UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-327/95-23 and 50-328/95-23

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77 and DPR-79

Facility Name: Sequoyah Units 1 and 2

Inspection Conducted: October 29 through November 25, 1995

Lead Inspector: S. E. Sparks for 12/14/95
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: R. D. Starkey, Resident Inspector
D. A. Seymour, Resident Inspector
S. E. Sparks, Project Engineer

Approved by: [signature] 12/15/95
Mark S. Lesser, Chief, Branch 6 Date Signed
Division of Reactor Projects

SUMMARY

Scope:

Routine resident inspection was conducted in the areas of plant operations, maintenance observations, surveillance observations, onsite engineering, plant support, and licensee event report closeout. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift and weekend activities at the plant.

Enclosure

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Results:

In the area of Operations, good performance was generally observed. Examples of good performance were: operator response to the Unit 1 reactor coolant pump motor ground condition, operator response to the Unit 1 simmering reactor coolant system code safety valves, operator response to the Unit 1 transient on November 18, requiring a manual turbine trip, and operator response to loss of the "A" train annunciators on November 21, 1995. Weaker operational areas observed included: lack of operator sensitivity by not documenting in logbook entries on November 8, the significant pipe movement event on Unit 1, a lack of attention to detail in assuring log entries are accurate, and two examples where operators were not sensitive in having problems addressed in a timely manner (paragraph 3).

In the area of Maintenance, good performance was observed. Examples of good performance included: significant backlog reduction of Unit 1 outage corrective maintenance, and maintenance associated with a Unit 1 emergency raw cooling water hanger. However, events and/or operator workarounds relating to equipment problems during the Unit 1 restart continued to occur. Examples of equipment problems during this period were: simmering code safety valves (paragraph 3.a.(2)), electrohydraulic control circuitry problems, (paragraph 3.a.(6)), failure of the "A" train annunciator inverter power supply, (paragraph 3.a.(7)), and inoperable redundant radiation monitors for the containment purge air exhaust flowpath (paragraph 4.b).

In the area of Engineering, good performance was observed. Examples of good performance included engineering investigations for the Unit 1 reactor coolant pump #4 seal high leakage investigation, and the Unit 1 reactor coolant pump motor fault root cause investigation (paragraph 6). One area identified as needing attention was the lack of a thorough technical review of a change in a routine operational evolution which resulted in a significant pipe movement event in the balance of plant during Unit 1 startup (paragraph 3.a.(3)).

In the area of Plant Support, good performance was observed. In the area of Security, implementation of the new security perimeter was accomplished in a good manner with thorough searches and good coordination/implementation of new gate house requirements (paragraph 7.a). However two examples of radiation monitor material condition problems were identified involving material availability. (Paragraph 3.a.5 and 4.b)

A summary assessment of licensee performance was conducted for activities associated with the Unit 1 Cycle 7 outage (September 9 through November 23, 1995). Good performance was observed in Operations, Maintenance, Engineering, and Plant Support areas during the outage. In addition, proper safety focus and attention was maintained on Unit 2, which operated at power throughout the Unit 1 outage. Management oversight was apparent and activities accomplished were assessed as improving the material condition of Unit 1. However, continued attention needs to be maintained on addressing other material condition issues during future outages (paragraphs 3.e, 4.e, 6.c, and 7.c).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

*R. Adney, Site Vice President
*J. Baumstark, Plant Manager
*D. Brock, Maintenance Manager
L. Bryant, Outage Manager
*M. Burzynski, Engineering & Materials Manager
D. Clift, Planning and Technical Manager
*M. Cooper, Technical Support Manager
*R. Driscoll, Nuclear Assurance & Licensing Manager
F. Fink, Business and Work Performance Manager
*T. Flippo, Site Support Manager
G. Enterline, Operations Manager
*C. Kent, Radcon/Chemistry Manager
*B. Lagergren, Manager of Projects
*K. Meade, Compliance Manager
*L. Poage, Site Quality Assurance Manager
R. Rausch, Maintenance and Modifications Manager
*J. Reynolds, Acting Operations Superintendent
J. Robertson, Independent Analysis Manager
*R. Shell, Site Licensing Manager
J. Smith, Regulatory Licensing Manager

NRC Employees

M. Lesser, Chief, Branch 6, DRP
*W. Holland, Senior Resident Inspector
*D. Seymour, Resident Inspector
*R. Starkey, Resident Inspector

* Attended exit interview.

Other licensee employees contacted included shift operation supervisors, shift technical advisors, plant operators, and other plant personnel.

Acronyms and abbreviations used in this report are listed in the last paragraph.

