U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-259, 50-260, 50-296
License Nos:	DPR-33, DPR-52, DPR-68
Report Nos:	50-259/97-11, 50-260/97-11, 50-296/97-11
Licensee:	Tennessee Valley Authority
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	October 26 - December 6, 1997
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EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/97-11, 50-260/97-11, 50-296/97-11

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection and an inspection of the licensee's motor-operated valve (GL 89-10) program.

Operations

Operator actions in response to a Unit 2 single control rod insertion and reactor scram were good. Procedures were actively referenced and correctly followed. Good performance was noted on the part of the assistant unit operator that identified an EHC fluid leak during performance of rounds. (Section O1.1)

Procedural controls of the control room emergency ventilation (CREV) system priority selector switch were not adequate to ensure that the switch was maintained in the correct position. (Violation 260,296/97-11-02, Failure to Control CREV Switch Position, Section O1.3) Further review is necessary regarding testing of the transfer control circuitry. (Unresolved Item 260,296/97-11-03, Adequacy of CREV Standby Train Circuit Testing, Section O1.3)

Two examples of status control issues were identified by the inspectors during this inspection. The first example is addressed by the violation for inadequate control of the CREV system priority selector switch. In addition, the inspectors identified a drain valve on a non-safety related service air compressor that was not in the required position. Additional NRC review of recent status control issues is warranted. (Inspection Followup Item 260,296/97-11-01, Status Control Issues, Section O1.2).

Adequate mechanisms were in place to prompt an annual licensee review of freeze protection equipment. Small bore and stagnant piping in RHRSW pump rooms could have been given priority during inspection and repair of freeze protection equipment so that the identified condition of uninsulated small bore piping in colder conditions would not have existed. The licensee's actions to place heaters in and tarpaulins over the RHRSW pump rooms provided a level of protection for the uninsulated piping. (Section O2.3)

Maintenance

Good mechanical maintenance performance was noted during replacement of the immersion heater coil assembly on the 2B EDG. Effective troubleshooting to determine the cause of burned lugs in the EDG control cabinet identified problems with the immersion heater even though the heater appeared to be working. (Section M1.1)

Engineering

Implementation of Generic Letter 89-10 at Browns Ferry was not sufficiently complete to permit the NRC to complete its review. (Section E1.3)

Inspectors identified that the licensee failed to revise procedures to declare the applicable system or train inoperable when certain motor-operated valves were placed in their non-safety positions (Section E1.3)

Inspectors identified that the licensee failed to prepare motor-operated valve trend reports in accordance with procedure requirements. (Section E1.3)

The licensee failed to evaluate test data to assess its Generic Letter 89-10 program design assumptions and improperly used actuator stall efficiency in evaluating motor-operated valve operability. (Section E1.3)

On two occasions during the inspection period, the NRC prompted problem evaluation reports (PERs) to be written. The first example was an NRC identified deficiency with a main steam pressure instrument calibration calculation. The original set point and scaling calculation for the main steam pressure instruments analyzed for a calibration frequency of 12 months versus the surveillance instruction frequency of 18 months. (Section E1.1) The second example involved problems with radiation monitor RM-90-130. (Section R2.1) In both of these examples, personnel did not initiate PERs when they were warranted.

Review of the technical operability evaluation (TOE) to evaluate the main steam line pressure transmitters, which were installed in the plant with incorrect upper range pressure limits, identified deficiencies with the TOE. The overall results of the TOE were not affected. No regulatory violations were identified concerning these non-safety related transmitters. (Section E1.1)

The licensee properly implemented the Core Operating Limits Report for Unit 2 Cycle 10 with respect to the revised TS requirements. (Section E1.2)

The licensee's incident investigation team performed well in investigating the equipment issues which caused the Unit 2 scram. The team studied available information, developed a theory of the cause, and in a prompt manner, performed electrical testing which supported the postulated cause. The investigation into the EHC fluid leaks was also thorough and determined the cause of the leaks in a reasonable time period. (Section E2.1)

Although the licensee's actions to decrease the oil particulate levels in the RCIC system were adequate, the RCIC oil particulate level issue represents another example of the difficulties that the licensee is experiencing with the lube oil analysis program. (Section E2.2)

Plant Support

Unexpected indications on the radioactive effluent monitor recorder were not thoroughly investigated prior to discontinuation of compensatory actions required for an inoperable monitor. The licensee subsequently completed a detailed investigation which identified that a leaking valve had caused the unexpected indications. The investigation also concluded that the monitor was not inoperable and that regulatory requirements were met during the period. (Section R2.1)

Report Details

Summary of Plant Status

Unit 1 remained in a long-term lay-up condition with the reactor defueled.

Unit 2 was brought critical on October 18, 1997, following the cycle 9 refueling outage. The unit reached full power on October 23, 1997. Electro-hydraulic control fluid leaks on turbine control valves caused several power decreases to perform maintenance during the inspection period. (Section E2.1) On October 28, 1997, the unit scrammed when a B reactor protection system (RPS) relay problem occurred while a half scram was already present on the A RPS system. (Sections 01.1, E2.1) The unit was brought critical on October 30, 1997, and remained at power during the inspection period with the exception of maintenance and routine testing downpowers.

Unit 3 operated at power with the exception of routine testing and several balance of plant maintenance issues which required power decreases.

I. Operations

01 Conduct of Operations

01.1 Unit 2 Single Control Rod Insertion and Reactor Scram

a. Inspection Scope (71707,93702)

The resident inspectors observed and reviewed the actions of control room operators in response to two separate unexpected plant transients. In one instance, a single control rod inserted unexpectedly during repairs of an electrohydraulic (EHC) fluid leak. Not directly related to this incident, an automatic reactor scram occurred shortly thereafter due to a problem with reactor protection system relays. Additional inspection regarding the cause of the scram is described in section E2.1 of this report.

b. Observations and Findings

At 12:23 p.m., on October 28, 1997, an Assistant Unit Operator noted a decreased Unit 2 EHC fluid reservoir level. It was determined that an EHC oil leak existed on the servo mechanism for the #1 turbine control valve. Reactor power was reduced to allow the valve to be shut for repairs. Upon closing the #1 control valve, an expected half scram was received on RPS channel A. Approximately 2 minutes after receiving the half scram, control rod 30-23 moved in to the full overtravel position. One of the resident inspectors was in the control room at the time and observed the rod insertion. The inspector noted that the rod appeared to travel from the full out position to the full overtravel position in less than 5 seconds. The licensee commenced corrective actions for the

rod drift in accordance with Abnormal Operating Instruction, 2-AOI-85-2, Uncoupled Control Rod. This included evaluating thermal limits and inspecting the CRD hydraulic control unit (HCU) for abnormalities. Subsequent inspection revealed that the HCU scram outlet valve for control rod 30-23 was leaking air past its diaphragm. The licensee postulated that air pressure on the scram valve was reduced by leakage through this path and leakage through the "B" powered scram solenoid pilot valve (SSPV). The "A" powered SSPV was de-energized due to the half scram. This caused the scram valve to open and resulted in the rod insertion.

At 2:50 p.m., repairs were completed on the #1 Control Valve (CV). The valve was opened and the half scram on RPS channel A was reset. At 3:08 PM the operators reshut the #1 CV in order to perform post maintenance testing. About 1 minute later, concurrent with the worker releasing a button to re-open the #1 CV, the reactor scrammed. Operators completed scram follow up actions satisfactorily. Reactor water level decreased to lowest level of about -32 inches and was rapidly restored by the feedwater pumps. The response of the feedwater pumps was as expected following the scram. No safety system problems were observed associated with the recovery. Additional review of the scram is described in Section E2.1.

Following the Unit 2 scram, both SSPVs and the scram outlet valve diaphragm, responsible for the single rod insertion, were replaced. One of the inspectors observed satisfactory scram time testing of the 30-23 control rod after the work was completed. Following completion of corrective actions (see section E2.1), a reactor startup was commenced late on October 29, 1997. Operator performance and control room conduct were observed to be good during the rod withdrawal to criticality.

c. Conclusions

The actions of the control room operators in response to these unexpected transients were good. Procedures were actively referenced and correctly followed. The EHC fluid leak was identified by an AUO during the performance of rounds.

