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

Report Nos.: 50-327/93-54 and 50-328/93-54

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 1 and 2

Inspection Conducted: November 29 to December 10, 1993

Inspector: Charles A Casto 1/20/94
C. A. Casto Date Signed

Team Members: R. Aiello, DRS, RII
R. Moore, DRS, RII
M. Branch, Surry, RII
M. Morgan, Farley, RII
D. LaBarge, Senior PM, NRR
R. Tjader, NRR, TSB
J. Shackelford, DRS, RII
J. Thompson, AEOD, DET
P. Wilson, DRP, RI

Approved by: Caudle A. Julian 1/20/94
C. A. Julian, Chief Date Signed
Engineering Branch
Division of Reactor Safety

Appendix 2 contains a list of acronyms and initialisms used in this report.

SUMMARY

Scope:

This special, announced inspection was conducted in the areas of management effectiveness, Operations, Maintenance, Post Restart Plan, and operational performance. Specifically, it included the areas of organization and staffing, integrated planning, work planning and control, leadership and direction, problem solving and decision making, corrective actions, and the effectiveness of improvement initiatives.

Results:

Station management was controlling work in accordance with a set of priorities that were conservative with regard to public health and safety. Highest priority has been placed on the safe operation of Unit 2. Equipment problems on Unit 2 have diverted resources from lower priority items including implementation of the Site Improvement Plan.

Operators were well trained, but deficiencies were found in management oversight of shift activities.

The threshold for identifying problems has been lowered and more were being identified by the line organization. Shifting priorities, however, diverted resources away from working off the resulting backlog. The preventive maintenance program for the balance of plant was weak and balance of plant failures have significantly impacted plant reliability. Improvements in the preventive maintenance program were contained within the Site Improvement Program.

In the areas inspected, an apparent violation was identified.

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1.0 BACKGROUND

The Sequoyah Nuclear Plant (SQN) consists of two pressurized water reactor (PWR) units with an ice condenser type containment. In March of 1993, a steam leak in a main turbine extraction steam line on Unit 2 resulted in the shut down of both units. After repairs were made, Unit 2 was brought back to service on October 11, 1993. Unit 1 remained shut down during this inspection. As a part of the overall plant improvement process the licensee developed a Post Restart Plan. In the Post Restart Plan the licensee outlined their actions planned to eliminate large backlogs of outstanding work and other programmatic improvements. Following the restart of Unit 2 in October of 1993, Region II chartered a post restart inspection team to assess the operational performance of Unit 2 since the startup and to assess the current implementation of the Post Restart Plan along with its impact on Unit 1 restart activities.

2.0 INSPECTION SCOPE AND OBJECTIVES (IP 93802)

This inspection focused on the functions of management effectiveness and decision making, Operations, Maintenance, Post Restart Plan, and operational performance. Specifically, it included the areas of organization and staffing, integrated planning, work planning and control, leadership and direction, problem solving and decision making, corrective actions, and the effectiveness of improvement initiatives.

3.0 MANAGEMENT EFFECTIVENESS, DECISION MAKING, AND OVERSIGHT (IP 93802)

3.1 Project Management

The team noted that there have been significant management changes at SQN over the past year. Many managers were new in their positions and it may be too soon to effectively measure success of this new team of managers. Additionally, several new managers, who lack power plant or PWR experience, were scheduled to start a training and familiarization program to broaden their knowledge and skills.

The team evaluated the four major priorities currently being managed at SQN. These were, in order:

(1) Safe and reliable operation of Unit 2.
(2) SIP implementation and backlog reduction.
(3) Unit 1 restart.
(4) Unit 2 refueling outage planning.

Based on public health and safety consideration, the team concluded that these priorities were appropriate. Further, the team concluded that work activities at the site were being controlled by management in accordance with these priorities.

3.2 Work Scope Identification

The team reviewed problem evaluation report (PER) performance indicators from January 1993 to present. It appeared that most PERs were identified by the line and not by the engineering organization. This was consistent with management's expectation on the threshold for problem identification. Hardware related issues were being factored into the project plan for resolution. However, in several cases extended compensatory actions are being implemented until the modification could be completed.

3.3 Resources

Although there were pockets of dedicated resources to resolve the four current priorities, for the most part Unit 2 reliability appeared to impact the other three priorities. In engineering, backlogs were worked by contract task groups with TVA personnel being used for Unit 1 restart and Unit 2 outage scope project management. Emerging issues on Unit 2 have redirected resources from lower priorities.

Unit 2 equipment problems added to the amount of work to be accomplished by maintenance. This adversely impacted the schedule and resources of the remaining priorities. Delayed resolution of the backlogs has the potential of impacting Unit 2 operation as well. For example, through reduction of the drawing deficiency backlog, a concern with containment integrity involving configuration of the Unit 2 Auxiliary Feedwater (AFW) penetration was identified. Additionally, a number of Balance of Plant (BOP) reliability improvements were treated as long range programs in the SIP.

3.4 Decision Making and Performance Indicators

For the most part, the team found that decisions made by department management were conservative. For example, the Operations Department determination that the residual heat removal (RHR) pump was inoperable, when the room cooler was isolated while in the RHR mode, was considered to be conservative. In contrast, however, department level managers and supervisors needed some direction by upper management. For example, middle managers and supervisors needed encouragement in initiating PERs to ensure that in-depth reviews of the conditions adverse to quality (CAQs) would be performed and the extent of the condition fully understood.

The team attended the December 8, 1993, Site Management Assessment Review Team (SMART) meeting where the November performance indicators were discussed. The performance indicator process was in an early stage of development. Some management representatives in attendance were unclear on the meaning of several indicators and the report itself contained obvious errors. This process, when understood and perfected should be useful in the future.

Proper guidance and direction was noted at the site Vice President and Plant Manager level. The new plant manager showed the team a plan where he outlined his expectations for his direct reports and other personnel who work for him. This plan contained appropriate elements for team building and goal setting.

3.5 Corrective Action Program

The team reviewed the CAQ program backlog currently in place at SQN. The CAQ program is described in Revision 8 of procedure Site Standard Practice (SSP)-3.4, Corrective Action. At the time of the inspection there were 483 PERs in the backlog with most of them from the 1993 time frame. A breakdown of the PERs showed that there were 4-1987, 8-1988, 10-1989, 11-1990, 38-1991, 40-1992, and 372-1993. The older PERs were tied to plant modifications yet to be completed. The team reviewed a listing provided by the licensee that depicted the planned completion date for closeout of the PERs. This list contained several September 30, 1994, dates that were described as artificial dates to flag an end of the fiscal year review to determine if the implementation could be funded. Project management provided a breakdown that showed there were 51 total unfunded hardware corrective action documents representing 27 pre-September 30, 1993, issues and 24 post September 30, 1993, issues. The team selected nine PER packages for review where the list showed that implementation was not scheduled or budgeted.

The team's review determined that appropriate short-term corrective actions were taken as interim measures until the modification could be implemented or reevaluated. Several of these short-term actions were compensatory measures that had an impact on operators until the final modification was implemented. For example, PER SQ910232 involving moisture entrainment in the sample lines for the Unit 1 and 2 Shield Building Exhaust Radiation Monitors 1,2-RE-90-400, required that room temperature be raised and temperature verification added to the operator rounds. The project management group was appropriately focusing resources to resolve the backlog.

3.5.1 Threshold for Work Requests

During tours of the plant the inspectors noted that material deficiencies were being identified through work request (WR) tagging. There were several WR tags attached to uncoated piping and hangers. These low threshold WRs indicate that material condition improvements were being recognized by operators, system engineers, and maintenance personnel. For example, a breakdown of WRs in backlog showed the following: Operations initiated 24% of the WRs, System Engineers 28% and Maintenance personnel 26%. During the December 3, 1993, reactor trip the team noted that a BOP system engineer, with WR in hand, was out walking down his system immediately after the trip. Several WRs were initiated during this walkdown.

3.5.2 CAQ (PER) Process

Through a review of the corrective action (CA) backlog and performance indicators, the team concluded that the number of PERs/Incident Investigations (II) has shown a steady increase. The percentage of Operations Department initiated PERs has also increased. The team noted that upper management's sensitivity to PER threshold appears more conservative than middle managers. The team was informed that changes to the CA process were being considered that should result in an even lower threshold. This lower threshold process will need considerable management oversight to ensure that a large backlog of PERs does not result. As stated earlier, the current CA process has approximately 483 PERs in backlog with an initiation rate of approximately 1,000 per year. Management expects that the lower threshold process may double or triple the number being generated.

4.0 OPERATIONS (IP 71707)

4.1 Objectives and Conclusions

The team's objective was to perform a broadly structured evaluation of plant operations and evaluate the ability of the Operations Department to respond to operating events; evaluate the effectiveness of scheduling and coordinating work; and assess the ability of the operations staff to operate Unit 2 while providing support during the Unit 1 outage. This assessment included an evaluation of the operational burdens placed on operators and what consequences those burdens might have on the ability to reliably and safely operate both units.

Overall, the team concluded that the Operations Department remained satisfactory. After observation of normal operations and events, the team concluded that operators were properly performing their role; appropriately manipulating controls; and they were thoroughly knowledgeable of plant systems. The team noted weaknesses existed in the areas of staffing; management of operation-based programs; communications; log taking; and configuration control.

4.2 Staffing

On-shift control room staffing was typically one Shift Operations Supervisor (SOS), who was in charge of operations for both units and four Assistant Shift Operations Supervisors (ASOS's). These individuals all held senior reactor operators licenses (SRO). The licensee had been maintaining two licensed Unit Operators (UO's) per unit since the December 31, 1992, dual unit trip.