2. **PLANT STATUS**

Unit 1 began the inspection period cooling down from MODE 3 to MODE 5 to replace a RCP seal package (day 51 of the Unit 1 Cycle 7 refueling outage). After the RCP #4 seal was replaced, the unit entered MODE 4 on

November 1, 1995. However, later on November 1, prior to entering MODE 3, the #2 RCP tripped on a ground fault condition. Unit 1 was cooled down to MODE 5 later the same day to replace the #2 RCP motor. This activity is further discussed in paragraph 3.a.(1). After the #2 RCP motor changeout was completed, Unit 1 began heatup and entered MODE 4 on November 6, 1995, and MODE 3 later the same day. Unit 1 was taken critical (MODE 2) on November 9, and connected to the grid on November 12, 1995. Over the next 6 days, the unit continued to increase power to approximately 89 percent. On November 18, 1995, Unit 1 experienced a runback and manual turbine trip when intercept valves for the "A" and "B" low pressure turbines closed. This event is further discussed in paragraph 3.a.(6). After repairs were accomplished relating to the intercept valve problem, Unit 1 was reconnected to the grid on November 20, 1995. Unit 1 operated at power for the remainder of the inspection period.

Unit 2 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

3. **PLANT OPERATIONS** (71707 and 92901)

a. Daily Inspections

The inspectors conducted selective examinations, on a day-to-day basis which involved control room tours, plant tours, and management meetings. The following activities were specifically reviewed:

(1) On November 1, 1995, with Unit 1 operating in MODE 4, (approximately 340 °F) Reactor Coolant Pump #2 experienced a motor trip. Operators were dispatched to the 6.9 KV Unit board and noted the pump breaker had tripped on a ground condition. Subsequent meggering of the electrical leads from the pump motor breaker to the pump motor supported a determination that the pump motor was the source of the ground. Operators then commenced a cooldown to return the Unit to MODE 5 and placed the plant in a condition to change out the #2 RCP motor. PER SQ951975 was written and a root cause investigation team was assembled to determine the cause of the failure of the RCP pump motor. Followup of the root cause investigation is discussed in paragraph 6.b.

The inspectors reviewed operator responses to the RCP motor ground condition and determined the event was handled in a good manner. Appropriate abnormal procedures were followed and the operator journal entries clearly described licensee actions during checkout of the pump motor condition.

(2) On November 8, 1995, during Unit 1 pressurization, two of the three RCS code safety valves indicated slight leakage when RCS pressure reached approximately 2150 psig.

Operators immediately reduced pressure in accordance with procedures to approximately 2000 psig, where the leaking code safety valves reseated. During the next 24 hours, the licensee reviewed the leakage issue and formulated an action plan to allow for RCS pressurization. The plan involved increasing RCS pressure at a rate not to exceed 25 psig per hour, and included gagging of a code safety, if necessary, to allow for system stabilization if valve leakage was experienced. On the evening of November 8, operators commenced pressurization of the Unit 1 RCS from about 2000 psig. Normal operating pressure (2235 psig) was reached approximately 3:00 a.m. on November 9, 1995. RCS safety valve leakage was not observed during this pressurization evolution.

The inspectors monitored licensee activities relating to RCS code safety valve leakage during this period. They noted that similar code safety valve leakage had been observed during past outages. In each previous case, the licensee had to reduce pressure, and after an additional soak period at reduced pressure, slowly increase RCS pressure to allow for pressurization of the RCS to normal operating pressure. PER SQ952057 was written on November 13, to document the leaking code safety valve problem.

The inspectors concluded the operator response to the leaking RCS code safety valves was good. However, leaking code safety valves continued to provide operational challenges during unit startups from outages.

(3) On November 12, 1995, while placing Unit 1, #2 feedwater heaters in service in accordance with procedure, significant pipe movement and damage to pipe restraining devices occurred. Operators closed low point drain and bypass valves associated with the extraction steam flowpath to the heaters and the pipe movement stopped. PER SQ952068 was initiated by operations to address the event.

The inspectors became aware of the event on November 14, and began a review of licensee activities associated with corrective actions for the occurrence. The inspectors reviewed operator logs for November 12 and 13 and determined that the log entries did not discuss the pipe movement or damage to the restraining devices after the event. Log entries for the UOs, ASOS, and SOS only discussed a feedwater heater string isolation at the time of the event.

The inspectors discussed the event with site engineering and system engineering personnel. They were informed that a structural integrity evaluation of the extraction steam line was conducted. The inspectors reviewed the structural evaluation and noted that it concluded that structural operability limits were not exceeded during the event.