01.2 Status Control of Operations Equipment

a. Inspection Scope (71707)

The inspectors reviewed the licensee's corrective actions after an incorrectly positioned service air system valve was identified by the NRC.

b. Observations and Findings

On November 10, 1997, the inspectors identified that a drain valve on the F service air compressor after-cooler condensate trap was partially open and discharging a water/air mixture. This valve had previously

been caution tagged in the throttled open position to remove moisture buildup since the licensee believed that the trap was not operating properly. The caution tag was subsequently removed and the valve was expected to be shut. The trap is a float type trap. The drain valve drains water from the trap body (vice other designs which drain from upstream of the trap). Operation of the trap bypass will drain water from the trap body, thus it will take some time for the body to fill back up and commence automatic trap operation again.

The licensee initiated a Problem Evaluation Report (PER) to investigate the cause of the mispositioned valve. Operations management postulated that an Assistant Unit Operator opened the valve to check for moisture and upon finding a significant quantity of liquid, left it throttled to complete draining with the intention of returning later to close it. Although the valve was not in the correct position and did affect the operation of the trap, overall operation of the service air system was not adversely affected. The PER evaluation noted several other mispositioned component incidents since January 1996. The PER corrective actions include a discussion of the PER and event with all shift crews, stressing the need for open and honest communication concerning errors and events. The Operations Superintendent will evaluate the use of red valve covers on valves in the vicinity to act as a reminder to the operator to re-close the valve. Operation of this particular trap with be covered during AUO requalification training. Also, the PER corrective actions indicated that an engineering work request was issued to address the adequacy of the condensate traps and the excessive moisture experienced with the new compressors.

c. Conclusion

The equipment identified out of the required position was not safety-related. The involved equipment remained operable. However, NRC inspectors identified two examples of status control issues during the inspection period. (See Section 01.3 for the second example.) In recent months, the licensee has identified other status control issues. Further review of recent status control issues is warranted. (Inspection Follow up Item (IFI) 50-260,296/97-11-01, Status Control Issues.)

01.3 Control Room Emergency Ventilation System Preferred Train Selector Switch Issues

a. Inspection Scope (71707, 37551)

The inspectors reviewed the effect of having the Control Room Emergency Ventilation (CREV) preferred selector switch in a position other than that required by work instructions. Surveillance testing was reviewed to determine if the automatic start feature of the CREV unit was adequately tested.

b. Observations and Findings

On November 19, 1997, one of the resident inspectors identified that the CREV system priority selector switch (0-XSW-031-7214) was in a position different than that described in work control instructions. Work being performed on the CREV system made the A train inoperable. Work control instructions (planning fragnet) required the preferred unit selector switch to be placed in the B position. The control room operators subsequently placed the switch in the B position. The inspector questioned the effect of the switch being selected to the A train which was inoperable.

Logic diagrams and control drawings were reviewed. The inspectors concluded that the B train of the CREV would have operated if called upon. This was based on the standby feature design of the two trains. Since the A train was selected, an initiation signal would be sent to both trains to start, however, only the preferred train would start immediately. The non-preferred system operation would be delayed for some time by a timer and flow switch arrangement. If the proper flowrate is not sensed in the preferred system after a time delay, the non-preferred system would start. The effect of having the A train selected would have resulted in the B train starting after a time delay. The time delay is incorporated into CREV system design. Therefore, the inspectors concluded that the switch being in the wrong position did not effect the operability of the B train.

The inspectors also questioned whether the flow switch/time delay circuitry was periodically tested. The flow switch is periodically calibrated. However, the time delay relay and associated contacts have not been periodically tested for both trains. Review of testing of the system per surveillance instruction 0-SI-4.2.G-2, Control Room Isolation and Pressurization Functional Test, indicated that the standby feature, via the time delay and flow switch arrangement, when the selector switch is selected to the B train, has not been tested since preoperational testing of the upgraded CREV system. The licensee determined that the current Technical Specifications did not specifically require testing to be completed; however, the Improved Standard Technical Specifications (ISTS) that the licensee has submitted for NRC approval, require testing of the control circuit. The licensee developed a work order to confirm that the CREVs train A low flow circuitry would start train A when the system priority selector switch is in the train B position. Testing will be performed on the required periodicity when ISTS is implemented. Additional review of the testing and potential effects of the standby train logic failures is necessary. (Unresolved Item 50-260,296/97-11-03, Adequacy of CREV Standby Train Circuit Testing)

The inspectors concluded that the licensee did not adequately control the system priority selector switch. Operating Instruction 0-OI-31, Control Bay and Off-Gas Treatment Building Air Conditioning System, Revision 49, did not have the appropriate guidance to maintain the preferred selector switch in the correct position. The procedure did not address the switch. Apparently, the procedure had not been properly

revised when the CREV system was modified in 1993. The inspector also observed portions of CREVs testing on December 1, 1997, during which the operators had to reposition the switch without specific guidance. This is identified as Violation 260,296/97-11-02, Failure to Control CREV Switch Position.

c. Conclusion

Procedural controls were not adequate to ensure that the Control Room Emergency Ventilation System priority selector switch was maintained in the correct position. Additional review is required to determine if control circuitry in the CREV system was adequately tested.

02 Operational Status of Facilities and Equipment

02.1 Auxiliary Unit Operator Rounds/Plant Tours

a. Inspection Scope (71707)

The inspector accompanied the Unit 3 rounds and control bay auxiliary unit operators (AUO) on plant tours. The inspection focused on AUO thoroughness and attentiveness to overall conditions. The resident inspectors also performed numerous tours to review plant conditions.

b. Observations and Findings

The inspector accompanied the Unit 3 rounds AUO on November 25, 1997, and the control bay AUO on November 29, 1997. The operators were knowledgeable about current plant conditions and equipment status. The operators also demonstrated knowledge of equipment deficiencies such as water leaks, oil leaks and out of service equipment. The Unit 3 rounds AUO also demonstrated initiative and sensitivity to safety system status by writing a work request on a minor Reactor Core Isolation Cooling (RCIC) system oil leak identified during the tour.

On November 25, 1997, the inspector observed local manual speed adjustment of the 3B recirculation pump motor generator (MG) set. The speed adjustment was performed manually to increase plant power and balance recirculation pump speeds, due to the recirculation pump MG set clutch scoop tube being locked in position because the speed controller was not functioning properly. The evolution was properly supervised by a licensed operator. The operators properly referenced and performed the procedure. Good communications and coordination of the evolution was observed between the control room unit operator and the personnel performing the speed change evolution. The inspector concluded that the infrequent evolution was performed in a controlled manner.

The inspectors identified that emergency equipment cooling water (EECW) leakage from the 3B RHR room cooler was not being properly collected. The licensee corrected the problem.

On December 1, 1997, the inspector noted water leakage from some of the Unit 3 drywell sandpit and vent sleeve drains. The licensee postulated that the source of the water from the drains may be from leakage past fuel pool cooling valves to the annulus between the drywell liner and concrete structure via an overflowing fuel pool liner leakage drain. The licensee experienced water leaking from several Unit 3 drywell penetrations in February 1997, which may be symptoms of the same or a similar problem. In addition, during early October 1997, water was found to be leaking from containment penetrations for the Unit 3 core spray and the drywell continuous air monitor which could also be evidence of this problem.

The licensee documented the February 1997, leakage in problem evaluation report (PER) 970400. The PER concluded that the source of the leak could not be determined and that the leak no longer existed. The corrective action for the PER was to monitor the penetrations during the during the next refueling outage. The PER also stated that any further corrective actions identified by this action item will be added to the PER by revising the PER. The licensee did not document the leakage identified in October or December 1997. Discussions with the licensee indicated that they were aware of the problem and planned to document their findings. Subsequent to discussions with the inspectors, the licensee developed a troubleshooting plan to attempt to determine the cause of the leakage.