At the time of the inspection, Unit 1 was in a refueling outage, with Unit 2 at 100 percent power. The team noted that ASOS's and Auxiliary Unit Operators (AUO's) were routinely working a large amount of overtime. Some AUO's and ASOS's had worked as much as 40 percent overtime during the past year. The Unit 1 outage may have contributed to this overtime and this burden was significantly increased during dual unit outages. All regulatory and administrative requirements on overtime were met by the licensee.

The licensee had attempted to alleviate some of this burden through the temporary transfers of four AUO's from Bellefonte and four AUO's from Browns Ferry to supplement the AUO's at SQN. Their duties were limited to independent verifications, motor operated valve testing, plant labeling, and valve stroke timing (but not valve operation). Each AUO had received specific training in these areas, and was primarily assigned to these activities related to Unit 1. The program was expected to end in January 1994.

The licensee's Nuclear Assurance Department performed an assessment of control room oversight during the Unit 2 restart on November 10, 1992. One observation by the department was that the staffing level for Operations was not always adequate to support all the required activities. PER SQ930723 was initiated to address ASOS staffing levels. Specifically, SSP 12.1, Conduct of Operations, section 3.2.1, requires the staffing of four ASOS positions. However, only two ASOSs were scheduled on the 0700-1900 shift on October 31, 1993. In addition, only three ASOSs were scheduled for the following shifts: 1900-0700 on October 5, 1993, 0700-1900 on October 16, 1993, 1900-0700 on October 17, 1993, 0700-1900 on October 30, 1993, and 2300-0700 on November 7, 1993.

4.3 AUO Rounds and Roundsheets

After review of all AUO roundsheets since the Unit 2 startup, the team found that, in some cases, the unit control room (UCR) and turbine building AUO round sheets were incomplete. On November 23, 1993, the Unit 2 turbine building round sheets were not completed, and for a brief period, no AUO was assigned to Unit 2 auxiliary building. A weekly auxiliary building AUO round (lower containment inspections to be performed on Thursday, November 25, 1993), was instead performed on Wednesday (the previous day) due to the pending holiday.

No auxiliary building round sheets were found incomplete. No Technical Specification (TS)-related rounds were found to be incomplete.

The team found several instances where AUO's had completed their assigned rounds and then would be reassigned to other AUO stations. In addition, some unit AUO UCR round sheets were not completed. After review of many AUO daily logs, the team noted that log keeping needed improvement. AUO's sometimes omitted work they performed from their logs.

The team reviewed the adequacy of AUO roundsheets and determined that some required readings lacked acceptance criteria. For example, several areas in the Unit 2 turbine building required the AUO to record pressures and temperatures without an upper or lower acceptance margin. The team found that UO's were not always reviewing the AUO roundsheets.

4.4 Management and Responsibility of Operations-based Programs

Various SOS's, ASOS's, and others were assigned responsibility for 20 operations programs. This program started by the Operations Manager in a memo dated March 26, 1993, which was amended by memorandum dated April 15, 1993. Those memoranda specified the personnel assigned to the programs and directed that they develop a trending capability to illustrate the status and progress of the assigned program, and prepare an action plan that listed the actions planned and scheduled to improve the program. Programs addressed by the memoranda included the Operator Aids Program, Annunciator Disablement, Clearance/Hold Order, Configuration Status, Justification for Continued Operations Book, Compensatory Measures Book, Control Room Instrumentation Zone Coding, Operations Computers, various procedure upgrades, Key Control, Equipment Status Verification, Fire Protection, Switchyard Controls, and Refueling Operation. A review of the status of this program showed that the personnel responsible had not fully developed the programs. This indicates a lack of followup by management.

Nuclear Assurance performed an extensive four-month assessment of operational performance from July 6, 1992, through November 12, 1992. Eleven areas (or modules) were performance-rated based on a scale from 1.0 to 4.0. The average rating value over the four-month assessment was 1.74. The program provided that a rating of 2.0 or greater indicated that improvement and corrective action was required. The results from the individual rating modules showed that of the 11 different modules, no unsatisfactory areas were found (3.0 or greater) with only one module area receiving an overall average rating greater than a 2.0 (equipment labeling and operator aids).

Operation's had not established their own, independent performance measures. Discussions with Operations Department managers indicated that they have been reviewing all areas of concern identified in the 1992 and 1993 update Quality Assurance (QA) assessments. Operations was relying upon the findings and audits from QA and other organizations to measure improvement. QA indicated that it was their intention that monitoring QA-identified items should be accomplished by the responsible line organizations.

Overall, the team found the evaluations conducted by QA, in the areas of Operations and Maintenance, very beneficial. QA assessments and audits were comprehensive, objective, and accurate. The team viewed these functions as crucial to the success of both the Operations and Maintenance organizations.

4.5 Operator Actions

During routine operations, the team found that the operators were attentive and responsive to plant parameters and conditions. For example, on November 30, 1993, the board operator noticed that the Unit 2, Number 3 main turbine governor valve had drifted shut approximately 1.0 percent in a 40 minute period. This observation was immediately reported to the ASOS and immediate corrective actions - dispatching of personnel and continuous monitoring of valve position - were performed.

4.5.1 Equipment out of Service

The team found that, for the documents reviewed, equipment out of service controls were adequate and tagging of instrumentation scheduled for surveillance testing/troubleshooting was thorough. For example, during initial troubleshooting efforts for a December 2, 1993, "Eagle 21" Solid State Protection System (SSPS) problem, instruments associated with the affected channel ("OP Delta T," "Delta T," "OT Delta T," Refueling Water Storage Tank and containment sump levels) were quickly marked and control room personnel were knowledgeable of indications that were suspect.

4.5.2 Logkeeping

Operators used narrative logkeeping. Logkeeping was timely, accurate and adequately reflected plant activities. It was in compliance with SSP-12.1, Conduct of Operations, paragraph 3.8. Equipment status changes were appropriately documented and control room personnel were, for the most part, aware of these changes. Manipulation of controls was performed only by licensed operators or by "operator in training" personnel who were under the observation of, and in the presence of, licensed reactor operators.

4.5.3 Control Room Atmosphere

Control room traffic and noise levels were relatively high, but with Unit 1 in preparation for restart, this "higher-than-normal" volume of traffic and higher noise level were to be expected. Control room lighting was adequate; however, there were a few dark spots/shadows around the board areas. For example, all observed ASOS personnel, upon receipt of control board annunciators, would immediately move into the control board operator desk area (since reading of the annunciators, from the ASOS desk area, was difficult). The number of annunciators in alarm on the operating unit were minimal.

4.5.4 Response to Events

The team observed and evaluated several significant events that occurred while on-site. They included: Rod Control Motor Generator set trip, SSPS Channel 4 failure, Condensate system transient, Raw Cooling Water (RCW) line leak, turbine building fire, Number 3 Governor valve swings and a reactor trip.

On December 1, 1993, a fire was reported in the Unit 2 turbine building. Operators responded promptly to the emergency, control room decision-making was adequate, and all fire protection alarms and equipment operated as expected. Deficiencies were noted with the fire watch duties and Hot Work Permit implementation. Hot Work Permit MODD15048 had been issued to Modifications personnel on December 1, 1993. The licensee's investigation of this fire revealed that, contrary to the applicable SSP's, all flammable material below or within 35 feet of hot work activities was not removed or adequately protected. And protective measures such as pans, cloth, and such were not in place to catch slag, molten metal, grinding dust, etc. This omission contributed to the fire. The failure to provide adequate fire protection barriers is considered an example of a failure to follow procedure violation (50-327,328/93-54-01) Failure to Provide Required Fire Protection Material.

The team observed control room decision-making and event mitigation during the December 2, 1993, Unit 2 condensate-feedwater transient involving the turbine vents and drains system. Operators noted condensate system pressure swings and heater drain pump motor current swings during normal operation. Subsequently, it was determined that the Number 7 Heater Drain Tank level controller had malfunctioned. Operators responded promptly and immediately began to assess the situation. Overall command and control room actions were adequate. The event lasted approximately one hour. Numerous on-going surveillance instructions (SIs) and Limiting Conditions for Operations (LCOs) were in effect just before the event occurred (e.g., Engineering Safety Function train B outage, AFW surveillance instruction, and control rod drive troubleshooting) which complicated plant conditions, but did not disrupt the operator's ability to diagnose the situation. There was some confusion in control room after Unit 1 personnel moved to Unit 2 to aid in operator response. When the control room became crowed, the SOS cleared all excess personnel from the control room. During the event the team noted poor use of operator repeat backs. At one point during the event control room operators became confused about the status of maintenance actions in the field because telephone communications were not repeated back between personnel in the field and in the control room. During the response to the event, the Shift Technical Advisor (STA) left the control room without informing the SOS. After discussions with the SOS and Operations Department management, this appeared to contradict the intent of the STA's role in the control room.

The team observed control room decision-making and the subsequent post trip review following the December 3, 1993, Unit 2 turbine trip/reactor trip from 100 percent power. After a failure in the voltage regulator system, the turbine and subsequently the reactor, were tripped by a "High Stator Coolant Water Temperature" signal. All safety-related equipment functioned as planned. Operator response was satisfactory. During the transient, operators attempted to take manual control of the base-adjust control to lower generator output voltage. When this attempt was unsuccessful, the turbine and reactor tripped. Some hardware failures also occurred. An erroneous first-out annunciator alarmed, indicating that the main feedwater pumps tripped first. The Stator Coolant Water trip signal also was invalid. Calculations after the event showed that Stator Coolant Water temperature should not have reached the trip point of the switch. Subsequent calibration of the Stator Coolant Water trip switch showed the switch, which had not been calibrated in 12 years, did not trip until temperature was significantly above the trip setpoint. Post trip evaluation by the licensee showed that a power supply transfer had caused the erroneous main feedpump trip signal and that a ground probably caused the Stator Coolant Water temperature trip signal. The team assessed the post-trip review by the licensee and found their evaluation comprehensive and thorough.

