U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report No: 50-327/97-18, 50-328/97-18

Licensee: Tennessee Valley Authority (TVA)

Facility: Sequoyah Nuclear Plant, Units 1 & 2

Location: Sequoyah Access Road
Hamilton County, TN 37379

Dates: December 21, 1997 through January 31, 1998

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(Sections E1.5, E8.3)

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Enclosure 2

EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/97-18, 50-328/97-18

This integrated inspection included aspects of licensee operations, maintenance, engineering, plant support, and effectiveness of licensee controls in identifying, resolving, and preventing problems; in addition, it includes the results of a Generic Letter 89-10 Motor Operated Valve closeout inspection.

Operations

- A weakness was identified because operators failed to promptly identify that a TS required remote shutdown instrument was inoperable and did not enter the 7-day LCO for approximately 90 hours (Section O1.2).

- Unidentified reactor coolant system leakage slowly increased over a seven month period and was approximately .30 gpm at the end of the inspection period (Section O2.1).

- A Non-Cited Violation was identified for the failure to take hourly log readings of AFD with the AFD monitor alarm inoperable (Section O8.1).

- A weakness was identified in operations based on an assistant unit operator (AUO) leaving an area while draining a tank which resulted in a glycol spill, operations inspecting the wrong sump/pit and signing off a PER as complete, and not removing caution tags after the documented completion of sump cleaning. These issues contributed to a 700 gallon contaminated water spill on January 9, 1998 (Section R1.2).

Maintenance

- The licensee's past corrective actions to correct problems with the site storm drain system were effective (Section M2.1)

- A Non-Cited Violation was identified for a missed TS surveillance requirement (SR 4.4.3.2.1.b) for not stroking the pressurizer PORVs in Mode 4 (Section M8.1).

Engineering

- Engineering support for the reactor coolant pump stator high temperature problem was considered to be good based on the guidance provided to operations which resulted in a well controlled and successful evolution (Section O2.1).

- Engineering's investigation of the safety injection system relief valve drifting setpoint issue was considered to be good. It identified that the relief valve setpoint drifting problem was primarily due to an ineffective preventive maintenance program (Section E1.1).

- The licensee's investigation into the safety injection relief valve setpoint drift problem identified that the relief valve guide ring was subject to severe corrosion when placed in a borated water environment (Section E1.1).

- Engineering support in dealing with the ongoing turbine impulse pressure switch setpoint drift problem was considered to be good (Section E1.2).

- A weakness was identified based on engineering's missed opportunity to verify proper positioning of the pressurizer spray valve following adjustment of the positioner resulting in abnormal pressurizer backup heater operation (Section E1.3).

- Concerns were raised by the inspectors regarding the licensee's disposition of a pressurizer level instrument which failed its calibration surveillance. The inspectors continued to review the licensee's evaluation. (Section E1.4)

- Based on NRC inspections and commitments in the licensee's letter dated February 12, 1998, the NRC is closing the review of the GL 89-10 program at Sequoyah (Section E1.5)

<u>Plant Support</u>

- A violation with two examples was identified for not frisking out of a posted radiologically controlled area (Section R1.1).

- A weakness was identified in that appropriate levels of management were not informed that posted frisking requirements had not been met and later that day additional personnel failed to meet the same posted frisking requirements (Section R1.1).

- A weakness was identified based on plant support laborers cleaning the abandoned upper head injection pit instead of the AEB sump and the assigned radiation control technician controlling the radiation work permit activities in the abandoned pit versus the AEB sump (Section R1.2).

Report Details

Summary of Plant Status

Unit 1 operated at full power for the entire inspection period.

Unit 2 operated at full power for the entire inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was considered to be good with the exception of the missed LCO entry noted in Section O1.2 and operational errors noted in Section R1.2.

O1.2 Operators Fail to Enter Action Statement for Failed Remote Shutdown Instrument

a. Inspection Scope (71707)

The inspectors reviewed the circumstances related to the failure of operators to recognize the entry into the TS action statement for an inoperable remote shutdown wide range pressurizer pressure instrument.

b. Observations and Findings

On December 21, 1997, at 9:00 p.m., a unit reactor operator, while in the auxiliary control room, observed that wide range pressurizer pressure indicator 1-PI-68-342C had failed low and questioned the operability of the instrument. Subsequently, at 12:04 a.m., on December 22, operations personnel determined that 1-PI-68-342C was a TS required instrument and entered the action statement for TS 3.3.3.5, Remote Shutdown Instrumentation. During their investigation, the operators determined that the auxiliary control room indicator had been inoperable since 5:52 a.m., on December 18, 1997,(approximately 90 hours from the LCO entry time). This determination was based on the time that the main control room wide range indicator, 1-PI-68-342A, located in the same instrument loop, had failed low. Repairs to 1-PI-68-342C were subsequently completed and the action statement was exited at 11:25 a.m., on December 22, approximately four days and six hours into the seven day allowed LCO outage time.

Several opportunities existed prior to December 22, to identify the inoperable auxiliary control room indicator. On December 18, when 1-PI-68-342A (the main control room instrument) failed, operators did not research control drawings to determine whether other instruments were affected by the failure and, therefore, did not recognize that the two instruments (1-PI-68-342A and 1PI-68-342C) were in the same instrument loop. On December 19, maintenance personnel discovered that 1-PI-68-342C had failed low, but did not ensure that the information was communicated to the control room. On December 20, operations personnel first became aware that 1-PI-68-342C had failed low, but did not recognize that a TS LCO entry was required because of a work request sticker on the indicator which led them to believe that the instrument had been previously evaluated for a deficiency. Additionally, the unit reactor operators performed general walkdowns of the auxiliary control room once a day (on the midnight shift) and failed to notice or question the failed instrument on at least two occasions (December 18 and December 19).

PER No. SQ972718PER was initiated to document the failure of operators to identify that entry into a TS action statement was required for the failed remote shutdown instrument. The PER concluded that the primary root cause for not entering the action statement was the failure of operators to review control diagrams to identify all affected components when the main control room instrument failed. On January 23, 1998, the inspector attended the Management Review Committee (MRC) meeting which discussed the root causes and corrective actions for the PER. The inspector concluded that the discussion of the event was thorough and that the proposed corrective actions were reasonable and complete.

c. Conclusions

The inspectors concluded that operators failed to promptly identify that a TS required remote shutdown instrument was inoperable. This is identified as a weakness in the thoroughness by which operators evaluate instrument failures.

O2 Operational Status of Facilities and Equipment

O2.1 Increase in Unit 1 Unidentified RCS Leakage

a. Inspection Scope (71707)

The inspectors monitored the licensee's response to the gradual increase in unidentified leakage over the last several months.

b. Observations and Findings

Since June 1997, to the present, the Unit 1 unidentified leakage rate has increased from approximately .05 gpm to approximately .30 gpm. At the same time the Unit 1 RCP #2 seal leakoff had slowly increased, and subsequently stabilized at approximately 4.8 gpm (normal leakoff is approximately 2.5 gpm). An increase in RCP #2 stator winding temperature from approximately 250 °F to 292 °F was also observed.