The inspectors also identified that one of the drywell vent sleeve drains had no drainage path. The end of the drain terminates near the floor. Normally the sand pit and vent sleeve drains are cut pipe ends which would drain to the floor area in the torus room. In this case, the pipe appeared to penetrate the floor surface. The licensee has initiated PER 971818 to address the drainage path issue.

c. Conclusion

The local manual speed adjustment of the recirculation pump motor generator set was properly supervised and controlled. The operators demonstrated good communications and coordination during the evolution. High sensitivity to safety system status was demonstrated by the AUOs demonstrated by the Unit 3 rounds AUO by initiating a work request on a minor RCIC turbine oil leak.

02.2 Freeze Protection Inspection

a. Inspection Scope (71714,71707)

The inspector reviewed the working copy of General Operating Instruction 0-GOI-200-1, Freeze Protection Inspection. Additionally, the Freeze Protection Inspection Discrepancy List and portions of electrical preventive instructions EPI-0-000-FRZ001, FRZ002, FRZ003 were reviewed. The inspector also performed walkdowns of the RHRSW pump rooms and channel diesel fire pump area and reviewed selected annunciator response procedures for freeze protection equipment failures.

b. Findings and Observations

Review of the working copy of 0-GOI-200-1, Freeze Protection Inspection, indicated that the licensee had appropriately considered changes made to the in-process procedure since it was initiated. The revision to the procedure included placing space heaters into the RHRSW pump rooms and installing tarpaulins over the RHRSW pump rooms.

The inspector questioned the mechanism which initiated the 0-GOI-200-1, Freeze Protection Inspection procedure. The licensee indicated that the procedure was initiated when the Operations Periodic Activity (OPA) database launched the freeze protection activity on August 1 of each year. The 0-GOI-200-1 procedure requests that Electrical Maintenance initiate the electrical preventive instructions EPI-0-000-FRZ001, FRZ002 and, FRZ003. Implementation of these procedures actually began when the repetitive preventive maintenance task form was implemented on September 3, 1997. Discussions with the licensee indicated plans to have the EPI-0-000-FRZ001, FRZ002, FRZ003 procedures completed by December 19, 1997. The inspector concluded that adequate mechanisms were in place to prompt an annual licensee review of freeze protection equipment.

The inspector toured the RHRSW pump rooms and the channel diesel fire pump area. Several areas were noted in the RHRSW pump rooms where small diameter pressure instrumentation lines had insulation removed for apparent work associated with the heat tracing. There were also examples of larger diameter piping and flange areas which were not insulated. The licensee had work requests listed on the freeze protection inspection discrepancy list which documented insulation missing and/or damaged in each of the four RHRSW pump rooms. The inspector considered that since the licensee's freeze protection inspection procedures were implemented in September, consideration could have been given to identifying and correcting problems with small bore and stagnant piping as a priority so that the current configuration of uninsulated small bore piping in colder conditions would not have existed. The inspector noted that the licensee's actions to place heaters in and tarpaulins over the RHRSW pump rooms provided a level of protection for the uninsulated piping.

During the tour of the channel diesel fire pump, the inspector noted that the engine exhaust pipe was not insulated in accordance with drawing 37W215-2, note 9, which required the calcium silicate insulation to extend through the roof and terminate at the outlet end of the exhaust pipe. The drawing note further stated that the insulation located outside shall have an aluminum jacket. The actual configuration terminated the insulation on the outside of the roof with an aluminum jacket, but the remainder of the outside pipe run to the outlet end was not insulated. The licensee initiated a PER to address the discrepancy. The licensee's initial review could not determine a need for the insulation.

During the inspection period, the inspector reviewed the Freeze Protection Inspection Discrepancy List as maintained on the Unit 1

computer. The inspector noted earlier in the inspection period that although the 3C emergency diesel generator (EDG) room heater had a work request card written indicating that the room heater would not come on, the discrepancy was not identified on the Freeze Protection Inspection Discrepancy List. In addition, the inspector noted the Freeze Protection Discrepancy List did not indicate if the discrepancy was safety related as suggested by the procedural guidelines. A subsequent review of the Freeze Protection Discrepancy List noted that the licensee had enhanced the list to address whether the system is safety related or not. The 3C EDG heater discrepancy had been added to the list.

The inspector compared the RHR Service Water System Index, 0-SIMI-23A, for 80 instruments which were listed as Electrical Maintenance responsible for periodic maintenance against the electrical preventive instruction EPI-0-000-FRZ001, Freeze Protection Program for RHRSW Pump Rooms etc., Revision 8, to verify that the instruments were tested. No problems were identified.

During the review of freeze protection program electrical preventive instructions, documentation errors were identified associated with jumper placement/removal and lead lifts. No equipment configuration issues were identified.

c. Conclusion

Adequate mechanisms were in place to prompt an annual licensee review of freeze protection equipment. Small bore and stagnant piping in RHRSW pump rooms could have been given priority during inspection and repair of freeze protection equipment so that the identified condition of uninsulated small bore piping in colder conditions would not have existed. The licensee's actions to place heaters in and tarpaulins over the RHRSW pump rooms provided a level of protection for the uninsulated piping.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Violation 260/96-06-02, Failure to Perform a 10CFR50.59 Evaluation Prior to Disabling Annunciator. The inspector verified that the revisions to Operating Instruction, OI-55, Annunciator System, as described in the response to the violation dated September 13, 1996 were completed. One of those actions was the completion of safety assessments for the annunciators referenced in the UFSAR. The inspector noted that the reactor vessel head leakoff annunciator had been disabled on October 31, 1997. With the assistance of Operations personnel, the inspector obtained a copy of the safety assessment performed for this annunciator. The assessment had been completed on July 31, 1996. The inspector verified that the assessment adequately addressed the aspects of the annunciator referenced in the UFSAR. The inspector verified that the requirements in OI-55 had been met for disabling the annunciator. The inspector noted that this was not the first cycle in which the alarm was disabled and reviewed the licensee's actions to resolve the issue causing the problem. After review of work orders, examination of the

pressure gage indications, and discussion with engineering personnel, the inspector concluded that the licensee's actions to resolve the issue have been progressive and reasonable. The determination that the inner seal ring is leaking seems accurate. Operation with just the outer seal ring is described in the UFSAR. The licensee has also listed resolution of the leaking seal on the Plant Equipment Action List and is continuing to pursue resolution. The violation is closed.

O8.2 (Closed) Violation 260/96-05-03, Customer Group Workers Exceeded Overtime Limits Without Approved Exemption. This violation was originally discussed in IR 96-05. The licensee's corrective actions were reviewed. The inspector performed a sample audit of Customer Group personnel work hours during the recent Unit 2 refueling outage. The review showed that the proper approvals were made for overtime hours which deviated from the licensee's overtime restriction procedure. The inspector also notes that management stressed, at plan of the day meetings during the outage, the importance for proper approvals for overtime deviations. The inspector concluded that the licensee's corrective actions were adequate. The violation is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Mechanical Maintenance Observation

a. Inspection Scope (62707)

The inspector observed mechanical maintenance work to replace the Unit 1 and 2 B emergency diesel generator (EDG) cooling water immersion heater.

b. Observations and Findings

On December 1, 1997, the inspector observed mechanical maintenance work to replace the cooling water immersion heater in the Unit 1 and 2 B emergency diesel generator. Discussion with the licensee indicated that during troubleshooting to determine the cause of burned lugs in the EDG control cabinet, testing indicated that problems may be present with the immersion heater even though the heater appeared to be working.

Mechanical maintenance drained the EDG cooling water system and replaced the immersion heater coil assembly. The maintenance craftsmen replaced the coil assembly in accordance with the step text in work order (WO) 97-011442-001. The inspector noted that the craftsmen stopped to have the WO step text revised when necessary. The immersion heater coil assembly that was removed from the EDG was found in a degraded condition. The decision to replace the immersion heater coil assembly was appropriate.

c. Conclusions

Good mechanical maintenance performance was noted during replacement of the immersion heater coil assembly on the 2B EDG. Effective troubleshooting to determine the cause of burned lugs in the EDG control cabinet identified problems with the immersion heater even though the heater appeared to be working.