Team members observed SE's in the control room providing help with plant system questions. Operators were relying on their expertise to resolve operational problems. Team members found this a benefit both to the operators and the SE's. It was also noted that one SE was in the plant immediately after the reactor trip, walking down his assigned system.

4.6 Communications

Communications between the reactor operators and the ASOS were appropriate and appeared to be adequate; however, compliance with procedural guidance in SSP-12.1, Conduct of Operations, paragraph 3.5.1, "repeat-back," was not always apparent. This was identified during the handling of the above events.

Often communications from the control board operators consisted of: 1) noting a received alarm/annunciator, 2) announcement of the received alarm, (sometimes without checking to see if anyone was receiving the message), 3) control of the alarm and related board operation, and 4) no verification or feedback from the receiver that the message was delivered. At times, this form of communication was not consistent with SSP-12.1, Conduct of Operations, paragraph 3.5.1.A., 3.5.1.C., 3.5.1.F. and 3.5.1.J.

Another example of ineffective communications occurred on December 1, 1993. Unit 2 SSPS Channel 4 experienced indication fluctuations of four minute durations. During troubleshooting of an electronic card in drawer 13 (the Residual Heat Removal (RHR) swapover from the Refueling Water Storage Tank function), maintenance personnel placed the channel in bypass, removed the card and returned the channel to normal status. The channel did not have the card installed for 12 hours. Removal of this card did not cause a loss of protective function and operability was not compromised. However, the operations staff considered the channel to be inoperable for the 12-hour period because of the missing card and because communications between the maintenance and operations personnel failed to clarify how placing the channel back into the normal position affected operability of the system.

During a condensate system transient the team noted that control room operators did not always repeat back telephone messages with field personnel. At one point during the transient, control room personnel were confused about the status of a level control transmitter. Maintenance personnel were working on the controller and control room personnel did not know if maintenance personnel were causing the swinging level controller output.

After further review, the team did note that communication was a scheduled topic in next operator requalification training cycle.

4.7 Turnovers

The team observed shift turnovers for Unit 2 during four days at 100 percent power and during shutdown operations after the turbine/reactor trip. Operator turnovers were approximately one hour in duration and appeared to be through and adequate in detail.

Operations shift turnovers were professional and provided the oncoming shifts with an adequate amount of information. During the observed turnovers, both operator and ASOS walkdowns of the control boards and document/log review by personnel were properly and appropriately performed and according to SSP-12.1, Conduct of Operations, paragraph 3.9.4.

4.8 Compensatory Actions and Work Arounds

The team noted that the licensee had only five formal compensatory actions. This was considered as a positive attribute by the team. Discussions with operations personnel and observations of the Post Restart Plan meetings indicated that there might be some confusion on the definition of compensatory actions. Some believed that compensatory actions were those actions caused by temporary conditions in implementation of the Emergency Operating Procedures, while others believed that they were actions caused by temporary conditions in Final Safety Analysis Report described systems. Nonetheless, the team found the items in the formal compensatory actions items list met both definitions and were appropriately identified and monitored.

Although not formal compensatory actions, the team did note some AUO "work arounds" that might burden or create extra work for the operators.

Some examples of work arounds were:

a. The 250 volt DC electrical board rooms contained no emergency lighting and operators were required to perform contingency actions in these areas during certain events. The licensee's operations policy manual and the emergency contingency action procedures required that operators carry flashlights with them whenever they leave the control room and use them when performing actions in areas where lighting was not adequate. In addition, operators have been instructed to leave the lights on in the battery board rooms to charge the day-glo tape around the breaker cubicles.

b. Operators were required to check temperatures in vital battery rooms twice per shift due to temperatures less than 75 degrees Fahrenheit because of inoperable room heaters and fans.

c. The radiation monitor on the High Crud Tank was inoperable. This condition increased the workload on the operations staff by forcing batch releases versus continuous processing. Batch releases required more operators to accomplish the task.

4.9 Operator Aids

There were a total of 141 operator aids posted in the plant. Of these 49 were for Unit 1, 43 were for Unit 2, and 49 for Common components. According to TVA's tracking system, 26 were designated as valid operator aids, and the rest were for information that would be supplied on drawings, eliminated by design changes or work requests, or eliminated by a procedure change. Five of the outstanding WRs were generated in 1990, 28 in 1991, 36 in 1992, and 72 in 1993.

After evaluating the program, the team found that some problems existed:

The feedback mechanism that would remove an operator aid once it has been incorporated into a procedure or a WR needed improvement. Some outdated operator aids still existed in the plant. Also, several operator aids were assigned to the Department of Nuclear Engineering (DNE) for resolution, but no apparent mechanism existed to track their resolution through DNE, nor to supply the name of the individual assigned responsibility for its resolution in DNE to the operations person assigned responsibility for the Operator Aids Program.

The quarterly review procedure (Operator Aids, 0-PI-OPS-000-028.0) required that if an operator aid was greater than 90 days old, the operator performing the review was to determine why the problem has not been corrected. Operations personnel could not show the team documentation that the determination had ever been made for any of the operator aids, although some had been in effect since 1990.

4.10 Configuration Control

The team found a weakness associated with configuration control management because of a problem with the ability to quickly account for all of the clearances (including interfacing systems) which could affect a particular plant system. This contributed to the October 2, 1993, reactor coolant drain tank (RCDT) event, discussed below.

Before the operations control center (OCC) ASOS can give approval to start work, he/she and the Unit ASOS/SRO have to verify that no clearances contained in the OCC's clearance index log could affect work scheduled to be performed. Since the clearance index is not "indexed" by system but by clearance number this becomes a tedious task. This method was not computerized and was performed by hand. Chance for error can be high during outages because the number of entries in the clearance index log can be several hundred or more. PER #SQ930586 discusses an event that occurred on October 2, 1993. A Unit 2 ASOS prepared a clearance to work on Boric Acid Valve 2-62-945, in preparation to pump down the RCDT to support Surveillance Instruction (SI) OPS-068-137.0. The clearance for Boric Acid Valve 2-62-945 was prepared using the boric acid system and other interfacing system drawings. An independent review was performed by another ASOS who also used those drawings. The clearance under which the valve was tagged was listed as system 62 (boric acid system). The clearance index was checked for all known clearances against this work. However, one of several RCDT interfacing systems (waste disposal system 77) was not checked for clearances because this system was not normally thought of as an "interfacing system" which needed to be checked. Consequently, a tagged boundary valve interfacing between this system and the boric acid system (waste disposal valve 2-62-949, which was also shown on the P&ID as in the incorrect valve position) prevented operations from pumping down the RCDT. A system walkdown by an AUO later identified the problem. This error had the potential to cause RCDT pump damage and other problems, although none occurred.

On December 2, 1993, the team was made aware of a potential containment breach of a Unit 2 AFW penetration while the unit was at power. Specifically, the licensee identified, through their II process in resolving PER #SQ930686, that an unknown valve configuration involving vent valves inside and outside containment may exist. The licensee proposed that the issue be treated as a missed TS SI 4.6.1.1 and that they verify compliance within the 24 hours allowed by TS 4.0.3. On December 3, 1993, after modifying the SI procedure to include verifying the status of the three unknown vent valves, the licensee made a containment entry (at power) and verified proper configuration of the penetration. Additionally, since the penetration in question is not normally used, the licensee locked shut the inside isolation valve and exited the 24 hour LCO.

The team reviewed the documentation associated with the AFW penetration to determine the root cause of this situation. The team found that during the licensee's response to a backlogged drawing deficiency (#93DD6872) for Unit 1, on October 1, 1993, a walkdown of Unit 1 and 2, conducted to determine the generic applicability of a deficiency, failed to identify that the Unit 2 penetration contained a vent valve. The team's discussion with the personnel involved with the October 1, 1993, walkdown revealed that the Unit 2 vent valve arrangement was missed for two reasons: (1) Personnel performing the walkdown did not get close enough to the valve to perform a detailed inspection and (2) the vent valve configuration was different from Unit 1 (it appeared to be a simple angle valve). The original design basis document (DBD) walkdowns, performed in 1986 and 1987, to reconcile the as-built plant to the design basis, that provided the original opportunity to identify and correct this failure, was not effective.

4.10.1 Components and Tests

Procedure SSP 12.2, System and Equipment Status Control, Revision 8, Section 6.0, Method of Test Awareness, describes the "test awareness log" and how it is used to aid in determining plant configuration. Section 6.1.D, requires that test awareness be maintained for all SI's, Test Instructions, Refueling Test Instructions, Special Maintenance Instructions, Maintenance Instructions, Special Test Instructions, Modifications Tests, and tests for WRs (unless specific exceptions are made by the operations superintendent). A review of the test awareness log showed that numerous Operations-performed SIs were not recorded in the log. One specific Operations Department SI, the Unit 2 AFW SI-276, Automatic Continuous Valve Stroke Operability Test, performed on December 2, 1993, was not recorded in the test awareness log. Discussions with the Operations Control Center personnel revealed that Operations-based surveillances are not recorded in this log because they were recorded in the shift logs (the UO logs). The team was told that a verbal exemption was the basis for not entering the SIs into the test awareness log. However, this practice appeared to conflict with the intent of SSP 12.2.