On January 9, 1998, the licensee entered Unit 1 containment to visually inspect RCP #2 for seal leakage and to inspect the pump motor cooler for accumulation of boron which was believed to be collecting on the motor cooler causing the increase in stator winding temperature. The visual inspection noted only a small amount of boron accumulated in the pump bowl but observed that a more significant amount of boron had accumulated on the pump motor cooler. The location of the RCS leak causing boron accumulation in the motor cooler could not be determined.

On January 13, 1998, the licensee finalized a plan, based on previous experience with RCP motor cooler boron accumulation, to isolate ERCW to the motor cooler. This would allow the boron to heat up, powderize, and blow out of the cooler. System Operating Instruction 1-SO-68-2, Reactor Coolant Pumps, Revision 17, was used during the performance of this evolution. The licensee knew from previous experience that when ERCW was isolated that the stator winding temperature would increase, stabilize at a slightly higher temperature, then decrease as the boron dried out and was blown out of the cooler. When this evolution started, the A-phase winding temperature was approximately 292 °F. After the ERCW was isolated to the motor cooler, the stator winding temperature slowly increased to approximately 304 °F, where it stabilized and then began a slow decrease as the boron was apparently being blown out of the cooler. Subsequently, ERCW was again supplied to the cooler and the winding temperature decreased to less than 250 °F. By the end of the inspection period the RCP stator winding temperature had started to increase and had reached approximately 260 °F.

c. Conclusions

Engineering support was considered to be good based on the guidance provided to operations which resulted in a well controlled and successful evolution.

Unidentified reactor coolant system leakage slowly increased over a three month period and was approximately .30 gpm at the end of the inspection period. The source of the reactor coolant system leakage has not been determined.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) URI 50-328/97-08-01, Potentially Inoperable Axial Flux Difference (AFD) Monitor Alarm. The plant operators had questioned the operability of the AFD Monitor alarm due to the "Computer Alarm, Rod

Deviation and Power Range Tilts" alarm window being in continuous alarm and not having reflash capability. The inspectors reviewed the operation of the alarm and noted that the function of the alarm had changed over the past several years due to changes in the method of monitoring/controlling axial offset. At one time the alarm functioned to warn the operator that the axial flux difference was outside a TS 5% target band. The TSs were revised which eliminated the TS target band and allowed the licensee to treat the 5% target band as an administrative limit and the TS limit became the doghouse noted in TS 3.2.1. However, when the TS was revised, the operation of the alarm was not changed to match the TS requirement. The licensee subsequently implemented a modification to the alarm circuitry to provide reflash capability to the alarm circuit if the actual AFD ever exceeds the TS 3.2.1 limits. The inspector concluded that the alarm was not operable during the 24 hour period that it was locked in and hourly logging of AFD was required. Based on discussions, the inspector concluded that AFD was being actively monitored by the control room operators, although not logged as required by TS 4.2.1.1.b. Based on these observations, the inspector concluded that this issue was a violation for the failure to take hourly log readings of AFD with the AFD monitor alarm inoperable, as required by TS 4.2.1.1.b. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the <u>NRC Enforcement Policy</u> (NCV 50-327, 328/97-18-01).

O8.2 <u>(Withdrawn) VIO 50-327/97-04-02, Failure to Meet the Surveillance Requirements of TS 4.10.3.2, For Performing Functional Testing of the Nuclear Instruments.</u> This violation is being withdrawn based on NRC letter EA 08-030 dated January 28, 1998. The letter noted that the licensee's procedure steps for declaring the initiation of physics testing, Mode 2 entry, and the initiation of control bank withdrawal were in conflict, which resulted in a failure to implement them as written. The letter noted that due to the low safety significance the NRC was exercising discretion in accordance with Section VII.B.6 of the Enforcement Policy, NUREG-1600, and was not citing this violation. The inspectors noted that corrective actions were reasonable and complete.

II. <u>Maintenance</u>

M1 Conduct of Maintenance

M1.1 <u>General Comments</u>

a. <u>Inspection Scope (61726 & 62707)</u>

Using inspection procedures 61726 and 62707, the inspectors conducted frequent reviews of ongoing maintenance and surveillance activities. The inspectors observed and/or reviewed all or portions of the following work activities and/or surveillances:

- WO 95-007297-027 — System Transition to Operability of New High Pressure Fire Protection System
- 2-SI-SXP-003.201.S — TDAFW Pump 2A-S Performance Test
- 0-PI-NUC-092.036.0 — Incore-Excore Detector Calibration
- 1-SO-68-2 — Reactor Coolant Pumps-Isolation of ERCW to Motor Cooler
- 2-SI-ICC-068-320.3 — Channel Calib[illegible]n Of Pressurizer Level Channel III, Rack 9, Loop L-68-320 (L-461)

b. Conclusions

In general the conduct of maintenance and surveillance activities was considered to be good.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Effectiveness of Site Storm Drainage System

a. Inspection Scope (62707)

Because of the recent heavy rains, the inspectors reviewed the licensee's past corrective actions related to the site storm drainage system.

b. Observations and Findings

On July 11, 1994, several storm drains, especially those near the turbine building, overflowed due to heavy rains and caused minor flooding in the turbine building and other non-safety related locations on site. This event was documented in Inspection Report 50-327, 328/94-18. Inspection report 94-18 documented that the licensee's response to the event was good but the inspectors questioned the ability of the storm drain system to handle the amount of rain received. The licensee initiated an incident investigation (PER No. SQ940507II) which concluded that catch basins and drain pipes were significantly (typically 50%) blocked and that preventive maintenance instructions prepared for the annual inspections of yard catch basins had not accomplished their intended purpose which was to ensure that the yard drainage system was functioning as designed. Following that event, the licensee initiated several corrective actions which included an extensive plan to clean the storm drains. All the corrective actions were completed by August 1995.

Recently, the inspector discussed the plant yard drainage system with the site lead civil/mechanical engineer and reviewed plant drawings to verify that the yard drainage pond (storm runoff retention pond) was at a lower elevation than those areas of the plant which drain into the pond and that it was not feasible for the pond to back up into the plant. The inspector then toured that portion of the plant owner controlled area where the drainage pond is located. The pond is designed with an overflow pipe, which is below the elevation of the areas that drain into the pond, and the overflow of the pond is directed into the Tennessee River.

c. Conclusions

Based on recent inspector observations of water run off during heavy rain conditions, the inspectors concluded that the licensee's past corrective actions related to the site storm drainage system were effective.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) URI 50-328/97-14-04, Missed TS Surveillance Requirement SR 4.4.3.2.1.b for Stroking the Pressurizer PORVs During Mode 4. This event was discussed in Licensee Event Report (LER) 50-327/97014 (see Section M8.2 of this report). The inspectors noted, from the sequence of events listed in the LER, that since 1994, the licensee had been performing the Unit 2 surveillance requirement of SR 4.4.3.2.1.b in Mode 5, rather than in Mode 4 as required. As described in the next paragraph, it appeared to the inspectors that the tests performed in Mode 5 were performed under the same plant conditions as the tests performed in Mode 4. The inspectors verified that the corrective actions, for the failure to perform the surveillance in the correct mode, were reasonable and complete. 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 (NCV 50-328/97-18-02).