III. Engineering

E1 Conduct of Engineering

E1.1 Incorrect Main Steam Pressure Detectors Installed in Plant

a. Inspection Scope (37551)

The inspector evaluated the licensee's technical operability evaluation (TOE) performed to evaluate main steam pressure detectors with different upper range limits than specified in the set point and scaling calculation document. The inspector also reviewed the licensee's corrective actions for an inspector identified incorrect calibration frequency calculation for some of the pressure instruments.

b. Observations and Findings

The inspector reviewed licensee corrective actions for pressure detectors installed in the main steam system which had different upper range limits than specified in the licensee's set point and scaling calculation documents. A maintenance worker replacing a failed pressure detector identified the condition. The installed transmitters were Rosemount Model 1153GB with a range code 9 (0-3000 psig) vice the specified range code 8 (0-1000 psig).

One group of the pressure transmitters detect main steam pressure and input into primary containment isolation system logic to initiate closure of the main steam isolation valves on low steam line pressure. The other group of pressure transmitters detect turbine first stage pressure and input into the reactor protection system to provide a signal to bypass the scram protective feature on turbine stop or control valve closure at power levels less than 30% (corresponding with a first stage pressure of 154 psig). The instruments are not safety related, however the setpoints are controlled by TS.

As part of the original design, selected transmitters were to be changed from range code 9 (0-3000 psig) to range code 8 (0-1000 psig) using a conversion kit. Subsequently, a Part 21 notice for this model transmitter required their return to the vendor for maintenance during

Unit 2 recovery. Non-converted transmitters were sent to the vendor. Subsequently, the range code 9 transmitters were installed in Unit 2. A walkdown of Unit 3 showed that the proper transmitters were installed. No violation of regulatory requirements occurred since the transmitters were not safety related.

The licensee performed a Technical Operability Evaluation (TOE) since errors caused by drift, instrument accuracy, and ambient temperature are dependent on the upper range limit of the instrument. The TOE determined that the instruments were operable.

The inspector reviewed the site standard procedure (SSP) SSP-12.57, Engineering Evaluations for Operability Determination, the Final Safety Analysis Report (FSAR), set point and scaling documents, calculations, and the applicable vendor manual. The inspector found that the TOE technically supported operability of the instruments. The inspector noted the following deficiencies:

- The temperature band used to calculate the ambient temperature errors was different than used in the original calculation. No justification for the new band was provided.
- Set point and scaling document information about environmental qualification and class (safety related or quality related) were different than that specified in the master equipment list.
- The original set point and scaling calculation for the main steam pressure instruments analyzed for a calibration frequency of 12 months vice the surveillance instruction requirement of 18 months.

The licensee subsequently revised the TOE, the set point and scaling document, and the main steam pressure instrument calculation based on the inspector's findings. The discrepancies did not affect the overall results of the TOE or the acceptability of an 18 month calibration frequency for the main steam pressure instruments.

A separate PER was not initially generated concerning the incorrect main steam pressure instrument calibration calculation although the situation warranted one. The inspectors brought this issue to licensee management attention. Subsequently, a separate PER was generated.

c. Conclusion

Although the technical operability evaluation was technically acceptable, the inspector identified several deficiencies in the documented evaluation. The individuals involved were reluctant to generate a separate PER concerning the incorrect calibration frequency calculation. The maintenance worker who identified the incorrect installed instruments demonstrated a good questioning attitude.

E1.2 Core Operating Limits Report

a. Inspection Scope (37551)

The inspector reviewed the Core Operating Limits Report for the Unit 2 Cycle 10 operation for compliance with TS.

b. Observations and Findings

Recent changes to Unit 2 TS were made to incorporate the Unit 2 outage upgrade of the power range neutron monitor instrumentation. Changes to thermal limits specifications were also made to implement average power range monitor and rod block monitor TS improvements, and maximum extended load line limit analyses. The inspector reviewed the core operating limits report to ensure compliance with the revised TS requirements.. No problems were noted.

c. Conclusions

The inspector concluded that the licensee properly implemented the Core Operating Limits Report for Unit 2 Cycle 10 in accordance with the revised TS requirements.

E1.3 Implementation of Generic Letter (GL) 89-10,"Safety-Related Motor-Operated Valve Testing and Surveillance"

a. Inspection Scope (Temporary Instruction 2515/109)

This inspection provided an assessment of the licensee's implementation of GL 89-10. The licensee notified the NRC that they had completed implementation of GL 89-10 in letters dated January 9, 1995, for Unit 2 and January 30, 1996 for Unit 3.

In July 1995 the NRC conducted an inspection of the GL 89-10 program and documented the results of that inspection in Inspection Report 50-259, 260, 296/95-19. The inspectors concluded that the licensee had implemented GL 89-10 for Unit 2 in a satisfactory manner. The inspectors found that the assumed values for valve factor, stem friction coefficient, and rate of loading, which the licensee had used in determining the settings and capabilities for GL 89-10 motor-operated valves (MOVs), were principally based on data from TVA nuclear power plants. The licensee indicated that it planned to update the data supporting the assumed values and to make adjustments to the MOV settings, when and where appropriate, to ensure that the MOVs were set-up using correct data. Additional MOV testing and evaluations were to be performed to complete implementation of GL 89-10 for Unit 3. The licensee's removal of a number of motor-operated valves from the scope of the GL 89-10 program was observed and questioned during the inspection and was identified as an inspector follow up item.

In September 1995 the NRC conducted a further inspection of the GL 89-10 program at Browns Ferry, concentrating on Unit 3. As documented in

Inspection Report 50-259, 260, 296/95-53, the inspectors concluded that the licensee's implementation of GL 89-10 for Unit 3 was in the process of being satisfactorily completed. The inspectors were unable to make a final assessment. The licensee had not completed the testing and evaluation of the Unit 3 GL 89-10 program MOVs. No Unit 3 MOV test data were available for inspector review. The inspector follow up item concerning the licensee's reduction of the GL 89-10 program scope remained open.

The current inspection was conducted to verify that the licensee had satisfactorily completed implementation of GL 89-10 for both Units 2 and 3. The principal areas examined were the previously identified inspector follow up item regarding program scope, the final MOV switch setting determinations and verifications of MOV capabilities established from the completed testing, and trending of MOV test and history data. The inspection also included a review of the periodic verification requirements specified by the licensee's GL 89-10 program, a record review to verify removal of MOV motor brakes, and a plant walkdown to observe the general condition of MOVs.

The inspection was conducted through a review of the licensee's GL 89-10 implementing documentation, interviews with licensee personnel, and observation of MOVs in the plant. The documents reviewed included:

- TVA Nuclear Standard Department Procedure MMDP-5, "MOV Program," Revision 1, dated September 26, 1997.
- TVA Standard Engineering Procedure DS-M18.2.21, "Motor Operated Valve Thrust and Torque Calculation," Revision 8, dated July 15, 1996.
- TVA Mechanical Design Standard DS-M18.2.22, "MOV Design Basis Review Methodology," Revision 1, dated July 29, 1991.
- Calculation MD-Q0999-910034, "NRC Generic Letter 89-10 - Motor Operated Valve Evaluation," Revision 13.
- Other documents referred to in the following paragraphs.
- Summary tabulations of MOV information and calculation results prepared by the licensee.

Prominent among the tabulations referred to above was a list of "available valve factors" (AVFs) for the licensee's GL 89-10 gate and globe valves. The AVFs were calculated using formulas described in previous inspection reports (e.g., Inspection Report 50-338, 339/97-01). The inspectors compared the AVFs for the licensee's GL 89-10 MOVs to valve factor requirements established in industry testing which the NRC had previously reviewed. These comparisons were performed to determine if the licensee's AVFs were reasonable.

b. Observations and Findings

1. Scope of MOVs Included in the GL 89-10 Program

A reduction in the scope of MOVs included in the Browns Ferry GL 89-10 program was questioned during Inspection 50-260, 296/95-19. The licensee had reduced the scopes for Units 2 and 3 from 56 MOVs each to 36 MOVs each, based on a re-evaluation of the functions of the MOVs. This reduction in scope was identified for further review as Inspector Follow up Item (IFI) 50-260(296)/95019-01, Reduced Scope of Valves in GL 89-10 Program.

