanger 1A. RBCCW is a shared system with portions of system equipment located in the Unit 1 reactor building required to support operation of Units 2 and 3. Fitup of the replacement heat exchanger outlet nozzle and the pipe nozzles was obtained by cold-pulling the pipe from its original position after disabling the rigid support on the pipe at each nozzle resulting in additional stresses/loads on the system. This had been performed under WO 02-013117-046, which implemented DCN 51195. Cold pulling was allowed by site procedure MAI 4.2B, Piping, provided rigid supports are removed. However, TVA G-Specification G-94, Piping Installation, Modification, and Maintenance, does not allow cold pulling without design engineering approval. This minor error was documented by the licensee in PER 66742 to address the oversight.

The inspectors reviewed TVAN Calculation, CDQ1-999-2004-0151, Revision 0, Pipe Stress Evaluation of RBCCW Heat Exchanger 1A Attached Piping. This calculation evaluated the cold spring load on the eight-inch shell side inlet and outlet piping of RBCCW Heat Exchanger 1A during replacement of this heat exchanger. The calculation also served as the operability evaluation to support PER 66742. The inspectors concluded that the cold spring loads induced in the shell side inlet and outlet piping of RBCCW Heat Exchanger 1A had not jeopardized the system's operability and was qualified for long term operation.

c. Conclusions

Modification activities associated with six permanent plant modifications were performed in accordance with the documented requirements.

E1.3 Unit 1 Restart Special Program - Fuse Issues (37550)

a. Inspection Scope

In Section III.13.6 of the BFN Nuclear Performance Plan (Revision 2), TVA described corrective actions for an electrical problem involving the misapplication of fuses that limit current in overload protection. The corrective action program as it was applied to support Units 2 and 3 restart contained the following actions:

- Revise the BFN fuse substitution program control document to reflect the appropriate standards.
- Perform calculations using revised design standards to specify the appropriate fuses for each application and document this activity on the fuse tabulation document.
- Conduct plant walkdowns to determine and document the installed fuses for compliance with the fuse tabulation, with the exception of motor control centers, where allowable substitution has been identified.
- Compare the results of the fuse tabulation with the walkdown for reconciliation.
- Document and resolve by the corrective action process all inadequate fuses identified in Item 4.
- Delete and replace fuse ratings on design drawings with a fuse identification before restart. The fuse tabulation would be the single source of fuse requirements for the applicable fuses.

The focus of this inspection was to review the fuse program activities that were being implemented for restart of Unit 1. Specific focus was on understanding the differences between those actions that were conducted for Units 2 and 3, versus those planned for

Unit 1. The inspection was conducted by interviewing design engineers and reviewing design output documents including drawings, calculations and design change packages.

b. Observations and Findings

The inspectors compared the Unit 1 fuse program to the Unit 2/3 programs to determine if they were equivalent. The primary differences identified were that Units 2/3 fuses were individually walked down and evaluated for acceptability. For Unit 1, instead of walking down and inspecting the fuses, all safety-related fuses are being replaced. The calculations for sizing the replacement fuses are being performed consistent with the criteria that was used for Units 2/3. The inspectors confirmed this by reviewing the fuse sizing calculations for a selected sample of components (i.e., HPCI valves FCV-73-3 and FCV-73-16, and Core Spray Pump 1A). The fuse sizing calculations reviewed involved both alternating current (ac) and direct current (dc) fuse applications. The specific calculations reviewed were identified as follows:

- EDQ1-28102002-0041, Revision 4, “250V DC Reactor MOV Boards 1A, 1B & 1C Fuse Evaluation,”

- ED-Q0211-920700, Revision 16, “Modifications To Fuse Evaluation For 4KV Shutdown Boards A, B, C, D, 3EA, 3EB, 3EC, 3ED,”

- ED-Q0211-880138, Revision 14, “Fuse Evaluation For 4KV Shutdown Boards A, B, C, D, 3EA, 3EB, 3EC, 3ED,”

- EDQ0268880134, Revision 11, “Fuse Program - 480V Reactor MOV Boards 1A/1B,”

- ED-Q0067-920666, Revision 7, “480V Reactor MOV Boards 1A/1B Control Circuit Fuse Sizing.”

Another difference is that Units 2/3 have fuse tabulations (45B721 series drawings) which serve as design output that is used to control the fuse replacement program. Unit 1 will use the Master Equipment List (MEL) as the design output to control the fuse replacement program. These differences were judged to be acceptable by the inspectors because the inputs to the MEL are controlled by the design control process. In addition, the fuse tabulations are derived from the MEL data base. Furthermore, the licensee revised the Unit 1 design drawings to delete fuse ratings from them and to add unique fuse identification numbers. Thus, the MEL Sheets will then be the single source for Unit 1 to determine fuse requirements for the fuse control program. This is consistent with the other unit drawings.

The licensee indicated that approximately 1400 safety-related fuses will be replaced prior to Unit 1 restart. The majority of the fuses will be replaced by DCNs 51090, 51091, 51110, 51216, and 51240. The inspectors observed the replacement of some non-safety fuses and did not identify any concerns. The inspectors noted that the craft followed the procedures in the work order package. The same processes will be applied to safety-related applications. The inspectors informed the licensee that additional inspections would be required to perform walkdowns of safety-related fuse replacements to verify that the fuse replacement program was being properly implemented for safety-related applications.

a. Conclusions

The inspectors concluded that the licensee's program to resolve the problems with misapplication of current-limiting fuses is acceptable to support Unit 1 restart. The program is equivalent in scope to those previously applied to the restart of the other units at Browns Ferry. However, additional inspection will be conducted to verify that the program was implemented adequately.

E1.4 Unit 1 Restart Special Program - Thermal Overloads (37550)

a. Inspection Scope

In Section III.13.4 of the BFN Nuclear Performance Plan (Revision 2), TVA described a design control problem with the application of thermal overloads (TOLs) in 480-Volt (V) ac and 250-V dc motor control centers. The corrective action program as it was applied to support Units 2 and 3 restart contained the following actions:

- Inspect the 480-V ac and 250-V dc safety-related motor control centers to determine and document the installed TOL ratings.
- Develop and issue a sizing criteria for TOLs.
- Evaluate the walkdown results against the sizing criteria.
- Replace or reset improperly sized TOL elements, as appropriate.
- Properly sized or replaced TOLs will be documented on a TVA design drawing to assure that current and future installations of thermal overloads are correct.
- For those Unit 2 harsh environment safe shutdown TOLs with qualification deficiencies, TVA will issue a design to disable the TOLs by disconnecting the control circuit interlocks until qualified TOLs are obtained.

This inspection focused on the corrective actions that were being implemented by TVA to resolve the thermal overload concern for the Unit 1 Restart. Specific focus was placed on understanding the differences between those actions that were conducted for Units 2 and 3, versus those planned for Unit 1. The inspection was conducted by interviewing design engineers and reviewing design output documents including drawings, calculations, and design change packages. A licensee self-assessment was reviewed to determine if deficiencies were routinely entered into the corrective action program. Walkdowns were performed to obtain motor nameplate data to verify that information used in the sizing calculations correctly reflected the as-built plant.

b. Observations and Findings

The Unit 1 TOL program was compared to the Units 2 and 3 programs to determine if they were equivalent. The primary differences identified were that the Units 2 and 3 thermal overloads were individually walked down, inspected, and evaluated for acceptability. However, for Unit 1, instead of walking down and inspecting the thermal overloads, all safety-related TOLs are scheduled to be replaced. The licensee has completed sizing calculations for TOLs used for protection of continuous duty motors and motor-operated valves and developed DCNs to replace all safety-related TOLs on Unit 1. The DCN packages have been issued and are scheduled to be worked in 2005 and 2006. Like Units 2/3, the Unit 1 TOL heaters and settings will be documented in design drawings and these drawings will be used to replace the TOLs when required. The Unit 1 TOL sizing calculations are also similar to the Units 2/3 design calculations in that they were developed in accordance with TVA design standards as well as industry standards. In addition, the TOLs were sized to ensure performance of the safety function consistent with NRC Reg Guide 1.106. The following two sizing calculations were developed by the licensee for Unit 1 TOLs:

- EDQ1-999-2002-0076, Thermal Overload Heater Calculation - Continuous Duty Motors, Revision 003

- EDQ1-999-2002-0075, Thermal Overload Heater calculation - Motor Operated Valves, Revision 004