System engineering personnel determined the cause of the event was operating the turbine connected to the grid for several hours without establishing extraction steam flow to the feedwater heaters. During past startups, operations established extraction steam flow to feedwater heaters within an hour after connecting the generator to the grid. However, during this startup, based on a Westinghouse recommendation to connect the generator to the grid at low power for approximately 8-hours prior to doing the turbine overspeed test, operators did not valve in extraction steam to the feedwater heaters. As a result, the licensee believed that moisture accumulated in the extraction steam line to a point where it filled the line. During the subsequent turbine generator startup on November 12, operators valved in the bypass lines for extraction steam and the pipe movement event occurred. Review of operating procedure determined that guidance required the #1 and #2 heaters to be placed in service after the turbine load was greater than 15 percent. Operations instituted interim corrective action (Standing Order No. 95-079) to address placing heater drains and vents in service in a timely manner to prevent condensation buildup in extraction steam lines. The inspectors verified the interim corrective action was instituted.

The inspectors concluded that the significant pipe movement event of November 12, 1995, on Unit 1 was caused by a change in a routine operational evolution, due in part to the Westinghouse recommendation. In addition, when the recommendation was made, the licensee did not conduct an adequate review of the change to see how it would affect plant operation. Also, operator sensitivity to documenting the occurrence in operator logs was weak.

(4) On November 14, the inspectors reviewed the November 13 Unit 1 UO log book entries for information related to problems the unit had experienced with the C-2 Heater Extraction Isolation Valve, 1-FCV-5-34 and pressurizer level transmitter, 1-LT-68-320. During the log book review, the inspectors noted three log book entry errors, all of which occurred on the November 13. The first entry error occurred at 3:00 a.m. The entry incorrectly identified the C-2 Heater Extraction Isolation Valve as 5-94 rather than 5-34. The second error occurred at 3:5[illegible] p.m. when the log entry incorrectly referenced TS LCO 3.2.1.1, Action 17-a., instead of TS LCO 3.3.2.1., Action 17-a., as the action statement being entered. The third error occurred at 6:50 p.m. when the log entry stated that "1-P-68-322 removed from trip

position and placed in normal." The actual instrument removed from tripped position was 1-P-68-323.

The inspectors considered these three examples, which all occurred on November 13, to represent a lack of attention to detail by licensed operators in ensuring that log book entries are accurate. The inspectors discussed these observations with the operations superintendent on November 15, 1995. The operations superintendent agreed with the inspector's conclusion. Other weaknesses related to log keeping are identified in paragraph 3 a. (3) of this report and in Inspection Report 327, 328/95-20. On November 17, the licensee initiated PER SQ952094PER to document that log keeping was not meeting acceptable standards.

(5) On November 15, 1995, during an operations shift turnover briefing, the inspectors noted that one of the operations top five concerns as listed on the shift turnover report, was the inoperability of flow instrument 0-FI-77-42. This condition required entry into ODCM 1.1.1, ACTION 33 whenever a liquid release was made from the plant. The concern also noted that this condition had been an operator work around since August 11, 1995. WR C201983 was identified as the maintenance document requesting maintenance for the instrument problem. At the end of the crew briefing, the inspectors questioned the SOS as to the status of the corrective actions for the instrument problem. The SOS could not provide status at that time. However, the SOS informed the inspector he would find out the status and provide the feedback. Later that day, the SOS informed the inspector that 0-FI-77-42 was still not working and additional maintenance was required.

The inspectors reviewed the work package associated with WR C201983 (WO 95-08292-00) and a printout of plant activity associated with the WO. On August 14, 1995, PER SQ951146 was written to address a flow tolerance problem associated with 0-FI-77-42. The PER interim corrective action required the use of a ultrasonic flow instrument until 0-FI-77-42 was repaired. The inspectors determined that the flow instrument job went on material restraint on August 17, 1995. The WO was removed from material restraint and available for work on October 30, and was awaiting PMT on November 11, 1995. After the inspectors questioned the status of the maintenance activity, they noted the WO status was again placed on material restraint on November 20, 1995. The inspectors discussed the activity with maintenance management and were informed additional problems were identified with 0-FI-77-42 on November 16, 1995, which required additional parts.

The inspectors concluded that appropriate attention was not given to correction of a problem associated with 0-FI-77-42, based on the issue being considered as an operator workaround and one of operations top five concerns.

(6) On November 18, 1995, at approximately 8:49 p.m., with Unit 1 operating at approximately 89 percent power, the unit experienced an automatic runback to approximately 75 percent power. After the runback, the "A" MFP appeared to be operating erratically, so operators decreased power to approximately 55 percent and secured "A" MFP operation. Operators then noticed that intercept valves for the "A" and "B" low pressure turbines were closed. Due to the valves being closed, a decision was made to reduce power to less than 50 percent and trip the main turbine. The turbine was tripped and the unit was stabilized at approximately 2 percent power with feedwater being supplied by AFW and with condenser steam dumps in operation.

The inspectors responded to the plant and monitored licensee activities after the transient. Plant and operator response to the transient was evaluated as good. An investigation team was assembled and the licensee determined that the event was caused by the failure of a circuit card in the analog EHC system. After discussion with Westinghouse, maintenance was accomplished on the EHC circuitry. The licensee then rolled the main turbine generator and reconnected to the grid on November 20, 1995. The licensee will conduct an inspection, during the next appropriate outage, of the Unit 2 EHC system protective feature circuitry.

