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

May 16, 2005

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 05000259/2005006

Dear Mr. Singer:

On April 16, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a quarterly inspection period associated with recovery activities at your Browns Ferry 1 reactor facility. The enclosed integrated inspection report documents the inspection results, which were discussed on April 26, 2005, with Mr. John Rupert and other members of your staff.

We previously informed you, in a letter dated December 29, 2004, of our plans for the transition of four Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) to be monitored under the ROP baseline inspection program. Consequently, as of January 2005, inspections for these cornerstones are integrated with Unit 2 and 3 ROP baseline inspections. They will no longer be documented in the Unit 1 recovery quarterly integrated reports such as this one, but will be documented in the Unit 2 and 3 Integrated Quarterly Reports.

This inspection examined activities conducted under your Unit 1 license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license and also with fulfillment of Unit 1 Regulatory Framework Commitments. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. A significant portion of your engineering activities, Special Program implementation, and modification activities were reviewed during this inspection period and found to be effective with no significant problems identified. However, based on the results of this inspection, three Severity Level IV violations of NRC requirements were identified resulting from an inadequate post-modification test procedure, failure to install pipe supports and welds in accordance with approved drawings, and the failure to follow procedures or maintenance work instructions. However, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the NCVs in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Browns Ferry Nuclear Plant.

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 05000259/2005006
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:	05000259/2005006
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Unit 1
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	January 16 - April 16, 2005
Inspectors:	W. Bearden, Senior Resident Inspector, Unit 1 E. Christnot, Resident Inspector R. Taylor, Acting Resident Inspector S. Walker, Resident Inspector, McGuire Site R. Chou, Reactor Inspector (Section E1.5) J. Lenahan, Senior Reactor Inspector (Section E1.2) B. Crowley, Senior Reactor Inspector (Sections E1.3, E1.4)
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 05000259/2005006

This integrated inspection included aspects of licensee engineering and modification activities associated with the Unit 1 recovery project. This report covered a 3-month period of resident inspector inspection. In addition, NRC staff inspectors from the regional office conducted inspections of Unit 1 Recovery Special Programs in the areas of large bore pipe supports and long term torus integrity; intergranular stress corrosion cracking and inservice/preservice inspections; and containment coatings. The inspection program for the Unit 1 Restart Program is described in NRC Inspection Manual Chapter 2509. Information regarding the Browns Ferry Unit 1 Recovery and NRC Inspections can be found at http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/bf1-recovery.html. Per the Partial Cornerstone Transition letter from the NRC to TVA dated December 29, 2004, four Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) are monitored under the ROP baseline inspection program as of January 2005. Consequently, inspections for these cornerstones are integrated with Unit 2 and 3 ROP baseline inspections and are no longer documented in the Unit 1 recovery quarterly integrated reports such as this one, but in the Unit 2 and 3 Integrated Quarterly Reports.

Inspection Results - Engineering

- Modification installation activities associated with four permanent plant design changes were observed and found to be performed in accordance with the documented requirements. (Section E1.1)

- The licensee's program for restoration of the coatings in the Unit 1 torus complied with NRC requirements. Inspectors reviewed licensee and industry standard requirements and inspected completed torus coatings No findings of significance were identified. (Section E1.2)

- The licensee's intergranular stress corrosion cracking (IGSCC) mitigation plan continued to meet commitments established by Regulatory Framework letters. Recirculation (Recirc) System, Residual Heat Removal (RHR) System, Reactor Water Cleanup (RWCU) System, Core Spray (CS) System, and Feedwater (FW) System piping replacement activities were meeting ASME Code and other regulatory requirements. (Section E1.3)

- The licensee's Inservice/Preservice Inspection Program met applicable regulatory requirements and licensing commitments. (Section E1.4)

- The Large Bore Pipe Support and Long Term Torus Integrity Programs were being adequately implemented with the exception of concerns in the area of verification of component/weld size and component dimensions/orientation. A Severity Level IV Non-Cited Violation for failure to install pipe supports and welds in accordance with drawings was identified during the current inspection. (Section E1.5)

- An Unresolved Item was identified for discrepancies in a documented pipe support location. (Section E1.5)
- Modification activities performed on Unit 2 and shared equipment during the Unit 2 refueling outage by Unit 1 personnel were generally adequate. However, early in the outage, poor work practices and lack of attention to detail resulted in an error when an incorrect electrical lead was lifted. Although no adverse conditions resulted from the error, the use of a non-standard method of flagging the electrical lead and poor communications contributed to the error. The licensee took prompt and effective corrective action early in the outage, so subsequent errors were reduced. (Section E1.6)
- The Control Room Design Review program continues to provide an adequate resolution of previously-identified Human Engineering Deficiencies. (Section E1.7)
- Activities associated with removal of two temporary alterations which had provided temporary air supply for torus coatings activities and eliminated a false alarm for loss of cooling to the spent fuel pool did not cause 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. Any system deficiencies were identified and appropriately addressed by the licensee’s corrective action program. (Section E1.9)
- The System Cleanliness Verification Program continues to provide comprehensive inspections of systems for identification of degradation or special requirements to support the Unit 1 recovery. (Section E1.9)
- Implementation of restart testing activities was generally acceptable. However, post-modification testing associated with replacement of the Unit 1 Main Bank Transformers failed to identify a wiring error resulting in a Severity Level IV Non-Cited Violation for an inadequate post-modification test procedure. Test deficiencies identified during performance of testing were documented under the licensee’s corrective action program. (Section E1.10)
- Two examples of a weakness in the licensee’s design change process were identified. Neither example resulted in the inoperability of required equipment. However, both examples resulted in some operator burden and delays in return to service of equipment used to support Unit 2 operation. (Section E1.10)

Inspection Results - Maintenance

- The inspectors determined the Maintenance Program was providing appropriate and comprehensive repairs to Unit 1 components which do not require design changes to support Unit 1 Restart. (Section M1.1)

- A Severity Level IV Non-Cited Violation with three examples of human performance errors was identified during the current inspection. The errors resulted from poor work practices and lack of sensitivity to error likely situations. The errors resulted in unplanned Engineered Safety Feature (ESF) actuations and unnecessary operator burdens. (Section M1.2)

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 piping in the reactor coolant, reactor water cleanup, and feedwater systems; reinstallation of balance-of-plant piping and turbine auxiliary components; installation of small and large bore pipe supports; and installation of new electrical cables, conduits, and conduit supports. Limited system return to service (SRTS) activities occurred during this reporting period. The licensee was initiating reactor vessel fill activities at the end of the reporting period.

II. Engineering

E1 Conduct of Engineering

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

a. Inspection Scope

The inspectors reviewed and observed permanent plant modifications for the Unit 1 common accident signal logic, Unit 2 common accident signal logic, Unit 1 control room annunciators, and Unit 1 Reactor Motor Operated Valve (RMOV) Boards. The inspectors evaluated the adequacy of the modifications and observed field work to verify that the design basis, licensing basis, and Technical Specification (TS) requirements for the systems had not been degraded as a result of the modifications.

b. Observations and Findings

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

The inspectors continued to review ongoing work activities associated with the permanent plant modification DCN 51016, Unit 1 Emergency Core Cooling System (ECCS) Accident Signal Logic. The purpose of the DCN was to restore the Unit 1 common accident signal logic, which is required for three unit operation. Preoutage activities observed by the inspectors included installation of electrical cables in control panels 1-9-32 and 1-9-33. These activities were performed to facilitate the installation of the common accident signal logic system on Unit 1 and Unit 2. The specific cables were for the logic system interface between the two units. Terminations of the electrical cables in the control panels were performed during the Unit 2 refueling outage. Additional observations made during the Unit 2 outage are described in Section E1.6.

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

The inspectors observed portions of the permanent plant modification activities associated with DCN 51018, Unit 2 ECCS Accident Signal Logic. The purpose of the DCN was to restore the Unit 2 common accident signal logic, which is required for three-unit operation. Pre-outage activities observed by the inspectors included installation of electrical cables in control panels 2-9-32 and 2-9-33. These activities were performed to facilitate the installation of the common accident signal logic system on Unit 2 and Unit 1. The specific cables were for the logic system interface between the two units. The terminations of the electrical cables in the control panels were scheduled to be performed during the Unit 2 refueling outage. Additional observations made during the Unit 2 outage are described in Section E1.6.

b.3 DCN 51090, 480-Volt Electrical System

The inspectors reviewed and observed selected permanent plant modification activities associated with DCN 51090, 480-Volt Electrical - Control Bay, System 57-4. The purpose of the DCN was to replace circuit breakers, fuses, install time delay relays, and make circuit breaker trip setting changes. The work activities observed in Unit 1 included replacement of fuses in 1A RMOV Board, cubicle 4A, power supply to RHR Pump 1A Cooler Fan; replacement of the circuit breaker in 1A RMOV Board, Cubicle 4A, power supply to North West Core Spray Room Cooler Fan; and the installation of time delay relays in the Unit 2 drywell blower control logic system.

b.4 DCN 51107, Annunciator Upgrade - Unit 1

The inspectors reviewed permanent plant modification activities associated with DCN, 51107, Annunciator Upgrade - Unit 1, System 55. The purpose of the DCN was to change the Unit 1 annunciator system from an analog to a digital system. The process used was to install a temporary alarm window, transfer the active alarms to the temporary window, install the new window, and transfer the alarms from the temporary window to the new window. This process ensured that the operators had alarms available for the operating systems on Unit 1, such as spent fuel pool cooling. Work activities observed in Unit 1 included replacement of alarm window 1-XA-55-4C, alarms for fuel pool cooling, drywell sumps, and reactor building closed cooling water systems; window 1-XA-55-8C, alarms for 250 volt DC RMOV boards, 480-volt AC ventilation boards, and 480-volt AC RMOV boards; window 1-XA-55-22A, alarms for residual heat removal service water, emergency equipment cooling water, and condensate storage systems; and 1-XA-55-22B, a new alarm window with alarms for radiological waste and condensate tunnel sump systems.

c. Conclusions

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

E1.2 Unit 1 Restart Special Program Activities - Containment Coatings - Repairs to Coatings in Unit 1 Torus (37550)

a. Inspection Scope

The inspectors reviewed the licensee's program for application of new Service Level I coatings in the Unit 1 torus that was qualified to ANSI standards. The inspectors reviewed procedures, inspected completed coatings in the Unit 1 torus, and reviewed records documenting application and inspection of the new coatings.

b. Findings and Observations

The inspectors reviewed TVA Specification G-55, Technical and Programmatic Requirements for the Protective Coatings for TVA Nuclear Plants, Revision 13, to verify that appropriate technical requirements were specified for application of the new Service Level 1 coatings, including qualification of the materials, qualifications and testing requirements for the coating applicators, environmental conditions during coating application, surface preparation, coating application, curing, inspection, repairs, and touch-up.

The inspectors also reviewed TVA procedure MAI-5.3, Protective Coatings, which specifies acceptance criteria for coatings, the quality control inspection requirements, and requirements for records for documentation of completed coatings to verify that the licensee's program for inspection of completed coatings complied with NRC requirements. The inspectors reviewed samples of completed QC inspection records and Problem Evaluation Reports (PERs) which documented and evaluated deficiencies in the coatings program.