During the licensee's extent of review for the Unit 2 event described above, it was identified that the Unit 1 PORVs had last been tested in Mode 5 and that the last test performed in Mode 4 was valid until January 18, 1998. In a letter to the NRC, dated November 21, 1997, the licensee requested an amendment to the Unit 1 TS to allow a one-time change, through operating cycle 9, to SR 4.4.3.2.1.b to perform stroke testing of the PORVs in Mode 5 rather than Mode 4. In a letter dated January 13, 1998, the NRC granted the one time Unit 1 TS amendment request. The NRC safety evaluation associated with that TS amendment stated that historically the surveillance is performed at the low end of the Mode 4 temperature range which is similar to conditions at which the test was performed in Mode 5. The TS amendment was granted based on the fact that the Mode 5 PORV testing was technically equivalent to testing performed with the unit in Mode 4.

M8.2 (Closed) LER 50-327/97014, Missed Surveillances as a Result of Inadequate Procedures and a Failure to Follow Procedure. The events associated with PORV missed surveillances were discussed in Section M8.1 of this report. The inspectors concluded that the licensee's corrective action for the testing of the EDG load sequence timers and lockout features was reasonable and complete.

M8.3 (Closed) IFI 50-327, 328/96-08-04, Review Calibration Instrument Accuracy Requirements. This IFI was originally written to follow up on the licensee's corrective actions to address an issue with calibration instrumentation. A standard voltmeter had been used to perform a calibration of a switchyard instrument; however, the voltmeter did not have the required accuracy. The licensee initiated a PER to address the issue and performed a root cause investigation of the problem. The licensee identified that the controlling procedure was inadequate in that it was a preventive maintenance procedure as opposed to being a surveillance instruction. The controlling procedures were revised to specify the proper measurement and test equipment. An extent of condition review was performed and no other problems with maintenance and test equipment were identified. The inspectors concluded that the licensee's corrective actions for resolving the issue were reasonable and complete.

III. Engineering

E1 Conduct of Engineering

E1.1 Safety Injection Relief Valve Setpoint Drift Investigation

a. Inspection Scope (37551)

The inspectors reviewed the licensee's investigation into the drifting safety injection relief valve setpoints.

b. Observations and Findings

The safety injection system relief valves have experienced lift setpoint drifting problems during the present SALP cycle. Until recently, the cause of the relief valve setpoint drift had not been identified.

Inspection Report 96-14 noted that the safety injection system relief valves had failed to lift within the acceptable setpoint range on November 2, 1996. The relief valve setpoints were not reset prior to startup which appeared to conflict with the ANSI B31.7 requirements. IFI 50-328/96-14-01 was identified, at that time, to follow up the resolution of the ANSI code issue.

Inspection Report 97-06 identified a violation (VIO 50-328/97-06-08) because the licensee had failed to implement prompt corrective actions to resolve a condition adverse to quality in that following the Safety Injection System over pressure event on November 2, 1996, the relief valves were not reset as required by the ANSI/ASME OM-1 requirements. The licensee had not identified the cause for the drifting set points at this time.

Inspection Report 97-12 noted that the safety injection system relief valves had failed to lift within the acceptable setpoint range during a system over pressure condition on September 9, 1997. IFI 50-328/97-12-

03 was identified to follow the licensee's resolution to the safety injection relief valve setpoint drift problem.

Inspection Report 97-17 identified a weakness with the licensee's preventive maintenance program as noted by the licensee. The licensee based this finding on industry reports that noted 70% of all relief valve failures were caused by aging and that the licensee's preventive maintenance program had not been revised to incorporate the industry information.

During the 1997 Unit 1 and Unit 2 refueling outages, the licensee performed setpoint testing of 10 relief valves from Unit 1 and 20 relief valves from Unit 2. Three valves were identified with setpoints being "out of tolerance." Others had drifted but were not out of tolerance as defined by the ANSI code (>6% from setpoint). The licensee also noted that since 1992, only five valves (three in 1997) were found with setpoints "out of tolerance."

Following the 1997 Unit 2 refueling outage, the licensee disassembled five of the relief valves, three of which had failed the "as found" tolerance testing. Two relief valves removed from the safety injection system were found to have severe corrosion on the guide rings. The licensee noted that the guide rings were fabricated from type 416 stainless steel which was subject to rust and corrosion especially in borated water service.

The inspectors noted that if a relief valve had not lifted or simmered and if the discharge piping did not allow borated water to enter the discharge port, the relief valve would not exhibit the corrosion of its guide ring. The safety injection system relief valves had lifted on multiple occasions and it appeared that the discharge piping could provide a loop seal and retain water in the discharge port of the relief valves. These observations would account for the excessive corrosion of the safety injection relief valves and why there was very little corrosion to the remainder of the relief valves used on other borated water systems.

The licensee concluded that the major cause for failure of the relief valves was aging. The licensee noted that most of the valves had little or no internal lubrication present and two of the valves were severely corroded. At the conclusion of the inspection period, the licensee was evaluating/discussing the guide ring material problem with the manufacturer (Crosby). The licensee and manufacturer were evaluating whether the guide rings could be economically manufactured out of the same material as the relief valve, type 300 stainless steel. The followup of the licensee's corrective action to resolve the Crosby relief valve degraded guide ring material issue is being identified as an inspector follow up item (IFI 50-328/97-18-03).

c. Conclusion

The licensee's investigation found that the relief valve setpoint drifting issue was due to aging and lack of an effective preventive maintenance program.

The licensee's investigation identified that the relief valve guide ring was subject to severe corrosion when placed in a borated water environment due to a material problem.

E1.2 Turbine Impulse Pressure Switch Drifting Problems

a. Inspection scope (37551)

The inspectors reviewed the licensee's continuing investigation into the drifting turbine impulse pressure switch setpoints.

b. Observations and Findings

Problems with the non-safety related turbine impulse pressure switches were first identified during the October 11, 1996, turbine run back, which resulted in an unplanned manual reactor trip (IR 97-13). Water intrusion into the switch assembly had caused the switches to stick. Following the event, all four of the switches were replaced with new calibrated switches. On February 25, 1997, Unit 2 experienced another turbine run back; however, the turbine did not run back as designed. The pressure switches were checked and found to be out of calibration.

The licensee and manufacturer identified that the electric micro switch holding screws had not been adequately torqued at the factory which accounted for two of the failures. However, this finding did not account for all of the setpoint drifting problems. Four switches from each Sequoyah unit (eight total) and four switches from the Watts Bar unit had experienced 80-100 pound set point shifts after initial calibration. The manufacturer concluded that due to deformation of the new diaphragm, a two month burn in period was required for each new switch.

During the October 1997, Unit 2 refueling outage, the licensee installed four manufacturer-modified pressure switches, which were not supposed to exhibit the previous setpoint drift problems. Within 90 days of installation, the licensee discovered that the switches were again drifting high.