On December 2, 1993, an operator discovered a Unit 2 Main Steam Isolation Valve (MSIV) control switch in the "test" position. Procedures require the control switch (Unit 2, 1-29B) be in the "normal" position. While this condition did not pose any operability concern, the switch was not in the proper position.

One operator aid that was used to remind the operators when important equipment is out of service for maintenance was found inconsistently installed. During maintenance on the 2B-B Emergency Diesel Generator (EDG), the "DO NOT INOP" tags used as reminder for the other plant diesel generators were found hung on the incorrect handswitches to accomplish the desired effect. The tags were hung on the MODE TRANSFER switches rather than the START/STOP switches. The licensee stated that they were placed on these switches to prevent confusion by operators in placing the tags on the START/STOP switch. However, the team found that the tags were placed inconsistently because at least one was found on a START/STOP switch.

4.10.2 Equipment Clearances

On November 30, 1993, a clearance was prepared and issued for Control and Auxiliary (C&A) Ventilation Board "1B2-B" (Clearance #1-93-2021). This was done in order to de-energize the panel for inspection, cleaning, and repair of the "Arrow-Hart" breaker contacts. The following activities were observed and reviewed:

a. The clearance was prepared and issued in accordance with plant procedure SSP-12.3, Equipment Clearance Procedure.

b. The breakers to be opened and fuses to be pulled were clearly and accurately identified and presented on approved clearance forms.

c. The clearance was adequately reviewed and hold tags were properly prepared and attached according to SSP-12.3.

d. An independent verification of tag attachment and proper identification of equipment "tagged" was adequately performed and placed according to SSP-12.3.

e. Labeling on one of the cubicles - the "Test Block In Instrument Shop" breaker cubicle(#4B2) - was not correct for the current system design. While originally supplying power to the shop, this breaker no longer supplied shop power and was considered as a "spare." This breaker was also noted as a "spare" on plant drawing #45N756-7.

f. The revision of the clearance procedure form used (Revision 4) for this clearance was superseded by a new revision (Revision 5) on November 22, 1993. However, this proved to be of no technical significance since Revision 5 incorporated wording changes only.

g. During observation of the work under this clearance, the team observed electricians working without proper safety equipment. Floormatts were not always used and some technicians worked without safety glasses.

h. On December 1, 1993, a clearance was also prepared/issued for C&A Ventilation Board "1A2-A" (Clearance #1-93-2025). As with the above clearance, this activity was performed to deenergize the panel for inspection, cleaning and repair of the "Arrow-Hart" breaker contacts. The following licensee preparation/issuance activities were observed and reviewed:

i. The clearance was prepared/issued according to Revision 5 of SSP-12.3. The breakers to be opened and fuses to be pulled were clearly and accurately identified and presented on approved clearance forms. The clearance was adequately reviewed and tags were properly prepared and attached according to SSP-12.3.

j. Independent verification of tags attachment and proper/appropriate identification of equipment "tagged" were adequately performed. Tagging was done in accordance with approved plant procedures. Labeling on the cubicles of this board was accurate and similar to drawing specifications.

k. As a mechanism for configuration control, the preparer listed panel breakers, that were not to be tagged, at the end of the form. This was an added benefit to those reading the clearance.

4.10.3 Operations Control Center

The OCC main function was to reduce the number of personnel that enter the control room area, have sole responsibility for tracking fire protection LCOs and coordinate the work flow in and out of the control room. This function has been in effect for about 18 months and appeared to be a major improvement over past operations. The OCC can be covered by a licensed SRO (ASOS) and is frequently staffed by a ASOS/STA individual. The main tool the OCC manager utilizes has been the Technical Specification Component Condition Record (TSCCR) and operations group test awareness log sheets.

However, the team did note some weaknesses in the OCC operation:

Utilization of the OCC computer databases was inefficient with noted limitations. The database was organized by using LCO tracking (or TSCCR) number, instead of using component or system number. Components and system numbers would help to accurately monitor the TS status of equipment. The database can potentially be sorted under a particular system "train" field, but this was also a problem. For example, the prime computer database which contains the TSCCR database (LCO tracking) could sort TSCCRs by train but this sort function has been rendered ineffective because ASOSs are not entering data into this field. On screen computing cannot be performed without having to print the entire sort.

The licensee has plans to transition to a fully computerized configuration control system. The computer software has been available and data is being loaded to provide the capability of displaying configuration control of systems and components, and clearances. The process is expected to be of great benefit.

4.11 Procedures

A walkdown using the Total Loss of AC Power Emergency Contingency Action procedure (ECA-0.0) and related procedures dealing with specific operator actions were reviewed. This procedure would be entered from the Reactor Trip or the Safety Injection Procedure (E-0). It was determined that the procedure was satisfactory to perform the desired actions for safe shutdown of the plant with no AC power available. Three steps where clarifications should be considered were found. In addition, the procedure contains steps for manually feeding the steam generators, but did not direct to feed the Number 1 steam generator first, which would seem to be desirable since it is the steam supply for the steam driven AFW. It was also noted that extra copies of procedures that were given to AUOs to perform various actions were not available in the main control room. These concerns were discussed with Operation's Department management and would be taken into consideration.

There were approximately 57 System Operating Instructions that were not yet upgraded to the new procedure format that more clearly separates procedure steps into Unit-specific steps. The licensee's goal was to have the process completed by the end of calendar year 1994. Operators and management have recognized this as a very desirable change.

4.12 Training

At least one day during the requalification cycle for each crew was devoted to simulator exercises with only one UO at the panels. This was done in an effort to provide training and experience should the situation develop during unit operation. There were no plans to change the commitment to have less than the normal complement of two UOs per shift on each unit. The team viewed this training as very beneficial.

The team observed a crew consisting of training staff personnel performing their annual requalification exam scenario on the SQN simulator. The scenario progressed from a feedwater line leak to an Anticipated Transient Without Scram (ATWS). The crew consisted of an SOS, ASOS, 2 UOs, and an STA. Five other training personnel, and the Operations Department Superintendent observed and graded the examination. The crew responded to all events in a professional and complete manner. All expected actions in response to the alarms and indications were as expected, in accordance with the scenario evaluation guide. Communications were clear, purposeful, and complete. The crew kept each other informed of actions, and used repeat-backs. The evaluators were thorough in their evaluation of the crew, and were satisfied with the crew performance on the scenario.

SRO equivalency training will be conducted for managers by a vendor with technical support from the SQN Training staff. There were six participants scheduled for the training, including the Plant Manager and the Operations Manager. Training was scheduled to be conducted for 11 weeks and will include control room and simulator training. Courses in thermodynamics, reactor theory, plant systems, emergency systems, electrical systems, spent fuel handling, technical specifications, plant operation, and specific normal operating and emergency procedures will be conducted. The course has been extended due to the need for the trainees to perform their normal job functions and is scheduled to run from December 6, 1993, to March 25, 1994.

5.0 MAINTENANCE (IP 62700)

5.1 Objective and Conclusion

The team's objective was to evaluate the effectiveness of maintenance functions in accomplishing maintenance in a prioritized and timely manner. Observations of logistics, material and personnel support, and coordination of operations clearances were included.

Overall the team concluded that maintenance remains satisfactory. In the field activities observed by the team, maintenance personnel were properly performing their tasks, using procedures, proper tools, and that field supervision was present. Nevertheless, the team determined that the planning and scheduling (PS) function has several problems. Further, the team concluded that the department recognizes those problems and with further implementation of the SIP most of the deficiencies should be resolved. Also, the team noted several problems in the use and control of vendor manual drawings.

SQN had previously identified weaknesses in the maintenance and PS areas, identified corrective actions for these problems, and documented the actions in the SIP. The team found examples of continuing performance weaknesses. Continuing problems with the operation of Unit 2 was challenging the organizations' ability to implement these corrective actions as scheduled. QA's performance evaluation was an excellent initiative. SQN's LCO maintenance program was also a good effort.

Continuing Unit 2 problems were challenging maintenance resources. Maintenance management recognized the challenge to their resource requirements and had, or was in the process of, obtaining additional personnel to work on lower priority efforts (backlog reduction and Unit 1 restart).

5.1.1 Backlog Reduction

At the time of the inspection, SQN had approximately 2,700 non-outage corrective maintenance requests in their backlog. SQN prioritized these work requests based on nuclear safety significance and impact on plant reliability (Priority 1 and 2 as the most significant). The team reviewed the maintenance backlog for the Unit 2 component cooling water and the Unit 2 shutdown boards. SQN had appropriately prioritized the backlog according to SSP-6.21, Initiation of Work Requests.

The team found that the licensee was successfully managing the backlog of high priority maintenance activities. There was essentially no backlog of Priority 1 and 2 maintenance orders. However, continuing Unit 2 problems were challenging maintenance resources concerning the reduction of low priority non-outage work orders. For example, following the December 3, 1993, Unit 2 trip, all of the electrical maintenance resources were directed toward the troubleshooting and repair of main generator problems and were not available to low priority backlog reduction. Maintenance management recognized this, and had or was in the process of obtaining additional personnel to work on lower priority efforts (backlog reduction and Unit 1 restart). Maintenance management was actively monitoring progress on backlog reduction and had a documented business plan in place for backlog reduction and other SIP activities.

5.1.2 Maintenance Performance Indicators

In October 1993, Maintenance published a report of monthly performance indicators. The team found this to be an excellent initiative. However, the team noted that many performance indicators had no input data. The formats were established but the data was not yet collected. Managers stated that data gathering for those indicators was in progress and would be included in future monthly reports.