The inspectors examined the completed coatings in the immersion zone of the torus. The inspection was performed after the licensee's final quality control acceptance inspection was almost completed. Some PERs were still open pending completion of corrective actions. The inspectors examined portions of the torus shell, inside and outside of four downcomer pipes, portions of supports in the immersion zone, and other hardware in the immersion zone. The inspectors independently examined the completed coatings and performed testing to independently determine the thickness of the completed coatings at approximately 3000 locations by use of several dry film thickness (DFT) gauges. The inspectors independently verified that the DFT gauges were properly calibrated. The inspectors identified a few small areas where the thickness of the completed coatings was outside the acceptable thickness limits specified in G-55. The licensee initiated PER 75236 to document and disposition this issue. The licensee determined that the measured minimum and maximum thicknesses were enveloped by the manufacturer's test data and were acceptable to use as is.

The inspectors reviewed PERs initiated to document and disposition deficiencies identified during application and inspection of the coatings in the torus. Subject areas included surface preparation, dry film thickness exceeding or not meeting limits established in the specifications, paint indications know as "holidays," and miscellaneous other issues. The inspectors also reviewed quality records documenting application of the coating in bays 6 and 15 in the torus. These records included environmental conditions, data on applied coatings materials, application method, identification of the applicators, QC inspection records, identification of inspection equipment and calibration information, and a list of PERs affecting work in the bay.

c. Conclusions

The inspectors concluded that the licensee's program for restoration of the coatings in the Unit 1 torus complied with NRC requirements. No findings of significance were identified.

E1.3 Unit 1 Restart Special Program Activities - Intergranular Stress Corrosion Cracking (IGSCC) - Welding of Replacement Recirc System, RHR System, RWCU, and CS System Piping (55050)

a. Inspection Scope

As part of the IGSCC Special Program, TVA is replacing the Recirculation (Recirc) system piping and portions of the Residual Heat Removal (RHR), Reactor Water Clean-Up (RWCU), and Jet Pump Instrumentation (JPI) piping systems with Type 316NG stainless steel material. In addition, the Core Spray (CS) system stainless steel piping is being upgraded by replacing it with carbon steel. The Feedwater (FW) Isolation Valves were being replaced with new valves. Also, the Reactor Vessel Level Indicating System (RVLIS) piping is being replaced to provide a more reliable measuring system as required by NRC Generic Letter 84-23. The applicable Codes for this work are: (1) Code for Power Piping USAS B31.1, 1967 Edition; (2) ASME Section XI, 1995 Edition, 1996 Addenda; and (3) ASME Section III, 1995 Edition, 1996 Addenda.

The inspectors observed completed and in-process welds and reviewed completed weld records, procedures, personnel qualification records, and material certification records, as detailed below to verify compliance with applicable requirements.

b. Observations and Findings

See Inspection Reports 50-259/2003-009, 2003-010, 2003-011, 2004-006, 2004-007, and 2004-009 for documentation of previous inspections in this area. During the current inspection, the inspectors observed/reviewed the following to verify compliance with the applicable Codes listed above:

- The inspectors visually inspected final weld surfaces for the following JPI, RVLIS, and FW system welds:

RWR-1-003-313	RFW-1-004-015	RFW-1-007-016
RWR-1-003-372	RFW-1-003-004	RFW-1-007-017
RWR-1-003-303	RFW-1-003-011	RFW-1-007-018
RWR-1-003-408	RFW-1-003-013	RFW-1-007-019
RWR-1-003-406	RFW-1-004-036	
RWR-1-003-445	RFW-1-004-037	
RWR-1-003-487	RFW-1-004-038	
RWR-1-003-516	RFW-1-004-039	
RWR-1-003-356	RFW-1-004-040	

- The inspectors observed in-process welding and reviewed in-process Weld Data Sheets for the following JPI and RVLIS welds:

RWR-1-003-314	RFW-1-003-003
RWF-1-003-005	RFW-1-003-006
RWF-1-003-010	RFW-1-003-012

- The inspectors reviewed the radiographic (RT) film for the following welds:

RWR-1-001-023	RWCU-1-004-043
RWCU-1-004-032	CS-1-007-010
CS-1-009-003	RHR-1-012-007
RHR-1-014-003	RFW-1-007-016
RFW-1-007-017	RFW-1-007-018
RFW-1-007-019	

- For the all of the Recirc, CS, RHR, and RWCU, JPI, and RVLIS System welds listed in the paragraphs above, the inspectors reviewed the Weld Data Sheets. In addition, nondestructive examination (NDE) and Quality Control (QC) personnel qualification records, welding material certification records, and welder qualification records were reviewed as detailed below. Also a sample of the NDE visual (VT), liquid penetrant (PT), magnetic particle (MT) examination records, as applicable, were reviewed.

- Certified Material Test Reports (CMTRs) were reviewed for the following heats/lots of welding material: 0.035" ER316/316L Spooled Wire - Heat/Lot XF8056; 0.125" ER316/316L Bare Wire - Heat/Lot D8134; 0.125" ER316/316L Bare Wire - Heat/Lot PH368; 0.093" ER316/316L Bare Wire - Heat/Lot 60279; 0.093" ER316/316L Bare Wire - Heat/Lot CM8256; 0.093" ER70S-3 Bare Wire - Heat/Lot C20824; 0.125" ER70S-6 Bare Wire - Heat/Lot DW8212; 0.035" ER70S-6 Spooled Wire - Heat/Lot 186921; 0.125" ER308L Bare Wire - Heat/Lot 8E2444; 0.093" ER308L Bare Wire - Heat/Lot C4611R308L; 0.125" IN308L Consumable Insert - Heat/Lot M8253; 0.035" ER308L Spooled Wire - Heat/Lot

XF7995; 0.035" ER309/309L Spooled Wire - Heat/Lot XM 7860; 0.125" E309 Bare Wire - Heat/Lot P7930; and 0.093" E309 Bare Wire - Heat/Lot 24243.

- The inspectors reviewed welder qualification records, including continuity records, as applicable, for 30 welders who welded on the above listed Recirc, RHR, CS, RHR, FW, JPI, and RVLIS System welds.

- Qualification records for 11 Level II MT examiners, 11 Level II PT examiners, 13 welding - VT examiners, two Level III RT examiners, and one Level II RT examiner, who performed QC and NDE of the Recirc, RHR, CS, RWCU, JPI, and RVLIS System welds listed above, were reviewed.

- Certification records for the following PT materials used to examine the above-listed Recirc, RHR, CS, RHR, FW, JPI, and RVLIS System welds were reviewed:

  Penetrant - Lot Numbers 03K08K, 01H05K, and 04M02K
  Remover - Lot Numbers 04G05K, 04L12K, and 03F22K
  Developer - Lot Numbers 04F04K, 04F05K, 03A03K, 04L04K, 04M04K, and 03A03K

c. Conclusions

The licensee's intergranular stress corrosion cracking (IGSCC) mitigation plan continued to meet commitments established by Regulatory Framework letters. Recirculation System, Residual Heat Removal (RHR) System, Reactor Water Cleanup (RWCU) System, Core Spray (CS) System, and Feedwater (FW) System piping replacement activities met ASME Code and regulatory requirements. No violations or deviations were identified.

E1.4 Inservice Inspection Data Review and Evaluation (73055)

a. Inspection Scope

The inspectors reviewed the Browns Ferry Unit 1 Inservice/Preservice Inspection (ISI/PSI) activities as detailed below to verify compliance with ISI/PSI requirements in accordance with regulatory requirements and licensee commitments. See NRC Inspection Reports 50-259/2004-007 and 50-259/2004-009 for previous inspections in this area.

As detailed in the licensee's ISI program, the first ten-year ISI interval, which began August 1, 1974, for Browns Ferry Unit 1 is currently in its third period and will end one year following the restart of the unit. The applicable Codes for the ISI program are: (1) ASME Section XI, 1995 Edition, 1996 Addenda, and (2) ASME Section XI, 1974 Edition, with Addenda through Summer 1975. For PSI of replaced components, the applicable Code is ASME Section XI, 1995 Edition, 1996 Addenda.

b. Observations and Findings

Repaired or replaced welds and components will receive a PSI in accordance with the requirements of ASME Section XI prior to returning repaired or replaced systems to service. The PSI examination of repaired or replaced welds susceptible to IGSCC will not be conducted until after a Mechanical Stress Improvement Process has been performed.

Observation/Review of ISI/PSI Activities

The inspectors reviewed the PSI examination reports for the FW system welds listed below. The records were compared to the Technical Specifications (TS) and the applicable Code (ASME Boiler and Pressure Vessel Code, Section XI, 1995 Edition with Addenda through 1996) to verify compliance.

RFW-1-007-016
RFW-1-007-017
RFW-1-007-018
RFW-1-007-019

In addition to review of the NDE, the inspectors reviewed:

- Qualification and certifications records for three Level II MT and three Level II UT examiners

- Certification records for: UT Flaw Detector Serial No. 0FC01; Thermometer Serial Nos. 522355 and 562775; Transducer Serial No. 99HV; Calibration Block Serial No. WB78; and Ultragel Batch No. 03125

c. Conclusions

The inspectors determined that the licensee's ISI/PSI activities observed/reviewed met applicable code requirements and licensing commitments. No violations or deviations were identified.

E1.5 Unit 1 Restart Special Program Activities - Large Bore Piping and Supports Program & Long Term Torus Integrity Program (50090)

a. Inspection Scope

The licensee's commitments for resolution of issues associated with the large bore and torus-attached piping and supports were stated in TVA letter dated December 13, 2002, Subject: Browns Ferry Nuclear Plant - Unit 1 - Regulatory Framework for the Restart of Unit 1. The inspectors discussed the program status and progress with the licensee's engineers. The current schedule is that the majority of modifications to large bore and torus-attached piping and supports will be completed by the end of this year, with the remainder by June 2006. IE Bulletins 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors, and 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems, are required to be addressed in order to restart the unit. The Large Bore Piping and Supports Program and Long Term Torus Integrity Program for the torus-attached piping and supports are to be implemented to meet the requirements of IE Bulletins 79-02 and 79-14. The licensee's process to meet the two bulletin requirements is through three phases: Phase I - gathering information and walkdown inspection for individual piping and supports; Phase II - analyzing the phase I walkdown discrepancies based on the existing drawings and documents and generating the modification packages if required; and Phase III - modifying the piping and supports.

The inspectors randomly selected and performed independent walkdown inspections of large bore and torus-attached piping supports. The inspections were performed with the licensee's engineers and Quality Control (QC) inspectors to evaluate the effectiveness of the licensee's walkdowns and repairs.

b. Observations and Findings

Walkdown inspections were previously performed by the licensee's contract engineering (Bechtel) personnel to document the as-built condition and configuration of the large bore and torus attached-piping and supports. The walkdowns for each individual piping and support were completed by a team of two personnel. The results of the walkdowns were documented on walkdown drawings. TVA procedure WI-BFN-0-CEB-01, Walkdown Instructions for Piping and Pipe Supports, which specified the requirements for performance of the walkdown, was used. The licensee's engineers reviewed and evaluated the walkdown results for as-built discrepancies by comparing them to the existing drawings. The licensee revised calculations to qualify the as-built conditions or implemented modifications if the components with the discrepancies could not be qualified. The modified portions of the components were inspected and accepted by the QC inspectors.

The inspectors, accompanied by QC inspectors and engineers, randomly selected piping segments and supports and independently examined selected attributes of supports and piping to verify dimensions, size, length, type, diameters, thickness, identification, and clearances for welds, base plates, spring cans, snubber brackets, component members, and anchor bolts, and compared these measured attributes to those shown on final as-built drawings.

The inspectors identified two undersized welds, one base plate rotated 90 degrees, two undersized components, and two dimensions out of tolerance.