The inspectors reviewed the calculations and walked down a sample of continuous duty motors to obtain motor nameplate data to confirm that such information as horsepower data, full load current, and service factor information used in sizing the TOLs in Calculation EDQ1-999-2002-0076 (Revision 003) reflected the as-built plant. The following motors were field-inspected:

1-MTR-73-47, HPCI Turbine Auxiliary Oil Pump
1-MTR-64-68, RHR Pump 1A Cooler Fan
1-MTR-77-8B, Reactor Building Floor Drain Sump Pump 1B
1-MTR-77-14B, Drywell Equipment Drain Sump Pump 1B
1-MTR-77-1A, Drywell Floor Drain Sump Pump 1A

Based on this review, the inspectors concluded that the calculations were accurate and complete. However, Calculation EDQ1-999-2002-0075 (Revision 004) contained several unverified assumptions regarding the installation of new motor-operated valves (MOVs) on Unit 1 that have to be confirmed after the MOVs are installed. In addition to the above, the inspectors reviewed self-assessment report BFR-REN-04-003, "Assess the Effectiveness of the Methods Used to Size the Thermal Overload Heaters for Unit

1," to verify that deficiencies identified are entered into the licensee's corrective action program.

c. Conclusions

The inspectors concluded that the licensee's program for Unit 1 TOLs is consistent with that used for restart of Units 2/3. However, additional inspection will be necessary to verify that the DCN packages and unverified assumptions in the TOL calculations are implemented adequately.

E1.5 Unit 1 Restart Special Program on Electrical Cable Splices and Terminations in EQ Applications (37550)

a. Inspection Scope

In 1986, the NRC issued Information Notice (IN) 86-53 alerting licensees to a potential safety problem involving improper installation of heat-shrinkable tubing over electrical splices and terminations. In addition to this information notice, an employee concern was brought up at Browns Ferry regarding problems with existing site procedures for installing electrical splices. Based on these concerns, TVA initiated a comprehensive program at Browns Ferry to ensure the adequacy of all class 1E electrical cable splices and terminations in harsh environments.

TVA's comprehensive splice program as described in the Nuclear Performance Plan (Revision 2) required all splices and terminations subject to 10 CFR 50.49 to be inspected and replaced if the splices did not meet installation standards. This program was implemented as part of the restart effort on Units 2 and 3. The NRC staff reviewed the implementation of this program during the restart of Units 2 and 3 and found it to be acceptable.

Based on discussions with licensee representatives, the inspectors determined that the Unit 1 Restart cable splice program will be similar to that implemented on Units 2 and 3; however, fewer walkdowns will be required since most of the existing cable splices are scheduled to be replaced prior to restart of Unit 1. The Environmental Qualification (EQ) cables and splices that are not scheduled to be replaced will be inspected and incorporated into the Unit 1 EQ Program through Unit 1 Restart DCNs. The licensee indicated that there are approximately 522 Unit 1 EQ splices. Of those, 505 new EQ splices will be installed as part of the Unit 1 restart. The remaining 17 EQ splices (currently installed) will be incorporated by documentation only changes to the EQ Program (i.e., EQ Change supplements).

This inspection focused on the evaluation and resolution of a concern involving EQ splices that were located below postulated flood levels in Unit 1. The inspectors also reviewed on-going activities to implement the cable splice program for the Unit 1 restart. This inspection was performed by interviewing design engineers, reviewing design calculations, and other design output documents associated with the implementation of the cable splice program.

b. Observations and Findings

The inspectors reviewed the licensee's analysis and corrective actions to resolve a concern involving splices in safety-related and EQ cables installed below flood level elevations in Unit 1 areas as defined by the "Line Break Analysis." Specifically, the inspectors reviewed Calculation EDQ199920030026, Revision 1, "Evaluation of Splices in 10 CFR50.49 and Safety Related Cables in Unit 1 Areas of Potential Flooding for Unit 1 Restart," to assess the adequacy of the licensee's analysis and corrective actions.

The calculation described a licensee program that was established to inspect all raceways containing safety-related and/or 10 CFR50.49 cables in Unit 1 areas below flood level elevations. The calculation summarized the results of walkdowns that were performed on EQ cable junction boxes, pull boxes, and conduit fittings that were opened and inspected for splices subject to submergence. The overall conclusion of the calculation was that the field inspections did not reveal any splices in EQ cables that were subject to submergence. However, those safety-related cables that were found to be located below flood level have since been reclassified to non-quality related, abandoned, deleted, and/or scheduled to be replaced for other reasons.

The calculation also referenced two DCN packages (i.e., DCN 51220 and 51211) that had been issued to abandon, delete, or replace the cables subject to submergence. The inspectors reviewed the DCN packages and confirmed that the cables had been either deleted, abandoned, or identified for replacement. Other actions taken by TVA to prevent recurrence of this issue, included revision of TVA Design Guide BFN-50-758, "Browns Ferry Nuclear Plant Power, Control, and Signal Cables for Use In Class 1 Structures," to require that cables shall not be routed below postulated flood levels unless an analysis is performed to verify acceptable cable operation during and after submergence and water-caused degradation.

The licensee stated that approximately 1421 cables will be included in the Unit 1 EQ Program. Of those, 1099 new cables will be installed as part of the restart program. The remaining 322 (currently installed) cables will be added to the EQ Program through documentation-only changes in the Unit 1 restart DCNs. The 322 existing cables have been walked down by the licensee to record cable data to establish qualification of the cables. In addition, the licensee examined the cable pull points to identify undocumented splices and cable damage.

The inspectors informed the licensee that future walk down inspections would be required by the NRC to determine if the cable splice program (including submerged cable splices) was being implemented satisfactorily.

c. Conclusions

The inspectors concluded that TVA has initiated a cable splice program consistent with the BFN Nuclear Performance Plan to ensure the adequacy of all Class 1E electrical cable splices and terminations in harsh environments on BFN Unit 1 (including cable splices located below flood levels). The program is scheduled to be completed prior to Unit 1 Restart and will require replacement of most of the Unit 1 EQ splices (approximately 522 total). The inspectors concluded that since most of the EQ cables and splices will be replaced prior to restart, it would be necessary to conduct further inspections after the cables and splices are installed to verify that the program is being implemented satisfactorily.

E1.6 Unit 1 Restart Special Program - Environmental Qualification (EQ) of Electrical Equipment (37550)

a. Inspection Scope

The inspectors reviewed the status of the EQ program that is being implemented to support the Unit 1 restart. In addition, one licensee self-assessment associated with this Special Program was reviewed.

b Observations and Findings

The NRC had previously reviewed and accepted the EQ program that was implemented to support restart of Units 2/3. The evaluation of the program was discussed in Section 3.2 of NUREG-1232, Volume 3, dated April 1989. In that evaluation, the staff concluded that the Browns Ferry equipment qualification program of electrical equipment located in harsh environments complies with the requirements of 10 CFR 50.49. The inspectors compared the Unit 1 EQ program to the Unit 2/3 programs to determine if they were equivalent. The Unit 1 EQ Program uses the same processes and procedures that are used for the Unit 2/3 EQ Programs. For example, the existing Unit 2/3 Equipment Qualification Data Packages (EQDPs) are being revised to address the Unit 1 EQ equipment including the Qualification Maintenance Data Sheets and the Field Verification Data Sheets. New EQDPs will also be issued for those Unit 1 EQ equipment items that are not currently included in the Unit 2/3 EQ Program.

The licensee plans to replace most of the Unit 1 EQ equipment including cables and splices prior to Unit 1 restart. The Unit 1 EQ equipment that is not scheduled to be replaced is being added to the BFN EQ Program through EQ Change Supplement (EQCS) documents which are included in the Unit 1 Restart DCN packages. The licensee indicated that the following equipment will not be replaced because the qualification is acceptable based on walkdown data and documentation reviews:

- RHR and CS pump motors
- 4 scram discharge instrument volume level elements
- 2 cooler units for the shutdown board room

- 322 cables
- 17 splices

The list of EQ equipment required to meet 10 CFR 50.49 will be contained in the MEL data base. The inspectors informed the licensee that additional inspections including plant walk downs will be required as work progresses to verify proper implementation of the EQ Program. The inspectors reviewed self-assessment report BFR-REN-04-002, “Assess the Effectiveness of the EQ Program Implementation for Unit 1 Restart,” and confirmed that deficiencies had been entered into the licensee’s corrective action program.

c. Conclusions

The inspectors concluded that the licensee’s program for the environmental qualification of electrical equipment on Unit 1 is consistent with that used for restart of Units 2/3. However, additional inspection will be necessary to verify that the adequacy of program implementation.