The inspectors noted that a BOP reliability study conducted in 1993 did not review this area. The licensee stated the scope of the BOP study did not include this level of detail.

The inspectors reviewed licensee activities associated with the event and corrective actions prior to startup. They considered the operator response to the transient and the troubleshooting of the problem to be good. However, the transient cause determination also identified a condition that had not been considered in the licensee's existing BOP reliability study.

(7) On November 21, 1995, at approximately 10:22 a.m., Unit 1, which was at 66% power, experienced a failure of the "A" train control room annunciator system. Each control room annunciator is powered from both an "A" and "B" train annunciator system. Failure of either annunciator train results in one of two light bulbs in each annunciator window becoming inoperable. Operators observed an abnormal blinking of several annunciators followed by a complete

failure of the "A" train annunciator system. Operators also noted the odor of burning electrical equipment. During this event AOP-P.08, LOSS OF CONTROL ROOM ANNUNCIATORS, Revision 0 and AOI 30, PLANT FIRES, Revision 12 were entered.

The partial loss of annunciation was determined to be caused by the failure of a regulating transformer, located internal to Panel 1-L-236, Annunciator Inverter. Panel 1-L-236 is located in a passageway between the main control room and the TSC. This inverter supplied the "A" train annunciators of both the Unit 1 and the common unit annunciators. Operators promptly deenergized the inverter and electricians were called to investigate. Power to the "A" train system was subsequently transferred to its alternate power supply which restored the "A" portion of the annunciation system.

The inspectors responded to the control room when notified of the failure by the SOS. The inspectors discussed the event with operations personnel and reviewed the actions taken in response to guidance provided in the AOP and AOI. The inspectors concluded that operators responded quickly, and cautiously, to the event while ensuring that the unit remained in a stable condition.

One deficiency was noted during this event and documented in a PER. The Incident Commander, who would normally respond to a fire alarm, was unable to hear the fire alarm in the new OCC located in the maintenance building. He was subsequently called by phone from the control room. The inspectors were concerned that there may be other areas within the plant where fire alarms and emergency declarations or instructions cannot be heard. This concern was brought to the attention of the site emergency planning director. The inspectors will monitor licensee actions associated with this issue during future inspections.

b. Biweekly Inspections

The inspectors conducted biweekly inspections, using the licensee's IPE information, to verify operability of the following ESF trains.

On November 7, the inspectors walked down the Emergency Gas Treatment System. The purpose of the EGTS is to maintain the containment annulus below atmospheric pressure at all times to ensure that all leakage from primary containment passes through the EGTS. The EGTS has two subsystems, a Annulus Vacuum Control System and a Air Cleanup System.

The inspection included a control room walkdown of the EGTS panel, a walkdown of the 480 volt shutdown board room breakers which power several system components, and a walkdown of the EGTS HEPA filter rooms. During the control room walkdown on November 7, the inspectors questioned the status of a WR sticker (C265149, dated November 27, 1994) written against Annulus Vacuum Fan 2A. There was a hand written note on the WR sticker which read "containment annulus vacuum fan A will not stop". The inspectors subsequently learned that WR C265149 had never been entered into the work planning system and that the problem with the fan apparently still existed nearly a year later. On November 13, 1995, WR C342474 was written to address the continuing problem with the 2A fan. The licensee also wrote PER SQ952071PER to document this issue.

The inspectors noted that operators allowed the WR sticker (WR C265149) to remain on the main control room board for nearly a year during which time the status of the WR was apparently not questioned and the deficient condition of the 2A Annulus Vacuum Fan continued to exist. The inspectors also noted that in November, 1994, there was an apparent omission in the work planning process which resulted in WR C265149 not being entered into the work scheduling system. Based on these observations, the inspectors concluded that operator sensitivity to degraded conditions, based on control room information, was weak.

With the exception of the deficiencies regarding the 2A Annulus Vacuum Fan, the inspectors concluded that the EGTS was properly aligned and that the condition of those components inspected was good.

c. Monthly Inspections

(1) On November 6, 1995, the inspectors reviewed the licensee's progress in completing procedure 1-SI-OPS-088-014.0, VERIFICATION OF CONTAINMENT INTEGRITY, Revision 2, prior to MODE 4 entry. The inspectors verified the positions of selected valves from control room indications. The inspectors also reviewed selected portions of 0-GO-1, UNIT STARTUP TO HOT STANDBY, Revision 0, and SOI-88.1, CONTAINMENT ISOLATION SYSTEM, Revision 36, and verified the positions of selected valves from control room indications. The inspectors concluded the licensee's containment integrity verification was acceptable and was completed as directed by procedures.