10 CFR 50, Appendix B, Criteria V, Instructions, Procedures, and Drawings, in part, states that "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

Contrary to the above, on February 16, 2005, the inspectors identified that activities affecting quality were not accomplished in accordance with drawings as follows:

(1) Pipe Support Drawing 1-47B458-565, Revision 002, for Core Spray system requires Item 5 (plate) - with dimensions 3/4" X 3-3/4" X 4"; however, field measurement determined the plate to be undersized with dimensions of 5/8" X 3-3/4" X 4".

(2) Pipe Support Drawing 1-47B458-829, Revision 001, for Core Spray system requires:

   (a) Item 7 (base plate) to be oriented towards north as depicted by Section B829 - B829; however, the base plate anchor bolts and member attachment was installed rotated 90 degrees.

   (b) Two 3/8" fillet welds at two connections between Item 3 (bent plate) and Item 10 (plate); however, field measurement determined two welds were undersized in that one weld measured 3/16" and other measured 1/4".

(3) Pipe Support Drawing 1-47B458-830, Revision 000, for Core Spray system requires Item 2 (strap) with dimensions of ½" X 4"; however, field measurement determined the strap to be undersized with dimensions of ½" x 3".

(4) Pipe Support Drawing 1-47B452-1467, Revision 002, for RHR system requires a dimension of 6-3/4" between center line of Item 8 (tube steel TS 6" X 6") and center line of Item 5 (lower anchor bolts in the base plate); however, field measurement determined the dimension to be 7-3/4", which is out of tolerance.

(5) Pipe Support Drawing 1-47B452-1468, Revision 001, for RHR system requires a dimension of 1'-6-7/8" from centerline of pipe to centerline of the spring can rod; however, field measurement determined the dimension to be 1'-8", which is out of tolerance.

The licensee's corrective actions were to perform evaluations and revise drawings and calculations in order to qualify the supports. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, and will be identified as a Severity Level IV Non-Cited Violation (NCV) 50-259/2005-06-01, Failure to Install Pipe Support Components and Welds in Accordance with Drawings. The licensee initiated PERs 77006, 76797, 76956, 76858, 76871, and 76945 in the Unit 1 Corrective Action Program to address these issues.

During the walkdown examination of the supports, the inspectors identified that Support 1-47B452-1468, Revision R001, was installed with two apparent discrepancies: (1) the support was rotated 180 degrees; and (2) one fillet weld size was measured 5/16" and the drawing requires 7/16". The licensee stated that the support was not rotated 180 degrees but was installed 1'-9" from the intended design location and that the weld measurement was acceptable and not undersized. The licensee also stated that dimensions for pipe support locations on the civil structural members shown on the support drawings are references only and are not required to be verified by the walkdown personnel or QC inspectors. The inspectors were concerned and considered that those dimensions should be checked and verified because pipe support location deviations will affect the qualification of the civil structure due to bending moments and associated reactions. This issue is identified as Unresolved Item (URI) 50-259/2005-06-02, Effect of Location Deviations for Pipe Support 1-47B452-1468, pending the licensee evaluation on the location change.

c. Conclusions

The Large Bore Pipe Support and Long Term Torus Integrity Programs were being adequately implemented with the exception of concerns in the area of verification of component/weld size and component dimensions and orientation. A non-cited violation was identified for failure to install pipe supports in accordance with drawings. In addition, an unresolved item was identified for the effects of the location deviations for Pipe Support 1-47B452-1468.

E1.6 Observation of Unit 2 Refueling Outage Activities (71111.17)

a. Inspection Scope

The inspectors observed or reviewed work performed by Unit 1 personnel on Unit 2 or shared systems during the Unit 2 refueling outage. The majority of these activities involved modifications and testing associated with DCNs 51016 and 51018. These DCNs implemented planned modifications to the common accident signal (CAS) logic for both units. Much of the CAS modification activities had been performed prior to the Unit 2 outage leaving certain portions which could only be performed while Unit 2 was not operating. Observation of pre-outage activities associated with DCNs 51016 and 51018 are discussed in Inspection Report 50-259/2004-09 and Section E1.1 of this report. Additional work performed during this outage involved modifications to 480-Volt Shutdown Board 2B, control room panel 1-9-22C, 4160-Volt Shutdown Board A, Unit 1 alarm system, and portions of the Raw Cooling Water system in the reactor and turbine buildings. The inspectors also observed or reviewed the applicable post-modification testing activities associated with these modifications.

b. Observations and Findings

The inspectors observed or reviewed work activities performed on Unit 2 and shared equipment. Work activities observed or reviewed included the following:

- DCN 51016, Unit 1 Common Accident Signal, complete cable pulls from Unit 1 control cabinets to Unit 2 control cabinets 2-9-32 and 2-9-33 and termination of cables in the Unit 2 control cabinets.

- DCN 51018, Unit 2 Common Accident Signal, Stages 1 thru 5, the work activities included the following: Stage 1, in Control Cabinets 2-9-3 and 2-9-32, installation of HFA relays, wire lifts, installation of jumpers, termination of new cables, and deletion of Division I RHR redundant initiation logic; Stage 2, in Control Cabinets 2-9-3 and 2-9-33, installation of HFA relays, wire lifts, installation of jumpers, termination of new cables, and deletion of Division II RHR redundant initiation logic; Stage 3, in Control Cabinet 2-9-32, modification of internal wiring associated with the B Emergency Diesel Generator (EDG); Stage 4, in Control Cabinet 2-9-33, modification of internal wiring associated with the D EDG; and Stage 5 deletion of redundant wiring on selected relays.

- DCN 51090, 480-Volt Electrical Distribution - Control Bay, Stages 61 and 62, System 57-4. Stage 61 involved the load shed time delay relay for the reset coil and the inhibit control circuit for the Unit 2 drywell blower fan 2B-1, and Stage 62 involved the load shed time delay relay for the reset coil and the inhibit control circuit for the Unit 2 drywell blower fan 2B-2. The time delay relays were installed in 480-Volt Shutdown Board 2B.

- DCN 51107, Control Room Panel 1-9-22, installation of new annunciator system and removal of unused electrical instrumentation.

- DCN 51215, 250-Volt DC Reactor MOV Boards, System 57-3, replacement of fuses, modification of compartments, replacement of thermo overloads, re-wiring of compartments, and replacement of selected breakers.

- DCN 51217, 4160-Volt Distribution - Reactor Building, System 57-5, installation of new 250-Volt DC control power cable in 4160-Volt Shutdown Boards A. The DCN directed that the old cable, designated as 1B95-IA, be abandoned, re-tagged as abandoned, and installation of new cable. The DCN also directed that the new cable be designated as 1B95-IA. In addition, a separate cable OES1716 was removed.

- DCN 51178, Raw Cooling Water, System 24, removed piping to abandoned chillers and coolers, removed and replaced old instrumentation, and removed/abandoned and replaced designated electrical cables.

The inspectors observed or reviewed testing activities involved with the modifications performed on Unit 2 and shared equipment. Testing activities observed or reviewed included the following activities:

- 2-SR-3.3.5.1.6(BI), Functional Testing of RHR Loop I Pump and Minimum Flow Valve Logic, post-modification test for DCN 51018, Stage 1, CAS modification of Division I of the RHR System. The purpose of the test was to perform a logic system functional test (LSFT) of the RHR System Loop I related to the automatic operation of Pumps 2A and 2D and associated valves. This procedure in conjunction with other tests satisfied the requirements of Unit 2 TSs. Part of the test was to verify that when Pumps 2A and 2D are operating separately or together, they would both trip upon a receipt of a common accident signal from Unit 1.

- 2-SR-3.3.5.1.6(CS II), CS System Logic Functional Test Loop II, post-modification test for DCN 51018, Stage 2, CAS modification of Division II of the CS System. The purpose of the test was to perform a LSFT of the Core Spray System Loop II related to the start of the CS Loop II pumps, provide a 480-Volt load shed signal, provide an ECCS initiation signal to the RHR System logic, and provide a start signal to the RHR Service Water pumps. This procedure in conjunction with other tests satisfied the requirements of Unit 2 TS. In addition, part of the test was to verify that the CS logic initiation would start the affected Unit 1 and 2 EDGs and the Unit 3 EDGs as part of the common accident signal logic.

- 2-SR-3.3.5.2.6 (A I), Functional Testing of RHR Loop I Valve Logic and Interlocks, post-modification test for DCN 51018, Stage 1, CAS modification of Division I of the RHR System. The purpose of the test was to perform a LSFT of the RHR System Loop I related to the automatic low pressure coolant injection (LPCI) initiation logic. This procedure in conjunction with other tests satisfied the requirements of Unit 2 TS. In addition, part of the test was to verify that when Division I is actuated only Division I equipment, such as RHR Pumps 2A and 2C would activate, and that Division II equipment would not activate.

- 2-SR-3.3.5.1.6(A II), Functional Testing of RHR Loop II Auto Initiation Logic and Injection Valve Opening Pressure Permissive Logic, post-modification test for DCN 51018, Stage 2, CAS modification of Division II of the RHR System. The purpose of the test was to perform a LSFT of the RHR System Loop II related to LPCI initiation Channel B and Trip System Bus Power Monitor. This test also verified that the channel initiation was from a combination of reactor low-low-low water level and high drywell pressure in conjunction with low reactor pressure. This procedure in conjunction with other tests satisfied the requirements of Unit 2 TS. In addition, part of the test was to verify that the initiation logic provided input to both the Division II and the Division I CAS Diesel Generator Output Breaker Re-Trip Logic.

- 2-SR-3.3.5.1.6(CS I), Core Spray System Valve Logic Functional Test Loop I, post modification test for DCN 51018, Stage 1, CAS modification of Division I of the Core Spray System. The purpose of the test was to perform a LSFT of the Core Spray System Loop I and was the same as procedure 2-SR-3.3.5.1.6(CS II) except this procedure was for Loop I. This procedure, in conjunction with other tests, satisfied the requirements of Unit 2 TS.

- PMTI-51018 Stage 3, Diesel Generator B (Breaker 1822) Unit Priority Re-Trip Logic, post-modification test for DCN 51018, Stage 3. The DCN, Stage 3, was implemented on the DG output breaker. The purpose of the test was to ensure that on a CAS actuation the B DG output breaker would align in accordance with the CAS logic.

- PMTI-51018 Stage 4, Diesel Generator D (Breaker 1816) Unit Priority Re-Trip Logic, post-modification test for DCN 51018, Stage 4. The DCN, Stage 4, was implemented on the DG output breaker. The purpose of the test was to ensure that on a CAS actuation the D DG output breaker would align in accordance with the CAS logic.

- Work Order (WO) 03-002713-16, perform voltage and polarity checks on the new 250-Volt DC control power cable, designated 1B95-IA, installed in 4160-Volt Shutdown Board A per DCN 51217, Stage 5.

During observation of the clearance implementation for Division II Core Spray Logic under WO 04-725316-002 craft personnel lifted an incorrect conductor. Step 23.2 of the WO directed the craftsman to lift conductor C7C1 of Cable ES2517-II at termination point JJ-23, which is the field side conductor. The craftsman lifted the internal wire instead of the field side conductor. The incorrect lift did not cause any adverse reaction or condition for plant operations. This issue was identified as a result of questioning from operations after they performed the second party verification, however, it was prior to hanging the clearance tag. As the result of this, a work stand-down was conducted along with a supplemental debrief with craft and operations personnel. The issue was captured by the licensee's corrective action program in PER 79213. The inspectors reviewed the licensee's investigation and determined that the error had occurred due to poor work practices and lack of attention to detail. The use of a non-standard method of flagging the electrical lead and poor communications contributed to the error.