Since the Unit 2 outage, the licensee continued to perform periodic calibration checks on the pressure switches on an increased frequency. The licensee noted that the pressure switches were continuing to exhibit up to a 10% setpoint drift and up to a 20% reset setpoint drift between calibration checks, based on data taken on January 9, 1998. The licensee's records, for all of the switches, indicated that the switches stop drifting after a period of time after being exposed to system pressure.

At the end of the inspection period, the licensee informed the inspectors that the manufacturer had identified the probable cause of the setpoint drift. The manufacturer concluded that the enclosure mounting support for the electric micro switches within the pressure switch was deforming. The manufacturer stated that a new pressure switch with stronger support would be provided to resolve the drifting setpoint issue. The affected pressure switches were identified as B761B 1000 PSI Ashcroft pressure switches manufactured by Dresser Industries. They are used in quality related rather than safety related applications at the Sequoyah site. The pressure switches provide pressure signals for the turbine run back circuitry and for the auxiliary feedwater actuation circuitry. The followup of the licensee's corrective actions to resolve the Ashcroft pressure switch drifting setpoint issue is being identified as an Inspector Followup Item (IFI 50-328/97-18-09).

c. Conclusions

Engineering support in dealing with the ongoing turbine impulse pressure switch setpoint drift problem was considered to be good.

E1.3 Pressurizer Backup Heater Operation Due To Spray Valve Leakage

a. Inspection Scope (37551 and 71707)

The inspectors reviewed the cause of the pressurizer spray valve abnormal leakage, which has resulted in the need for the continuous operation of one group of pressurizer backup heaters during the present Unit 2 operating cycle.

b. Observations and Findings

During a control room walkdown the inspectors noted that a pressurizer backup heater group was continuously energized to maintain reactor coolant system pressure. Discussions with the operators indicated that the pressurizer spray valve was leaking.

The inspectors verified that the required operation of the backup heater group did not impact technical specification (TS) requirements for pressurizer heater capacity. The TS requirement for 150 kW of heater capacity is based on operation during natural circulation and the spray valve leakage would only be a concern during forced circulation operation.

The inspectors discussed the issue of setting the valve stroke for the pressurizer spray valve. Engineering noted that during the last operating cycle the pressurizer spray valve was rotating slightly past the fully closed position which was causing a valve position indication problem. During the Unit 2 Cycle 8 refueling outage, the licensee adjusted the valve operator. This was done while the plant was in Mode 5 and the adequacy of the adjustment could not be verified at that time.

The system engineer informed the inspectors that he had planned to verify the adjustment when the plant reached Mode 3. However, when the unit reached Mode 3, the system engineer was involved with other issues and was unable to perform the post maintenance testing on the valve. Operations energized one of the backup heater groups and continued with the plant startup. Because of plant conditions, the valve position cannot be adjusted once the unit is in Mode 1 or Mode 2. The missed opportunity to perform the post maintenance position verification is considered to be a weakness.

c. Conclusions

A weakness was identified based on system engineering's missed opportunity to verify proper positioning of the pressurizer spray valve following adjustment of the positioner resulting in abnormal pressurizer backup heater operation.

E1.4 Potentially Degraded Pressurizer Level Instruments

a. Inspection Scope (37551)

The inspectors reviewed the equipment history, surveillances and various problem evaluation reports (PERs) associated with concerns related to the proper operation of pressurizer level (hot calibration) instrument 68-320.

b. Observations and Findings

During the Unit 2 refueling outage, during October and November, 1997, the inspectors noted in the control room logs that a pressurizer instrument channel had failed its calibration surveillance and that a Technical Operability Evaluation (TOE) had been completed. The TOE indicated that the instrument had failed its "as left" calibration (3 of 9 points out of specification), did not meet manufacturer's specifications for hysterisis (required .5% vs. actual 1%) and pressure shift (required .5% per 1000 psi vs actual 1% per 100 psi) and was not in conformance with the scaling documents for generation of the calibration setpoint data. The TOE concluded that the pressurizer instrument was acceptable as-is and Unit 2 was restarted.

The inspectors reviewed the issue further and noted in the surveillance history that the calibration data was changed in 1988. The change was based on personnel having stepped on the instrument condensing pots and bent them downwards. The work history indicated that either the calibration data needed to be changed or the condensing pots restored prior to startup. The calibration procedure was revised and the bent condensing pot lines were deferred.

When the condensing pot lines were eventually repaired, the calibration procedure was not revised. Following the Unit 1 drain down event in April of 1997, the licensee noted a conflict between the pressurizer level instrument as-built piping diagrams and the values used for calibration of all three of the pressurizer level instruments (hot calibration). During walkdowns of the pressurizer level sensing lines and instruments in containment, the licensee verified that the piping diagrams were correct and that the calibration procedures were in slight error of 1% to 2%.

At the end of the inspection period, the inspectors were reviewing the requirements for resolution of degraded equipment conditions as documented by Generic Letter 91-18, Revision 1. The inspectors were also reviewing concerns with the accuracy of the TS pressurizer high level trip setpoint (92%) and repairs to the pressurizer level sensing piping following the 1988 discovery non-conformance. This issue is identified as an Unresolved Item pending further inspector review (URI 50-328/97-18-04).

c. Conclusions

An Unresolved Item was identified concerning potentially degraded pressurizer level instruments.

E1.5 Implementation of Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"

a. Inspection Scope (Temporary Instruction 2515/109)

TVA's implementation of GL 89-10 was previously reviewed and determined insufficient during NRC Inspection 50-327, 328/97-06. Outstanding issues were identified which involved the long-term capabilities of certain motor-operated valves (MOVs) and MOV groups. In a letter to the NRC dated July 8, 1997, TVA committed to nine actions to address these issues. NRC verification of completion of the actions was identified as inspector followup item 50-327, 328/97-06-07, Actions to Resolve Remaining GL 89-10 Issues.

The current inspection assessed TVA's resolution of the nine issues and completion of related commitments. In addition, the inspection further examined TVA's implementation of trending recommended by GL 89-10. The inspection was conducted through reviews of documentation and interviews with licensee personnel.

b. Observations and Findings

1. Commitment Completion and Issue Resolution

Commitment 1 (Licensee Tracking No. NCO970056001)

NRC Inspection 50-327, 328/97-06 found that TVA did not have sufficient test data to justify the 0.40 valve factor that it had assumed in calculating the design-basis thrust requirements for several gate valve groups. To resolve this issue, TVA committed to revise its calculations and use a (more easily supported) group valve factor of 0.60, unless test data was available to support a different value. TVA further indicated that, if it did not already have test data to justify the valve factors used, it would evaluate industry data to justify the valve factors.