The team observed that rework was not clearly defined or tracked. Maintenance managers monitored machinery history and considered rework as repeated corrective maintenance on a component within 18 months. However, they did not consider maintenance in response to failed post maintenance testing as rework.

5.2 Maintenance Observations

The team observed several maintenance activities during the inspection period. The observed performance of ongoing maintenance activities was satisfactory. Maintenance personnel accurately followed their work instructions. The work instructions were appropriately detailed. Maintenance personnel ensured all required tools and replacement parts were at the job site before work began. The inspectors observed both foremen and general foremen at the job sites supervising work activities.

5.2.1 Scaffolding

SQN's scaffolding program was not adequately implemented. The team identified two scaffolds that were not erected according to program requirements. SQN had restrained one scaffold by attaching the scaffold to a Unit 2 safety injection pump cooling water line. Step 5.5 of SSP-7.55, Criteria for the Erection of Scaffolds and Ladders including those in Seismically Qualified Structures, prohibited using the cooling water line as a scaffold attachment point. In another instance the team observed an unrestrained scaffold located adjacent to a Unit 1 safety injection pump. Step 5.3 of SSP-7.55 required that the scaffold be restrained. The failure to follow the requirements of SSP-7.55 is an example of a failure to follow procedure violation (50-327,328/93-54-01) Failure to Properly Erect Scaffolding in Safety Related Areas.

5.2.2 Housekeeping

Unit 2 housekeeping was generally good. The team noted a layer of dirt on horizontal surfaces in the EDG rooms. Housekeeping in Unit 1 was satisfactory. The team found Unit 1 lower containment housekeeping weak. The inspectors observed significant quantities of debris on the containment floor (pieces of tape, plastic, ball pens, and tie wraps). The team also found many tools left in areas where no work was in progress. Housekeeping in some Unit 1 auxiliary building contaminated work areas was weak. Dirt, debris, tools and trash cluttered the floors in these areas. The team also observed inadequate foreign material exclusion barriers in use for the Unit 1 turbine driven auxiliary feed water pump under maintenance. A cotton glove was being used to block the opening for the outboard bearing oil temperature instrument and openings in the turbine casing were not completely blocked.

5.3 Planning and Scheduling

In September 1993, the licensee reorganized the site's PS functions into a single department. This was done, in part, to correct previously identified weakness in this area. The team found, however, that some of these weaknesses continued.

5.3.1 Backlog Reduction

At the time of inspection, approximately 700 non-outage work orders were ready to be worked. However, PS had not scheduled most of these activities. Scheduling for non-outage work was limited to two weeks. This prevented effective long-term planning of resources for low priority corrective maintenance and contributed to the maintenance backlog. Scheduling accuracy was low. On average, only 68 percent of the maintenance activities were performed as scheduled. SQN intended to implement a rolling quarterly maintenance schedule in early 1994 to correct this weakness. This schedule should help alleviate the short two-week window for scheduling.

Approximately 2,000 work requests required planning. When the team inspected this item, planning did not have a tool in place to judge if efforts to plan the backlog would meet site goals for backlog reduction. PS management was in the process of increasing their staff to ensure this backlog would be reduced according to site goals.

PS management maintained a forced outage work schedule. However, the team identified that only 70 percent of the work on the schedule was planned.

5.3.2 Performance Indicators

The team found that the PS organization was monitoring progress on reducing PS backlogs and SIP activities. However, planning management lacked some tools to monitor performance. As described above, planning was not monitoring the planning backlog. In addition, replanning due to planning errors was not monitored.

5.3.3 Communications

The licensee conducted several different meetings to coordinate maintenance activities, including daily scheduling meetings between maintenance, planners, schedulers, procurement, operations and engineering. The team noted some problems in this area.

The Foreman's Preliminary Freeze Meeting scheduled for December 3, 1993, did not occur due to the lack of planners at the meeting. Planned scheduling meetings regarding the forced outage schedule have been cancelled due to resource demands to support Unit 2 operation. There were no planning meetings during the inspection.

5.3.4 Technical Specification Related Maintenance

SQN's LCO maintenance program was a good initiative. SSP-7.1, Work Control, contained the requirements for the program. The program had good controls to minimize the time in which an LCO action statement was voluntarily entered to perform planned maintenance. The program required that several activities be completed before a TS required component was removed from service. It included pre-staging of parts and tools, system pre-maintenance walkdowns, preparation of applicable tagouts and radiation work permits, and scaffold erection. The program also required that planned LCO maintenance that would exceed 60 percent of the allowable outage time be pre-approved by plant management. The team noted that probabilistic risk assessments (PRA) insights were not utilized in determining risk of performing planned maintenance. The personnel who administer the program lacked PRA training.

5.3.5 Work Package Quality

The team found problems with some work packages. These problems are documented below.

The team observed that some work packages lacked the specification of foreign material exclusion (FME) control requirements as required by SSP 6.22 Planning Work Orders. For example, the work order (WO 93-00855-00) to replace the DC fuel oil priming pump on the 2B EDG did not contain any FME control requirements although the fuel oil system was opened to atmosphere. PS management stated that they had only recently implemented FME control requirements (April 1, 1993) and the work packages of concern were prepared before this date. They had not conducted a review of work packages prepared before April 1993 to add applicable FME requirements. This was a weakness.

A gasket (Garlock) previously installed on the 2B EDG lube oil cooler was not the gasket called out in a preventive maintenance (PM) procedure. PM 041552000 had been revised in 1992 to require the use of a red rubber gasket. However, the applicable vendor manual specified an asbestos gasket. Maintenance personnel could not provide the team with an engineering evaluation that had approved the use of the red rubber gasket. The licensee subsequently performed an operability evaluation that found the red rubber and Garlock gaskets were acceptable.

An SSPS (Eagle 21) repair WO (WO# 93-10793-00) identified three channel check procedures to be performed in no specific order. It suggested that the channel checks should be performed in parallel. This lead to confusion and contributed to placing all the channels out of the bypassed condition.

The team noted that planners had incorrectly annotated several work packages with regard to whether the planned maintenance involved entering a TS LCO action statement. SSP-6.22 required that planners enter applicable TS requirements into work packages. Discussions with planning supervisors indicated that they rely on Operations to correctly evaluate whether there was LCO applicability. The team noted that Operations had correctly identified applicable LCOs for each of the affected work activities. SSP-6.22 stated that planners should assess the job, preferably by visual inspection. The team found that planing had not visually assessed any of the work observed during the inspection.

5.4 Self Assessment

Neither the Maintenance Department nor the PS organization conducted routine self assessments of performance. The team found that SQN's QA group was performing this function. As noted above, the team reviewed QA's Maintenance Performance Evaluation Reports and the most recent QA maintenance audit (SQA93308). Particularly noteworthy was the maintenance performance evaluation. The purpose of the effort was to provide feedback to management concerning the "real time" performance of maintenance. The process involved a graded initial four-month evaluation of maintenance activities to provide a baseline of performance. This process was then repeated on 90 day intervals to monitor improvements and declines in performance. The team found this process was successful in monitoring performance. As a result of this process, maintenance and PS have developed formal corrective actions to improve performance. The most recent evaluation showed an improving trend in maintenance performance.

5.5 Use and Control of Vendor Manuals and Drawings

The QA Audit (93308) also noted problems with the incorrect use of vendor drawings. Use and control of vendor manuals and drawings has been a longstanding problem at SQN. NRC Generic Letter (GL) 83-28, "Vendor Interface for Safety-related Components," first addressed weaknesses between vendor interfaces and licensees in 1983. In 1987-88, the licensee hired a contractor to perform the initial assembly of vendor manuals on-site. These manuals were then reviewed by site engineering to identify needed changes. Many deficiencies were identified resulting in an overwhelming backlog. As of November 29, 1993, over 1,300 items affecting 471 safety-related vendor manuals needed addressed. At least three events have occurred since November 1993 involving vendor manual errors or procedural non-compliance problems. Event summaries for the three events are discussed below.

An electronic card in the Unit 2 Number 3 turbine governor valve electrohydraulic control (EHC) controller has failed on at least two occasions in the past. The first failure occurred November 29, 1993, and the card was replaced with a card of a different design (a Westinghouse-modified design). The card replacement work was performed under SSP 2.8, Drawing Control and SSP 2.10, Vendor Manual Control. Specifically, SSP 2.8 required that before using non-verified vendor drawings, the user shall determine if the component design information existed in other documentation that contained the needed information. If this information could not be verified by the user, then the drawing must be reviewed and evaluated by engineering prior to work being performed. This was not done prior to card replacement after the November 29, 1993, failure and was later identified by the licensee after the team expressed concern over vendor manual control. This is identified as an example of a failure to follow procedures violation (50-327,328/93-54-01) Failure to Properly Verify Vendor Drawings During Maintenance Activities.

A second example occurred on November 17, 1993, when the Unit 2 reactor coolant system (RCS) charging header air-operated flow control valve (2-FCV-62-93) failed to close on demand. The licensee's evaluation determined that the approved safety-related vendor manual contained information that the valve and valve operator were both manufactured by Masoneilan, when the valve operator was a Copes-Vulcan operator. The vendor manual had specified a Masoneilan regulator setting of 30 psig that was incorrect for the Copes-Vulcan operator. The engineering review (as required by SSP 2.10) of the vendor manual failed to identify this problem. Discussions with the Vendor Control Manual Manager revealed that, prior to 1991, calibration cards were used instead of vendor manuals to perform work. There was a high assurance that the instructions on the calibration cards were correct. Since the vendor manual was not routinely used, this problem went unnoticed until one month before the November 17, 1993, event. This problem was first identified during the performance of calibration on the same valve in Unit 1, although the pressure was sufficient for the Unit 1 valve. However, the instrument data package (IDP) [illegible] placed on hold because the pressure was found sufficient on the Unit 1 valve and no Unit 2 action was considered necessary. Subsequently, work was performed on Unit 2 with the erroneous IDP resulting in miscalibration.