The inspectors also reviewed corrective action documents issued by the licensee documenting conditions adverse to quality observed during the outage. PERs reviewed by the inspectors included the following:

- PER 79865, documented that during the performance of 2-SR-3.3.5.1.6(CS II), Core Spray System Logic Functional Test Loop II, Valve 2-FCV-75-50, Core Spray System Loop II Test Valve, failed to open when required. Trouble shooting determined that the initiating relay actuated as required; however, fouled contacts on the relay prevented the valve from opening. The contacts were cleaned and the valve tested properly.

- PER 79213, documented that during the installation of DCN 51018, while wire lifts were being performed, the wrong wire was lifted in that the internal panel wire was lifted and not the external field installed wire in panel 2-9-33. The internal panel wire was subsequently re-landed and the external field installed wire was lifted.

- PER 80336, documented that during the performance of 2-SR-3.3.5.1.6(CS I), Core Spray System Logic Functional Test Loop I, the core spray pump trip alarms did not occur as stated in a step in the procedure. Further review determined that the pump trip was from an automatic signal and the alarms would not occur under that condition. A procedure change was submitted and the test was completed.

- PER 80090, documented that during the performance of 2-SR-3.3.5.1.6© II), Functional Testing of RHR Loop II Valve Logic and Interlocks, several steps could not be performed as written such as the following: Step 7.2.22 called for rotating the ECCS Logic Test Switch to the D-F position when the switch was already in that position; Step 7.5.5 required that Panel 2-9-32 be energized when the panel was de-energized; and Steps 7.5.5.1 and 7.55.2 were written as if Panel 2-9-32 was energized when the panel was actually de-energized. Procedure changes were submitted and the test was completed.

- PER 79914, documented that during the performance of 2-SR-3.3.5.1.6(CS II), CS System Logic Functional Test Loop II, a step in the procedure called for a voltage measurement instead of a continuity check. A procedure change was submitted, the continuity check was performed, and the test was completed.

The licensee took prompt and effective corrective action early in the outage, including a work activity stand-down to re-emphasize expectations for work practices and quality. Subsequent errors were therefore reduced during the outage.

c. Conclusions

Modification activities performed on Unit 2 and shared equipment during the Unit 2 refueling outage by Unit 1 personnel were generally adequate. However, early in the outage, poor work practices and lack of attention to detail resulted in an error when an incorrect electrical lead was lifted. Although no adverse conditions resulted from the error, the use of a non-standard method of flagging the electrical lead and poor communications contributed to the error. The licensee took prompt and effective corrective action early in the outage, so subsequent errors were reduced during the outage

E1.7 Control Room Design Review (CRDR) Program (37551)

a. Inspection Scope

The inspectors performed reviews and observations of various modifications activities associated with the CRDR program. The DCNs for the CRDR program also included resolution of Human Engineering Deficiencies (HEDs).

b. Observations and Findings

The inspectors' reviews and observations of the implementation activities of the CRDR and HED program DCNs included removal and relocation of hand switches, relocating indicating lights, installing various types of indicators, moving system operating controls and alarms from one panel to another, and installing updated recorders. The following DCNs were reviewed and observed:

- DCN 51093, CRDR Modifications to Control Room Panel 1-9-2 to Resolve Identified HEDs. Various radiation monitoring systems and indications were affected by this DCN.

- DCN 51094, CRDR Modifications to Control Room Panel 1-9-3 to Resolve Identified HEDs. High Pressure Coolant Injection (HPCI), CS, and RHR system controls and indications were affected by this DCN.

- DCN 51096, CRDR, Modifications to Control Room Panel 1-9-5 to Resolve Identified HEDs. Nuclear Instrumentation, Standby Liquid Control, and Control Rod Drive system controls and indications were affected by this DCN.

- DCN 51100, CRDR, Modifications to Control Room Panel 1-9-20 to Resolve Identified HEDs. Condensate Transfer and Condensate Storage system controls and indications were affected by this DCN.

The inspector reviewed selected licensee corrective action documents issued to document problems identified during the CRDR work activities. PERs reviewed by the inspectors included the following:

- PER 78277, documented a failure of a green indicating RUNNING light. The failure occurred during the performance of the PMTI for a modification involving the Unit 2 Drywell Blower 2B-5. Further investigation determined that the failure was due to an intermittent auxiliary contactor that supplied power to the green RUNNING light. The auxiliary contactor was not part of the modification. The modification was successful in that the blower would have tripped and could have been re-started after the time delay. WO 05-712698-00, was initiated to repair the auxiliary contactor.

- PER 79031, documented that during the performance of the PMTI for Valve 0-2-177, Condensate Head Tank Outlet, the indicating lights did not agree with the valve hand control switch 0-HS-2-177, located on control room Panel 1-9-22A. This issue is further discussed in Section E1.10.

c. <u>Conclusions</u>

Based on review of selected modifications the inspectors concluded that the licensee's Control Room Design Review program continues to provide an adequate resolution of previously-identified Human Engineering Deficiencies. No violations or deviations were identified.

E1.8 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed licensee procedure Standard Program and Process (SPP)-9.5, Temporary Alterations. The inspectors also reviewed the following temporary alterations: Temporary Alteration Configuration Form (TACF) 1-04-014-064, Air Supply for Unit 1 Torus Coatings Activities, and 1-84-054-078, Low Discharge Pressure Annunciator on the Fuel Pool Cooling Pumps - System 78. 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

The inspectors reviewed and observed selected removal activities for the temporary alterations involved with the Unit 1 Torus coatings activities and the Unit 1 spent fuel pool cooling alarms. The temporary alterations reviewed and observed were as follows:

- TACF 1-04-014-064, Air Supply for Unit 1 Torus Coatings Activities, was initiated and installed to support contractor sandblasting and coatings activities in the Unit 1 Torus. The TACF used two spare 8-inch secondary containment penetrations, Z15651024 El 588 ft and Z15651025 El 586 ft, located along the south wall of the Unit 1 Reactor Building, to install three 3-inch air line hoses. Two new flanges, one per penetration, with gaskets and valves, were installed and bolted to the interior penetration flanges. The installation of the TACF was previously reviewed and documented in Inspection Report 50-259/2004-09. The inspectors reviewed and observed portions of the removal of the TACF and activities associated with returning the secondary containment penetrations to normal status. The inspectors noted that secondary containment integrity was maintained during removal of the TACF.

- TACF 1-84-054-078, Low Discharge Pressure Annunciator on the Fuel Pool Cooling Pumps - System 78, was initiated and installed to eliminate a false alarm for a loss of cooling to the spent fuel pool. This occurred only when one of the two pumps was operating. The original design installed a pressure indicating switch (PIS) on the discharge of each of the fuel pool cooling pumps, 1A and 1B. Each PIS would initiate a control room alarm on low pump discharge pressure. When one pump was shutdown, the PIS for that pump would activate the control room alarm. This would indicate a false alarm for a loss of cooling to the spent fuel pool. The TACF installed a sensing line, with a shutoff valve, between each PIS. During two-pump operation, the shutoff valve would be closed and both switches would monitor the respective cooling pump discharge pressure. During single-pump operation, the shutoff valve would be opened and both switches would monitor the single cooling pump discharge pressure. The temporary alteration was installed in 1984 and was removed in conjunction with implementation of DCN 51107, Replace Main Control Room Alarm Window Box 1-9-4C, Stage 15-Spent Fuel Cooling. The new modification installed a separate alarm and processor for each pump at the local panel.

c. Conclusions

The inspectors determined that removal activities associated with the two temporary alterations issued to provide temporary air supply for torus coatings activities and to eliminate a false alarm for loss of cooling to the spent fuel pool 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 inspector reviewed and observed portions of the licensee's system return to service (SRTS) activities. The SRTS activities were performed in accordance with Technical Instruction 1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart.

In addition, the inspectors reviewed the Cleanliness Verification Program (CVP) to evaluate the effectiveness of this program to support SRTS for Unit 1 Restart. The inspectors also reviewed a sample of corrective action documents issued by the licensee to address cleanliness issues identified as the result of licensee inspections of Unit 1 systems. Program requirements are specified in Technical Instruction 1-TI-474, Cleanliness Verification Program, Revision 0. 1-TI-474 references included: ANSI N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants; General Electric SIL 322, Cleaning of External Surfaces of Stainless Steel Piping; Procedure MSI-1-000-PRO001, Cleanliness of Unit 1 Fluid Systems; Procedure 0-TI-373, Plant Lay-up and Equipment Preservation; NRC Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Watercooled Nuclear Power Plants; and NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment. The CVP for Unit 1 was previously discussed in Inspection Report 50-259/2004-06.

b. Observations and Findings

b.1 System Pre-Operability Checklist (SPOC) Activities

SRTS activities continued during the reporting period. The SRTS process consisted of three parts: System Plant Acceptance Evaluation (SPAE), which consists of verification of design changes, engineering programs analysis, drawings, calculations, corrective action items, and licensing issues; System Pre-Operability Checklist (SPOC) I, which consists of the completion of items required for system testing; and SPOC II, which consists of the completion of system testing and the completion of items that affect operational readiness. During this report period, the SPAE process was completed for Emergency Equipment Cooling Water, System 67. The inspector reviewed and observed portions of the licensee's SRTS activities for the following:

- System 67, Emergency Equipment Cooling Water, SPOC I and SPAE activities
- System 25, Raw Service Water, SPOC I and SPAE activities
- System 34, Vacuum Priming, SPOC I and SPAE activities
- System 78, Fuel Pool Cooling, SPOC I and SPAE activities
- System 23, RHR Service Water, SPOC I and SPAE activities
- System 33, Service Air, SPOC I and SPAE activities
- System 69, Reactor Water Cleanup, SPOC I and SPAE activities
- System 79, Fuel Handling, SPOC II activities
- System 244, Communications, SPAE activities

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 was adequately addressed by the Unit 1 Restart corrective action program.

b.2 Cleanliness Verification Program

The Unit 1 CVP is intended to verify that for all internal and external surfaces of piping systems and associated components, the cleanliness requirements for fluid systems, both gas and liquid, are in accordance with TVAN requirements and industry standards; provide detailed remedial cleaning instructions for internal and external surfaces of piping systems and associated components whose internal and external surfaces do not meet respective cleanliness criteria as a result of extended lay-up or work activities; and provide criteria for continued Unit 1 system lay-up, after cleanliness acceptance, until such time as the system is returned to service.

The inspectors determined that the CVP applies to all Unit 1 fluid systems (steam, water, air, gas, or oil) and associated components which will be subject to the SPOC process. The list of SPOC systems covered by this procedure were listed in an attachment to 1-TI-474. System internal cleanliness requirements are divided into five classifications as follows:

- Class A, which requires a high level of internal cleanliness applicable to critical systems, structures, and components and includes such items as fuel elements, control rod drive mechanisms, delicate instruments, close tolerance items, and carefully controlled surfaces or assemblies.

- Class B, which requires a high level of internal cleanliness and includes systems which have a direct fluid contact with the reactor core and fuel. Also included are systems which are not normally in fluid contact with the core or fuel but are designed to be in contact under certain conditions, such as shutdown cooling systems, emergency core cooling systems, radwaste processing systems, and spent fuel cooling systems. As a special case, the main generator cooling system is also in the classification.