E1.7 Restart Test Program (37551)

a Inspection Scope

The inspectors performed an initial review of the licensee’s ongoing activities associated with development of the comprehensive Restart Test Program (RTP). The RTP consists of development of Baseline Test Requirements Documents (BTRDs), System Test Specifications (STSs), specific component and system RTP procedures such as Post Modification Test Instructions (PMTIs) and Technical Instructions (TIs), and will culminate in performance of the applicable testing during restart. The inspectors reviewed the RTP to develop an understanding of the licensee’s approach, compare it to the RTP for the Unit 2 and 3 recoveries, and to verify it appropriately encompassed the necessary system testing for restart.

b. Observations and Findings

TVA letter dated December 13, 2002, “Browns Ferry Nuclear Plant - Unit 1- Regulatory Framework for the Restart of Unit 1," provided TVA’s proposed regulatory framework for restart of Unit 1. The licensee stated that TVA’s plan for the restart of Unit 1 was based on regulatory requirements, special programs, commitments, technical specification improvements, and TVA-identified deficiencies and concerns that were resolved prior to Units 2 and 3 restarts. The licensee also stated that the RTP for Unit 3 had utilized normal surveillance testing to a greater extent than done during Unit 2 restart. Also, additional administrative controls to ensure the status of the operating units was considered during planning and scheduling of restart testing, eliminated complete Loss of Off-site Power/LOCA tests and most drywell vibration testing and reduced the number of management assessment hold points during power ascension.

b.1 Baseline Test Requirements Document (BTRD) Review

The Unit 1 Recovery Project identified and developed a total of 50 BTRDs which define the scope of testing considered necessary to demonstrate that for Unit 1 operation, and concurrent Units 2 and 3 operation, a specific system can meet the functional requirements for safe shutdown of Unit 1 from all operational transients, accidents, and special events. These tests are identified in licensee document ND-Q0999-910033, Safe Shutdown Analysis (SSA). The BTRDs were developed using the following reference documents:

- Technical Instruction 1-TI-469, Baseline Test Requirements
- Detailed design criteria documents, such as BFN-50-0727, Environmental Qualification, BFN-50-7001, Main Steam System, and BFN-50-7082, Standby Diesel Generator
- Drawings such as schematic, elementary, flow, and wiring diagrams
- Document ND-Q0999-940013, Reliability Analysis of the Pre-Accident and Common Accident Signal Logic for Units 1, 2, and 3

The BTRDs also used applicable Drawing Change Authorizations (DCA) and Design Change Notices (DCNs).

The BTRDs are stand-alone engineering system testing documents, which listed the total number of test modes for each system and listed verified and unverified assumptions. For example: 01-BFN-BTRD-001, Main Steam System, listed 27 test modes, 01-BFN-BTRD-075, Core Spray System, listed 15 test modes, and 01-BFN-BTRD-064C, Secondary Containment, listed one test mode. Following the licensee's review of the SSA, lists of functional tests were developed to cover all test modes required for all systems needed to support safe shutdown, and were included in the BTRDs. All identified functional tests were covered by Test Scoping Documents (TSDs) which were included as attachments to the BTRDs. The TSDs defined the safe shutdown test requirements for all modes addressed in the SSA and described the scope of testing, required system configurations, initial system conditions, special test precautions, and listed the acceptance criteria for the tests. Test modes for some systems will be tested in conjunction with other systems. For example: Test mode 075-04, provide reactor coolant pressure boundary, listed in 01-BFN-BTRD-075, Core Spray System, will be included in 01-BFN-BTRD-068, Reactor Recirculation System. Some of the systems have test modes that require system operation from outside the control room, referred to as the Backup Controls (BUC) testing. The inspectors selected four BTRDs including selected associated test modes for review.

1.) <u>01-BTRD-075, Core Spray (CS) System</u>

Five of 15 test modes for the CS System were reviewed. Test modes reviewed included the following:

- Test mode 075-01 is for providing supply cooling water to the reactor (auto initiation). These test objectives were defined in Attachments A, B, C, and D. Attachment A defined the test requirements to verify the pumping capability of the CS pumps, the generation of a start signal from the CS logic, and the proper operation of the CS minimum flow valves. Attachment B defined the test requirements to verify that the opening and/or closing times of selected valves in the CS system were within specified times. Attachment C defined the test requirements to confirm that the CS system will automatically initiate and all four CS pumps start on either normal AC power or diesel generator power upon receipt of an accident signal. Attachment D defined the test requirements to demonstrate the operational logic of the inboard, outboard, and test bypass valve logic for the CS system.

- Test mode 075-07 provides a start signal to the D/G system on high drywell pressure or reactor low water level and provides an accident signal to the 4-kV system logic on either high drywell pressure or reactor low water level coincident with reactor low pressure; and test mode 075-17, provides load shed signal to 480-VAC system on reactor low water level or coincident high drywell pressure and low reactor pressure, were both defined in Attachment G. This attachment defined the test requirements to verify that the CS system provides a start signal to the diesel generators, an accident signal to the 4KV logic system, and a load shed signal to the 480-VAC system.

- Test mode 075-15 provides a LOCA signal from Unit 2 to inhibit automatic initiation of one loop of CS of Unit 1, and provides a LOCA signal from Unit 1 to inhibit automatic initiation of one loop of CS of Unit 2; and test mode 075-16, inhibit automatic initiation of one loop of CS in Unit 2 given a LOCA signal from the CS system of Unit 1, and inhibit automatic initiation of one loop of CS in Unit 1 given a LOCA signal from the CS system of Unit 2, were both defined in Attachment L. This attachment, referred to as the common accident signal logic, defined the test requirements to demonstrate that, in the event of an accident signal in both Units 1 and 2, the Division II start permissive signal is blocked on Unit 1 and the Division I start permissive signal is blocked on Unit 2. This will dedicate the Division I ECCS systems to Unit 1 and the Division II ECCS systems to Unit 2.

- Test mode 075-11 and test mode 075-12 provide low reactor water level and low reactor pressure initiation logic signals to the RHR system for low pressure cooling injection mode. Both of these test modes were defined in Attachment H.

2.) <u>01-BFN-BTRD-074, Residual Heat Removal (RHR) System</u>

Six of 19 test modes for the RHR System were reviewed. Test modes reviewed included the following:

- Test mode 074-01, automatic low pressure coolant injection (LPCI) on reactor pressure vessel low water level signal or high drywell pressure, with concurrent low reactor pressure vessel pressure permissive signal, and manual LPCI signal from the control room, test objectives were defined in Attachments A, B, and C. Attachment A defined the test requirements to verify the automatic and manual LPCI initiation logic of the RHR system demonstrating the system responses for the following: From standby mode to LPCI mode and containment cooling mode to LPCI; from shutdown cooling mode and LPCI manual initiation mode to standby; testing of the LPCI mode and the 2/3 core height containment drywell spray inhibit; and testing of the 5 minute throttle valve delay and the timing sequence of the RHR pumps using normal and diesel power sources. Attachment B defined the test requirements to verify that the opening and/or closing times of selected valves in the RHR system were within specified times. Attachment C defined the test requirements to confirm that the LPCI mode of the RHR system has the ability to meet the injection requirements and a proper flow path is provided.

- Test mode 074-02 provides suppression pool cooling to maintain suppression pool water temperature below limits to ensure that pump net positive succession head (NPSH) requirements are met and that complete condensation of blowdown steam from a design basis accident can be expected. Test objectives were defined in Attachments A and C. Both attachments are explained above.

- Test mode 074-03 provides spray to the drywell and torus for containment cooling and lowering containment pressure under post-accident conditions. Test objectives were defined in Attachments A, C, D, and E. Attachments A and C are explained above. Attachment D defined the test requirements to verify unimpeded flow from each nozzle in the torus spray piping when the RHR system is used in the torus spray cooling mode. Attachment E defined the test requirements to verify that the RHR system will provide drywell containment spray.

- Test modes 074-24 and 074-25 provide divisional inhibit operation. These modes were similar to CS System test modes 075-15 and 075-16, as previously discussed. The test objectives for both modes were defined in Attachment J, which defined the test requirements which were similar to the requirements of Attachment L in the CS system BTRD.

- Test mode 074-19 provides for manual operation of the LPCI, torus cooling, and shutdown cooling modes from outside the control room. Test objectives were defined in Attachment F which defined the test requirements to confirm that the required system modes can be manually achieved from outside the control room. This attachment, part of the BUC testing, also referenced the equipment and their positions or status required to meet the three cooling modes.