To assess TVA's completion of this commitment and resolution of the related issue, the inspectors reviewed summary data for all of Sequoyah's GL 89-10 gate valves and the thrust calculations and valve factor bases for the following sample of the gate valves: 1FCV-01-018, 1FCV-03-179A, 2FCV-03-047, 2FCV-68-332, and 2FCV-68-333. The inspectors found that the thrust calculations applied a valve factor of 0.60 or higher unless a lower value had been justified based on Sequoyah's in-plant testing. Further, TVA made an effort to obtain and evaluate industry test data to justify the valve factors applied when it did not have applicable data from it's own tests. However, the inspectors found that the data TVA had obtained to justify its valve factors were inadequate in several instances. Therefore, the commitment was generally met but did not result in complete resolution of the original issue. The inspectors identified the following concerns regarding the test data that TVA used in valve factor justifications:

- Gate Valve Group 1, Walworth 4-inch/600# flex-wedge gate valves. This group included 7 steam supply isolation valves to the Turbine Driven Auxiliary Feedwater Pump (TDAFWP). Three of the valves (2FCV-001-17, 1FCV-001-018, and 2FCV-001-018) were required to isolate for a steam line rupture accident and, therefore, would have to close under blowdown flow. TVA applied a 0.60 valve factor in the thrust calculations for all Group 1 valves. It did not have in-plant or industry test data for these valves but did have data for larger Walworth valves which supported a 0.50 valve factor under pumped flow. On the basis of that data, the licensee considered it conservative to apply a 0.60 valve factor to the Group 1 valves. The inspectors questioned basing the valve factor justification on testing of larger valves, especially as blowdown flow conditions were experienced by some Group 1 valves.

- Gate Valve Group 2, Anchor/Darling 4-inch/600# flex-wedge gate valve. This group consisted of a single gate valve (1FCV-001-17) which served as a steam supply isolation valve to the TDAFWP. TVA used test data obtained from similar valves that were tested at Arkansas Nuclear One (ANO) to justify the use of a 0.65 valve factor for 1FCV-001-17. However, the inspectors noted that this valve would have to close under steam blowdown flow conditions. Because the ANO valves were not tested under steam blowdown conditions, the inspectors were concerned that the test data would not be directly applicable to 1FCV-001-17.

- Gate Valve Group 8, Crane 12-inch/300# split-wedge gate valves. TVA assumed a valve factor of 0.60 in calculating thrust requirements for these safety injection valves. TVA had no Sequoyah test data to justify the 0.60 value and indicated it had not been able to obtain industry test data applicable to these valves. The inspectors were concerned with this lack of justification, as the valves had marginal capabilities in the open safety function direction, based on calculations applying a 0.60 valve factor.

In a letter to the NRC dated February 12, 1998, the licensee committed to actions to resolve the above concerns. The letter stated that the Electric Power Research Institute (EPRI) Performance Prediction Methodology (PPM) would be used to determine the thrust requirements for valves from Groups 1, 2, and 8 (taking into account any blowdown performance requirements) and that the PPM results would be incorporated into the design and setup calculations. The inspectors noted that the PPM was based on extensive valve testing and was acceptable to the NRC, subject to the provisions of a related safety evaluation. The licensee's letter indicated the actions for the above valves would be complete by about September 30, 1998.

In addition to the above concerns regarding justification for the valve factors assumed in determining thrust requirements for gate valve Groups 1, 2, and 8; the inspectors identified several less significant concerns regarding the licensee's gate valves, which licensee personnel stated would be evaluated and addressed in Sequoyah's long-term MOV program:

- Gate Valve Group 9, Walworth 3-inch/1500# solid-wedge gate valves. The licensee used the results from tests performed on two similar valves at its Watts Bar plant to justify applying a 0.60 valve factor to gate valve Group 9. The closing valve factors obtained from the Watts Bar tests were 0.519 and 0.146, exhibiting a larger difference than expected for similar valves. The cause for this large variation was not explained.

- Gate Valve Groups 10, 14, and 21: Anchor/Darling 8, 18, and 14-inch/300# double-disc gate valves. The licensee used in-plant test results from gate valve Group 22 (Anchor/Darling 8-inch/300# double-disc gate valves) to justify applying a 0.60 valve factor to these three groups. The inspectors found some weakness in the support for this value because of the variability in the valve factors (0.23 to 0.59) determined from the Group 22 test data and because the Group 22 valves were significantly smaller than the valves in Groups 14 and 21. The concern regarding these valves was limited, as they were capable of accommodating much higher (1.2 or greater) valve factors than 0.60.

- Gate Valve Group 23, Copes Vulcan 14-inch/1500# double-disk gate valves. TVA used the results of open stroke tests performed on four similar valves at Diablo Canyon to justify a 0.60 valve factor for Group 23. The adequacy of the testing was questioned by the inspectors as they found that the tests had been performed with hydro pumps for the pressure source instead of system pumps, resulting in little flow. Also, TVA did not have any valve factor data for the closing direction, which was a safety function direction for these valves. The concern regarding these valves was limited, as they were capable of accommodating a much higher (0.85) valve factor than would typically be expected for gate valves.

Commitment 2 (Licensee Tracking No. NCO970056002)

NRC Inspection 50-327, 328/97-06 identified that the licensee did not have sufficient information to demonstrate the adequacy of the torque requirements established for operation of Sequoyah's Pratt butterfly valves. The torque requirements had been provided by the manufacturer (Pratt). To resolve this issue, TVA committed to work with Duke Power Company or obtain appropriate test data from other sources to validate the Pratt requirements.

To assess the licensee's actions for this commitment, the inspectors reviewed the following:

- Licensee documentation addressing this commitment collected under tracking number NCO970056002
- Calculations documenting the design-basis review, torque, and capability assessments for valves 2-FCV-67-146, 0-FCV-67-152, 0-FCV-70-194, and 0-FCV-70-198
- Essential Raw Cooling Water System (System 67) Flow Diagrams 1,2-47W845-1, Revision 21; and 1,2-47W845-2, Revision 53
- Design Criteria SQN-DC-7.4, Revision 11, Essential Raw Cooling Water System
- Final Safety Analysis Report Sections 9.2.1.2 (Component Cooling System) and 9.2.2 (Essential Raw Cooling Water System)

The inspectors found that the licensee had been obtaining and evaluating Pratt butterfly valve test data from Duke Power Company, consistent with its commitment. However, the original issue was not resolved as this effort was still ongoing. The results had not been factored into the butterfly valve torque calculations and only the smaller Pratt butterfly valve sizes were being addressed. The results obtained from Duke indicated a small nonconservatism (less than 10%) in the manufacturer's predicted torque requirements for the smaller size valves. This increased torque requirement was well within the capabilities of the licensee's valves.

In its letter to the NRC dated February 12, 1998, the licensee committed to revise its calculations for the smaller (18-inch and under) Pratt butterfly valves, based on the Duke test data. In addition, the licensee committed to obtain additional torque test data or run the EPRI PPM to validate the torque requirements for Sequoyah's 20 and 24-inch Pratt butterfly valves. The letter indicated these actions would be complete by about September 30, 1998.

Commitment 3 (Licensee Tracking No. NCO970056003)

NRC Inspection 50-327, 328/97-06 found that the switch setting sheets used to specify the switch settings for Sequoyah's safety related MOVs had not been revised to incorporate all of the most recent setting limits determined in reconciling the design setting values with test results in the thrust calculations. To resolve this issue, TVA committed to issue a design change notice (DCN) to update the switch setting sheets after the thrust calculations were completed (by December 1, 1997). The inspectors found that TVA issued DCN S-13223A on November 11, 1997, which updated the switch settings for the Generic Letter 89-10 MOVs. The inspectors compared the settings identified in the DCN with the results contained in the related thrust calculations and confirmed agreement. The licensee had completed the commitment and the related issue was resolved.