- Class C, which requires an intermediate level of internal cleanliness and generally includes closed cooling water systems that cool components containing reactor coolant, such as the Reactor Building Closed Cooling Water (RBCCW) system which cools the non-regenerative heat exchanger for the RWCU system. Included in this classification are the carbon steel portions of systems that are Class B systems, such as the carbon steel portions of the spent fuel pool cooling system. Also included in this classification are peripheral components that are in fluid contact with these systems. These systems are normally constructed of carbon steel or copper alloys and contain high-purity water. Compressed gas systems and waste gas systems are in this classification.

- Class D, which requires only a nominal level of internal cleanliness. These are systems that are normally used for raw water services and do not usually contain high-purity water. These systems are normally constructed of carbon steel.

- Class E, which requires an intermediate level of internal cleanliness. This classification includes systems which contain non-aqueous liquids in normal operation, such as turbine oil, diesel fuel, and EHC fluid. Also included in this classification are systems constructed of non-metallic piping or metallic piping with non-metallic liners carrying non-aqueous solutions. In addition, systems such as compressed air, control air, service air, and diesel starting air are in this classification.

External cleanliness verification is controlled by Procedure MSI-1-000-PRO001, Cleanliness of Unit 1 Fluid Systems. The activities were to be performed in accordance with the criteria of the procedure while observing the following:

- External surfaces which will be inaccessible after installation must be cleaned prior to installation.

- Grease, oil, and other forms of foreign contamination on external surfaces which are not removed by demineralized water shall be removed by the method described in Procedure MSI-1-000-PRO001.

- The removal of temporary tape and other markings on external surfaces must be performed by the method described in Procedure MSI-1-000-PRO001.

Procedure MSI-1-000-PRO001 will be used to implement specific remedial cleaning methods. The recommendations of Procedure 0-TI-373 will be used to provide system corrosion protection.

The inspectors determined that when remedial cleaning is required, Procedure 1-TI-474 required that the system engineer prepare a Detailed Flush Plan (DFP). The DFP must include:

- The extent of remediation shall be based on acceptance criteria, individual observations, photographs, and recommended corrective actions obtained during the CVP process.

- Cover sheet with a marked-up flow diagram showing the extent of the system piping to be cleaned. Additional information relative to cleaning shall be indicated such as valve alignments, remedial cleaning methods to be employed, system point(s) of entry, system drainage, flushing media quality, required cleanliness class, and acceptance criteria.

- Piping systems/components that are to remain in an extended outage status after cleaning shall be evaluated for lay-up in accordance with Procedure 0-TI-373.

- Flushing to reduce radiation dose at hot-spots or at other locations of localized radiation exposure from imbedded emitters may also be considered.

The inspectors noted that if the acceptance criteria for piping cleanliness cannot be met, a PER shall be written and the degraded condition and recommended corrective action(s) shall be indicated on the System Cleanliness Verification plan in order to document the findings. In addition, a WO will be initiated to perform remedial cleaning and the cleaning details shall be performed in accordance with a DFP.

The inspectors reviewed a sample of PERs issued by the Unit 1 staff to address problems identified during inspections of systems. The inspectors noted that most of these PERs documented the presence of foreign material or need for flushing identified during boroscope or camera inspections of piping segments. In each case a WO was issued to correct the discrepant condition.

c. Conclusions

SRTS activities continued to be performed in accordance with procedural requirements. Any system deficiencies were identified and appropriately addressed by the licencee's corrective action program. The System Cleanliness Verification Program continues to provide comprehensive inspections of systems for identification of degradation or special requirements to support the Unit 1 recovery.

E1.10 System Restart Testing Program Activities (37551)

a. Inspection Scope

The inspectors reviewed the on-going activities associated with the Restart Test Program (RTP). The RTP items reviewed and observed portions of Post-Modification Test Instructions (PMTIs) 1-PMTI-BF-51090-S57-64+S79 (Stages 57 Thru 64 and Stage 79), Functional Testing of Unit 2 Drywell Blower Load Shed (reset coil) Time Delay Relays, Inhibit Hand Switches, and Alarm Circuits; 1-PMTI-BF-002.009, Functional Testing of Hand Switches 1-HS-2-170A, -171A, -173A, and -259A and Level Indicator 1-LI-169 on Control Room Panel 1-9-22-1; 1-PMTI-BF-231.012, Functional Testing of 4160/480-VAC Shutdown Transformer TS1B Cooling Fans; 1-PMTI-BF-236.001, Functional Testing of Unit 1 Main Bank Transformer 1A, 1B and 1C Coolers; and, 1-PMTI-BF-023.049, Functional Testing of RHR Service Water (RHRSW) Pump C3 Handswitch on Control Room Panel 1-9-3. The inspectors also reviewed selected corrective action documents initiated during the RTP process to document test deficiencies or other problems.

b. Observations and Findings

b.1 Observation of Testing Activities

The following PMTIs were developed and approved to test portions of the associated DCNs. Areas involved in the tests were the Unit 1 Control Room Area, Unit 2 Control Room Area, the Unit 1 Reactor Building, and the Switchyard. Pre-test briefings were held, assignments were made, and communications were established prior to performance of testing. The inspectors observed and reviewed portions of the following testing:

- 1-PMTI-BF-51090-S57-64+S79 (Stage 79): This section of the PMTI performed a functional test for stage 79 of DCN 51090, 480-VAC Reactor Motor Operated Valve (RMOV) Boards and 480-VAC Shutdown Boards - Control Bay, Systems 57- 4. Stage 79 added alarm circuit wiring to six Unit 2 drywell blower inhibit switches. The alarm circuits functioned as designed for all six inhibit switch combinations, including having greater then two switches in the INHIBIT position.

- 1-PMTI-BF-51090-S57-64+S79 (Stage 59): This section of the PMTI performed a functional test for stage 59 of DCN 51090. Stage 59 involved the load shed time delay relay for the reset coil and the inhibit control circuit for the Unit 2 Drywell Blower Fan 2B-3. Drywell Blower 2B-3 failed to restart at step 6.2.17. During the test, a wiring error was discovered and corrected. Troubleshooting was perform using WO 04-720414-14. The test was resumed and completed satisfactorily. PER 76706 was initiated to document the troubleshooting required due to a test failure.

- 1-PMTI-BF-002.009 (Stage 2): This PMTI performed a functional test for Stage 2 of DCN 51100, CRDR Control Room Panel 1-9-22. Stage 2 involved the movement of hand switches 1-HS-2-170A, -171A, -173A, and -259A and Level Indicator 1-LI-169 from Control Room Panel 1-9-21 to Control Room Panel 1-9-22-1. The indicator and switches were all part of System 2, Condensate Storage and Transfer System. The DCN was part of the CRDR program. The test was completed satisfactorily.

- 1-PMTI-BF-231.012: This PMTI performed a functional test for stage 2 of DCN 51216, 480-VAC System - Reactor Building, System 57-4. This DCN replaced the 4160/480-VAC transformer TS1B with a new safety-related transformer designed to meet Environmental Qualification (EQ) requirements at power uprate conditions. The test involved the activating of the two temperature switches and verifying that the cooling fans started and the alarms activated in the control room. This DCN was part of the licensee's EQ program. The test was completed satisfactorily.

- 1-PMTI-BF-236.001: This PMTI performed a functional test of the cooling system of the Unit 1 main bank transformers. DCN 51470, Replace Unit 1 Main Transformers for Power Uprate, System 236, replaced the transformers with higher rated transformers. The PMTI included testing of the fan motors, oil pump motors, electrical contactors, associated relay logic, and control schemes for the cooling system. The test also verified the following: the transfer from normal power to emergency power for the fans and pumps; the fans and pumps operated per design; and applicable annunciators functioned when required. This DCN was part of the Extended Power Uprate (EPU) program. The test was completed satisfactorily.

- 1-PMTI-BF-023.049: This PMTI performed a functional test for stage 22 of DCN 51094, CRDR Control Room Panel 1-9-3. Stage 22 involved the relocation of handswitch 0-HS-23-91-A/1, RHRSW Pump C3, on Control Room panel 1-9-3. The test verified the start, stop, and motor trip-out contacts associated with the handswitch. This DCN was part of the CRDR and HED programs. The test was completed satisfactorily.

b.2 Wiring Error Discovered During PMTI Following Unit 2 Drywell Blower Load Shed Time Delay Relay Modification (71153)

The inspectors reviewed PER 76668 which was issued by the licensee to document a test deficiency associated with DCN 51090. During performance of Step 6.2.17 of 1-PMTI-BF-51090-S57-64+S79, the Unit 2 Drywell Blower 2B-3 failed to restart after the time delay relay timed out as required. The licensee's root cause evaluation stated that the failure of the drywell blower to restart as required was due to a wiring error which had occurred during implementation of the modification. Specifically, Post Issuance Change (PIC) 63654 was approved as an advanced authorized (AA) change to revise Drawing Change Authorization (DCA) 51090-176 to indicate that wiring was to be changed from Terminal 6C to Terminal 8C on Switch XS-70-44A. AA PIC 63654 also required that the change was to be included as Note 8 to the DCA. Although the wiring changes specified in the this AA PIC were correctly incorporated into the drawing section of the DCA, the construction notes, generated from the DCA, did not include the wiring change. The wiring was installed in accordance with the construction notes rather than the PIC or DCA resulting in the wiring error which prevented the drywell blower from restarting after the time delay. The inspectors concluded that although the wiring error was discovered during post-modification testing, the error did result in a delay in returning the drywell blower to service. However, this condition did not constitute a significant problem because an adequate number of Unit 2 drywell blowers were otherwise available and no TS Limiting Conditions for Operation (LCO) actions were required.

b.3 Wiring Error on Condensate Head Tank Outlet Valve Indication

The inspectors reviewed PERs 79031 and 79168, which documented a post-modification test deficiency and the inadequate resolution of that deficiency. Specifically, during the performance of the PMTI for Valve 0-2-177, Condensate Head Tank Outlet Valve, the indicating lights did not agree with the actual position of Hand Control Switch 0-HS-2-177, located on Control Room Panel 1-9-22A. The valve handswitch had been modified by DCN 51100, Stage 5, as implemented under modifications WO 02-011698-05. Actual valve position was in agreement with the hand switch position but not with valve position indicating lights. WO 05-713048-000 was issued to correct the wiring for the indicating lights. However, this WO incorrectly changed the valve control circuit rather than the light indicating circuit which resulted in both the switch and the indicating lights disagreeing with the actual valve position. Additional WO steps were added to WO 05-713048-000 to correct the errors in the valve control circuit and light indicating circuit. These errors resulted in a delay in restoring Valve 0-2-177 to service and an unnecessary operator burden.

The circumstances described in PERs 76668, 79168 and 79031 were considered as examples of a weakness in the licensee's design change process. Neither example resulted in the inoperability of required equipment. However, both examples resulted in delays in return to service of equipment used to support Unit 2 operation and some operator burden. The weakness is being addressed in the associated PERs.

b.4 Unplanned Electrical Transient on Units 2 and 3 Due to Wiring Error During Unit 1 Main Transformer Replacement (71153)

The inspectors reviewed B Level PER 74534 which was initiated to document an unplanned electrical transient which occurred on January 6, 2005, on Units 2 and 3. The event had resulted from a wiring error during replacement of the Unit 1 Main Transformers. The transient occurred after the implementation of DCN 51470, which replaced the Unit 1 main bank transformers, and was the result of a disturbance on the local electrical grid. The disturbance caused the transformer's ground differential relay to activate causing the Unit 1 transformers to trip, which should not have occurred. The relay activation was due to a wiring error, which affected the polarity of the relay coil. This in turn caused the 4-kV Unit Boards 1A, 1B, 1C, and the 4-kV A Common Board to transfer to their respective alternate power supplies.

