ENCLOSURE 1

INTERIM SALP REPORT

U. S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

NRC INSPECTION REPORT NUMBER
50-327/89-01 AND 50-328/89-01

TENNESSEE VALLEY AUTHORITY (TVA)

SEQUOYAH NUCLEAR PLANT, UNITS 1 AND 2

FEBRUARY 4, 1988 - FEBRUARY 3, 1989

TABLE OF CONTENTS

I. INTRODUCTION

The Systematic Assessment of Licensee Performance (SALP) program is an integrated NRC staff effort to collect available observations and data on a periodic basis and to evaluate licensee performance on the basis of this information. The program is supplemental to normal regulatory processes used to ensure compliance with Nuclear Regulatory Commission rules and regulations. It is intended to be sufficiently diagnostic to provide a rational basis for allocating Nuclear Regulatory Commission (NRC) resources and to provide meaningful feedback to the licensee's management regarding the NRC's assessment of their facility's performance in each functional area.

The last SALP appraisal period for Sequoyah was for the period March 1, 1984 through May 31, 1985 with the SALP report being issued on September 17, 1985. In August 1985, both units were shutdown for Environmental Qualification (EQ) verification. In the September 17, 1985 letter transmitting the TVA SALP reports, the NRC communicated that significant programmatic and management deficiencies existed in TVA's nuclear program and pursuant to 10 CFR 50.54(f), TVA was requested to address these deficiencies prior to the startup of any nuclear unit. TVA responded by issuing and implementing the Corporate and Sequoyah Nuclear Performance Plans. NRC evaluation of the performance plan implementation is documented in NUREG-1232, Volumes 1 and 2, respectively, and NRC inspection reports. Further SALP review was deferred pending restart of Unit 2. By letter dated May 26, 1988, TVA was notified that the normal SALP evaluation process had recommenced as of February 4, 1988.

An NRC SALP Board, composed of the staff members listed below, met on March 28, 1989, to review the observations and data on performance, and to assess licensee performance in accordance with Chapter NRC-0516, "Systematic Assessment of Licensee Performance." The guidance and evaluation criteria are summarized in Section III of this report. The Board's findings and recommendations were forwarded to the Associate Director for Special Projects, Office of Nuclear Reactor Regulation, for approval and issuance.

This report is the NRC's assessment of the licensee's safety performance at Sequoyah for the period February 4, 1988 through February 3, 1989.

The SALP Board for Sequoyah was composed of:

- B. D. Liaw, Director, TVA Projects Division (TVAPD), Office of Nuclear Reactor Regulation (NRR) (Chairman)
- L. J. Watson, Acting Assistant Director for Inspection Programs, TVAPD, NRR
- S. C. Black, Assistant Director for Projects, TVAPD, NRR
- R. C. Pierson, Assistant Director for Technical Programs, TVAPD, NRR
- D. M. Collins, Chief, Radiological Protection and Emergency Preparedness Branch, Region II (RII)
- A. F. Gibson, Director, Division of Reactor Safety, RII
- J. N. Donohew, Senior Project Manager, TVAPD, NRR
- K. M. Jenison, Senior Resident Inspector, TVAPD, NRR

The following staff also attended the Sequoyah SALP Board meeting:

J. Brady, TVAPD, NRR
P. Harmon, TVAPD, NRR
G. Hubbard, TVAPD, NRR
S. Weiss, TVAPD, NRR
B. Zalcman, Technical Assistant, NRR
E. Goodwin, TVAPD, NRR
B. Desai, TVAPD, NRR
K. Landis, RII
R. Borchardt, RII Coordinator, EDO
T. Rotella, TVAPD, NRR

A. Licensee Activities

Both units began the assessment period in shutdown from an extended outage that began in August 1985. TVA agreed, in 1985, not to restart the units without receiving NRC approval.