In a letter dated October 7, 1996, the NRC informed the licensee that it had concluded that the criteria used by TVA in re-evaluating the safety functions of the Browns Ferry MOVs were unsatisfactory and may have resulted in inappropriate removal of MOVs from the Browns Ferry GL 89-10 program. An assessment for the valves removed was enclosed with the letter. The NRC requested the licensee to re-examine the safety functions of the Browns Ferry MOVs consistent with the NRC assessment and to provide any appropriate corrections to the GL 89-10 program. The licensee was asked to notify the NRC of the findings of the re-examination and the actions taken as a result of those findings.

In a letter dated January 6, 1997, the licensee provided a response to the NRC's request for re-evaluation of the safety functions of the MOVs removed from, or not included in, the Browns Ferry GL 89-10 program. The licensee stated that 15 MOVs were being added to the individual GL 89-10 sub-programs for Units 2 and 3. The licensee also stated that plant procedures were being revised to require that the applicable system, or train, for 18 MOVs (per unit) be declared inoperable if the valve was taken out of its normal (i.e., safety) position for testing. The licensee noted that the applicable Browns Ferry Technical Specification Limiting Conditions for Operation would govern until such testing was completed and the valve was returned to its normal position. The letter identified the involved MOVs and the dates when these commitment actions would be implemented. The addition of 15 valves to each unit's sub-program was to be completed by January 31, 1997. The procedure changes regarding operability during testing for 18 MOVs were to be completed by February 21, 1997.

During this inspection, the inspectors verified that the 15 MOVs listed in the licensee's letter of January 6, 1997, had been included in the GL 89-10 sub-programs for Browns Ferry Units 2 and 3. The GL 89-10 sub-programs for Units 2 and 3 at Browns Ferry each contained 34 gate valves and 17 globe valves. The inspectors reviewed a sample of the related licensee's procedures to determine whether the associated system or train would be declared inoperable when any of the identified 18 MOVs were placed in their non-safety positions. The inspectors found that the licensee failed to provide the appropriate procedural requirements for several MOVs. For example, Surveillance Instruction (SI) 3-SI-4.5.B.1.c(II), Revision 9, did not declare Unit 3 RHR Loop II inoperable when MOV 3-FCV-74-66 was cycled. Similarly, SI 2-SI-4.5.B.1.c(II),

Revision 21, did not declare Unit 2 RHR Loop II inoperable when MOV 2-FCV-74-66 was cycled. The licensee's failure to revise plant procedures in accordance with its January 6, 1997 letter is a deviation from a commitment (260,296/97-11-04).

2. Determinations of Settings and Verifications of MOV Capabilities

Switch Settings

The licensee controlled the operation of MOVs in its GL 89-10 program through a combination of torque and limit switches. The torque switch was bypassed in the closing direction for 95 to 98% of stroke length as confirmed by diagnostic data. For opening, the torque switch was bypassed for the entire stroke.

The licensee calculated the thrust and torque requirements for MOVs in the GL 89-10 program using standard industry equations. The predicted thrust requirements for gate valves were calculated typically assuming a 0.4 valve factor with a 20% safety factor. For globe valves, the licensee assumed a valve factor of 1.0 for closing and 1.2 for opening. The licensee typically assumed a stem friction coefficient of 0.15 and margin for potential reduction in thrust output under dynamic conditions (referred to as rate of loading) of 10% for gate valves and 15% for globe valves. For MOVs with roller-screw stem nuts, the licensee based the stem friction coefficient on manufacturer's information. Diagnostic error and torque switch repeatability were accounted for in the switch setting calculations. The licensee established its assumptions for determining predicted thrust and torque requirements based on test data principally from Browns Ferry and other TVA nuclear power plants.

The inspectors noted that thrust settings for a few MOVs at Browns Ferry had not been updated in the controlling setting drawings to reflect the results of the dynamic tests performed earlier in 1997. The licensee acknowledged that its MOV setting drawings needed to be updated. Accuracy of the MOV setting drawings will be re-evaluated prior to the NRC closing its review of the Browns Ferry GL 89-10 program.

For some MOVs, the licensee assumed run efficiency in the closing direction when predicting the torque output capability of its actuators. The inspectors noted that the actuator manufacturer is preparing new guidelines that might affect the acceptability of the licensee's use of run efficiency. Licensee personnel stated that they were aware of this situation and would address the capability of the affected MOVs when the new guidance was issued.

Design-Basis Capability

At Browns Ferry, the licensee had dynamically tested 8 gate valves and 7 globe valves in Unit 2, and 5 gate valves and 7 globe valves in Unit 3

as part of its GL 89-10 program. The test data for each of these valves was used to establish its valve factor, stem friction coefficient, and rate of loading. Using these, the calculations and settings for each of the dynamically tested valves were revised.

For MOVs tested at partial design-basis differential pressure conditions, the licensee extrapolated test data from test conditions to design-basis conditions in evaluating thrust and torque requirements. Appendix E of MMDP-5 provided guidelines for in-plant differential pressure testing of MOVs at Browns Ferry. The inspectors noted that the guidelines did not clearly address test conditions that would provide sufficient contact load to assure reliable data. The inspectors did not identify any cases where this resulted in unsatisfactory data. The licensee agreed that clarification was appropriate and indicated that additional guidance for test setup conditions, such as prepared by the Electric Power Research Institute, would be provided to ensure reliable extrapolation of dynamic test data.

For the non-dynamically tested valves, Browns Ferry still relied on the general valve factor assumptions (e.g., 0.4 for gate valves) established by the licensee's corporate office for determining the predicted thrust and torque requirements. It had not formally assessed the validity of these assumptions based on test information. The inspectors found that some of the results from tests performed at Browns Ferry did not support the assumptions. For example, dynamic tests completed at Browns Ferry in 1995 (subsequent to previous NRC GL 89-10 inspections) on MOVs 3-FCV-75-09, 3-FCV-75-37, and 3-FCV-74-71 revealed gate valve factors of 0.6 or greater. The inspectors also noted that the licensee had not performed a documented evaluation of the test data to verify the adequacy of the program assumptions for stem friction coefficient and rate of loading effects. The licensee's failure to evaluate dynamic test data in relationship to its GL 89-10 program assumptions could have resulted in MOVs being incapable of performing their safety functions.

The inspectors found that the issue of the licensee's failure to assess the validity of its assumptions, as discussed in the preceding paragraph, had been identified in a licensee self-assessment conducted in May 1997. In the self-assessment report dated November 7, 1997, the licensee determined that the Browns Ferry GL 89-10 program was not adequate to support an NRC inspection of GL 89-10 implementation. One of the recommendations in the self-assessment report was that justifications and analyses were needed to strengthen the basis for the assumed valve factor and other appropriate factors. This was identified for resolution in Browns Ferry Problem Evaluation Report (PER) 971770 (initiated on November 12, 1997). The PER stated that the licensee's corporate engineering office had issued a white paper that concluded that a valve friction factor of 0.6 should be used for gate valves that could not be dynamically tested. The PER also indicated that the valve factor guidance provided in Design Standard DS-M18.2.21 was inadequate and that an evaluation of the MOVs in the GL 89-10 program was required to ensure the ability of these MOVs to perform their safety functions. Using a valve factor of 0.6 for gate valves and 1.2 for globe valves,

the licensee reviewed the capability of its GL 89-10 MOVs to perform their safety functions. In some cases, the licensee relied on actual dynamic test data or bypass of the torque switch to justify the operability of its MOVs. The licensee was currently completing its plans for justifying the design assumptions for valve factor, stem friction coefficient and rate of loading effects. In a letter dated December 15, 1997, the licensee indicated it would revise its GL 89-10 program by January 30, 1998, to address issues such as the adequacy of the design assumptions. The inspectors considered the licensee's failure to evaluate test data to assess its GL 89-10 program design assumptions to be a violation of the requirements of 10 CFR 50, Appendix B, Criterion III, "Design Control." The inspectors verified that the violation was not repetitive. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-260,296/97-11-05). Another example is identified in a subsequent paragraph of this report section.