Commitment 4 (Licensee Tracking No. NCO970056004)

NRC Inspection 50-327, 328/97-06 identified that, while TVA had tested most of Sequoyah's globe valves under dynamic conditions, it had not verified that the test data supported the 1.0 closing valve factor which had been assumed in thrust calculations for Velan globe valves. In response, TVA committed to review globe valve differential pressure test data to determine if the 1.0 closing valve factor was adequate. The record of completion of this review reported that a valve factor of 1.1 was determined more appropriate. This revised valve factor was included in the revised thrust calculations. The inspectors reviewed the thrust calculation for 2FCV-63-003 and verified that a valve factor of 1.10 was used for the closing direction. The licensee's actions for this commitment were complete and resolved the related issue.

Commitment 5 (Licensee Tracking No. NCO970056006)

NRC Inspection 50-327, 328/97-06 identified that TVA was relying on results from pumped-flow testing to justify the thrust predictions for the pressurizer block valves (1/2FCV-68-332/333). Pumped-flow testing would not adequately represent the blowdown flow conditions which would be experienced by a block valve in closing off flow from a failed-open pressurizer relief valve. In response to this issue, TVA committed to perform maintenance improvements to the valves' internals to better accommodate operation under blowdown flow and committed to use the EPRI PPM to establish thrust requirements for the valves.

The inspectors verified that TVA had completed PPM calculations to establish thrust requirements for the block valves through a review of the documented results. Also, the inspectors reviewed work requests and work orders included in the commitment completion documentation (under tracking number NCO970056002) which confirmed that the maintenance improvements had been completed for the Unit 2 block valves. In accordance with the licensee's commitment, the maintenance improvements for the Unit 1 valves are scheduled for the Fall 1998 outage. The issue will not be fully resolved until the maintenance improvements are completed on the Unit 1 valves.

Commitment 6 (Licensee Tracking No. NC0970056007)

NRC Inspection 50-327, 328/97-06 identified that containment spray valves 1/2FCV-72-002/039 had marginal capability to perform their design-basis function. TVA committed to verify disc orientation and perform a PPM calculation to better establish the thrust requirements for these valves. TVA also committed to determine improvements for these valves. A re-evaluation of the valves' safety functions determined that they would not be required to close against any differential pressure. Therefore, valve disc orientation would not be an issue. The inspectors confirmed that the PPM calculations had been completed and found that they determined that the open thrust requirements exceeded the actuators' capabilities. In response, the licensee developed an operability evaluation which showed that the available valve factor capability of the Sequoyah valves (based on measured pump differential pressures and packing loads) exceeded valve factor requirements. The valve factor requirements were determined based on data obtained in testing similar valves at Diablo Canyon and EPRI. The inspectors verified that TVA had scheduled design changes to increase actuator capability for these valves to be completed during the next outage for each unit.

Commitment 7 (Licensee Tracking No. NC0970056008)

NRC Inspection 50-327, 328/97-06 identified that TVA had not included any margin for MOV degradation in calculating valve requirements. In response, TVA committed to add a 5% margin as a minimum requirement to provide for valve degradation. The inspectors reviewed the thrust calculations for a sample of valves (1FCV-01-018, 1FCV-03-179A, 2FCV-63-003, 2FCV-03-047, 2FCV-68-332, and 2FCV-68-333) and determined that the 5% margin for valve degradation had been included. TVA had completed its commitment and the issue was resolved.

Commitment 8 (Licensee Tracking No. NC0970056009)

NRC Inspection 50-327, 328/97-06 identified that TVA had not considered the potential loss of thrust caused by load sensitive behavior for those valves that were controlled by limit switch. In response, TVA committed to revise the thrust calculations to include a minimum of 10% margin to address load sensitive behavior under limit switch control, until an evaluation was completed to determine the appropriate value. The inspectors reviewed the thrust calculations for a sample of valves (1FCV-01-018, 1FCV-03-179A, 2FCV-63-003, 2FCV-03-047, 2FCV-68-332, and 2FCV-68-333) and determined that a minimum 10% margin had been included. In addition, a 20% margin had been included for the Reactor Coolant System Pressurizer Block Valves (2FCV-68-332 and 2FCV-68-333) based on the assumptions applied to the non-tested members of gate valve Group 7. These revised requirements were included in the MOV settings changes that were implemented by Commitment NC0970056003. Based on this sample, the inspectors found that licensee personnel had revised the thrust calculations to include margin for load sensitive behavior, as committed. This resolved the issue.

Commitment 9 (Licensee Tracking No. NCO970056010)

NRC Inspection 50-327, 328/97-06 identified that the reactor coolant system pressurizer block valves (2FCV-68-332 and 2FCV-68-333) had marginal capability with respect to their actuators' torque structural limits for the open direction. TVA committed to revise the Sequoyah calculations to increase in the torque ratings of the actuators and resolve the actuator structural capability issue.

In the current inspection, the inspectors confirmed that TVA had applied results from Limitorque Actuator Fatigue Life Analysis, Version 1.0, to justify extending the actuators' ratings from 250 ft-lb to 280 ft-lb (a 12% increase). The analysis indicated that it would be acceptable to open the valves 150 times under the worst-case design-basis conditions. A safety factor of 5.25 was applied to arrive at the 150 cycle limit. The inspectors considered the licensee's actions to adequate to complete the commitment and resolve the issue.

Commitment 10 (Licensee Tracking No. NCO970056011)

TVA committed to provide a letter to the NRC describing status of the nine commitments above by December 31, 1997. The inspectors verified that TVA had provided the subject status letter, dated December 19, 1997.

Degraded Voltage

In reviewing TVA's calculations for block valves 2FCV-68-332 and 2FCV-68-333, the inspectors questioned the degraded voltage values used in the capability calculations. For MOVs that did not actuate automatically in response to a design accident, TVA assumed that the grid voltage supplied to the 480 V bus would be at about 100 percent rather than at the degraded grid setpoint of 93.5 percent. This assumption was based on Sequoyah's use of automatic tap changers. Details of the licensee's bases were evaluated by the NRC Office of Nuclear Reactor Regulation (NRR), Electrical Engineering Branch, and the assumption was determined acceptable. The evaluation was documented in a docketed NRC memorandum from J. Calvo to R. Wessman, dated February 12, 1998.

2. Implementation of MOV Trending

The inspectors previously reviewed the licensee's implementation of MOV trending during Inspection 50-327, 328/97-06. At that [illegible] the licensee had just completed an outage and had not prep[illegible] report documenting the trending recommended by GL 89-10. Duri[illegible]e current inspection, the inspectors obtained and reviewed the tr[illegible]eport subsequently prepared to determine if it indicated that [illegible]examination of MOV data for trends recommended by GL 89-10 was completed. The inspectors found that information included in the report generally indicated that trending was being performed in accordance with the recommendations of GL 89-10. However, the inspectors noted that enhancements could be made in the following areas:

- Although the report contained a large amount of data, there were no charts or graphs to indicate trends or the lack thereof.