On February 4, 1988, Unit 2 received NRC permission to enter Modes 4 and 3 (hot shutdown and hot standby) and began the heatup process. The plant was heated up using reactor coolant pump heat and entered Mode 4 on February 6, 1988. While in Mode 4, approximately nine personnel errors occurred which included inadvertent Main Steam Isolation Valve (MSIV) closures and feedwater isolations, generation of a reactor trip signal, and a loss of Volume Control Tank (VCT) level. None of the events resulting from those personnel errors represented significant safety concerns of their own accord and collectively appeared to be typical of what one would expect of a near term operating plant going through the same evolution.

On February 27, 1988, Unit 2 entered Mode 3. While in Mode 3, a number of events occurred including inadvertent closure of all four MSIVs, exceeding Technical Specification (TS) surveillance limits for Reactor Coolant System (RCS) leakage, exceeding RCS cold leg accumulator boron concentration, and two events involving auxiliary feedwater pump operability and charging pump operability of which the later involved escalated enforcement. The majority of these events were personnel related and were responded to by the licensee in an adequate manner.

On March 22, 1988, the NRC Commissioners voted to allow Unit 2 to restart. On March 30, the NRC approved entry into Mode 2 (Startup). On March 31, prior to actually beginning dilution, the licensee determined that modifications would be required on one of the three pressurizer safety valve loop seals, and the restart was delayed. During resolution of problems with pressurizer loop seals, a tube leak was identified in the #3 steam generator. On April 7, Unit 2 began a cooldown to Mode 5 (cold shoutdown) to repair the steam generator tube leak and complete pressurizer loop seal modifications.

On May 7, Unit 2 began the heatup process again and entered Mode 4. On May 11, Unit 2 entered Mode 3 and on May 12, Unit 2 entered Mode 2. Control rods were withdrawn and dilution to criticality began. On May 13, the reactor achieved criticality, entered Mode 1 (power operation), and the generator was synchronized with the grid. On May 15, the NRC granted permission to allow operation above 30% power and power escalation was resumed. During the power escalation process several minor events occurred which included the discovery of an unqualified splice in the circuitry for one of the steam generator water level indicators.

On May 19, Unit 2 tripped from 73% power due to steam flow/feed flow mismatch coincident with low-low steam generator level. This situation occurred due to maintenance being performed concurrently on two pieces of equipment which together could cause a reactor trip (one channel of steam generator level indication to replace the unqualified splice and the #3 heater drain tank level controller which resulted in plant oscillations). On May 20, after corrective actions for the trip were completed, NRC permission was given to restart Unit 2.

On May 21, Unit 2 achieved criticality, entered Mode 1, and was synchronized with the grid.

On May 23, Unit 2 tripped from 70% power on low flow in RCS Loop #4. This occurred due to a personnel error while performing a surveillance instruction on the loop #4 flow transmitters. On May 24, Unit 2 achieved criticality, synchronized with the grid and began power escalation.

On May 24, while Unit 1 was in partial drain to plug steam generator tubes, a loss of decay heat removal occurred due to an operator error in positioning valves while changing the residual heat removal (RHR) system alignment.

On May 29, 1988, Unit 2 achieved 100% reactor power.

On June 6, 1988, Unit 2 tripped from 98% power on steam flow/feed flow mismatch coincident with low level in #4 steam generator. The trip occurred while performing a surveillance on the feedwater regulating valves and resulted because a diode was missing in the block circuit.

On June 8, 1988, Unit 2 tripped from 12% power on low-low level in #2 steam generator. The trip was caused by operator error when placing the feed pump controller in the automatic position which resulted in steam generator level oscillations.

On June 9, 1988, Unit 2 tripped from 20% power on low-low level in #2 steam generator. The trip was caused by transients in feed flow and steam generator level which were initiated by feedwater heater isolations.

On June 13, 1988, TVA met with the NRC staff to discuss the root causes for the five reactor trips which had occurred since Unit 2 restarted on May 18, 1988. Corrective actions identified included reducing the number of outstanding secondary plant work requests which could contribute to balance of plant induced reactor trips.