The inspectors found that the licensee had incorrectly evaluated the operability of several MOVs in Problem Evaluation Report (PER) 940066 (initiated on March 22, 1994). In the evaluation, the licensee had relied on the "stall efficiency" of MOV actuators to evaluate the operability of the MOVs. The actuator manufacturer had provided a value for stall efficiency for use by licensees in evaluating potential structural damage in the event of an actuator motor stall condition. The manufacturer, Limitorque, specifically stated that the use of stall efficiency was not reliable for predicting actuator output capability. For example, see Limitorque Maintenance Update 92-1 (issued in 1992) or Application Guide for Motor-Operated Valves in Nuclear Power Plants (NP-6660-D, dated March 1990) prepared by the Electric Power Research Institute. A current evaluation using the appropriate efficiency showed that the valves had been operable. However, the inappropriate use of stall efficiency in predicting actuator output could have resulted in the licensee not recognizing an inoperable condition of a safety-related MOV. The inspectors considered the licensee's use of stall efficiency to represent a violation of the requirements of Criterion III of 10 CFR 50, Appendix B, Design Control. The inspectors found that the licensee had recognized that use of stall efficiency was inappropriate and that evaluations subsequent to PER 940066 did not use stall efficiency. For example, the licensee evaluated the operability of its GL 89-10 MOVs in its recent PER 971770 using pullout or run efficiency (rather than stall efficiency) together with consideration of the applicable motor curves. The inspectors verified that the violation was not repetitive. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-260,296/97-11-05). Another example is identified in a preceding paragraph of this report section.

MOV Degradation

The inspectors found that the licensee had not provided clear guidance for addressing potential degradation of MOV performance. The licensee agreed that its guidance could be clarified and initiated steps for this action.

3. MOV Trending

GL 89-10 suggested that MOV data on failures and corrective actions (including repairs, analyses, as-found deteriorated conditions, etc.) be periodically examined at least every two years or after each refueling outage to establish trends in MOV operability. Currently, the licensee implemented this trending through requirements in Procedure MMDP-5. Until Revision 0 of MMDP-5 became effective on August 20, 1997, the trending requirements were specified by Site Standard Practice SSP-6.51, "Program Plan for Generic Letter 89-10," Revision 3, effective January 10, 1996. MMDP-5 required issuance of an MOV trending report at the completion of every testing cycle (18 months or end of each refueling outage). The report was to include (1) MOV signature analysis report and (2) maintenance history (corrective and preventive). SSP-6.51 had required a similar report at the same periodicity. The inspectors found that the licensee had not prepared the trending report required by the procedures. The licensee's failure to prepare the trend report required by procedures is a violation of 10 CFR 50, Appendix B, Criterion V, "Procedures" (50-260,296/97-11-06).

4. Periodic Verification of MOV Capability

In Section 3.13 of MMDP-5, the licensee stated that the purpose of periodic monitoring of MOVs was to ensure continued MOV ability to function under design-basis conditions, and to identify isolated or generic problems with MOVs or the overall program. MMDP-5 also noted that periodic verification should identify deterioration of MOV components before significant degradation occurs. MMDP-5 indicated that the licensee was working with the owners groups to share test data. In a letter to the NRC dated March 17, 1997, the licensee stated that it was participating in a joint owners group program in response to GL 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves. The licensee's plans for MOV periodic verification were found to be adequate for GL 89-10. The NRC may re-assess the licensee's long-term MOV periodic verification program as part of its review for GL 96-05.

5. Walkdown

The inspectors conducted a plant walkdown of MOVs to assess their condition. A previous walkdown described in Inspection Report 50-259, 260, 296/95-53, reported that cover bolts were loose or missing on several MOVs. The inspectors did not observe any similar examples during the current inspection. The inspectors noted a significant difference in the quality of stem grease applied to various MOVs. This

was apparently due to the licensee's past use of different stem greases. A future closeout inspection for GL 89-10 will examine whether the licensee's justification of stem friction coefficient and rate of loading effects are applicable to the different greases or a possible mixture of the greases. The inspectors also observed the presence of a plastic cap on an actuator grease relief line for one MOV (2-FCV-74-106). This was not a GL 89-10 MOV. The licensee acknowledged the inspectors' walkdown findings and stated that appropriate action would be taken.

6. Motor Brakes

Inspection Report 50-259, 260, 296/95-53 indicated that motor brakes had not been removed from MOVs 3-FCV-73-34, 40, and 44. During the current inspection, the inspectors reviewed documentation attached to BFPER 940038 which verified that the brakes had been removed.

c. Conclusions

Implementation of GL 89-10 at Browns Ferry was not sufficiently developed to permit the NRC to complete its review. The inspectors did not identify any immediate operability concerns with GL 89-10 MOVs at Browns Ferry.

The inspectors identified a violation involving the licensee's failure prepare a trend report required by procedures and a deviation from a licensee commitment to revise procedures to assure the applicable system or train for certain MOVs would be declared inoperable when the MOVs were placed in their non-safety positions during operation. In addition, a non-cited violation resulted from (1) a failure to evaluate MOV test data to verify that it supported GL 89-10 program design assumptions and (2) improper use of actuator stall efficiency.

A summary of the principal actions to be performed by the licensee to address the issues identified in this inspection and complete implementation of GL 89-10 is as follows:

- Preparation of test-based justifications for the valve factor, stem friction coefficient, and rate of loading assumed in the design calculations for each GL 89-10 MOV (including MOVs with special features such as roller screw stem nuts, different stem greases, or mixed stem greases). (Refer to NCV 50-260,296/97-11-05)

- Updating of calculations and MOV setting drawings based on the justified assumptions.

- Implementation of trend reporting based on the periodic reviews recommended by GL 89-10. (Refer to VIO 50-260, 296/97-11-06)

- Correction of procedures that did not implement the licensee's commitment to assure that the applicable system or train for certain MOVs would be declared inoperable when the MOVs were placed in their non-safety positions during operation. (Refer to DEV 50-260,296/97-11-04)

In a letter dated December 15, 1997, the licensee committed to revise the Browns Ferry GL 89-10 program by January 30, 1998, to address the design input issues identified during this inspection. Further, the licensee committed to revise its MOV design calculations to reflect the GL 89-10 program design input revisions by March 31, 1998, for Unit 3, and August 31, 1998, for Unit 2. The NRC will re-inspect the GL 89-10 program at Browns Ferry following notification from the licensee that the issues described in this report are sufficiently resolved to permit verification that the intent of GL 89-10 has been met. The licensee stated that a status letter would be provided to the NRC by March 2, 1998, indicating its progress in completing the commitment actions.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 Reactor Scram Due to EHC Leak and Reactor Protection System Relay Problem

a. Inspection Scope (37551, 93702)

The inspectors monitored and reviewed the licensee's investigation and corrective actions following a Unit 2 reactor scram.

b. Observations and Findings

After the Unit 2 reactor scram on October 28, 1997, the licensee appointed an Incident Investigation (II) team headed by an engineering manager to determine the cause of the scram. Some initial information indicated that a scram air header pressure problem was involved. Later on October 28, the licensee simulated the same conditions which existed when the scram was received and inspected the air system. No problems were found. The low pressure was subsequently determined to have occurred after the scram as expected. The inspectors reviewed information relating to previous scrams which supported the conclusion that the scram air system had performed as expected.

The investigation continued and early on October 29, the II team developed a postulated cause of the scram. Additional troubleshooting and diagnostic testing enabled the team to conclude the following sequence of events associated with the scram:

- A half scram was present on the A side of the Reactor Protection System (RPS) due to the #1 turbine control valve (CV) being closed for repair of an electrohydraulic control fluid leak.