The final example occurred on December 4, 1993, when a vendor performed troubleshooting activities on the voltage regulator for main generator using potentially unapproved vendor drawings. Refer to paragraph 5.7 of this report for more details.

5.6 Identification of Check Valve Failure

The licensee had discovered that the check valves associated with the thermal barrier heat exchangers in the Component Cooling System (CCS) had exhibited common cause failures in both units. The SQN plant uses two check valves in series upstream of each reactor coolant pump (RCP) thermal barrier heat exchanger. There are four thermal barrier heat exchangers (one associated with each RCP). These check valves form the boundary between piping runs rated at 2485 psig and piping rated at 150 psig. The safety function of these valves is to protect the low pressure portions of the CCS in the event of a rupture of the thermal barrier heat exchangers. These valves had not been previously tested by the licensee. The issue was first identified in June of 1993, as a result of a Watts Bar Nuclear (WBN) plant PER #930166, which was issued as a result of NRC Information Notice 89-54, "Potential Overpressurization of the Component Cooling Water System."

The issue at WBN was a result of the licensee's failure to meet ASME Section III requirements by not having a relief valve in the low pressure piping inside the reactor containment to accommodate high pressure leakage from a postulated thermal barrier leak past the thermal barrier check valves. SQN evaluated the WBN PER and determined that the issue was not applicable at SQN due to the fact that SQN was not an ASME Section III plant (SQN is an ANSI B31 plant).

However, during prestartup reviews, the inspectors questioned the adequacy of the licensee's evaluation on the basis that even though the subject valves and piping were not subject to ASME code requirements, the check valves performed an important safety function in preventing postulated thermal barrier leakage from potentially overpressurizing the low pressure piping both inside and outside of the containment. The licensee agreed to test the valves at the next available opportunity.

On November 13, 1993, a radiographic inspection of all Unit 1 check valves was performed (Unit 1 was in Mode 5 at the time). The results of the inspection indicated that seven out of the eight valves were stuck open and that the eighth valve had a piston installed upside down. The valves in question were Hancock #7440 lift check valves.

As a result of the findings associated with the Unit 1 check valves, the licensee elected to perform a shutdown of Unit 2 (which was operating at 100% power at the time) and inspect the valves on that unit. It was found that seven out of eight valves were also stuck open on Unit 2. As a result of these failures, the licensee conducted a formal root cause and incident investigation of the event. It was determined that the root cause of the check valve failures was oxide wedging of the piston against the bonnet caused by corrosion product buildup in the area between the piston and bonnet. The contributing causes to the corrosion buildup were identified to be previously poor water chemistry in the CCS due to significant Essential Raw Cooling Water (ERCW) inleakage and a failure to periodically cycle the valves to verify their operability.

The licensee's immediate corrective actions included the disassembly and refurbishment of the Unit 2 check valves. Additionally, the extent of the condition was evaluated to determine whether other valves in the plant would be susceptible to the same failure mechanism. The current configuration at the plant does not lend itself to any meaningful testing of the valves, as would be performed on similar valves in an ASME Section XI program. The licensee's Section XI program had not included these valves for testing; however, an "augmented testing" program had identified these valves as candidates for possible future testing or inspection. This augmented program was being developed in response to NRC Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs." The guidance in GL 89-04, states, in part, that even though components may not meet the specifications of ASME code class 1, 2 and 3, testing programs should test any such components in accordance with their safety significance. The licensee had recognized the intent of this guidance and had developed a list of components to be evaluated for potential testing under the augmented program in their upcoming 10 year inservice inspection (ISI) interval.

The long term corrective actions for the check valves had not been finalized at the time of the inspection. The licensee had been considering several alternatives that included system modifications. The licensee's incident evaluation had concluded that the Unit 2 check valves would be operable for the remainder of the operating cycle due to the refurbishment that was performed and the fact the water chemistry control had been adequate since 1991. Additionally, other check valves in the system had been inspected 11 months previously and were not found to exhibit similar corrosion. These valves were reinspected as a result of this event, and verified to be operable. These observations were used a basis for justifying that significant corrosion product buildup would not occur in the current operational environment for at least an 11-month interval.

The licensee had requested that Westinghouse perform a PRA of this event in an attempt to evaluate the overall safety significance. The Westinghouse evaluation concluded that the overall safety significance was relatively low due to the fact that the catastrophic failure of the RCP thermal barrier heat exchangers was a very low probability event. Additionally, the Westinghouse evaluation took considerable analytical credit for another check valve in the common supply piping to the thermal barrier heat exchangers. This particular check valve, and the associated piping was rated at 150 psig. The licensee had conducted engineering evaluations that concluded that the low pressure piping and check valve can withstand reactor coolant pressure without catastrophic failure. Thus, the Westinghouse PRA used generic failure rates for these components even though the equipment in consideration was postulated to be under demand in conditions significantly outside the operational conditions to which it is normally subjected. Notwithstanding the analytical analyses performed by both Westinghouse and the licensee, this event was considered significant due to the potential for RCS leakage outside of containment as well as the implications associated with not testing equipment that might be necessary to mitigate such an event.

5.7 Voltage Regulator/Exciter Troubleshooting

On December 3, 1993, a turbine trip followed by reactor trip occurred. This trip was preceded by fluctuations in the generator excitation system. The licensee initially thought the root cause was emanating from the voltage regulator.

During a plant walkdown on December 4, 1993, the team observed TVA and Westinghouse personnel troubleshooting the Unit 2 voltage regulator. The troubleshooting did not appear to be preplanned and the team observed the vendor using uncontrolled vendor drawing to test the voltage regulator circuit. The work was being performed under an existing WR (C-207880) dated October 28, 1993, with Contracted Personnel Interface forms and other standard forms repeated for the December 4, 1993, troubleshooting. Since the licensee had experienced a number of problems in the voltage regulation system following the March 1993 trip, they determined a more thorough root cause analysis was required. The licensee developed a plan to identify all equipment and interfaces with voltage regulation using a freebody analysis that included all of the voltage regulator internal components as well as all external equipment interfacing with the regulator. A Westinghouse/TVA team was assembled to evaluate the overall test plan and review the test results. On December 5, 1993, another Westinghouse consultant was brought in to conduct a Kepner Tregoe (KT) analysis to determine the thoroughness of the TVA evaluation process. The KT analysis has determined that the facility evaluation process was satisfactory. On December 8, 1993, another TVA contractor (an electrical systems expert) was brought in from Browns Ferry to review the KT and the facility's root cause analysis determination. That consultant and the Westinghouse consultants have come to the same conclusions as the licensee regarding the root cause.

The licensee had hypothesized that during tne March extraction steam rupture event when steam entered the voltage regulator, an over-excitation of the exciter occurred. A high current resulted that caused exciter temperatures to become elevated. Consequently, this caused degradation of the exciter field windings.

On December 8, 1993, the licensee conducted a visual inspection inside the exciter and they discovered multiple potential grounds in the field windings. This was actually determined to be partly due to inadequate re-insulation following an exciter overhaul. These grounds, which caused degradation of the exciter, caused perturbations in the voltage regulator that caused the latest transient.

The team has concluded that this detailed analytical approach to resolving this problem has strengthened the technical staff's ability to approach, resolve and mitigate similar events in the future. The team identified this approach, for conducting root cause analysis, as a strength.

6.0 POST RESTART PLAN AND UNIT 1 RESTART (IP 93802)

6.1 Objectives and Conclusions

The team reviewed the implementation and status of the Post Restart Plan (Plan) as described with scheduled performance dates in the SIP. Additionally, the team verified that Unit 2 post restart work designated as "priority" was scheduled for performance. The Unit 2 "priority" work was included in the Master Items List (MIL) included in the SIP. The Plan was a management tool at SQN to focus resources on activities to improve plant performance. The improvement activities designated in the Plan were to be initiated following plant restart that occurred on Unit 2 on October 11, 1993. The Plan applied to both Unit 2 and Unit 1. Management oversight and involvement in station activities were considered key improvement strategies. These were implemented by daily and weekly management/staff meetings observed by the team.

6.2 Plan Content

Specific Plan actions were listed in the SIP. The SIP provided a schedule of action item start and completion dates for approximately 280 items divided into four categories. The category AA items were identified as backlog issues reflecting outstanding work such as WR/WOs, and drawing deviations. Also in this category were items that reflected current performance levels or status rather than a backlog, such as delinquent Preventive Maintenance items (PM's). Category BB items were BOP improvements primarily consisting of design changes. Category CC included actions to improve management and people effectiveness. Category DD items included actions to improve procedures and programs. The original Plan was approved by the site vice president on August 20, 1993.

6.3 Plan Changes

The team reviewed a SIP schedule dated November 23, 1993, which incorporated changes to the original SIP. The revised SIP contained more action items (295 as opposed to 280). Additionally, there were 28 schedule changes on existing action items. The majority of the changes delayed the start date for an action item from one to six months. In ten cases the scheduled completion date was extended in proportion to the start date change. The SIP coordinator indicated that the original SIP schedule was based on Unit 2 continuous operation and Unit 1 restart by the end of November 1993. On this basis, more resources would have been engaged in SIP activities than has been available due to Unit 2 transients and Unit 1 restart delays. In particular, diversion of resources to Unit 2 support has impacted the projected SIP schedule. Overall, the team concluded that the changes to the Plan, as demonstrated by SIP schedule changes, did not represent a significant deviation from the intent of the original August 20, 1993 Plan.