- There were no comments or comparisons on the effectiveness of the MOV program. The status of resolution of previous problems was not mentioned. For example, there were no comments on the effect of replacement of contactors that were previously a problem.

c. Conclusions

With the commitments made in the licensee's letter dated February 12, 1998, the inspectors determined that the licensee met the intent of GL 89-10 in verifying the design-basis capability of the safety-related MOVs at Sequoyah. The licensee's letter identified the following items to be addressed:

- The valve factors employed in calculating the required thrusts for gate valve Groups 1, 2, and 8, will be more fully justified.

- TVA was obtaining test data for smaller (18-inch and under) Pratt butterfly valves from Duke Power Company. TVA will further evaluate the data and revise the Sequoyah calculations based on the results. In addition, TVA will improve its support for the predicted torque requirements calculated for Sequoyah's larger (20 and 24-inch) Pratt butterfly valves.

- Maintenance improvements will be completed on the Unit 1 pressurizer PORV block valves.

Based on the NRC inspections and the licensee's commitments in its letter dated February 12, 1998, the NRC is closing the review of the GL 89-10 program at Sequoyah. Resolution of the outstanding licensee commitments is identified as inspector followup item 50-327, 328/97-18-08, Remaining GL 89-10 Concerns. The outstanding commitments are described above under the headings for Commitments 1, 2, 5, and 6. This item will also track the completion of the remaining commitments from inspector followup item 50-327,328/97-06-07.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Open) IFI 50-327/97-18-05, Updated Final Safety Analysis Report (UFSAR) Update To Include Plant Modifications To the Main Switchyard. During a 1993 NRC inspection at Sequoyah, concerns were identified regarding the adequacy of the 161 kv offsite power grid voltage. TIA 94-021 was initiated by Region II and forwarded to NRR for evaluation. After the TIA was initiated, the licensee implemented switchyard modifications to provide more reliable and stable grid voltage which eliminated the original 1993 concerns. The licensee plans to update the Safety Analysis Report to include those switchyard modifications in Amendments 13 and 14. This inspector follow up item is being opened to track the completion of the switchyard modification update to the Safety Analysis Report contained in sections 8.2.1 and 8.2.2. of the UFSAR.

E8.2 (Closed) URI 50-327/97-06-09, Remote Position Indicator Test. Based on plant walkdowns and a review of Section XI test records, the inspectors identified a potential problem with the turbine driven auxiliary feedwater pump throttle valve position indication. The position indication was not properly set and only monitored 50% of valve travel. The inspectors noted that the throttle valve was functioning properly over 100% of its stroke but were concerned with the Section XI testing requirements. The licensee provided an evaluation that supported the adequacy of the Section XI testing and the throttle valve position indication was reset to indicate/measure the full stroke of the valve. The inspectors concluded that the as found condition was acceptable, although not correct, and the licensee's subsequent corrective actions were reasonable and complete. The inspectors were concerned with the performance of the ASME Section XI required, 2 year surveillance, on remote position indication verification. Followup of this concern will be performed as an Inspector Followup Item (IFI 50-327/97-18-06).

E8.3 (Closed) Inspector Followup Item 50-327, 328/97-06-07: Actions to resolve remaining GL 89-10 issues. TVA's actions to resolve this item are discussed in E1.5.b.2 above. Most of the actions originally identified to this item had been completed. Those remaining and significant concerns identified in the current inspection will be tracked under the new inspector followup item identified in E1.5.c.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls (83750)

R1.1 Personnel Monitoring Discrepancies

a. Inspection Scope (71750)

The inspectors evaluated a concern with a potential failure by personnel to monitor (frisk) when exiting a radiologically controlled area (RCA) in the control building.

b. Observations and Findings

On the morning of January 26, 1998, an NRC inspector accompanied the control building assistant unit operator (AUO) on rounds. During the tour, the inspector and the AUO entered the Unit 2 mechanical equipment room, which was a posted RCA. Just prior to exiting the area (Door A-188), they encountered a hexagonal red sign (Stop sign) which stated "Frisk Hand and Feet Prior to Exiting; Then Process Through Whole Body

Frisker." The AUO told the NRC inspector that the sign was not applicable and both exited the area without frisking hands and feet.

After completing the tour, the inspector attempted to exit the RCA; however, his hard hat was contaminated and radiation control assistance was requested. While the inspector's hat was being decontaminated, the inspector discussed the posting of the Unit 2 mechanical equipment room, with the radiation control technician. Subsequently, the posting and frisking issue was discussed with the NRC senior resident inspector.

After decontaminating the inspector's hat, the radiation control technician went with the AUO to the mechanical equipment room to observe the posting. The licensee stated that the technician had told the AUO that he was supposed to frisk hands and feet prior to exiting the area, at that time.

Later in the day on January 26, the resident inspector discussed the issue with a Region II health physics inspector, who had just arrived on site. The inspector went with a member of radiation control management to tour the mechanical equipment room and discussed the posting. The supervisor informed the Region II inspector that frisking was not required and both individuals exited the area without frisking.

After further discussions, on the morning of January 27, 1998, the radiation control supervisor determined that he had incorrectly interpreted the posting requirements and that his actions had been inappropriate. He promptly notified the NRC inspectors of the error and initiated a PER. It was noted that since the mechanical equipment room was posted as a RCA, frisking prior to leaving the area was required and that they had both inappropriately exited the room on the previous afternoon.

The licensee took prompt corrective actions to communicate the frisking requirements to site personnel, the room was reposted, walkdowns of similar areas was performed, and a third party review to evaluate consistency and clarity of RCA postings was performed.

The general requirements for the radiation control program are contained in the Radiological Control Instruction, RCI-1, Radiological Control Program. Section 4.0-D states "Prior to exiting the RCA, all personnel shall monitor themselves in a whole body contamination monitor. A hand and foot frisk may be utilized in lieu of these monitors if authorized by RADCON." The Unit 2 mechanical equipment room was posted as a radiologically controlled area and was posted with requirements for frisking of hands and feet. On two occasions on January 26, a total of four personnel failed to frisk prior to exiting the Unit 2 mechanical equipment room. These failures to follow the Radiological Control Program instructions by not properly frisking out of a posted radiologically controlled area, are considered to be two examples of a failure to follow procedure and are identified as violation (VIO 50-328/97-18-07).

c. Conclusions

A violation with two examples was identified for not properly frisking out of a posted radiologically controlled area.

Communications were considered to be weak in that both the radiation control technician and the AUO were aware on the morning of January 26 that the posted requirements had not been met; however, appropriate levels of management were not informed of the issue which led to the second example of the inappropriate frisking violation.