(2) During this period, the inspectors reviewed the INPO final report for the evaluation conducted in June of 1995 at the Sequoyah Nuclear Plant. Based on the review, the inspectors concluded the NRC perception of licensee performance at the time of the evaluation was consistent with the INPO results.

d. Licensee NRC Notifications

(1) On November 1, 1995, the licensee made a call to the NRC as required by 10 CFR 50.72. The issue involved an unplanned ESF actuation (feedwater isolation) on Unit 1 due to a sensed high level condition in the #1 steam generator. Unit 1 was in MODE 4 at the time with main feedwater isolation valves closed. The actuation had no safety effect on the unit since AFW was already supplying feedwater to the steam generators and was not affected by the ESF signal. The cause of the ESF actuation was opening of the loop 1 MSIV with a differential pressure across the valve that was higher than expected.

(2) On November 18, 1995, the licensee made a voluntary call to the NRC regarding the Unit 1 transient discussed in paragraph 3.a.(6). The call was made, in part, due to extensive public and media inquiries after the transient. The inquiries were due to noise from moisture separators/reheaters relief valves lifting when their respective intercept valves closed.

e. Summary of Operations Performance for Unit 1 Cycle 7 Outage Period

During this period, the inspectors reviewed inspection results associated with Operations performance during the period of the Unit 1 Cycle 7 outage (September 9 through November 23, 1995).

Operations performance was generally good involving evolutions associated with Unit 1. Also, very good operational and safety sensitivity was demonstrated in Unit 2 operation during this period. Good operator performance was observed during Unit 1 maneuvers throughout the period, and a lower threshold to identification of problems was also noted. Examples of weaker performance included identification of issues in implementation of the clearance process along with examples of operator weaknesses in logkeeping.

Within the areas inspected, no violations were identified.

4. **MAINTENANCE OBSERVATIONS** (62703 and 92902)

During the reporting period, the inspectors verified by observations, reviews, and personnel interviews that the licensee's maintenance activities resulted in reliable operation of plant safety systems and components, and were performed in accordance with regulatory requirements. Inspection areas included the following:

a. Unit 1 Maintenance Backlog Review

Several maintenance activities were observed during the Unit 1 outage, and each was performed in a good manner and in accordance with procedures. U1C7 was a well planned and executed outage even though maintenance personnel were challenged on several occasions by emergent issues. In general, the licensee performed well in responding to emergent maintenance problems. Two noteworthy examples of unanticipated maintenance activities were the failure of the #1 seal on RCP #4 and the motor change-out on RCP #2 necessitated by a motor grounding problem.

During U1C7 the total WR/WO backlog, including outage and non-outage WR/WOs, was reduced by approximately 13 percent. The total non-outage backlog remained essentially constant throughout U1C7. The fact that Unit 2 WR/WO backlog did not increase during U1C7 indicated that an appropriate level of attention was given to maintaining Unit 2. Also, Unit 2 did not experience a significant transient during U1C7 which was a positive indicator of total maintenance effort. A review of maintenance activities deferred to future outages indicated that those deferrals were justified.

b. On November 7, 1995, a Unit 2 invalid Train B CVI occurred due to the failure of 2-RE-90-131, Containment Purge Air Exhaust Monitor. The failure was attributed to an electronics module failure in the monitor. The licensee subsequently determined that no spare parts were available onsite to repair RE-131. At the time when RE-131 failed, the redundant monitor, 2-RE-90-130, was out of service. RE-130 had been declared inoperable on October 12, 1995, when the monitor pump motor failed. RE-130 was placed on material restraint on October 23, 1995, when it was determined that spare parts needed to repair the monitor were not in stock. With both containment purge air exhaust radiation monitors inoperable, TS required that the containment purge supply and exhaust valves be maintained closed. With these valves in their required closed position, operators were unable to purge containment. Typically, operators must purge containment approximately once per shift so as not to approach the limits of TS 3.6.1.4, Containment System-Internal Pressure, which requires that primary containment internal pressure be maintained between -0.1 and 0.3 psig relative to the annulus pressure. However, during the time that both radiation monitors were out of service, containment pressure did not exceed the TS limit. The licensee subsequently returned both radiation monitors to service by deciding to operate RE-130 without pump overload protection until replacement parts could be installed and by using a module from another radiation monitor to repair RE-131.

The inspectors discussed this maintenance activity with the cognizant system engineer who provided the inspectors a time-line of the maintenance items related to RE-130 being out of service and its eventual return to service. The inspectors noted that there were several opportunities for the licensee (including Operations, Maintenance, and Procurement) to have expedited the repair of RE-130. Following the failure of RE-131, the licensee began to question their work process in so far as what caused the delay in repairing RE-130. The licensee commenced an evaluation of the work process and documented this event in PERs SQ952022 and SQ952024. An event critique and recommended corrective actions will result from the PER reviews.