6.4 Management Involvement

The team reviewed management involvement in the SIP through interviews with management and observation of management meetings in the operations, maintenance and engineering organizations. The operations manager was designated as primary action owner for 36 SIP items. Those items were assigned to secondary action owners and were reviewed weekly. Operations managers were aware of their responsibilities in the Plan and were monitoring those items.

The maintenance manager was designated as primary action owner for 17 SIP items. Secondary action owners were assigned and action plans were developed to address SIP items. The manager was aware of the status of assigned items and action plans were developed for action items. The manager had allocated resources specifically to address backlog WR/WOs, determined opportunities to assign additional resources based on station demands, and was evaluating the WR/WO backlog content to facilitate planning of work accomplishment.

The engineering manager was designated primary action owner for approximately 65 SIP items. Secondary action owners were assigned and action plans were developed to address backlog items. The backlog items in engineering were assigned to contractor engineering groups. In particular, drawing deviations and upgrades that represented a large volume of engineering work were being addressed by contractor groups.

Discussions with engineering management demonstrated that the manager was aware of the status of assigned SIP items.

The team observed a monthly SMART meeting on December 8, 1993, which specifically addressed progress on SIP category AA (backlog) items. The site vice president and plant manager reviewed the status of each backlog/performance indicator item with the primary action owners. The status of AA items was documented on the November 1993 SIP monthly report. In cases where the backlog item did not meet its projected goals (e.g., WR/WOs, drawing deviations), the action owner was required to develop an action plan to improve performance. Management also addressed establishing a consistent definition for operator aids and compensatory actions that were trended by Operations. Although the SMART meeting thoroughly addressed category AA (backlog) items, the team noted that management did not address the status of other category SIP items.

Overall, management involvement in the SIP category AA backlog items was good as demonstrated by review of plant documentation and observation of staff meetings. The management meetings demonstrated that all levels of site management were focussed on the Plan and that the Plan represented a major station priority. Management focus on the progress of category BB, CC, and DD items could be improved, however.

6.5 Monitoring of Plan Progress

The team reviewed implementation of the licensee's process for monitoring SIP action items' progress. The Technical Support Manager was designated as the SIP coordinator. Business Practice (BP) 315, Maintenance of Site Improvement Plan, Revision 0, provided the process for use, revision, distribution, and status reporting of the SIP. The coordinator compiled a monthly SIP status report that provided the status of the 50 category AA (backlog) items using trend curves. A matrix in the report identified the trend of each backlog or performance indicator item. A negative trend indicated that the performance on that item did not meet its projected goal. The team reviewed the November monthly report and noted that thirteen items were identified by negative trends. These items were addressed in the SMART meeting previously discussed.

The most significant negative trends were in WR/WOs, drawing deviations and drawing upgrades. There were 2,684 open WR/WOs; the goal for November was approximately 2,000. There were 587 drawing deviations; the November goal was 240. There were 3,837 outstanding category 3 to category 2 drawing upgrades; the November goal was 2,800.

Although the licensee's monitoring of category AA SIP action items was good, the team noted that the monitoring of non-category AA items could be improved. The remaining category items had start and completion schedule dates but no intermediate milestones dates to facilitate management assessment of action item progress. For example, item CC-513 to complete the system engineer qualification program listed a start date of October 1, 1993, and completion date of April 17, 1995, however, it contained no intermediate milestones. Item DD 13-506, to develop a plan and implementation schedule for maximizing use of non-intrusive check valve testing to fulfill ASME Section XI requirements, lacked intermediate milestones. This action item was scheduled for October 1, 1994, through May 1995. Additionally, the team noted that the monthly report did not address the status of non-category AA items.

6.6 Plan Progress

The team reviewed the status of SIP action items and concluded that progress on the Plan was adequate. A SIP completion list dated December 3, 1993, listed the items that were completed. Approximately 50 items had been completed on schedule or several weeks earlier than scheduled. Most of the completed actions were to accomplish process and program evaluations or revisions. Others included development of the Plan and approval of the 1994 fiscal year budget. One category AA backlog item was completed that required elimination of old unverified assumptions in calculations. Although the completed items did not indicate the magnitude of resources of the remaining items, the timely schedule completions indicated a licensee commitment to meet their established goals. The team verified that scheduled action start dates for ongoing SIP items were initiated as scheduled. At the date of this inspection, the schedules for November 23, 1993, were met.

The licensee indicated that the Unit 2 operational transients have impacted progress on reduction of backlogs. Resources have been diverted from maintenance, operations, and engineering to address several equipment failures and plant transients that have occurred since Unit 2 restart in October 1993. The licensee has taken action to maintain performance on the Plan. Maintenance had developed action plans to assign more maintenance crews to backlog work as future plant opportunity windows develop. Operations was training approximately 15 TVA personnel from other sites to assist in backlog work. Engineering management indicated that the goals for drawing backlogs assumed less manhours per drawing issue than were actually required in resolving individual drawing items. Engineering was developing a funding proposal for more contractors to address the drawing backlogs.

6.7 Conclusion

The team concluded that the implementation of the Plan was adequate based on the early implementation stage and the impact from Unit 2 operational transients. Changes made to the original SIP schedule were not significant. The November 23, 1993, SIP scheduled action items were met. Responsibility and accountability for action items were assigned. Monitoring and management focus on backlog issues was good, however, monitoring and focus on non backlog SIP issues could be improved. In particular, intermediate milestones for long term action items needed to be defined. Progress although impacted by plant events remained generally on schedule.

7.0 UNIT 1 RESTART (IP 93802)

7.1 Work Deferrals

The team reviewed the restart work deferrals for Unit 1 and the incorporation of emerging Unit 2 issues into the Unit 1 restart work scope. There were approximately 100 Unit 1 restart work deferral requests with approximately 45 approved work deferrals. Work deferrals were evaluated by the system engineer and the outage manager. The outage manager provided a weekly summary of deferred work to the Management Review Committee. The team reviewed all approved work deferrals and concluded that the deferred work determinations were conservative. The deferred work that was approved represented no potential impact on Unit 1 safe and reliable operation.

It was noted by the team that the documentation of the basis for a deferral was inconsistent. Although the outage manager and system engineer provided adequate background in discussions to substantiate a deferral, some deferral documents did not provide a clear statement of why a work task could be deferred without impact to Unit 1 operation. The team concluded that the Unit 1 restart deferral activity was adequate and work deferrals were conservative.

There were many examples of issues emerging from Unit 2 operations being incorporated into the Unit 1 restart work scope. Unit 1 heater drain tank flow control valves were reset due to flow testing on Unit 2. Due to problems on Unit 2 air regulators, 120 air regulators were replaced on Unit 1. Inspection and cleaning of Arrow-Hart electrical contactors was performed on both Units. As a result of a leak on the Unit 2 letdown heat exchanger head, the Unit 1 letdown heat exchanger head gaskets were replaced. Reactor head vent valve leaks on Unit 2 resulted in flow testing on Unit 1 vent valves to identify leaks. Other Unit 1 emerging work included four to five work requests initiated daily due to ongoing Unit 1 testing and maintenance. The team concluded that emerging issues were adequately evaluated and added to the Unit 1 work scope.

8.0 UNIT 2 OPERATIONAL PERFORMANCE (IP 93802)

8.1 Objectives

The team made an assessment of the operational performance of Unit 2 since the October restart. This evaluation included root cause evaluation performed by the licensee and by the team.

8.2 Conclusions

After review of those root causes the team made the following three conclusions on the recent performance of Unit 2:

a. Less than thorough corrective action in the past has contributed to recurring events.

On December 1, 1993, a transient occurred in the condensate system that was initiated by a failed level control valve (LCV) on the number 7 heater drain tank, LCV 2-6-190. This failure was caused by a failure in the diaphragm of the LCV. Although not the same failure mode as the recent Letdown valve failures, it does indicate a continuing problem with air operated valves in the plant. Further, this failure may have been caused by vibration of the level indicating controller on the number 7 heater drain tank. This vibration occurred due to periodic flashing of steam in the tank. The licensee recalibrated the level instrument to eliminate the problem.

An earlier condensate system transient on November 10, 1993, was initiated when the licensee valved in steam to the turbine building heating system. These two transients seemed related and had a common root cause. In both cases the level control instrument on the number 7 heater drain tank was causing an overly sensitive response of the LCV's.

On December 3, 1993, Unit 2 experienced a plant trip due to main generator exciter problems (a fault occurred in the exciter-to-voltage regulator). Problems with the reliability of the main unit voltage regulator contributed to the event. The licensee had experienced reliability problems with the Unit 2 voltage regulator after the steam extraction pipe rupture event in March that sprayed the voltage regulator with steam and moisture.

During the inspection, RCW supply lines to the main generator hydrogen coolers were leaking. These leaks were caused by vibration induced stress in the RCW lines. This vibration was noted in 1992 and a temporary load installed in the area around the lines to dampen the vibration. However, the licensee did not fully consider the effects of the induced stress on the lines. Thus, the corrective action did not fully eliminate the vibration problem.

b. Underdeveloped maintenance programs have contributed to unreliable operation.