- The 5A-K14B relay, associated with the B1 RPS circuitry, unexpectedly de-energized. The team found this through a detailed

review of computer information involving relay conditions at the time of the scram. The 5A-K14B relay has contacts in the RPS circuitry which serve to de-energize some of the scram solenoid pilot valves (as well as other functions). It is located at the bottom of a long sequence of normally shut contacts, any of which open to initiate a scram signal. Two of those contacts are from one GE HFA relay connected to the CV fast closure circuitry which senses CV closure as a function of EHC pressure at the valve. The parallel relay (5A-K14F) in the B1 RPS circuitry did not de-energize. The licensee performed testing which showed that, on decreasing voltage, the 5A-K14B relay contacts began to chatter or cycle at a voltage value above that at which the relay (and the 5A-K14F relay) de-energized. The 5A-K14B relay which is a CR105 contactor, was replaced and tested. The relay will be examined for more information on the failure mechanism. The other RPS scram solenoid pilot valve relays were also tested and no others were found to display the characteristics seen on the 5A-K14B.

- The licensee also conducted cycling of the turbine control valves and monitored pressure indications at the point that a turbine control valve fast closure signal (decreasing EHC pressure) would be sensed. The testing showed that cycling of the valves caused notable (300-400 psig) downward spikes in EHC fluid pressure. Subsequently, the licensee indicated that modification of the EHC system to reduce these oscillations (installation of orifices) was being considered.

- Despite testing, the licensee did not find any problem with the turbine fast closure relay which has two contacts in the B1 RPS circuitry to the 5A-K14B relay. It is postulated that the momentarily sensed decreased EHC fluid pressure caused the relay contacts to open just long enough to de-energize the sensitive 5A-K14B relay.

- The conditions resulted in about half of the Unit 2 SSPVs getting an "electrical" scram signal (channel A ½ scram and the one relay in the B1 channel). This would cause the Group I and IV rods to get a scram signal. This theory also conforms with an Senior Reactor Operator's (SRO) observation that the Group I and IV rod groups scram lights appeared to have actuated before the other two groups.

- A "B" RPS side backup scram valve was energized by the 5A-K14B (in conjunction with the half scram) which vented air off of the control rod drive air header and a full scram was actuated.

The resident inspectors directly observed portions of the troubleshooting and corrective actions. Workers replacing the 5A-K14B relay were attentive in their work and were utilizing good stop-think-ask-and-act techniques. The inspectors examined recorder traces which supported the licensee's conclusions regarding EHC fluid pressure oscillations and relay performance. Portions of testing of some of the

other RPS relays were observed. The inspectors noted that the pressure switches set point for turbine fast closure input to RPS were conservatively above the value specified in the Updated Final Safety Analysis Report (UFSAR).

One of the inspectors attended the restart Plant Operations Review Committee meeting and noted that the II team made an effective presentation regarding the electrical equipment performance which caused the scram. The inspector questioned if General Electric (GE) had any additional information regarding the EHC pressure spike theory and the parallel RPS relays not being actuated. At the time, it was not known if additional information was available, but management indicated that it was being pursued. The II team also recommended several long term action items including development of stronger procedural guidelines for repairs of a control valve servo while at power. Prior to restart, the licensee tested the other scram contactors and did not identify any problems.

A few days later, a GE engineer noted that Service Information Letter (SIL) 508, Scram Contractor Coil Life and Maintenance, addressed a similar issue. The SIL was issued in February 1990 and addressed an unexpected scram at another Boiling Water Reactor which had been caused by some scram contactors dropping out during very short duration scram signals. The inspector obtained a copy of the SIL and the licensee's documented actions in response to the SIL. The circumstances involved in the scram described in the SIL appear to be very similar to the Browns Ferry scram. The SIL recommended that preventive maintenance be performed in the contactors and that their service life be reviewed. Documentation indicated that the Browns Ferry Unit 2 scram contactors had been replaced in 1988 and thus would not be expected to be approaching end of service life. The inspector reviewed portions of Procedure EPI-099-RLY001, and concluded that it addressed the preventive maintenance recommended in the SIL.

Licensee Event Report (LER) 260/97-007 was submitted to the NRC on November 25, 1997, and addressed the scram. The LER included description of corrective actions to reduce EHC pressure decreases during control valve movement through EHC system modifications.

After startup of the unit, several other incidents of control valve servo leaks occurred on Unit 2. (A total of six servo leaks occurred on Unit 2 since startup after the refueling outage). The leaks were identified through careful monitoring of the EHC tank levels. In each case, power was reduced and the servos were replaced. The licensee revised the repair procedures to include recommendations from the II team. The inspectors verified that TS requirements were met during the work activities which included installation of jumpers around pressure switches with inputs into the Reactor Protection System.

The licensee formed a team which continued to investigate the cause of the leaks. The investigation included extensive testing of postulated causes and working with the servo vendors. Subsequently, the licensee

determined the leaks were due to vibration or pressure oscillation induced movement of a servo port plug which was not secured sufficiently to prevent the movement. The plug movement (a few mils) resulted in degradation of an o'ring seal and consequently EHC oil leaked out of the servo. The leaking servos had been replaced during the most recent refueling outage with rebuilt servos. The licensee indicated that the servos are rebuilt by two vendors which utilize different means of securing the plug. The plugs on the leaking servos were secured in a manner that appeared to allow slight movement of the plug. At the close of this report, the licensee was attempting to procure replacement servos of the type which seem to allow less plug movement. For the interim period, the licensee has revised work instructions for servo replacement such that the plug will be more securely fastened. Unit 3 also has the same type of servos installed but no leakage has been detected. Those servos apparently were from a different batch than the Unit 2 servos. The licensee is continuing to investigate the magnitude and significance of vibrations in the Unit 2 EHC system. Work instructions have been developed to install a pressure transducer on a Unit 2 control valve during the next replacement that is performed. The device will monitor EHC fluid pressure at the control valves.

Problem Evaluation Report (PER) 971714 described the investigation and corrective actions regarding the EHC leaks. The PER noted that additional EHC system modifications, including installation of accumulators and control valve manifolds, are planned as part of the Power Uprate Project. These modifications are referenced in GE Turbine Information Letter 1123, issued November 14, 1992. The modifications are intended to reduce EHC fluid pressure oscillations. Operations is continuing to closely monitor EHC reservoir fluid level on both units. The inspectors verified that the enhanced monitoring is being properly performed.

c. Conclusions

The inspectors concluded that the licensee's incident investigation team performed well in investigating the equipment issues which caused the scram. The team studied available information, developed a theory of the cause, and in a prompt manner, performed electrical testing which supported the postulated cause. The investigation into the EHC fluid leaks was also thorough and determined the cause of the leaks in a reasonable time period.

E2.2 RCIC Lube Oil Particulate Levels Increased

a. Inspection Scope (37551)

The inspector reviewed data and developed a time line to assess the licensee's actions in response to high particulate levels in the Reactor Core Isolation Cooling (RCIC) system lube oil. Oil samples indicated a particulate count which was in the action range as identified by the licensee's procedures and documentation in the vendor manual.

b. Observations and Findings

On October 20, 1997, a lube oil sample was taken from the RCIC system following work which had been performed during the Unit 2 outage which ended October 18, 1997. Oil analyses results were issued from the licensee's Central Laboratory on October 22, 1997, which identified a particulate count of ISO 20/15.

On November 3, 1997, the licensee initiated a work request C337743 to sample the oil again to verify the high particulate content and change the oil if necessary. On November 6, 1997, the sample was taken to verify Central Laboratory results. Browns Ferry laboratory determined the particulate count to be high and that an oil change was required. On November 21, 1997, the licensee changed the oil in the RCIC system. Sampling following the oil change indicated a high level of particulate. The licensee changed the oil and sampled for particulate levels several times in an attempt to decrease particulate levels to within the normal range. Analyses of the oil sample taken from the RCIC system following a 15 minute run on November 23, 1997, showed a particulate level of ISO 18/14 which placed the system in the Alert Range. The Alert Range requires that the lube oil be filtered or replaced at the next refueling outage if the alert limits persist. On November 23, 1997, the licensee declared the RCIC system operable.