The inspectors concluded that the licensee recognized the significance of a situation which resulted in both radiation monitors being out of service simultaneously. The licensee initiated actions to prevent recurrence.

c. Unit 1 ERCW Hanger Repair

On November 1, while Unit 1 was in MODE 4, the #2 RCP tripped on a ground fault condition. Licensee troubleshooting determined that the trip was caused by a ground in the pump motor. The licensee replaced the #2 RCP with the RCP removed for refurbishment during the U1C7. On November 4, during a post maintenance walkdown, the licensee discovered the anchors on hanger 47A450-21-25 (ERCW hanger) for #2 RCP auxiliary equipment were partially pulled loose from the polar crane wall. The ERCW hanger was fabricated from an I-beam and supported several conduits. The licensee wrote PER SQ952002PER to document this finding.

The licensee cut the I-beam approximately 9 inches from the wall, and performed a pull test on the hanger anchors. The anchors did not pass the pull test. The licensee removed the supporting plate from the wall, repaired the concrete area by inserting shims, and redrilled the bolt holes in the supporting plate for larger bolts. When the licensee attempted to reinstall the bolts, they hit rebar in two places with the longer bolts. The licensee welded an extension to the supporting plate, drilled two holes in the extension, anchored the supporting plate, and successfully performed a pull test on the 4 bolts. The licensee repaired the I-beam by welding a metal plate between the cut edges.

The licensee concluded, in the PER, that the most probable cause of the hanger damage was contact of the lifting rig with the hanger as the pump was lifted during replacement of the #2 RCP. Several licensee personnel had been assigned to monitor the lifting process, however the tight confines of the area may have prevented observation of the interference. An interference was not observed or reported at the time of the pump lift. The licensee inspected the other 3 RCPs, and did not find any damaged hangers/support plate anchors.

The licensee delayed entry into MODE 4 until all welding in containment was completed. This decision was based on their concern that the welding magnetic field could cause interference with the RPS circuitry and cause a possible false SI.

The inspectors reviewed the PER; selected portions of WO # 95-12974-00, which implemented the repair; the 10 CFR 50.59 Evaluation of Changes, Tests, and Experiments, Appendix B, Safety Assessment Format; and performed a visual inspection of the hanger in containment. Based on this review and discussions with the licensee, the inspectors concluded that this maintenance activity was conducted in a good manner.

d. Followup reviews were accomplished during the inspection period for the following items:

(Open) IFI 327, 328/93-23-05, Review of Licensee Program to Test Non-TS Molded Case Circuit Breakers. The item involved a lack of a formal test program for the subject breakers. During this period, the inspectors reviewed an outline of a proposed molded case circuit breaker maintenance and testing program. This program would result in issuance of a maintenance document over a seven month period beginning in January of 1996. The inspectors concluded the program would address this item; however, they will review implementation of the program over the next seven months prior to closing this item.

e. Summary of Maintenance Performance for Unit 1 Cycle 7 Outage Period

During this period, the inspectors reviewed inspection results associated with Maintenance performance during the period of the Unit 1 Cycle 7 outage (September 9 through November 23, 1995).

Maintenance performance during the outage period was good and better than past outages. Outage management was effective and demonstrated very good safety sensitivity in addressing emergent problems. The Unit 1 corrective maintenance backlog was significantly reduced while maintaining the backlog on Unit 2 constant. In addition, several long standing issues were addressed with modifications which eliminated past problems. Examples were new lower compartment cooler coils, new control rod step counters, and replacement of safety-related pump room coolers. However, several events and/or operator workarounds relating to equipment problems during the Unit 1 startup indicated that continued focus was necessary in addressing plant material condition issues.

Within the areas inspected, no violations were identified.

5. **SURVEILLANCE OBSERVATIONS** (61726 and 92902)

During the reporting period, the inspectors ascertained, by direct observation of licensee activities, whether surveillances of safety significant systems and components were being conducted in accordance with technical specifications and other requirements. The inspection included a review of 1-SI-OPS-082-026.B, LOSS OF OFFSITE POWER WITH SAFETY INJECTION - DG 1B-B CONTAINMENT ISOLATION TEST, Revision 7, which was performed October 21 - 24, 1995. The purpose of this SI was to verify the operability of EDG 1B-B, the safety injection signal, and ESF equipment.

The inspectors reviewed the test data and discussed the test results with the licensee. The inspectors specifically reviewed the test director logs, test deficiencies, and the EDG 1B-B 24 hour test data. The data reviewed indicated that testing satisfied the TS surveillance requirements. The inspectors concluded that the test was accomplished in a good manner.

Within the areas inspected, no violations were identified.