After review of the SIP and PM program, the team concluded that PM program implementation could be more effective. An example of this was the stator coolant water temperature switch. This temperature switch tripped during the December 3, 1993, reactor trip event. After further evaluation, the licensee found that this switch had not been calibrated for 12 years. The team also noted that not all of the BOP reliability study findings or Reliability Centered Maintenance (RCM) program findings had been incorporated into the PM program. Some of the maintenance items that could significantly improve plant reliability include:

-Stator Cooling Water System improvements.
-Replacement of obsolete Seal Oil pressure switches.
-PM on main generator cooling system.
-PM on BOP transmitters.
-Comprehensive assessment of the flow accelerated corrosion program.
-Improved industry experience database.

These items are contained in the SIP and are on schedule.

c. Full implementation of the SIP will improve overall plant improvement.

Several items in the SIP could improve the operational performance of the plant. There are some backlog items that will greatly improve the reliability of plant systems. Within the SIP itself, there are several items that are identified, that were also identified in the BOP reliability program, that are awaiting engineering evaluation, that should improve plant reliability. The team believes that as the SIP progresses, plant reliability should continue to improve.

9.0 NUCLEAR EXPERIENCE REVIEW PROGRAM (IP 93802)

The team inspected the Nuclear Experience Review (NER) program for the generic treatment of non-cited violations (NCV's) and information identified at other TVA sites. Inspectors reviewed SSP-4.4, Managing the Nuclear Experience Review Program, Revision 2 dated October 8, 1993, for the policy on referring issues to other TVA sites. Appendix B of this procedure identifies several documents that, as a minimum, must be screened for generic applicability. This list includes NRC violations as an item that must be screened. It does not differentiate between non-cited and cited violations. Further, the list of documents to be screened does not limit the scope of documents that might be reviewed by the NER program.

Although Appendix B does not require screening of NRC Inspection Reports, it does suggest that Inspection Reports could be screened if appropriate. Appendix D of this procedure also provides criteria for reviewing the effectiveness of the NER program. Reviews are required to be conducted on an annual (or shorter) basis.

The team reviewed the NER program to determine the extent of program evaluation of Adverse Condition Reports from Watts Bar. For 1993, approximately one-third of the Watts Bar generated II's and Inspection Report violations were being acted upon by other TVA organizations in addition to Watts Bar. Many Conditions Adverse to Quality identified at Watts Bar were related to construction activities and not generally applicable to other TVA sites.

The team reviewed NER item 910994, NRC Inspection Report 390,391/90-3, an NCV concerning 24 incore detectors in special nuclear material inventory. This item was screened for generic applicability to other

TVA sites. Also, NER item 921057002, an NCV concerning the lack of vacuum cleaner controls in radiation controlled areas, was screened for generic applicability. Action items and informational notices were sent to other TVA nuclear sites.

NRC Operational Readiness Assessment Team (ORAT) Inspection Report 50-327/93-201 and 50-328/93-201, discussed management of the NER program. In this Report, ORAT reviewed eight NRC Information Notices (INs), two related NRC Bulletins, and implementation of the NER program. The ORAT found that the licensee's NER program was generally effective, but appeared to have certain weaknesses. These weaknesses were viewed as "observations" and not "deficiencies." The ORAT also noted that the scope of the various self-assessment activities for the program was not clearly reflected concerning thoroughness of evaluations and adequacy of resolutions. The licensee had developed plans and actions to address these deficiencies. This team did not find any further examples of these weaknesses.

The team concluded that there was no generic programmatic deficiency regarding the screening of NCVs or NRC Inspection Reports from Watts Bar in the SQN NER program.

10.0 EXIT MEETING

The inspection scope and results were summarized on December 10, 1993, with those individuals identified in Appendix 1 of this report. The inspectors described the areas inspected and discussed in detail the overall conclusions and the inspection findings listed below. Although reviewed during the inspection, proprietary material is not contained in this report. Dissenting comments were not received by the team.

Item Number	Description and Reference
327, 328/93-54-01	A Violation of Technical Specification 6.8.1 for failure to follow procedures with multiple examples.

Appendix 1

Persons Contacted

Licensee Employees

K. Allen, Surveillance Manager
*J. Baumstark, Operations Manager
*R. Bellamy, Program Manager
T. Bennett, Mechanical Maintenance General Foreman
D. Brock, Scheduling Manager
*L. Bryant, Maintenance Manager
*M. Burzynski, Engineering Manager
*D. Clift, Planning Manager
*M. Cooper, Acting Maintenance Manager
J. Dvorak, Operations Procedure Changes
*R. Drake, Project Management/Controls, Manager
*R. Driscoll, Site Quality Manager
*S. Emert, MPC
*G. Enterline, Corporate Operations Support
*R. Eytchison, Vice President Nuclear Operations
*R. Fenech, Vice President, Sequoyah
*R. Field, Nuclear Engineering
*T. Flippo, Site Support Manager
*J. Gates, Outage Manager
*M. Gann, Field Modifications Manager
*R. George, Project Management
*J. Hamilton, Inspection and Materials Manager
*O. Hayes, Operations Program Manager
L. Hodges, Shift Operating Supervisor
R. Johnson, Assistant Shift Operating Supervisor
*W. Justice, ASME Section XI/Technical Programs
*D. Keuter, Vice President, Nuclear Readiness
*R. King, Operations Training Manager
*O. Kingsley, President, Generation Group
*J. Klien, Maintenance Programs
*D. Lundy, Technical Support Manager
*B. McCreary, Lead Specialist
*M. Medford, Vice President, Technical Support
T. Nahay, Modifications Manager
W. Nesmith, Instruments and Controls Manager (Eagle)
*L. Poage, Nuclear Audit and Assessment Manager
R. Poole, Instrument and Controls Manager
*K. Powers, Plant Manager
*J. Proffitt, Licensing Engineer
*W. Pruett, Corrective Action Coordinator
R. Rausch, Planning and Scheduling Manager
G. Sanders, Operations Support Manager
*R. Shell, Site Licensing Manager
*M. Shepherd, Training Manager
*M. Skarzinski, TP&P Manager
*J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
H. Tirey, Shift Operating Supervisor

*P. Trudel, Design Engineering Manager
*A. Varner, Nuclear Assurance Assessment Supervisor
*J. Walker, Operations Staff
*J. Ward, Engineering and Modifications Manager
*N. Welch, Operations Superintendent
*K. Whittenburg, Public Relations Manager
*J. Wilkes, Shift Operations Supervisor
W. Wright, Pipe Fitter General Foreman

NRC Employees

*R. Aiello, Operator Licensing Examiner
*M. Branch, Senior Resident Inspector, Surry
*C. Casto, Section Chief
*A. Gibson, Director, Division of Reactor Safety
*F. Hebdon, NRR, Project Directorate II-4
*B. Holland, Senior Resident Inspector, Sequoyah
*P. Kellogg, Section Chief, DRP Section 4A
*D. LaBarge, NRR, Senior Project Manager, PD II-4
*R. Moore, Reactor Inspector
M. Morgan, Resident Inspector, Farley
*J. Shackelford, Reactor Inspector, DRS
S. Shaeffer, Resident Inspector, Sequoyah
*J. Thompson, AEOD, Reactor Inspector
*T. Tjader, Reactor Engineer, NRR, Technical Specifications Branch
*P. Wilson, RI, Senior Resident Inspector, Calvert Cliffs

*Attended exit interview.

Other licensee employees contacted included control room operators, maintenance personnel and other plant personnel.

Appendix 2

Acronyms and Initialisms

AC	Alternating Current
AEOD	Office for Analysis and Evaluation of Operational Data (NRC)
AFW	Auxiliary Feedwater
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineering
ASOS	Assistant Shift Operating Supervisor
ATWS	Anticipated Transient Without Scram
AUO	Auxiliary Unit Operator
BOP	Balance of Plant
BP	Business Practice
CA	Corrective Action
C&A	Control and Auxiliary
CAQ	Condition Adverse to Quality
CCS	Component Cooling System
DBD	Design Basis Document
DC	Direct Current
DNE	Department of Nuclear Engineering
ECA	Emergency Contingency Action
EDG	Emergency Diesel Generator
EHC	Electrohydraulic Control
ERCW	Essential Raw Cooling Water
FME	Foreign Material Exclusion
GL	Generic Letter
I&C	Instrument and Controls
IDP	Instrument Data Package
II	Incident Investigation
ISI	In-service Inspection
LCO	Limiting Condition for Operation
LCV	Level Control Valve
MIL	Master Issues List
MSIV	Main Steam Isolation Valve
NCV	Non-cited Violation
NER	Nuclear Experience Review
NRC	Nuclear Regulatory Commission
OCC	Operations Control Center
ORAT	Operational Readiness Assessment Team
PER	Problem Evaluation Report
P&ID	Piping and Instrumentation Drawing
PLAN	Post Restart Plan
PM	Preventive Maintenance
PRA	Probabalistic Risk Assessment
PS	Planning and Scheduling Department
PSIG	Pounds Per Square Inch Gage
PWR	Pressurized Water Reactor
QA	Quality Assurance
RCDT	Reactor Coolant Drain Tank
RCM	Reliability Centered Maintenance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCW	Raw Cooling Water

RHR	Residual Heat Removal
SE	System Engineer
SI	Surveillance Instruction
SIP	Site Improvement Program
SMART	Sequoyah Management Assessment Review Team
SOS	Shift Operating Supervisor
SQN	Sequoyah Nuclear
SSP	Site Standard Practice
STA	Shift Technical Advisor
SRO	Senior Reactor Operator
TS	Technical Specification
TSCCR	Technical Specification Component Condition Record
TVA	Tennessee Valley Authority
UCR	Unit Control Room
UO	Unit Operator
WO	Work Order
WR	Work Request