3.) <u>01-BFN-BTRD-023, Residual Heat Removal Service Water System (RHRSW)</u>

Three of seven test modes for the RHRSW System were reviewed. Test modes reviewed included the following:

- Test mode 023-01 provides cooling water to the RHR system heat exchangers. Test objectives were defined in Attachments A and C. Attachment A defined the test requirements to verify that the RHRSW system is capable of providing adequate flow to the Unit 1 A, B, C, and D RHR heat exchangers and to verify the Unit 1 flow path integrity. This attachment also defined that the scope of the test was to demonstrate that each of the eight RHRSW designated pumps, i.e., A1, A2, B1, B2, C1, C2, D1, and D2 would deliver at least 4500 gpm to their associated RHR heat exchangers. Attachment C defined the test requirements to verify that the RHRSW system is capable of providing adequate flow to two RHR heat exchangers, in two different units, with two RHRSW pumps aligned to a single loop. This attachment will also test the system operation for an accident occurring in one of the three units, to verify that cooling water would be supplied to the accident unit and to both non-accident units to support orderly shutdowns. To support orderly shutdowns, two RHRSW pumps will be configured to supply a single header which will be aligned to one heat exchanger in each of the two non-accident units. Licensee analysis showed that the most demanding configuration was to align RHRSW pumps D1 and D2 to the same header providing cooling water to Unit 1 RHR heat exchanger 1D and Unit 2 heat exchanger 2D.

- Test mode 023-03 provides cooling water to the Emergency Equipment Cooling Water (EECW) system upon start of the RHRSW pumps. Test objectives were defined in Attachments D and F. Attachment D defined the test requirements to confirm that each of the RHRSW pumps dedicated to the EECW system, A3, B3, C3, and D3, can be manually operated from the control room and cannot be operated from the remote panel when the corresponding Unit 1 transfer switch is in the Normal position. Attachment F defined the test requirements to confirm that each of the RHRSW pumps dedicated to the EECW system, and the swing pumps, A1, B1, C1, and D1, will auto start upon receipt of both Unit 1 Common Accident Signals A and B, with the corresponding transfer switches in either the Normal or Emergency positions.

- Test mode 023-08 provides manual RHRSW system operation from outside the control room for cooling water to the RHR heat exchangers. Test objectives were defined in Attachment B. This attachment, part of the BUC testing, defined the test requirement that two loops of the RHRSW system can be operated outside the control room to provide cooling water to Unit 1 RHR system heat exchangers 1B and 1D.

4.) <u>01-BFN-BTRD-064D, Primary Containment Isolation System (PCIS)</u>

Three of five test modes for the PCIS were reviewed. Test modes reviewed included the following:

- Test mode 064D-01 provides the signal to close Main Steam System and Sample Water Quality System Group 1 Primary Containment Isolation Valves. Attachment A defined the test requirement that the PCIS will provide Group 1 isolation signals upon receipt of an accident or abnormal transient trip signal input.

- Test mode 064D-02 provides the signal to close RHR, Core Spray, and Radwaste systems Group 3 Primary Containment Isolation Valves. Attachment C defined the test requirement that the PCIS will provide Group 3 isolation signals upon receipt of an accident or abnormal transient trip signal input.

- Test mode 064D-04 provides the signal to close Containment Purge and Reactor Building Ventilation, Containment Inerting, Containment Air Dilution, and Radiation Monitoring systems Group 6 Primary Containment Isolation Valves, as well as, isolate air conditioning system supply ducts to the Control Room (CR), initiate emergency CR pressurization, trip ventilation fans, position ventilation dampers, and initiate the Standby Gas Treatment System (SGTS). Attachment D defined the test requirements that the PCIS will provide Group 6 isolation signals upon receipt of an accident or abnormal transient trip signal input.

During the review of the CS system BTRD, the inspectors observed that Test Modes 075-11 and 075-12 stated that the CS system provided initiation logic signals for the LPCI mode to the RHR system. However, during the review of the RHR system BTRD, the inspectors noted that Test Mode 074-24 incorrectly stated that these initiation logic signals came from the RHR system logic. This observation was discussed with the licensee and PER 68031 was issued for resolution.

b.2 <u>System Test Specification (STS) Review</u>

The purpose of STSs are to define the scope of testing considered necessary to demonstrate operability of systems required for Unit 1 restart. The STSs are system testing documents, which included separate sections for restart test requirements, modification test requirements, Units 2 and 3 test program applicability, ITEL punchlist items, work orders and maintenance history/status, and additional test requirements. Each section listed the test requirement, basis for the requirement, plant instruction used to satisfy the requirement, and date of completion of the instruction. The inspectors noted that 60 of 66 required STSs had been developed. The inspectors reviewed the following STSs:

- 1-STS-075, CS System,
- 1-STS-074, RHR System.
- 1-STS-023, RHRSW System.
- 1-STS-064D, Primary Containment Isolation System.

The inspectors noted that each STS included a cover sheet which contained a signed concurrence that the Restart System Engineer, Restart System Engineering Supervisor, and Restart Test Manager had concurred with the planned testing for Return To Service (RTS) of the system. The cover sheet also contained an unsigned concurrence which indicated that the individuals listed above, plus the Plant Restart Manager, for future use to indicate concurrence upon completion of the system testing for RTS. In addition, each STS listed the test requirements, which were based on the BTRD, and the plant instructions to be used to meet the requirements. During the review of the CS system STS, the inspectors observed that Section VI, Additional Test Requirements, listed one requirement involving room temperature monitoring indication. The requirement referenced rooms A and C, but incorrectly listed the test procedure for rooms B and D. The inspectors also questioned the need for an additional test requirement for the RHR room temperature monitoring indication. This observation was discussed with the licensee and PER 67147 was issued for resolution. The inspectors also observed that the STS for the RHR system did not list test modes 074-24 and 074-25 or the instructions required for testing and that the STS for the RHRSW system did not list the test mode 023-08. These observations were discussed with the licensee and PER 68031 was issued for resolution. These observations were considered minor inconsistencies and were not violations of applicable requirements.

b.3 Post-Modification Test Instruction (PMTI) Review

The purpose of PMTIs was to test specific equipment that would not be otherwise tested by an existing plant procedure, such as 1-PMTI-BF-074.156, RHR Division II Auto Injection Inhibit Key Lock Switch, and 1-PMTI-BF-075.055, CS Division I Auto Injection Inhibit Key Lock Switch. The tests applied to quality-related equipment as well as non-quality related equipment. The inspectors noted that the Unit 1 recovery RTP group had developed 33 PMTIs of a total of 62 PMTIs identified for development. The PMTIs consisted, in part, of test purpose, test scope, test objectives, and acceptance criteria. The tests contained appendices for such items as test director assignment sheet, chronological test log, data sheets, calculations, deficiency log, and measurement and test equipment information. The inspectors reviewed the following PMTIs:

- 1-PMTI-BF-035.013, Main Generator Temperature Monitoring System Testing
- 1-PMTI-BF-064.116, Steam Tunnel Booster Fan
- 1-PMTI-BF-002.001, Initial Performance Testing of Condensate Pump Impellers

The inspectors observed that the test for the condensate pumps was developed for the increased flow required for the planned extended power uprate. No significant findings were identified during the review of PMTIs.

c. Conclusions

During the initial review of the licensee's RTP, several minor discrepancies associated with the development of test requirements were identified. These discrepancies were discussed with licensee management and entered into the corrective action program. Based on those documents reviewed, the inspectors concluded that the licensee's RTP was meeting commitments established by the licensee's Regulatory Framework letters. The inspectors will continue to review the licensee's program for developing and satisfying RTP requirements and the resultant testing plans during future inspections. Implementation of the RTP and observation of testing will also be done during future inspections.