6. **ONSITE ENGINEERING** (37551 and 92903)

During the reporting period, the inspectors conducted periodic engineering evaluations for regional assessment of the effectiveness of the onsite engineering staff. The inspection included a review of the following activities:

a. Unit 1 #4 RCP Seal High Leakage Investigation.

On October 28, 1995, operators noticed increased seal leakoff flow for the Unit 1 RCP #4, #1 seal. The abnormal condition was discussed in inspection report 327, 328/95-21. During this inspection period, Unit 1 was placed in MODE 5, and the seal package for RCP #4 was replaced. An investigation team was formed to determine the cause of the failed seal. The investigation team included experts from consultants familiar with root cause analysis, and pump seal experts from Westinghouse. The maintenance personnel involved in the seal removal specifically focused on any abnormality that could have caused the seal to fail. The removed seal was inspected and no abnormal conditions were observed. At the end of the inspection period, the licensee had not determined a cause for the observed high seal leakage.

The inspectors reviewed licensee activities associated with the investigation, and were briefed several times during this period by the lead investigator and other engineering personnel. The inspectors concluded the licensee was conducting a good root cause investigation, and appropriate conservative actions were taken (seal replacement) prior to Unit 1 startup from the Cycle 7 refueling outage.

b. Unit 1 RCP Motor Fault Root Cause Investigation

On November 1, 1995, the Unit 1, #2 RCP motor breaker tripped on a ground fault condition. Subsequent checkout of the motor cables from the breaker to the pump determined the electrical fault to be in the motor. PER SQ951975 was written to institute appropriate corrective actions for the problem. A root cause investigation team was formed on November 1 to review the problem and determine the cause of the failure.

The inspectors monitored the licensee's initial planning activities associated with the investigation. They noted that the licensee established a tentative plan and schedule for the root cause determination group, which included information gathering, short term actions, and motor inspection activities. The effort involved site and corporate engineering and maintenance organizations. In addition, a Westinghouse expert for RCP motor problems was consulted early in the investigation.

On November 21, 1995, the inspectors were briefed on the status and preliminary results of the failure evaluation. The licensee determined the failure was in the first coil of the C phase winding. They also noted the area of the failure was the most stressed coil during motor starting. Current motor rewind techniques provide higher insulation resistance in the area where the failure was observed. The licensee has refurbished three of the four RCPs for each unit using the new techniques.

The inspectors concluded the licensee planned and conducted a very good root cause investigation for the Unit 1 RCP motor fault problem. In addition, the licensee has implemented a motor refurbishment program which addressed future potential problems of this nature.

c. Summary of Engineering Performance for Unit 1 Cycle 7 Outage Period

During this period, the inspectors reviewed inspection results associated with Engineering performance during the period of the Unit 1 Cycle 7 outage (September 9 through November 23, 1995).

Engineering performance during this outage period was good. Good performance included 24 hour support to other departments from technical support, component engineering, and site engineering to address emergent outage technical issues, new designs to eliminate operator workarounds, and better engineering investigations for emergent problems during Unit 1 startup. One area in need of improvement was assurance of adequate technical reviews for changes in routine operational evolutions.

Within the areas inspected, no violations were identified.

7. **PLANT SUPPORT** (64704,71750, 82301 and 92904)

During the reporting period, the inspectors conducted reviews to ensure that selected activities of the following licensee programs were implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

a. Physical Security

During the period of November 17 through 19, 1995, the licensee instituted their new protected area modification. This modification resulted in a significant area of the plant being incorporated into the protected area. The transition period involved searching all new protected area locations and movement of the protected area access location to a new facility.

The inspectors were briefed on the transition process on November 16, 1995. The brief discussed aspects of the transition process which would assure the licensee was in compliance with their site security plan. The licensee instituted the transition plan on November 17, and completed the searches on November 18, 1995. The inspectors observed their office search for inclusion into the new protective area on November 17. The inspectors observed good implementation of the new protective area requirements when licensee employees arrived for work on November 20 and 21, 1995.

The inspectors concluded the licensee implemented the new security perimeter in a good manner. Office searches were thorough and coordination/implementation of new gate house requirements went well.

b. Fire Protection

During this inspection period the inspectors reviewed the licensee's program for fire watch training. The inspectors verified that the licensee has a qualification program for new fire watches which must be completed prior to performing duties. The program includes a 3 to 3 1/2 hour training session using a lesson plan (FPT-213.000, Sequoyah-Fire Watch Initial Training), practical training, and an examination. The training program additionally requires a 1 to 1 1/2 hour annual requalification using a second lesson plan (FPT-213.500, Sequoyah-Fire Watch Refresher Training) and an examination. The inspectors also verified that personnel who presently perform fire watch duties have received the required training.

The inspectors concluded that the licensee has an acceptable program for training and requalifying fire watches.

c. Summary of Plant Support performance for Unit 1 Cycle 7 Outage Period

During this period, the inspectors reviewed inspection results associated with Plant Support performance during the period of the Unit 1 Cycle 7 outage (September 9 through November 23, 1995).