DCN 51470 had replaced the existing Unit 1 24-kV to 500-kV Main Bank Transformers 1A, 1B, and 1C, with new higher Kilo Volt-Ampere (KVA) rated transformers. This modification was part of the licensee's Extended Power Uprate (EPU) program. Field work associated with this DCN was completed on December 7, 2004, and the Unit 1 main bank transformers were returned to service on December 20, 2004, after performance of post-modification testing in accordance with a special vendor test package performed as part of WO 03-005849-066. The wiring error which caused this event had not been identified during post-modification testing prior to returning the main bank transformers to service. WO 05-710175-000 was issued by the licensee to resolve the wiring error.

The inspectors reviewed the licensee's root cause evaluation associated with this event. The licensee determined that the event had occurred due to a wiring error associated with Test Switch 1-HS-236-0123. This test switch had two wires, 5AG and 5A2, that had been placed on the wrong switch terminals. Several contributing causes included:

- The original design that was issued was incomplete in that it did not contain wire numbers on the test switch. The wiring diagram drawing depicted the switch as a front view, however, the depiction was actually a back view layout. There was no note on the drawing to alert the user to this.

- An exception was taken, within the DCN, to the vendor manual standard on the polarity of the ground differential relay. There was no note on the drawing or any other design document to alert the user about this exception.

- An attempt had been made to compensate for the incomplete design with a Post Issuance Change (PIC), but this did not fix the problem. Advanced Authorized (AA) PIC 61611, was issued and included a note to drafter, "rotate test switch image to reflect Drawing Change Authorization (DCA) 60053-113." However, the change was never implemented in the field. In addition, the PIC did not contain wire numbers.

10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on December 20, 2004, licensee personnel returned the Unit 1 Main Bank Transformers to service after performance of an inadequate post-modification test. This inadequate test procedure resulted in the 4-kV Unit Boards 1A, 1B, 1C, and the 4-kV A Common Board to transfer to their respective alternate power supplies. Based on a review of the licensee's PER investigation results and associated corrective actions and discussions with licensee personnel, the inspectors determined that the failure was of low safety significance. Although this event resulted in an unnecessary operator burden, there was no actual loss of safety function during the unplanned electrical transient because all safety related equipment remained fully functional. A Severity Level IV Non-Cited Violation (NCV) 50-259/2005-06-03, Inadequate Post Modification Test Procedure, was identified. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. These events were documented by the licensee in PER 74534.

c. Conclusions

Implementation of restart testing activities was generally acceptable. However, post-modification testing associated with replacement of the Unit 1 Main Bank Transformers failed to identify a wiring error resulting in a NCV for an inadequate post-modification test procedure. In addition, the inspectors identified two examples of a weakness in the licensee's design change process which resulted in delays in return to service of equipment used to support Unit 2 operation and in some operator burden. Test deficiencies identified during performance of testing were documented under the licensee's corrective action program.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) Generic Letter (GL) 83-08, Modification of Vacuum Breakers on Mark I Containments

The inspectors reviewed GL 83-08: Modification of Vacuum Breakers on Mark I Containments. The purpose of this GL was to request licensees with BWR Mark I containments to consider measures to reduce vulnerability to vacuum breaker damage due to chugging and condensation oscillation loads during severe accident conditions. In response to GL 83-08, the licensee committed to modify the torus vacuum breakers on all three Browns Ferry units. This commitment was documented in TVA letter dated November 5, 1984. NRC review of the vacuum breaker modifications on Units 2 and 3 was documented in Inspection Report 259, 260, 296/90-33. The inspector reviewed finalized DCN 51189, which included the design details of mechanical modifications to the primary containment for Unit 1. Specifically, Stage 1 to this DCN includes the modification of the drywell and torus vacuum breakers to improve strength and reliability. The inspectors determined that this would appropriately address the issue for

Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.2 (Closed) GL 98-01, Year 2000 Readiness of Computer Systems at Nuclear Power Plants

The inspectors reviewed GL 98-01, Year 2000 Readiness of Computer Systems at Nuclear Power Plants. The purpose of this GL was to require licensees to provide information regarding their programs, planned or implemented, to address the year 2000 (Y2K) problem in computer systems at their facilities. Subsequent to issuance of this GL, Supplement 1 to GL 98-01 was issued on January 14, 1999, and provided licensees with a voluntary alternative response to that required in GL 98-01. The inspectors reviewed the licensee's letters dated July 22, 1998, June 29, 1999, and September 20, 1999, which provided information requested by GL 98-01. The NRC staff reviewed these responses and concluded that all requested information had been provided. That review was documented in an NRC Letter dated October 18, 1999. In addition, the inspectors held discussions with engineering personnel to determine the licensee's plans for updating plant computer and digital control systems on Unit 1. The inspectors determined that the new Unit 1 plant process computer will be a new state-of-the-art computer which will have the same functionality as those of Units 2 and 3. Furthermore, the various replacement digital control systems and software planned for installation on Unit 1 will be similar to existing systems used in Units 2 and 3. Replacement equipment will be newly manufactured or identical to that of Units 2 and 3 which was manufactured and installed post-Y2K. Based on the above review, the inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.3 (Closed) GL 89-16, Installation of a Hardened Wetwell Vent

The inspectors reviewed GL 89-16, Installation of a Hardened Wetwell Vent. This GL requested licensees with BWR Mark I containments to consider voluntary measures to reduce vulnerability to severe accident challenges. In response to GL 89-16, the licensee committed to install a hardened vent on Unit 2 during the first scheduled refueling outage after restart and prior to restart of Units 1 and 3. This commitment was documented in a TVA letter dated October 30, 1989. NRC review of the installation of the hardened vent on Unit 2 was documented in Inspection Reports 259,260,296/92-44; 93-02; 93-07; and 93-18. NRC verification of the hardened vent modification on Unit 3 was documented in Inspection Report 259, 260, 296/95-38. The inspector reviewed DCN 51189, which included the design details of mechanical modifications to the primary containment for Unit 1. Specifically, Stage 2 to this DCN includes the addition of hardened wetwell vent piping similar to that installed on Unit 3. The inspectors determined that this would effectively addressed the issue for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.4 (Closed) Bulletin 86-02, Static "O" Ring Differential Pressure Switches

The inspectors reviewed Bulletin 86-02, Static "O" Ring Differential Pressure Switches. This bulletin was issued as the result of problems identified with the static "O" ring Series 102 or 103 differential pressure switches supplied by SOR, Inc. Several industry events have been reported where the switches had failed to actuate within the setpoint tolerance or failed to actuate. Testing by some licensees indicated that switches performed erratically. Some of the problems identified were failure to actuate due to corrosion, setpoint drift, offset due to calibration, and sensitivity to exposure to operating conditions. Licensees were requested to determine whether or not they had these switches and to take certain actions to assure that system operation was reliable. The licensee's response to this bulletin, dated July 20, 1987, committed to the replacement of existing pressure switches with new pressure switches in each unit prior to restart as part of the environmental qualification upgrade program. The inspectors noted that this bulletin had been previously reviewed for Unit 1 and was documented in Inspection Report 50-259,260,296/93-04. Four differential pressure switches for RHR minimum flow valves, 1-FS-74-50 and 1-FS-74-64, and CS minimum flow valves, 1-FS-75-21 and 1-FS-75-49 are to be replaced. However, replacement switches similar to those used on Units 2 and 3 cannot be used because they are obsolete. The inspectors determined that the licensee is procuring switches of a new design which are scheduled to be replaced under DCN 51238, CS System, and DCN 51199, RHR System. Implementation of the new design will be reviewed under existing Inspector Followup Item (IFI) 259/93-04-01, Review Static "O" Ring Switches Per IEB 86-02 Prior to Restart. The inspectors determined that no further actions were required for Unit 1 under Bulletin 86-02. Therefore, this item meets the closure criteria established for Unit 1 recovery issues and is closed for Unit 1. IFI 259/93-04-01 will remain open pending further review of the actual replacement switches.

E8.5 (Closed) TMI Action Item II.F.1.2.D, Accident Monitoring, Containment Pressure

The inspectors reviewed TMI Action Item II.F.1.2.D, Accident Monitoring, Containment Pressure (old number II.F.4), to determine the status of the licensee's efforts in this area. The licensee had previously reported compliance in a letter dated October 1, 1990. In addition, closure of this item prior to restart of Unit 2 was documented in NRC Inspection Report 50-259,260,296/90-29. That NRC review had included in-plant inspections of applicable instrumentation in Unit 2 and verification that the TSs were updated to include the instruments. The inspectors noted that the applicable Unit 1 instrumentation was upgraded in response to NUREG 0737 (TMI Action Items) during the Unit 1 Cycle 5 refueling outage in 1983. TS Amendment No. 92, which added operability and surveillance requirements associated with these monitors for Unit 1, was approved by the NRC, by letter dated December 12, 1983. The inspectors noted that the licensee has planned further upgrades to these monitors prior to the Unit 1 recovery. The inspectors reviewed DCNs 51243 and 51245, which provided the details associated with planned upgrades to accident monitoring instrumentation in the drywell and reactor building on Unit 1. The inspectors determined that the licensee's planned upgrades were intended to bring Unit 1 instrumentation up-to-date, remain comparable to Units 2 and 3, and maintain compliance with NUREG 0737 requirements. The inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.6 (Closed) TMI Action Item II.F.1.2.E, Accident Monitoring, Containment Water Level

The inspectors reviewed TMI Action Item II.F.1.2.E, Accident Monitoring, Containment Water Level (old number II.F.5), to determine the status of the licensee's efforts in this area. The licensee had previously reported compliance in a letter dated October 1, 1990. The inspectors noted that the applicable Unit 1 instrumentation was upgraded in response to NUREG 0737 during the Unit 1 Cycle 5 refueling outage in 1983. TS Amendment No. 92, which added operability and surveillance requirements associated with these monitors for Unit 1, was approved by the NRC, by letter dated December 12, 1983. In addition, NRC inspectors had performed in-plant inspections of applicable instrumentation in all three units and verified that the suppression pool water level instruments met NUREG 0737 requirements prior to restart of Unit 2. Those reviews were documented in NRC Inspection Reports 50-259,260,296/89-40 and 90-32. The inspectors noted that the licensee has planned further upgrades to these monitors prior to Unit 1 recovery. The inspectors reviewed DCNs 51243 and 51245, which provided the details associated with planned upgrades to accident monitoring instrumentation in the drywell and reactor building on Unit 1. The inspectors determined that the licensee's planned upgrades were intended to bring Unit 1 instrumentation up-to-date, remain comparable to Units 2 and 3, and maintain compliance with NUREG 0737 requirements. The inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

III. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Program

a. Inspection Scope

The inspectors performed a program review of the Unit 1 Maintenance Program. Specifically, the inspectors evaluated this program to evaluate the effectiveness of the program to support physical recovery of Unit 1 systems and upgrade/repair items outside the licensee's formal design change process.

b. Observations and Findings

The inspectors determined that the Unit 1 maintenance program provides for "like-for-like" repairs of components which do not require design changes and covers 14 specific areas. Within each maintenance area, work orders were issued to repair, refurbish, or replace individual components. The 14 areas included:

- HFA Relays: A total of 349 HFA relays, within the Unit 1 boundary, were identified as requiring replacement. The inspectors documented the activities associated with the relay replacement in previous inspection reports. As of March 9, 2005, a total of 275 relays had been replaced.