E1.8 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed licensee procedure SPP-9.5, Temporary Alterations, and a temporary alteration associated with the Residual Heat Removal Service Water (RHRSW) System to ensure that procedure and regulatory requirements were met. This temporary alteration was installed under Temporary Alteration Control Form (TACF) 1-04-003-023 to support heat exchanger replacement activities associated with the RHRSW System. The inspectors reviewed the associated 10 CFR 50.59 screening against the system design bases documentation and reviewed selected completed work activities of the system to verify that installation was consistent with the modification documents and the TACF. In addition, special emphasis was placed on the potential impact of this temporary modification on operability of equipment required to support operations of Units 2 and 3.

b. Observations and Findings

TACF 1-04-003-023 was issued to install a temporary piping jumper from the RHRSW supply header in the Unit 1 Reactor Building to the 1A RHRSW heat exchanger and 1C RHRSW heat exchanger discharge header as a means of flushing the new RHRSW piping installed by WO 03-001371-001, in conjunction with DCN 51177, RHRSW in Reactor Building - System 23. The piping from the A RHRSW pump and the C RHRSW pump to the heat exchangers has been idle since the Unit 1 shut down in 1985. Upon completion of the flushing activities, the temporary piping jumper will be removed and the permanent piping will be installed by a separate work activity. The inspectors reviewed the 10 CFR 50.59 screening questions and the evaluation. The evaluation concluded that the proposed TACF did not require NRC approval. The licensee evaluation also concluded that the proposed TACF could be implemented per plant procedures without obtaining a License Amendment.

c. Conclusions

The inspectors determined that the temporary alteration associated with the RHRSW system did not cause any significant impact on the operability of equipment required to support operations of Units 2 and 3. No violations or deviations were identified.

E1.9 System Return to Service Activities (37550)

a. Inspection Scope

The inspectors reviewed and observed portions of the licensee's ongoing system-return-to-service (SRTS) activities. The inspectors used the licensee's Technical Instruction 1-TI-437, System Return to Service (SRTS) Turnover Process For Unit 1 Restart, during this review. The licensee initiated the SRTS process earlier this year and the inspectors were focused on assessing the adequacy of their process as it was first exercised on some support systems.

b. Observations and Findings

The SRTS process consisted of three parts as follows: The System Plant Acceptance Evaluation (SPAE), which consists of design changes, engineering programs analysis, drawings, calculations, corrective action items, and licensing issues; the System Pre-Operability Checklist (SPOC) I, which consists of the completion of items required for system testing; and the SPOC II, which consists of the completion of system testing and the completion of items that affect operational readiness. Included within the SRTS process are system walkdowns. The inspector reviewed and observed portions of the following licensee's SRTS activities:

- System 8, Turbine Drains and Miscellaneous Piping, which included the SPAE process and the SPOC I process

- System 12, Auxiliary Boilers, which included the SPAE process and the SPOC I process

- System 33, Service Air, which included the SPAE process and the SPOC I process

- System 37, Gland Seal, which included the SPAE process and the SPOC I process

- System 40, Station Drainage, which included the SPAE process and the SPOC II process

- System 78, Fuel Pool Cooling, which included the SPAE process and the SPOC I process

During this report period the SPAE process and the SPOC I process were both completed for System 8, System 12, and System 33.

Activities observed included periodic meetings to discuss the SRTS status of various systems, which included the status of the SPOC I checklists, the status of the SPAE process, and the status of the SPOC II checklists. The activities also included observation of licensee walkdowns of portions of plant systems and review of PERs initiated during the SRTS process. Specific PERs reviewed by the inspectors are listed in the report attachment. Each of these PERs were adequately addressed by the Unit 1 Restart corrective action program.

c. Conclusions

SRTS activities continued to be performed in accordance with procedural requirements. System deficiencies were identified and appropriately addressed by the licencee's corrective action program.

E7 Quality Assurance in Engineering Activities

E7.1 Licensee Quality Assurance Oversight of Recovery Activities (Identification and Resolution of Problems) (71152)

a. Inspection Scope

The inspectors evaluated the adequacy of the licensee corrective actions to address various documented deficiencies indicating problems with the licensee welding program. The inspectors reviewed selected PERs and observed field activities. In addition, the inspectors held discussions with TVA and Stone & Webster Engineering Corporation (SWEC) management personnel, Nuclear Assurance (NA) personnel, welding engineers, and craft personnel. The inspectors evaluated of the adequacy of licensee management and NA oversight of welding program activities, effectiveness of self-assessments and audits in this area, and corrective actions associated with documented deficiencies. Also, the inspectors' review was to assess whether any issues were processed in accordance with licensee Procedure SPP-3.1, Corrective Action Program.

b. Observations and Findings

The inspectors determined that during the first half of 2004, various PERs indicated potential adverse trends in four specific areas related to the TVA welding program. These areas included weld material issue and control, weld engineering documentation errors, welder performance deficiencies, and Qualified Individual (QI) errors. Multiple examples of weld filler material control errors, weld documentation errors and weld performance errors required evaluation to determine if any common cause factors required specific actions by the licensee. In addition, as of March 1, 2004, the acceptance rate for welding QC inspections had been approximately 95%, which had not satisfied the licensee's goal of 98% QC acceptance rate.

Weld Material Issue and Control

Fifteen PER conditions had been identified within the weld material issue centers where weld filler materials were mixed, were in the wrong storage/issue bin, were damaged, or were not identified correctly. In addition, eight PER conditions were identified where filler material was either left unattended or discarded incorrectly by Unit 1 welders. The licensee documented this potential adverse trend in PER 63896. The majority of the PERs were related to mixed, damaged, or filler materials that were not identified correctly. Most of these errors were identified by craft or QC personnel prior to use of the weld filler material. No examples of actual use of incorrect weld filler material in any safety-related application were identified. Based on discussions with welders and weld material issue station personnel, the licensee determined that the process for certification/training for issuing weld filler material was inadequate.

Weld Engineering Documentation Errors

Four PER conditions identified examples where the Detail Weld Procedure Specification (DWPS) or Non-Destructive Examination (NDE) was incorrectly assigned, 57 PER conditions identified administrative errors on Weld Data Sheets (WDSs), and five PER conditions identified examples where the WDS did not match design requirements. These errors were made by the WDS preparer and not corrected by the reviewer. In each case, the errors were identified by either QC or NA oversight personnel prior to the acceptance of the WDS as a completed record. The licensee documented this potential adverse trend in PER 65044. Based on its review, the licensee attributed these errors to inattention to detail by the WDS reviewer to ensure that WDS were 100% correct prior to issuance. The licensee also determined that the inadequate staffing level for weld engineering had been a contributor and that some of the errors could be attributed to excessive implementation requirements (approximately 30% of data entries on WDS were not needed).

Welder Performance

Sixty-two PER conditions identified poor weld quality or welds that didn't meet design requirements and 11 PER conditions identified where the welder failed to follow documented requirements. TVA documented this potential adverse trend in PER 65148.

QI Errors

Licensee QI personnel verify the quality of completed welding activities prior to contacting QC for inspections. QI personnel had previously been selected craft foreman. Two PER conditions were identified where a welder had added weld material without being qualified, four PER conditions identified where the QI function was performed by an inactive QI, 45 PER conditions identified QI failures in identifying poor weld quality or welds that did not meet design requirements, 33 PER conditions identified omissions or errors by the QI in WDS documentation, and 16 PER conditions where the QI failed to follow the documented requirements. TVA documented this potential adverse trend in PER 65047.

Licensee Resolution of Welding Program Deficiencies

Various corrective actions were taken in response by the licensee to the documented deficiencies. These actions included stand downs with all welding craft, supervision, weld filler material station attendants, and weld engineering personnel to reinforce existing standards and expectations. The licensee hired additional weld engineering personnel. After August 2, 2004, craft personnel were no longer allowed to perform QI functions. After that date, only weld engineers could perform that function.

Additional performance monitoring of craft welders and foremen was performed by management, welding engineers, and NA personnel. A special licensee corporate assessment of the welding program was conducted. In addition, a focused self-assessment of welding activities was commenced and was still in progress at the conclusion of this inspection period.