Performance in the Radiological Protection area of Plant Support was very good. Examples were continued aggressive reduction of radwaste generation, and ALARA performance in achieving the person-rem and personal contamination events outage goals for original outage scope of work. However, emergent work during the outage increased outage scope and resulted in additional dose.

Performance in the Security area of Plant Support was good during this period. The new protective area boundary was implemented with minimal impact on site activities at the end of the outage.

Within the areas inspected, no violations were identified.

8. **LICENSEE EVENT REPORT REVIEW** (92700)

The inspectors reviewed the LERs listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspectors' review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

a. (Closed) LER 327/95-11, Power Range Neutron Flux Monitor Inoperable Longer than Allowed By Technical Specifications. The issue involved one channel of the power range neutron flux monitor not indicating correctly. It was determined that the signal cable from the lower detector to the monitor gradually became disconnected over a period of time as a result of moving the control room monitor drawer in and out. The cable was reconnected and the power range channel was returned to service. A review of computer data indicated that the channel had been out of service for approximately four hours prior to the time of discovery.

The remainder of the Unit 1 power range monitor cables were inspected and determined to be acceptable. The cable that was disconnected was determined to have been installed incorrectly. That deficiency was corrected. The Unit 2 cables were also inspected. Two cables were found to be loose and were tightened. The two Unit 2 loose cables did not affect the operability of the associated power range channels. The remaining Unit 2 cables were determined to be acceptable. Based on licensee corrective actions, this LER is closed.

b. (Closed) LER 328/92-08, Reactor Trip as a Result of One Protection Channel (RTD Loop) Being in the Tripped Condition when a RTD Loop in Another Channel Failed, Completing the Two-Out-Of-Four Logic. The issue involved varying resistances in containment electrical penetrations. The issue was previously discussed in NRC Inspection Reports 327, 328/93-39, and 327, 328/94-34.

During the Unit 1 Cycle 7 outage, five additional electrical penetrations were replaced with new Conax modular design penetrations. In addition, the licensee continued with their root cause analysis of the problem. The licensee stated that they will revise their response to LER 328/92-08 after this analysis is completed. Based on licensee corrective actions to this point, this LER is closed.

Within the areas inspected, no violations were identified.

9. **EXIT INTERVIEW**

The inspection scope and results were summarized on November 30, 1995, with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
IFI 327, 328/93-23-05	OPEN	Review of Licensee Program to Test Non-TS Molded Case Circuit Breakers (paragraph 4.d).
LER 327/95-11	CLOSED	Power Range Neutron Flux Monitor Inoperable Longer than Allowed By Technical Specifications (paragraph 8.a).
LER 328/92-08	CLOSED	Reactor Trip as a Result of One Protection Channel (RTD Loop) Being in the Tripped Condition when a RTD Loop in Another Channel Failed, Completing the Two-Out-Of-Four Logic (paragraph 8.b).

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items discussed and/or closed in paragraphs 4 and 8.

10. ACRONYMS AND ABBREVIATIONS

AFW	-	Auxiliary Feedwater
ALARA	-	As Low As Reasonably Achievable
AOI	-	Abnormal Operating Instruction
AOP	-	Abnormal Operating Procedure
ASOS	-	Assistant Shift Operations Supervisor
BOP	-	Balance of Plant
CFR	-	Code of Federal Regulations
CVI	-	Containment Ventilation Isolation
DRP	-	Division of Reactor Projects
EDG	-	Emergency Diesel Generator
EGTS	-	Emergency Gas Treatment System
EHC	-	Electrohydraulic Control
ERCW	-	Essential Raw Cooling Water
ESF	-	Engineered Safety Feature
°F	-	Degrees Fahrenheit
HEPA	-	High-efficiency Particulate Air
IFI	-	Inspector Followup Item
INPO	-	Institute of Nuclear Power Operations
IPE	-	Individual Plant Examination
KV	-	Kilovolts
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MFP	-	Main Feedwater Pump
MSIV	-	Main Steam Isolation Valve
NRC	-	Nuclear Regulatory Commission
OCC	-	Operations Control Center
ODCM	-	Offsite Dose Calculation Manual
PER	-	Problem Evaluation Report
PMT	-	Post Maintenance Testing
psig	-	Pounds Per Square Inch
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RPS	-	Reactor Protection System
RTD	-	Resistance Temperature Detector
SI	-	Safety Injection
SI	-	Surveillance Instruction
SOS	-	Shift Operations Supervisor
TS	-	Technical Specification
TSC	-	Technical Support Center
U1C7	-	Unit 1 Cycle 7 Refueling Outage
UO	-	Unit Operator
WO	-	Work Order
WR	-	Work Request