- Enhanced Packing: A total of 65 large bore valves were identified as requiring enhanced packing. The valves were located in various safety-related and non-safety related systems. As of March 9, 2005, a total of 27 valves had been completed.

- Limitorque Valve Operator Removal: A total of 130 Limitorque valve operators were identified as requiring removal. The valve operators were located in various safety-related and non-safety related systems. As of March 9, 2005, a total of 128 valve operators had been removed.

- Type AK Electrical Circuit Breakers: A total of 41 type AK circuit breakers were identified as requiring maintenance. The circuit breakers were located in various 480-Volt switchgear. As of March 9, 2005, none of the work on the circuit breakers had been completed.

- Type 4-kV Electrical Circuit Breakers: A total of 24 type 4-kV circuit breakers were identified as requiring maintenance. The circuit breakers were located in various 4-kV switchgears. As of March 9, 2005, a total of 3 circuit breakers had been completed.

- Large Electrical Motors: A total of 19 large electrical motors were identified as requiring maintenance. The motors were located in systems such as CS, RHR, and Condensate. As of March 9, 2005, a total of 6 large electrical motors had been completed.

- Large Pumps: A total of 21 large pumps were identified as requiring maintenance. The pumps were located in systems such as HPCI, CS, RHR, and Condensate. As of March 9, 2005, a total of 8 large pumps had been completed.

- Check Valves: A total of 173 check valves were identified as requiring maintenance. The valves were located in various safety-related and non-safety related systems. As of March 9, 2005, a total of 56 check valves had been completed.

- Relief Valves: A total of 239 relief valves were identified as requiring maintenance. The valves were located in various safety-related and non-safety related systems. As of March 9, 2005, a total of 18 relief valves had been completed.

- Air-Operated Valves: A total of 403 air-operated valves were identified as requiring maintenance. The valves were located in various safety related and non-safety related systems. As of March 9, 2005, a total of 50 air operated valves had been completed.

- Live Loaded Valve Packing: A total of 70 large bore valves were identified as requiring live loading on their respective packing. The valves were located in various systems. As of March 9, 2005, a total of 25 had been completed.

- Valve Leak-Off Connections: A total of 73 valves were identified as requiring that their leak-off piping be cut and capped. The valves were located in various systems. As of March 9, 2005, a total of 25 had been cut and capped.

- Limitorque Installation: A total of 252 Limitorque valve operators were identified as requiring installation. The valve operators were located in various safety-related and non-safety related systems. As of March 9, 2005, a total of 31 valve operators had been installed.

- Heaters and Heat Exchangers: A total of 48 feedwater heaters and heat exchangers were identified as requiring repairs and upgrades. The heaters and heat exchangers were located in systems such as feed water heating and cooling water systems. As of March 9, 2005, a total of 8 heaters and heat exchangers had been completed.

c. Conclusions

The inspectors determined the Maintenance Program was providing appropriate and comprehensive repairs to Unit 1 components which do not require design changes to support Unit 1 Restart.

M1.2 Human Performance Errors (71153)

a. Inspection Scope

The inspectors discussed the following events with operations, engineering personnel and licensee management. The inspectors reviewed system response and verified that the actions which occurred were expected. The inspectors also reviewed the system alignment following recovery actions to verify that the system and components were in the required standby configuration. The inspectors also reviewed corrective action documents to verify that the event description, causes, and proposed corrective actions were appropriate. The licensee's reviews identified that human performance errors were the apparent causes. The inspectors did not identify any deficiencies with the licensee's reviews. The inspectors also reviewed NUREG-1022, Event Reporting Guidelines, to verify that actions taken were appropriate.

b. Observations and Findings

b.1 Unintended Engineered Safety Feature (ESF) Actuation Due to Pulling Incorrect Fuse

On January 12, 2005, during fuse replacement activities, an unintentional ESF actuation occurred resulting in Units 1, 2, and 3 reactor/refuel zone fan isolations, the initiation of all three Standby Gas Treatment (SBGT) trains, and the initiation of "A" train Control Room Emergency Ventilation (CREV). This event occurred while Unit 1 personnel were in the process of performing work under WO 03-17179-009. This WO implements a portion of DCN 60074, Control Bay Fuse Replacement Program. The licensee's review of the event determined that the spurious actuation was the result of an operator error. Operations personnel incorrectly pulled fuse, 1-FU-90-137A, for Reactor/Refuel Zone Radiation Monitors, 1-RM-90-141 and 1-RM-90-142. Step 22 of this WO was to remove fuse, 1-FU-90-131BA, which powers RBCCW Effluent Radiation Monitor, 1-RM-90-131. Radiation Monitor 1-RM-90-131 was not in service at the time. Both fuses were located in Unit 1 Control Room Panel 1-9-4 and access to the inside of the panel was restricted such that second party verification was not possible. The licensee's review of the event identified that the apparent cause was a failure to use self-checking techniques. Operators had failed to utilize flagging of the correct fuse prior to fuse removal. Flagging of fuses was the management expectation whenever second party verification is not possible. PER 74817 was issued by the licensee to document the licensee's corrective actions for this event.

b.2. Unintended ESF Actuation Due to Unit 1 Personnel Performing Wire Termination Without Adequate Equipment Clearance

On February 17, 2005, an unplanned Group 6 isolation occurred while Unit 1 personnel were performing wire lift/termination activities in the Unit 1 Auxiliary Instrument Room. This resulted in a Unit 1 reactor and refuel zone fan isolation, A and C SBGT initiation, and A CREV initiation. While performing work under WO 02-016196-007, which supported DCN 51189, Secondary Containment, System 64, craft personnel were de-terminating wires in Junction Box JB2893, which inputs to Panel 1-PLN-9-42 for limit switches to containment isolation valves 1-FCV-64-19, 1-FCV-64-20, and 1-FCV-64-21. The licensee's review of the event determined that the spurious actuation was the result of a blown fuse in Panel 1-9-42 in the Unit 1 Auxiliary Instrument Room. That fuse, 1FU-9-42, had blown due to the failure to follow licensee procedure requirements and poor work practices. Specifically, fuse 1FU-9-42 had cleared when the associated electrical lead was de-terminated while power was still applied. Hold Order 1-064-094, which was available to support this planned modification had not been issued. That hold order would have removed the affected fuse. PER 76996 was issued by the licensee to document the licensee's corrective actions for this event.

The inspectors reviewed the licensee's root and contributing causes and determined that the event occurred due to the failure to follow procedure SPP-10.2, Clearance Program. SPP-10.2, Step 3.2K, requires that actual work shall not begin on equipment until the clearance has been issued. Also, the craft supervisor failed to walkdown the clearance boundaries prior to authorizing work to start. In addition, the electricians were complacent and failed to pay adequate attention during voltage measurements and missed the presence of voltage in the electrical lead.

b.3 Inoperable Division I 480-VAC Load Shed Logic Due to Lack of Sensitivity to Work Involving Error-Likely Situation

On February 28, 2005, an unplanned loss of power to the Units 1 / 2 Division I 480-VAC load shed logic occurred when an electrician contacted and broke a protruding light socket in Panel 25-44A-11, 480-VAC Logic Aux Relay Panel. The broken indicator light shorted and resulted in clearing fuses 1-FU1-231-25-44AA and 1-FU1-231-25-44AB, which caused the inoperability of the load shed logic and the unplanned entry for Unit 2 LCO 2-231-TS-2005-0060. Unit 2 TS 3.8.1, Electrical Power Systems, required that both divisions of the Unit 1 480-VAC load logic remain operable. This event occurred during performance of WO 03-001001-061, which supported DCN 51216, 480-VAC distribution, when the electrician was standing up after bending to retrieve a cable tag during final housekeeping at completion of cable de-termination work. The inspectors reviewed the licensee's corrective actions for this event. PERs 77577 documented the licensee's actions associated with this event. In addition, PER 77613 documented the licensee's actions associated with the unplanned LCO entry. The licensee determined that the event occurred due to inattention by craft personnel during work in sensitive equipment. WO 03-001001-061 contained precaution for protection of sensitive plant equipment, including a warning not to bump the panels.

Due to this and previous events, the licensee temporarily halted all critical electrical modification activities which could have an adverse impact on operating equipment and conducted stand-down meetings with Unit 1 modifications personnel prior to restarting critical electrical modifications activities. During the stand-down, management communicated lessons learned from these events and the expectation that human performance error prevention tools would be used. In addition, management reinforced the expectation that craft supervision was expected to remain with critical work activities while workers were in the work area. The inspectors observed both craft and craft supervision stand-down sessions.

Based on the review of this event and the two previous events, the inspectors concluded that the events had resulted from inadequate work practices by the craft personnel and lack of sensitivity by craft and craft supervision to error-likely situations. 10 CFR 50, Appendix B, Criteria V, Instructions, Procedures, and Drawings, in part, states that "...activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Contrary to the above, on January 12 and February 28, 2005, licensee personnel failed to follow requirements as required by approved work instructions. In addition, on February 17, 2005, licensee personnel failed to follow requirements of the equipment clearance procedure as specified in SPP-10.2. These incorrect acts resulted in inadvertent ESF actuations and unnecessary operator burdens. Based on a review of the licensee's PER investigation results and associated corrective actions and discussions with licensee personnel, the inspectors determined that the failures were of low safety significance. There was no actual loss of safety function during the unplanned ESF actuations because all aspects of the ESF remained fully functional. In addition, the loss of power to the Division 1 load shed logic was of low safety significance due to the limited amount of Unit 1 equipment which was available. A Severity Level IV NCV 50-259/2005-06-04, Failure to Follow Equipment Clearance Procedure and Maintenance Work Instructions, was identified. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. These events were documented by the licensee in PERs 74817, 76996, 77577, and 77613.

c. <u>Conclusions</u>

As a result of poor work practices and lack of sensitivity to error-likely situations, human performance errors resulted from failure to follow the equipment clearance procedure or correctly implement approved work instructions, which challenged ESFs and systems important to safety. The actual significance was low because there was no actual loss of safety function. The inspectors identified the licensee's failure to follow maintenance work instructions as a Severity Level IV NCV. Corrective actions associated with these events were reviewed and were deemed to be adequate. Based on a review of the licensee's root and contributing causes and discussions with Unit 1 management, the inspectors concluded that the planned and completed actions were appropriate and comprehensive. The inspectors concluded that the licensee's response to the events was appropriate.