To address weld filler material control problems, additional training of issue station attendants was conducted. In addition, Unit 1 weld issue stations have subsequently been placed under the supervision of Unit 1 welding engineering, with daily oversight of filler material issue activities by a weld engineer. Periodic management, welding engineer, and NA observations of issue station activities occurred. Fewer examples of filler material control and issue errors have been identified. The inspectors visited the Unit 1 filler material station (turbine building) and Unit 1 Fab Shop filler material issue station and observed weld filler material storage, material separation practices, and filler material issuance to craft personnel. No deficiencies were identified by the inspectors during these observations.

c. Conclusions

Increased management focus and oversight of the welding program has initially resulted in fewer documentation errors and improvement in welder performance. In addition, as of October 1, 2004, the acceptance rate for welding QC inspections had improved to greater than 97%. However, the inspectors will continue to evaluate the effectiveness of the licensee's long term corrective actions in the area. No violations or deviations of significance were identified.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) IFI 50-259/87-33-02: Failure of Drywell Control Air Isolation Valves to Meet Design Criteria

In August 1987, during performance of a Unit 2 restart test procedure, a test discrepancy was discovered. Specifically, the drywell control air suction valves 2-FCV-32-62 and 2-FCV-32-63 failed "as-is" upon loss of control air instead of failing closed, as required. The licensee determined the cause of this malfunction to be the improper implementation of an equipment modification intended to upgrade the solenoid valves for environmental qualification. This condition will be resolved on Unit 1 by DCN 51182 which implements various design changes to the Drywell Control Air System to provide a more reliable pneumatic source to certain safety-related components. Stage 2 to DCN 51182 will delete valves 1-FCV-32-62 and 1-FCV-32-63. The design resolutions were previously implemented on Unit 2 and the inspection and the closure of this item for Unit 2 were documented in Inspection Report 50-259,260,296/89-35. The design resolutions were implemented on Unit 3 and the inspection and the closure of this item for Unit 3 were documented in Inspection Report 50-259,260,296/95-16. The inspector reviewed DCN 51182, which included the design details of the modification to the drywell control air system. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Units 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, and have only minor consequences, this item meets the closure criteria established for the Unit 1 recovery issues. This issue is closed for Unit 1.

E8.2 (Closed) IFI 50-259/85-15-08: Limitorque Valve Actuator Inspection Program

In March 1985, during performance of a Unit 3 surveillance test, the Unit 3 Residual Heat Removal (RHR) Pump "C" suction valve, 3-FCV-74-12, failed to close. The failure was attributed to the motor pinion gear being installed in the reverse direction.

The inspectors determined that orientation of the motor pinion gear is a known historical issue at Browns Ferry. The issue relates to which direction the lock-wire hub of the motor pinion is oriented. Limitorque model SMB-000, SMB-00, SMB-0, and SMB-5 actuators orient the lock-wire hub towards the motor. SMB-1, SMB-2, SMB-3 and SMB-4 actuators orient the lock-wire hub from the motor. The inspectors reviewed

Electrical Corrective Instruction ECI-0-000-MOV001, Maintenance for Limitorque Motor-Operated Valves and Mechanical Corrective Instruction, MCI-0-000-ACT004, Maintenance of SMB-0 Through SMB-4 Limitorque Actuators, and verified that adequate guidance for orientation of the motor pinion gear was specified in these maintenance procedures. In addition, proper orientation is covered in Limitorque maintenance training. The inspectors reviewed the licensee's Generic Letter 89-10 valve database and verified that the MOV actuators for all ECCS systems will be replaced with new actuators. In addition, the inspectors verified that the licensee's plans for Unit 1 recovery include refurbishment of remaining safety-related MOV actuators. This condition is resolved on Unit 1 by various DCNs which replace or refurbish existing actuators to all safety-related MOVs. The design resolutions were previously implemented on Units 2 and 3 and the inspection and the closure of this item for Units 2 and 3 were documented in Inspection Report 50-259,260,296/88-10. Therefore, because this item is effectively being tracked in the licensee's corrective action program and because any implementation performance deficiencies would likely be detected by licensee oversight programs and have only minor consequences, this item meets the closure criteria established for Unit 1 recovery issues. Because this problem was originally identified while the unit was shutdown and defueled and will be corrected prior to re-start, no violation of NRC requirements occurred. This issue is closed for Unit 1.

E8.3 (Closed) URI 50-259/87-02-02: Wrong Limitorque Gear Ratios

In January 1987, the licensee discovered that the Unit 2 High Pressure Coolant Injection (HPCI) steam isolation valve, 2-FCV-73-2, might not be capable of closing against design differential pressure of 1250 psid. The Unit 2 motor-operated valve (MOV) limitorque operator had a worm gear ratio of 33:1 rather than the required ratio of 60:1 as installed on Units 1 and 3. Subsequent reviews determined that three other MOVs, 1-FCV-69-1, 3-FCV-69-2, and 3-FCV-69-12, also could potentially have improper limitorque operator gear ratios.

The design resolution associated with MOV 2-FCV-73-2 was previously implemented on Unit 2 with ECN E-2-P7054 and the inspection and the closure of this item for Unit 2 was documented in Inspection Report 50-259,260,296/88-16. The design resolution associated with MOV 3-FCV-69-2 was implemented on Unit 3 with DCN W20897A. In addition, MOV 3-FCV-69-12 was evaluated as acceptable. The inspection and the closure of this item for Unit 3 was documented in Inspection Report 50-259,260,296/95-19. The inspector reviewed DCN 51046, which included the design details of the modification for RWCU Drywell Isolation Valve, 1-FCV-69-1. Specifically, this MOV will be replaced with a new valve and actuator during the ongoing RWCU pipe replacement project. Therefore, because this item is effectively being tracked in the licensee's corrective action program and because any implementation performance deficiencies would likely be detected by licensee oversight programs and have only minor consequences, this item meets the closure criteria established for Unit 1 recovery issues. Because this problem was originally identified while Unit 1 was shutdown and defueled and will be corrected prior to re-start, no violation of NRC requirements occurred. This issue is closed for Unit 1.

E8.4 (Closed) IFI 50-259/87-37-03: Reactor Water Level Sensing Lines

This item involves questions pertaining to the licensee's resolution of the February 13, 1985 reactor water level mismatch event. Circumstances associated with this event were reviewed by General Electric and the determination of probable cause and recommended actions were documented in GE letter G-ER-6-333, dated August 21, 1986. The cause of the event was determined to be the rigid instrument piping which would not allow adequate movement for thermal growth of the reactor vessel.

The design resolution associated with the reactor water level sensing lines was previously implemented on Unit 2 with ECN E-2-P7131 and the inspection and the closure of this item for Unit 2 was documented in Inspection Report 50-259,260,296/89-35. The design resolution associated with the reactor water level sensing lines was implemented on Unit 3 with DCN W17463A. The inspection and the closure of this item for Unit 3 was documented in Inspection Report 50-259,260,296/95-16. The inspector reviewed DCN 51163, which included the design details of the modification for reactor water level sensing lines in the Unit 1 drywell and DCN 51231 which included the design details of the modification for reactor water level sensing lines in the Unit 1 reactor building. Specifically, these DCNs replace the reactor water level sensing lines with new lines and provide for verification of proper slope and seismic supports. Therefore, because this item is effectively being tracked in the licensee's corrective action program and because any implementation performance deficiencies would likely be detected by licensee oversight programs and have only minor consequences, this item meets the closure criteria established for Unit 1 recovery issues. Because this problem was originally identified while Unit 1 was shutdown and defueled and will be corrected prior to re-start, no violation of NRC requirements occurred. This issue is closed for Unit 1.

E8.5 (Closed) IFI 50-259/84-41-04: Relocate HPCI EGM Control Boxes

In October, 1984, during an inspection of the HPCI systems of all units, it was identified that it was necessary to relocate the HPCI EGM control boxes. This was due to the harsh environment of high temperature and high humidity in which the control boxes were located. Steam leaks and the resulting condensation inside the EGM control boxes would accelerate the corrosion and deterioration of the terminals and connections. The licensee initiated plans to move the EGM control boxes off the HPCI stands and relocate them to areas where any leaks would not impinge directly upon them. This item was closed in Inspection Report (IR) 259, 260, 296/88-21 for Unit 2 in July, 1988, when the licensee initiated Design Change Request (DCR) 2349 and installed the design change through Engineering Change Notice (ECN) P3184. This item was closed in Inspection Report (IR) 259, 260, 296/95-43 for Unit 3 in August, 1995, when the licensee initiated and installed DCN W17834A. The licensee initiated DCN 51221, Main Steam System-Electrical in Reactor Building to resolve the issue for Unit 1. Stage 2 of the DCN was initiated to relocate the EGM control box. The inspectors reviewed DCN 51221, Stage 2, and observed that the control box will be relocated through WO 03-010484-10. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected identically to the Unit 3 solution with the same process and design change, and because any implementation performance deficiencies would likely be detected by the licensee oversight programs with only minor consequences, this item meets the closure criteria established for Unit 1 recovery issues. This item is closed for Unit 1.