Chemistry Instruction (CI) CI-130, Diesel Fuel and Lube Oil Monitoring Program, Revision 5, Attachment 3, describes the RCIC lube oil particulate guidelines. The procedure describes three ranges: Normal Range (ISO 16/13), Alert Range (ISO 18/15), and Action Range (ISO >18/>15). The procedure states that the particulate counts which exceed the alert range require immediate corrective action to be taken to restore the oil to normal or alert levels. The procedure further states that the HPCI/RCIC system may remain "functional" for a period not to exceed 30 days while resampling / filtering / replacement activities are in process. The licensee interpreted the procedural requirements to mean that the oil should be changed within 30 days. The RCIC oil was changed within thirty days of the date when the oil analysis results were issued from the licensee's Central Laboratory on October 22, 1997. The licensee is in the process of developing guidance for the lube oil program on site.

In inspection report 259,260,296/97-08, the inspector concluded that weaknesses in the licensee's lubrication oil analysis program permitted the incorrect type of lubricating oil to be added to a second EDG several months after it had been installed in a different EDG.

c. Conclusions

Although the licensee's actions to decrease the oil particulate levels in the RCIC system were adequate, the RCIC oil particulate level issue represents another example of the difficulties that the licensee is

experiencing with the lube oil analysis program. The licensee has not determined the cause of increased particulate but has determined it is not due to excessive bearing wear.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) Inspection Follow up Item 50-260,296/95-19-01: reduced scope of valves in GL 89-10 program. This item involved the licensee's removal of a number of valves from its GL 89-10 program. The licensee's actions to resolve this item are discussed in E1.3.b.1 above. The licensee's actions in returning valves to its program were satisfactory, except as addressed by the violation described in that section of this report.

IV. Plant Support

R2 Status of Radiation Protection and Chemistry Facilities and Equipment

R2.1 Radioactive Effluent Monitor Problems

a. Inspection Scope (37551, 71750)

During review of operating logs, the resident inspectors had noted discussion of a problem involving the radioactive effluent monitor (0-RM-90-130). The inspector questioned resolution of the problem and the absence of a Problem Evaluation Report at a subsequent Management Review Committee (MRC) meeting. Several days later, the problem occurred again. The inspectors questioned plant management regarding the problems and the operability status of the monitor. The licensee formed an investigation team. The inspectors reviewed the regulatory and procedural requirements for the monitor, examined the detector and associated piping, and monitored the licensee's investigation.

b. Observations and Findings

The resident inspectors noted that the October 21, 1997, operating logs described an incident in which the radwaste operators had secured an effluent release after it was noted that the radiation monitor was indicating an activity level which dropped to less than the background level recorded before the release began. In accordance with the Offsite Dose Calculation Manual, the monitor is required to normally be operable during releases. Releases are permitted to be continued with an inoperable monitor if compensatory measures are completed. The release was subsequently restarted. At a Management Review Committee meeting, the resident inspector questioned the resolution of the problem and the absence of a Problem Evaluation Report (PER). Subsequently, maintenance personnel reported to the inspector that the problem had been attributed to demineralized water remaining in the detector after a cleaning evolution.

On October 27, the problem occurred again. The monitor was not declared inoperable and two releases were made without compensatory sampling performed. PER 971713 was initiated on October 28 to address the issue. After MRC review of this PER on October 29, the inspector questioned the operability status of the monitor since releases were being made without completion of compensatory measures required by the Offsite Dose Calculation Manual (ODCM). The inspectors also questioned plant management regarding resolution of the problems. The monitor was declared inoperable (administrative decision) on October 29 and compensatory measures were completed for all releases. An Incident Investigation (II) team was formed to investigate the problems.

After some investigation, the team identified that the problem was caused by water leaking out of the detector housing volume through a closed drain valve. Maintenance personnel found an accumulation of crud on the valve seat which allowed leakage through the valve. Drainage of water out of the volume decreased the shielding between the detector and the chamber walls. When a release was started, the volume was refilled with low activity water and the radiation levels sensed by the detector were reduced. The valve was replaced and the licensee subsequently conducted testing which supported the postulated cause. During a subsequent release, the decreased radiation levels were not observed.

The investigation team concluded that the RM-130 monitor had, in fact, been functional despite the water draining problem. The team also verified that the ODCM compensatory measures had been completed for all periods in which the monitor had been inoperable. The inspectors reviewed portions of Technical Instruction 0-TI-45, Liquid Process Radiation Monitors. This procedure determines the alarm setpoints as required by the ODCM. At Browns Ferry, liquid radwaste batch discharges are controlled by procedure 0-SI-4.8.A, Liquid Effluent Permit. Representative samples are analyzed prior to the discharge and the monitor serves as an independent check during the discharge. The inspectors noted numerous conservatisms were applied in the set point determinations for RM-130, including conservative assumptions regarding condenser circulating system (dilution) water flow. After review of the procedures and discussions with the team, the inspectors concluded that the decreased background effects observed did not adversely affect the operability of the monitor.

On December 2, 1997, the proposed corrective actions for PER 971713 were reviewed by the Management Review Committee (MRC). Initially, the actions did not address the inspector's principle concern that observed abnormalities associated with the RM-130 were not fully understood and radioactive material releases were permitted to continue without compensatory measures. During the MRC meeting, the Site Vice President directed that a corrective action be added which addressed this concern. The inspector discussed the concern with the Operations Manager and verified that the concern would be adequately addressed.

c. Conclusions

Unexpected indications on the radioactive effluent monitor recorder were not thoroughly investigated prior to discontinuation of compensatory actions required for an inoperable monitor. The licensee subsequently completed a detailed investigation which identified that a leaking valve had caused the unexpected indications. The investigation also concluded that the monitor was not inoperable and that regulatory requirements were met during the period.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspector presented inspection findings and results to licensee management on December 12, 1997. Other formal meetings to discuss report issues were conducted on November 21, and December 3, 1997.

The licensee acknowledged the findings presented. Proprietary information is not included in this inspection report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
J. Brazell, Site Security Manager
R. Coleman, Acting Radiological Control Manager
M. Cooper, Corporate Component Engineering Manager
J. Corey, Radiological Controls and Chemistry Manager
T. Cornelius, Emergency Preparedness and Planning
C. Crane, Site Vice President, Browns Ferry
R. Greenman, Training Manager
J. Johnson, Site Quality Assurance Manager
R. Jones, Assistant Plant Manager
G. Little, Acting Operations Manager
D. Nye, Site Engineering Manager
J. Schlessel, Acting Maintenance Manager
K. Singer, Plant Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Licensee Self-Assessments
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparations
IP 71750:	Plant Support Activities

IP 92901:	Follow up-Plant Operations
IP 92902:	Follow up-Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactor
TI 2515/109:	Implementation of Generic Letter 89-10

ITEMS OPENED, DISCUSSED, AND CLOSED

OPENED

Type	Item Number	Status	Description and Reference
IFI	260,296/97-11-01	Open	Status Control Issues (Section O1.2)
VIO	260,296/97-11-02	Open	Failure to Control CREV Switch Position (Section O1.3)
URI	260,296/97-11-03	Open	Adequacy of CREV Standby Train Circuit Testing (Section O1.3)
DEV	260,296/97-11-04	Open	Inadequate Procedural Controls for MOV Activities (Section E1.3)
NCV	260,296/97-11-05	Closed	Inadequate Design Assumptions for MOV Capability (Section E1.3)
VIO	260,296/97-11-06	Open	Failure to Prepare the Trend Report Required by Procedures (Section E1.3)

CLOSED

Type	Item Number	Status	Description and Reference
VIO	260/96-06-02	Closed	Failure to Perform a 10CFR50.59 Evaluation Prior to Disabling Annunciator (Section O8.1)
VIO	260/96-05-03	Closed	Customer Group Workers Exceeded Overtime Limits Without Approved Exemption (Section O8.2)
IFI	260,296/95-19-01	Closed	Reduced Scope of Valves in GL 89-10 Program (Section E8.3)