V. Management Meetings

X1 Exit Meeting Summary

On April 26, 2005, 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

<u>SUPPLEMENTAL INFORMATION</u>

KEY POINTS OF CONTACT

<u>Licensee personnel</u>

T. Abney, Nuclear Site Licensing & Industry Affairs Manager
R. Baron, Nuclear Assurance Manager, Unit 1
M. Bennett, QC Manager, Unit 1
R. Bentley, NDE Level III
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
B. Ditzler, TVA Welding Engineering Supervisor, Unit 1
R. Jones, Plant Recovery Manager, Unit 1
S. Kane, Licensing Engineer
D. Kehoe, Nuclear Assurance, Unit 1
J. Lewis, ISI Program Engineer, Unit 1
G. Lupardus, Civil Design Engineer, Unit 1
J. McCarthy, Licensing Supervisor, Unit 1
J. Ownby, Project Support Manager, Unit 1
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 37550	Onsite Engineering
IP 37551	Engineering
IP 50090	Pipe Support and Restraint Systems
IP 55050	Nuclear Welding General Inspection Procedure
IP 57050	Visual Testing Examination
IP 57060	Liquid Penetrant Testing Examination
IP 57090	Radiographic Examination Procedure Review/Work Observation/Record Review
IP 71111.17	Permanent Plant Modifications
IP 71111.23	Temporary Plant Modifications
IP 71153	Event Followup
IP 73755	Inservice Inspection Data Review and Evaluation
IP 73055	Preservice Inspection
IP 92701	Follow-up

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-259/05-06-01	NCV	Failure to Install Pipe Support Components and Welds in Accordance with Drawings (Section E1.5)
50-259/05-06-03	NCV	Inadequate Post-Modification Test Procedure (Section E1.10)
50-259/05-06-04	NCV	Failure to Follow Equipment Clearance Procedure and Maintenance Work Instructions (Section M1.2)

Opened

50-259/05-06-02	URI	Effect of Location Deviations for Pipe Support 1-47B452-1468 (Section E1.5)

Closed

83-08	GL	Modification of Vacuum Breakers on Mark I Containments (Section E8.1)
98-01	GL	Year 2000 Readiness of Computer Systems at Nuclear Power Plants (Section E8.2)
89-16	GL	Installation of a Hardened Wetwell Vent (Section E8.3)
86-02	BU	Static “O” Ring Differential Pressure Switches (Section E8.4)
II.F.1.2.D	TMI	Accident Monitoring, Containment Pressure (Section E8.5)
II.F.1.2.E	TMI	Accident Monitoring, Containment Water Level (Section E8.6)

Discussed

259/93-04-01	IFI	Review Static “O” Ring Switches Per IEB 86-02 Prior to Restart (Section E8.4)

LIST OF DOCUMENTS REVIEWED

Section E1.1: Plant Modifications

Procedures and Standards

SPP-9.3, Plant Modifications and Engineering Change Control, Rev. 9
MAI-4.2B, Piping, Rev 20
G-94, Piping Installation, Modification, and Maintenance, Rev. 2

DCNs

DCN 51016, Unit 1 Emergency Core Cooling System (ECCS) Accident Signal Logic
DCN 51018, Unit 2 ECCS Accident Signal Logic
DCN 51090, 480 Volt AC Electrical System
DCN 51107, Annunciator Upgrade, Unit 1

Section E1.2: Unit 1 Restart Special Program Activities - Containment Coatings

Specifications & Procedures

TVA General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants, Rev. 13, dated 2/17/04.
MAI-5.3, Protective Coatings for Service Level I, II, III and Corrosive Environments, Rev. 40, dated 11/12/04.
Walkdown Instruction WI-BFN-1-MEB-03, BFN Unit 1 Primary Containment Coatings Inspection Plan (for identification of uncontrolled coatings and coatings that were applied to stainless steel)
TI-417, Inspection of Protective Coatings in the Interior Surfaces of Primary Containment, Rev. 1

Problem Evaluation Reports (PERs)

70318, High Failure Rate for Applicators Taking Qualification Test to Apply K&L 6548/7107 Coatings.
71787, Expired Shelf Life of Keeler and Long Epoxy Primer.
72303, Inadequate Coatings Application - First Coat of Vyguard
72325, Sandblasting Overblast Damaged Existing Coatings.
72897, Accumulation of Dust and Debris on Surfaces to be Coated.
72962, Surface Preparation Deficiencies.
72900, Surface Preparation Deficiencies.
73229, Surface Irregularities in Completed Coatings.
74346, Inadequate Coatings Quality - Contaminated with Grit and Debris.
74760, Dry Film Thickness Does not Meet G-55 Specification.
74924, Holidays in Finished Coatings.
74989, Holidays in Finished Coatings Caused by Scaffolding.
75031, Clarification for Holiday Testing.
75255, Low DFT Readings.
75257, Low DFT Readings.
75258, Holidays in Finished Coatings, Three Locations.

75236, DFT Readings Outside Of G-55 Requirements.

Miscellaneous Documents

Work Plan 03-018473-015, including QC Inspection Records.
Work Plan 03-018473-023, including QC Inspection Records.

Section E1.3: Unit 1 Restart Special Program Activities - Intergranular Stress Corrosion Cracking (IGSCC) - Welding of Replacement RECIRC System, RHR System, RWCU, and CS System Piping

DCNs and Work Documents

DCN 51163, Replacement of Reactor Vessel Level Indication System (RVLS) Reference and Sensing Lines
DCN 51045, Changes in Response to NRC Generic Letter 88-01 "NRC Position on IGSCC IN BWR Austenitic Stainless Steel

Section E1.4: Inservice/Preservice Inspection (ISI/PSI)

Procedures and Standards

N-UT-76, Generic Procedure for Ultrasonic Examination of Ferritic Pipe Welds, Rev. 4
N-MT-6, Magnetic Particle Examination For ASME and ANSI Code Components and Welds, Rev. 26

Section E1.5: Unit 1 Restart Special Program Activities - Large Bore Piping and Supports Program & Long Term Torus Integrity Program

Procedures

WI-BFN-0-CEB-01, Walkdown Instruction for Piping and Pipe Supports
General Specification G-66, Requirements for the Use of Undercut Anchors Set in Hardened Concrete During Installation, Modification, and Maintenance, Rev. 7

Drawings

ISO. N1-174-5R, Residual Heat Removal System, Sheet 1
ISO. N1-175-4RA, Core Spray Cooling System, Sheet 1
ISO. N1-175-4RB, Core Spray Cooling System, Sheet 1
ISO. N1-175-1R, Torus Analysis of Core Spray Piping System, Sheet 1
Pipe Support Drawing No. 1- 47B452-1467, Rev.R2
Pipe Support Drawing No. 1-47B452-1468, Rev. R1
Pipe Support Drawing No. 1-47B458-556, Rev.R2
Pipe Support Drawing No. 1-47B458-557, Rev.R2
Pipe Support Drawing No. 1-47B458-558, Rev.R1
Pipe Support Drawing No. 1-47B458-559, Rev.R2
Pipe Support Drawing No. 1-47B458-560, Rev.R2
Pipe Support Drawing No. 1-47B458-564, Rev.R2
Pipe Support Drawing No. 1-47B458-565, Rev.R2

Pipe Support Drawing No. 1-47B458-566, Rev.R2
Pipe Support Drawing No. 1-47B458-567, Rev.R2
Pipe Support Drawing No. 1-47B458-568, Rev.R2
Pipe Support Drawing No. 1-47B458-829, Rev.R1
Pipe Support Drawing No. 1-47B458-830, Rev.R0
Pipe Support Drawing No. 1-47B458-831, Rev.R2
Drawing No. O-47B435-4, Rev. R004, Mechanical General Notes Pipe Supports
Drawing No. O-47B435-6, Rev. R004, Mechanical General Notes Pipe Supports

Problem Evaluation Reports (PERs)

77006, pipe support issues
76797, pipe support issues
76956, pipe support issues
76858, pipe support issues
76871, pipe support issues
76945, pipe support issues

Section E1.6: U2 Outage

Problem Evaluation Reports (PERs)

79865, during performance of 2-SR-3.3.5.1.6(CS II), 2-FCV-75-50 failed to open
79213, during the installation of DCN 51018, an incorrect wire was lifted in panel 2-9-33
80336, during the performance of 2-SR-3.3.5.1.6(CS I), the core spray pump trip alarms did not occur as expected
80090, during the performance of 2-SR-3.3.5.1.6(CS II), several steps could not be performed as written
79914, during the performance of 2-SR-3.3.5.1.6(CS II), the procedure called for a voltage measurement instead of a continuity check

Section E1.7: Control Room Design Review

Modifications

DCN 51093, CRDR, Modifications to Control Room Panel 1-9-2
DCN 51094, CRDR, Modifications to Control Room Panel 1-9-3
DCN 51096, CRDR, Modifications to Control Room Panel 1-9-5
DCN 51100, CRDR, Modifications to Control Room Panel 1-9-20

Problem Evaluation Reports (PERs)

78277, during the PMTI for the Unit 2 Drywell Blower 2B-5 green indicating RUNNING light failed.
79031, during the performance of the PMTI for valve 0-2-177, the indicating lights did not agree with the valve hand control switch 0-HS-2-177, located on control room panel 1-9-22A

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 1-04-014-064, Air Supply for Unit 1 Torus Coatings Activities
TACF 1-84-054-078, Low Discharge Pressure Annunciator on the Fuel Pool Cooling Pumps - System 78.

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
1-TI-474, Cleanliness Verification Program, Rev. 0
0-TI-373, Plant Lay-up and Equipment Preservation, Rev. 4
MSI-1-000-PRO001, Cleanliness of Unit 1 Fluid Systems, Rev. 1

Problem Evaluation Reports (PERs)

76034, metal grindings found in suction line of A recirc loop during rinsing of line
76930, need for flushing of 1A reactor feed pump turbine lower housing identified during boroscope exam
78302, metal shavings identified during boroscope exam of core spray spoolpiece
79270, slag, debris, and dust found in 1A1 moisture separator during camera inspection

Section E1.10: Restart Test Program

Procedures and Standards

Technical Instruction 1-TI-469, Baseline Test Requirements, Rev. 1
Post Modification Test Instruction (PMTI) 1-PMTI-BF-51090-S57-64+S79, Functional Testing of 480 VAC Reactor MOV Bards and 480 VAC Shutdown Boards - Control Bay, System 57-4, Rev. 0
PMTI 1-PMTI-BF-035.013, Main Bank Transformers 1A, 1B, and 1C, Rev. 1
PMTI 1-PMTI-BF-002.009, Functional testing for DCN 51100, CRDR Control Room Panel 1-9-22, Rev. 0
PMTI 1-PMTI-BF-231.012, Functional testing for DCN 51216, 480 VAC System Reactor Building, System 57-4, Rev. 1
PMTI 1-PMTI-BF-236.001, Functional testing for DCN 51470, Replacement of Unit 1 main Transformers, System 236, Rev. 0
PMTI 1-PMTI-BF-023.049, Functional testing for DCN 51094, CRDR Control Room Panel 1-9-3, Rev. 0

Problem Evaluation Reports (PERs)

74534, unplanned electrical transient due to wiring error on Unit 1 main transformers
76668, PMTI test deficiency for drywell blower 2B-3
76706, wiring error on drywell blower 2B-3
79031, wiring error during WO 05-713048-000
79168, PMTI test deficiency for handswitch 0-HS-2-177

Other Documents

WO 03-005849-066, special vendor test package for Unit 1 main transformers
WO 05-713048-000, correction of wiring error for handswitch 0-HS-2-177
WO 05-710175-000, correction of wiring error on Unit 1 main transformers

Section M1: Conduct of Maintenance

Procedures and Standards

SPP-10.2, Clearance Program, Rev 6

Work Documents

WO 02-016196-007, electrical cable determinations for DCN 51189
WO 03-001001-061, electrical cable determinations for DCN 51216
WO 03-017179-009, replace fuses for DCN 60074

Problem Evaluation Reports (PERs)

74817, Unplanned Group 6 isolation while replacing fuses
76996, Unplanned Group 6 isolation while performing wire terminations
77577, Unplanned loss of Unit 1 Division I load shed logic
77613, Unplanned LCO for Unit 1 Division I load shed logic