III. Maintenance

M1 Conduct of Maintenance

M1.1 Replacement of General Electric Type HFA Relays (37551)

a. Inspection Scope

The inspectors continued to observe and review the licensee's ongoing activities associated with General Electric type HFA relays. The Unit 1 recovery personnel, at the end of this report period, had changed out a total of 192 of the 349 HFA relays initially identified as needing to be replaced.

b. Observations and Findings

The inspectors observed the ongoing replacement activities in the Unit 1 Auxiliary Instrument Room. The following activities were reviewed and observed:

- WO 04-716376-12, GE HFA relay BFR-1-RLY-001-2E-K30 in panel 9-30
- WO 04-716376-14, GE HFA relay BFR-1-RLY-001-2E-K07 in panel 9-30
- WO 04-717565-06, GE HFA relay BFR-1-RLY-073-23A-K02 in panel 9-39
- WO 04-717565-14, GE HFA relay BFR-1-RLY-073-23A-K03 in panel 9-39

The inspectors also reviewed PERs issued by the licensee documenting conditions adverse to quality observed during the change out process. The majority of the PERs continued to be for historical issues involving drawing discrepancies.

c. Conclusions

Based on review of records and observation of ongoing work the inspectors concluded the licensee's HFA relay replacement program was complying with the applicable requirements.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Preoperational Status of the Radiological Protection Program

a. Inspection Scope

The objective of this part of the inspection was to determine the potential readiness to transition future Unit 1 inspections and oversight of the Radiological Protection (RP) Program to the Reactor Oversight Process (ROP), focusing on controls for maintaining occupational exposures ALARA and the licensee’s radioactive material processes and transportation. The ROP is the NRC’s inspection program for operating reactors, and selected inspection areas (designated as Cornerstones) of the ROP can be incorporated for U1 once NRC inspections conclude that the area can be adequately monitored under the ROP. This transition process is described in NRC Manual Chapter 2509

b. Observations and Findings

The inspectors evaluated the licensee’s readiness to transition future Unit 1 inspections in select RP program areas to the ROP. This was accomplished by inspecting select RP programs for Units 2 and 3 under the ROP while evaluating Unit 1 RP specific conditions and the areas of inspection defined in the routine RP ROP inspection procedures and the ROP Performance Indicators for RP.

From a review of select records and discussions with cognizant licensee representatives, the inspectors determined that the original forecast for the Unit 1 Recovery projected exposure was 1,023 man-rem (Fiscal Year 2002 to 2007); however, based on past, current and projected activities, the projected exposure was revised to 780.033 man-rem. At the time of the inspection, the licensee had observed 344.856 man-rem of the projected 363.941 man-rem through Fiscal Year 2004.

From a review of select records, discussions with cognizant licensee representatives, and direct observations of radioactive material processing and transportation activities, the inspectors assessed several shipments being prepared for transport to a burial site. From those observations, reviews and discussions, the inspectors found that the licensee conducted radiation area and removable contamination surveys, labeled containers, and prepared records appropriately for those shipments observed during the inspection.

Based on this review and the lack of any significant findings or weaknesses in the area of RP, the inspectors did not identify any impediments to the future transition of Unit 1 RP inspections under the Occupational and Public Radiation Safety Cornerstones for the ROP. This transition will likely be reflected in the 2005 ROP Inspection Plan for Unit 1. Specific documents reviewed are listed in the report attachment.

c. Conclusion

The licensee's RP program was being adequately maintained. Changes to the program since the last inspection were consistent with licensee commitments and NRC requirements.

Based on focused RP reviews for Unit 1, inspectors did not identify any impediments to the planned transition of Unit 1 RP inspections and oversight for the Occupational and Public Radiation Safety Cornerstones to the normal ROP.

R8 Miscellaneous Plant Support Issues (92701)

R8.1 (Closed) URI 50-259/04-06-01: Licensee Demonstration of Adequacy of Reactor Building (RB) Gaseous Effluent Sampling

During the previous inspection in this program area (NRC Inspection Report 050-260, 296/04-02), the inspectors determined through discussions with cognizant licensee representatives, reviews of select records, and direct observations that the inlet sample lines to the RB Vent Effluent Radiation Monitors (1, 2, & 3-RM-90-250) had 90-degree bends rather than bends with radii that are five times the diameter of the sample line, as specified in American Nuclear Standard Institute (ANSI) N13.1-1969, "Guide to Sampling Radioactive Materials in Nuclear Facilities." The adequacy of the sampling system was assessed by Battelle Pacific Northwest Laboratories during 1991 and the results of that assessment were documented as an attachment to NRC Inspection Report No. 50-259, 260, 296/92-10. Battelle's report stated that the air sample transport tubes "would appear to be adequate if one accepts the licensee's position that particle sizes under sampler operation conditions will remain no larger than a couple of microns." During this inspection, the inspectors determined that the licensee conducted a particle size measurement study using a cascade impactor. The licensee analyzed a representative of air samples from the Units 2 and 3 Reactor Water Cleanup Heat Exchanger Rooms; Units 1, 2, and 3 refuel zones; and the RB equipment hatches. A minimum of three measurements were made in each location using the cascade impactor. The measurements were averaged and a predominant particle diameter of 0.3 microns was observed with an average of all plant locations indicating 90% of the particulate mass to be less than or equal to 2 microns in diameter. In addition, the licensee determined that 99.5% of the surface area was from particulates less than or equal to 2 microns in diameter. Based on a review of this report and discussions with cognizant licensee representatives, the inspectors determined that the licensee had demonstrated the adequacy of RB gaseous effluent sampling in accordance with Section 4.2.2.1 of ANSI N13.1-1969. The inspectors determined that no further actions were required for Unit 1. This item is closed for Unit 1.

R8.2 (Closed) URI 50-259/04-07-02: Adequacy of DOP Testing of Portable HEPA Filter Units

This item was associated with concerns about the adequacy of the licensee's program for testing of portable HEPA filter units. The inspectors completed the review of the June 9, 2004, Unit 1 Reactor Building contamination event. This review was documented in Inspection Report 50-260, 296/2004-04. Based on that review the inspectors determined that a violation of NRC requirements had occurred. A Non-Cited Violation (NCV) 50-260, 296/04-04-03, Failure to Implement Adequate Engineering Controls for Airborne Radioactive Material, was identified. The inspectors determined that no further actions were required for Unit 1. This item is closed for Unit 1.

V. Management Meetings

X1 Exit Meeting Summary

On October 25, 2004, the resident inspectors presented the inspection results to Mr. John Rupert and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

T. Abney, Nuclear Site Licensing & Industry Affairs Manager
M. Bali, Electrical Engineer (Bechtel)
R. Baron, Nuclear Assurance Manager, Unit 1
D. Beckley, Electrical Engineer (Bechtel)
M. Bennett, QC Manager. Unit 1
D. Burrell, Electrical Engineer, Unit 1
T. Butts, SWEC Mechanical Supervisor
P. Byron, Licensing Engineer
J. Corey, Radiological and Chemistry Control Manager, Unit 1
W. Crouch, Mechanical/Nuclear Codes Engineering Manager, Unit 1
R. Cutsinger, Civil/Structural Engineering Manager, Unit 1
R. Drake, Maintenance and Modifications Manager, Unit 1
B. Hargrove, Radcon Manager, Unit 1
R. Jackson, Bechtel
S. Johnson, TVA Welding Engineering Supervisor, Unit 1
R. Jones, Plant Recovery Manager, Unit 1
S. Kane, Licensing Engineer
J. Lewis, ISI Program Engineer, Unit 1
G. Lupardus, Civil Design Engineer, Unit 1
J. Ownby, Project Support Manager, Unit 1
J. Pettitt, Pipe Replacement Task Manager
J. Rupert, Vice President, Unit 1 Restart
J. Schlessel, Maintenance Manager, Unit 1
J. Symonds, Modifications Manager, Unit 1
E. Thomas, Bechtel
D. Tinley, NDE Level III & Unit 1 ISI Project Manager
J. Valente, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 37551	Engineering
IP 55050	Nuclear Welding General Inspection Procedure
IP 71111.17	Permanent Plant Modifications
IP 71111.23	Temporary Plant Modifications
IP 83502.02	Radioactive Material Processing and Transportation
IP 83728	Maintaining Occupational Exposure ALARA
IP 84750	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 92701	Follow-up

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

None

Opened

None

Closed

50-259/87-33-02	IFI	Failure of Drywell Control Air Isolation Valves to Meet Design Criteria (Section E8.1)
50-259/85-15-08	IFI	Limitorque Valve Actuator Inspection Program (Section E8.2)
50-259/87-02-02	URI	Wrong Limitorque Gear Ratios (Section E8.3)
50-259/87-37-03	IFI	Reactor Water Level Sensing Lines (Section E8.4)
50-259/84-41-04	IFI	Relocate HPCI EGM Control Boxes (Section E8.5)
50-259/04-06-01	URI	Licensee Demonstration of Adequacy of Reactor Building Gaseous Effluent Sampling (Section R8.1)
50-259/04-07-02	URI	Adequacy of DOP Testing of Portable HEPA Filter Units (Section R8.2)
05000259/2515/154	TI	Spent Fuel Material Control and Accounting at Nuclear Power Plants (Section O8.1.1)
05000259/2515/156	TI	Offsite Power System Operational Readiness (Section O8.1.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section E1.1 Design Change Packages