R1.2 Inadvertent Release from Unit 2 Additional Equipment Building Sump

a. Inspection Scope (71750)

The inspectors reviewed the events associated with an inadvertent release of several hundred gallons of contaminated water from the Unit 2 additional equipment building (AEB) sump. The inspectors also reviewed the previous issues related to the release which contributed to the adverse condition.

b. Observations and Findings

On January 10, 1998, at approximately 12:35 a.m., the Unit 2 Auxiliary Building AUO reported water flowing out of the AEB from under the exterior door. The event resulted in contamination of the AEB lower floor and the outside yard area from the security door to the storm drain. It was estimated that approximately 700-800 gallons of low level contaminated water seeped out under the AEB door and the majority of the contaminated water probably entered the storm drains during the release.

The inspectors reviewed the historical issues that led to the release. On September 1, 1997, the ice condenser ice making machines were taken out of lay up and placed in standby in preparation for the Unit 2 outage. This permitted a leaking sight glass on the ice machine to overfill the glycol overflow collection tank. Operations noted the overfilled tank and directed the auxiliary building AUO to drain the tank. The AUO began to drain the overflow collecting tank to a 55 gallon barrel; however, he left the area before completing the task. When he returned, he found the barrel had overflowed onto the floor.

The AEB building sump was tested for glycol and the test noted that the sump contained approximately 10% glycol. It was estimated that the sump contained about 500 gallons of nearly black water which contained glycol, oil and other debris. On September 1 the sump pumps were caution tagged to prevent glycol contamination of the waste cleanup system. The licensee planned to clean the sump prior to removing the caution tags.

The sump cleaning was delayed until after the Unit 2 outage in the event that more glycol leaked into the sump during the ice making evolution. The Unit 2 outage was completed on November 3, 1997, and documentation noted that the sump cleaned by December 3, 1997. The caution order on the sump pumps not released and the pumps remained deactivated.

Following the event, he licensee discovered that th AEB sump had not been cleaned as docum ted. The plant support labore s had mistakenly cleaned the adjacent upper head injectio pit instead of the AEB sump. A radiation control technician had been assigned to monitor the laborers, in lieu of a special radiation work permit. The technician also mistakenly identified the abandoned upper head injection pit as the assigned cleanup area. Subsequently, operations mistakenly verified the AEB sump had been cleaned after inspecting the upper head injection pit and signed off the PER.

At 9:29 p.m., on January 9, 1998, the main control room received an AEB sump high level alarm. The AUO noted that the AEB sump level was high but not increasing rapidly. The AUO set up a temporary pump to pump the sump contents to 55 gallon drums and requested drums be sent to the AEB. At 12:22 a.m., on January 10, the drums were delivered to the door outside the AEB. At 12:28 a.m., the AUO noted water flowing out from under the AEB door and the control room directed that the sump pumps be started to pump the AEB sump to the floor drain tank. Outflow of water from the AEB stopped at about 12:36 a.m.

The licensee subsequently noted that the AEB sump pump discharge isolation check valves were degraded and had leaked though excessively while operations was pumping the Cask Decontamination Collecting Tank to the Floor Drain Collecting Tank. This led to overflowing the AEB sump due to the sump pumps being disabled.

The inspectors noted poor operating practices in that the AUO left the area while draining the glycol overflow collecting tank to a 55 gallon drum which subsequently overflowed, operations signed off the PER that the sump had been cleaned after inspecting the upper head injection pit, and the clearance on the sump pumps was not removed in a timely manner after the documented completion of the AEB sump cleaning.

The inspectors noted poor action in that the radiation control laborers cleaned the wrong area and signed off the work documents.

c. Conclusion

A weakness was identified in the area of operations based on an AUO leaving the area while draining a tank which resulted in a glycol spill, inspecting the wrong sump/pit and signing off the PER as complete, and not removing the caution tags after the documented completion of the sump cleaning.

A weakness was identified in the area of plant support based on the plant support laborers cleaning the abandoned upper head injection pit instead of the AEB sump and the assigned radiation control technician controlling work in the abandoned pit versus the AEB sump.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 9, 1998. The MOV inspection exit was conducted on January 23, 1998. The licensee acknowledged the findings presented.

During the inspection period, the inspectors asked the licensee whether any materials would be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

*Bajestani, M., Site Vice President
*Burton, C., Engineering and Support Systems Manager
*Butterworth, H., Operations Manager
Fecht, M., Nuclear Assurance Manager
Gates, J., Site Support Manager
*Freeman, E. Maintenance and Modifications Manager
*Herron, J., Plant Manager
Kent, C., Radcon/Chemistry Manager
Koehl, D, Assistant Plant Manager
O'Brien, B., Maintenance Manager
Salas, P., Manager of Licensing and Industry Affairs
*Summy, J., Assistant Plant Manager
*Valente, J., Engineering & Materials Manager

* Attended exit interview

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92901:	Followup - Operations

IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support
TI 2515/109: Inspection Requirements for Generic Letter 89-10, Safety-Related Motor-operated Valve Testing and Surveillance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

Type	Item Number	Status	Description and Reference
NCV	50-327,328/97-18-01	Closed	Failure to Log AFD at Least Once Per Hour With AFD Monitor Alarm Inoperable (Section O8.1)
NCV	50-328/97-18-02	Closed	Failure to Stroke Pressurizer PORVs in Mode 4 (Section M8.1)
IFI	50-328/97-18-03	Open	Follow up on Corrective Action to Resolve Issue With Crosby Relief Valve Degraded Guide Ring Material (Section E1.1)
URI	50-328/97-18-04	Open	Resolve Issues Related to Pressurizer Level Instrumentation (Section E1.4)
IFI	50-327/97-18-05	Open	Safety Analysis Report (SAR) Update To Include Plant Modifications To the Main Switchyard (Section E8.1)
IFI	50-327/97-18-06	Open	Follow up on Concern with Two Year Surveillance on Remote Position Indication Verification (Section E8.2)
VIO	50-328/97-18-07	Open	Two Examples of Failure to Frisk When Exiting the RCA as Required by Procedure RCI-1 (Section R1.1)
IFI	50-327, 328/97-18-08	Open	Remaining GL 89-10 concerns (Section E1.5.c)
IFI	50-328/97-18-09	Open	Ashcroft Pressure Switch Setpoint Drift (Section E1.2)

Closed

Type	Item Number	Status	Description and Reference
URI	50-328/97-08-01	Closed	Potentially Inoperable Axial Flux Difference (AFD) Monitor Alarm (Section 08.1)
URI	50-328/97-14-04	Closed	Missed TS Surveillance Requirement SR 4.4.3.2.1.b for Stroking the Pressurizer PORVs During Mode 4 (Section M8.1)
LER	50-327/97014	Closed	Missed Surveillances as a Result of Inadequate Procedures and a Failure to Follow Procedure (Section M8.2)
IFI	50-327, 328/96-08-04	Closed	Review Calibration Instrument Accuracy Requirements (Section M8.3)
URI	50-327/97-06-09	Closed	Remote Position Indicator Test (Section E8.2)
IFI	50-327, 328/97-06-07	Closed	Actions to resolve remaining GL 89-10 issues (Section E8.3).

Discussed

Type	Item Number	Status	Description and Reference
VIO	50-327/97-04-02	Withdrawn	Failure to Meet Surveillance Requirements of TS 4.10.3.2 for Performing Functional Testing of the Nuclear Instruments (Section 08.2)