Procedures and Standards

SPP-9.3, Plant Modifications and Engineering Change Control, Rev. 9

DCNs

DCN 51080, Reactor Protective System (RPS), System 099
DCN 51152, Core Spray (CS) - Drywell, System 075
DCN 51189, Primary Containment System (PCS), System 064A and Primary Containment Isolation System (PCIS), System 64D
DCN 51199, Residual Heat Removal (RHR) - Reactor Building, System 074
DCN 51163, Reactor Vessel Level Indicating System (RVLIS) - Drywell, System 03
DCN 51231, Reactor Vessel Level Indicating System (RVLIS) -Reactor Building, System 03

Section E1.2 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

DCNs

DCN 51016, Unit 1 Emergency Core Cooling System (ECCS) Accident Signal Logic
DCN 51018, Unit 2 ECCS Accident Signal Logic
DCN 51107, Control Annunciator Upgrade, System 55
DCN 51199, RHR, System 74
DCN 51200, CS, System 75
DCN 51195, Reactor Building Closed Cooling Water (RBCCW), System 70

Other Documents

PER 66742, fitup of the heat exchanger outlet nozzle and the pipe nozzles was obtained by cold pulling the pipe from its original position
TVAN Calculation, CDQ1-999-2004-0151, Rev 0, Pipe Stress Evaluation of RBCCW Heat Exchanger 1A attached piping

Section E1.7 Restart Test Program

Procedures and Standards

Technical Instruction 1-TI-469, Baseline Test Requirements

Other Documents

ND-Q0999-910033, Safe Shutdown Analysis (SSA)
ND-Q0999-940013, Reliability Analysis of the Pre-Accident and Common Accident Signal Logic for Units 1, 2, and 3
01-BFN-BTRD-075, Core Spray System
01-BFN-BTRD-074 Residual Heat Removal
01-BFN-BTRD-023 Residual Heat Removal Service Water System
01-BFN-BTRD-064D Primary Containment Isolation System
System Test Specification 1-STS-075, Core Spray System
System Test Specification 1-STS-074, RHR System
System Test Specification 1-STS-023, RHRSW System
System Test Specification 1-STS-064D, Primary Containment Isolation System
1-PMTI-BF-035.013, Main Generator Temperature Monitoring System Testing
1-PMTI-BF-064.116, Steam Tunnel Booster Fan
1-PMTI-BF-002.001, Initial Performance Testing of Condensate Pump Impellers

Section E1.8 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

Other Documents

TACF 1-04-003-023, Install a Piping Jumper in the Supply Lines to the 1A RHRSW Heat Exchanger and 1C RHRSW Heat Exchanger

Section E1.9 System Return to Service Activities

Procedures, Guidance Documents, and Manuals

Technical Instruction 1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Rev. 0
0-TI-404, Unit One Separation and Recovery, Rev. 4

Problem Evaluation Reports (PERs)

PER 61212, a one inch drain line connects to Condenser B and not to Condenser C as shown on drawing 1-47E807-2
PER 61569, during observations of welding arc marks were noticed near three welds which were outside the weld areas

PER 66320, 3 ft section of piping was demolished, not adequately documented, and the original configuration is unknown
PER 67856, some installed piping configurations are not depicted correctly on system drawings
PER 67888, damaged 3/8 inch rod pipe support was discovered during the system walk down
and PER 68293, three of six motor operated Limitorque valves failed the post maintenance test
PER 64108, gland seal water piping and components servicing the condensate pumps are not depicted correctly on the system drawing

<u>Section E7.1 Licensee Quality Assurance Oversight of Recovery Activities</u>

<u>Nuclear Assurance Audit/Assessment Reports</u>

Browns Ferry Maintenance Audit SSA0405, July 2004
TVA Corporate Engineering Welding Assessment, August 3 - 12, 2004

<u>TVA Corrective Action Documents</u>

PER 63896, potential adverse trend associated with weld filler material handling and control
PER 65044, potential adverse trend associated with weld engineering documentation issues
PER 65047, potential adverse trend associated with Qualified Individual (QI) issues
PER 65148, potential adverse trend associated with welder performance

<u>Section R1 Radiological Protection</u>

<u>Procedures, Instructions, and Guidance Documents</u>

Radioactive Material Shipment Manual, Revision (Rev.) 36A, dated 01/20/04
Tennessee Valley Authority Nuclear Common Technical Procedure (TVANCTP), 10 CFR 61 Waste Characterization, RWTP-101, Rev. 0, dated 04/29/02
TVANCTP, Radioactive Material/Waste Shipments, RWTP-100, Rev. 0, dated 04/29/02
TVANCTP, Use of Casks, RWTP-102, Rev. 1, dated 01/09/04
Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant (BFNP), Radiological Control Instruction (RCI), RCI-15.1, Maintaining Occupational Radiation Exposures as Low as Reasonably Achievable (ALARA), Rev. 31, dated 01/20/04
TVA, BFNP, RCI, RCI-15.2, Temporary Shielding, Rev. 20, dated 10/09/03
TVA, BFNP, RCI, RCI-15.3, ALARA/Radwaste Committee, dated 02/23/04

<u>Records, Worksheets, and Data</u>

10 CFR 61 Analysis Reports, Unit 1 Dry Active Waste Smears dated 10/10/03 and Unit 1 Chemical Decon Resin dated 05/30/02
Browns Ferry U1 Plan of the Day dated 09/08/04
Browns Ferry U1 Restart Cobalt Reduction Plan Update
Radioactive Material Manifests, Shipment Nos. 040603 dated 06/03/04, 040708 dated 07/15/04, and 040718 dated 07/22/04
Self-Assessment Report, Dry Active Waste (DAW) Processing, dated 08/22/04
Self-Assessment Report, Assessment Number (No.) BFN-ENV-01-002, Transportation of Radioactive Material and Waste
Self-Assessment Report, Assessment No. CRP-ENV-02-003, Radioactive Waste Program Performance

Self-Assessment Report, Assessment No. CRP-ENV-03-001, Low-Level Radwaste Storage and Radwaste Minimization
Self-Assessment Report, Assessment No. CRP-ENV-04-003, Hazardous Material Transportation Security Plan (TSP)
TVANTCP, Radioactive Material/Waste Shipments, Shipment #040905, RWTP-100, Rev. 0, Pre-Shipment Checklist dated 09/09/04
Uniform Low-level Radioactive Waste Manifest, Shipment ID No. SCN-0087-04 dated 09/09/04, Shipment No. 040906 dated 09/09/04, and Shipment No. 040907 dated 09/09/04
Unit 1 Recovery Projected Exposure in Man-REM

Corrective Action Program Documents

Problem Evaluation Report (PER) 03-010318-000, A radwaste individual failed to attend a training session
PER 03-016590-000, Radiation levels on a drum that contained old TIP created a high radiation area and radwaste laborers had to change to another RWP
PER 03-019901-000, Evaluation of radwaste generation for Fiscal Year 2003
PER 03-023612-000, Radwaste laborer has facial contamination from washing down the internals of “E” Phase Separator
PER 04-000635-000, 400 ft^2 of the 565' Radwaste Building, Waste Packaging area becomes contaminated while filling shipping cask
PER No. 46306 dated 07/01/03, Self Assessment BFR-RIM-03-002 Area for Improvement - Unit 1 Restart Project workers display a weakness in reading and understanding radiological maps
PER No. 49908 dated 07/01/03, Self Assessment BFR-RIM-03-002 Area for Improvement - Unit 1 ALARA Reports need additional improvements to bring them in line with the best industry practices
PER No. 50283 dated 05/27/03, Work began on ALARA Planning Reports 03-1001, 03-1002, 03-1008, 03-1010 and 03-1011 before being reviewed by the ALARA/Radwaste Subcommittee
PER No. 50284 dated 05/27/03, ALARA Planning Reports 02-0016, 02-0018, 02-0055, 02-0063, 02-0068, 03-1000, and 03-1011 were not submitted to the ALARA group prior to the commencement of work