On June 19, 1988, the NRC granted permission to restart Unit 2. On June 30, 1988, Unit 2 reached 70% reactor power (holding for core life extension).

On September 27, 1988, the NRC granted permission for Unit 1 to enter Mode 4. While in Mode 4, several unanticipated reactor trip signals were generated due to personnel errors while performing surveillances.

On October 20, 1988, Unit 1 entered Mode 3. While in Mode 3, the UHI membrane was ruptured while putting the system in service due to improperly labeled valves. Equipment problems such as steam generator safety valve seat leakage, pressurizer safety valve seat leakage, reactor vessel inner seal leakage, and steam dump packing leakage were encountered and properly resolved.

On November 6, 1988, Unit 1 entered Mode 2 and went critical. On November 10, 1988, Unit 1 entered Mode 1, the generator was synchronized with the grid, and power escalation began. Several personnel errors related to equipment surveillances caused ESF actuations while in Modes 2 and 1.

On November 18, 1988, Unit 1 tripped from 72% power due to an electrical ground in the main generator stator. During the forced outage to repair the generator stator, repairs to leaking steam generator safety valves and a pressurizer safety valve were also accomplished.

On December 25, 1988, Unit 1 achieved criticality, entered Mode 1, the generator was synchronized with the grid, and power escalation began.

On December 26, 1988, Unit 1 tripped on low-low level in #4 steam generator. The trip was caused by a series of events that started with a manual trip of the turbine due to generator seal rubbing. After the turbine trip, steam generator level was controlled using manual feedwater control which resulted in a feedwater isolation from high-high level in #2 steam generator followed by the reactor trip on low-low level in #4 steam generator.

On December 27, 1988, Unit 1 achieved criticality and began power escalation. On December 30, 1988, Unit 1 achieved 98% reactor power.

On January 19, 1989, Unit 2 was shutdown to begin the scheduled cycle 3 refueling outage after 210 continuous days of operation.

B. Direct Inspection and Review Activities

During the assessment period, routine inspections were performed at the Sequoyah facility by the NRC staff. Special inspections were conducted as follows:

- February 4 - June 25, 1988; a series of special inspections of the Unit 2 heatup and restart effort were conducted by the NRC Sequoyah Restart Task Force. These inspections included control room observation and reviews of activities associated with the restart effort. (88-02,88-17,88-20,88-22,88-26, 88-28,88-34)

- February 1-19, 1988; a special inspection was performed to assess the corrective actions performed by TVA in response to the findings of the Integrated Design Inspection. (88-13)

- February 8-12, 1988; a special inspection was conducted to assure that the licensee's corrective action program implementation adequately dispositioned adverse conditions, including generic issues. (88-15)

- February 15-19, 1988; a special inspection of the open restart issues in the civil engineering area was conducted to determine that adequate corrective action and resolution had occurred to support the restart of Unit 2. (88-12)

- February 29 - March 4, 1988; a special operational readiness inspection was conducted to assess the adequacy of the licensee's preparations for Unit 2 restart. (88-16)

- March 14-23, 1988; a special fire protection inspection was conducted for Unit 2 restart in the area of implementation of the requirements of 10 CFR 50 Appendix R, Sections III.G, III.J, III.L, and III.O including safe shutdown logic. (88-24)

- June 20 - July 8, 1988; a special Safety System Quality Evaluation vertical slice review was conducted on the Containment Spray System to assess the licensee's Nuclear Performance Plan implementation for Unit 1 restart. (88-29)

- July 11-15 and August 23-24, 1988; a special inspection was conducted to assess the effect of excessive cooldowns following reactor trips on end-of-life shutdown margin. (88-35)

- July 25-28, 1988; a special fire protection inspection was conducted for Unit 1 restart in the area of implementation of the requirements of 10 CFR 50 Appendix R, Sections III.G, III.J, III.L, and III.O including safe shutdown logic. (88-37)

- August 29 - September 2, 1988; a special operational readiness inspection was conducted to assess the adequacy of the licensee's preparations for Unit 1 restart. (88-42)

- September 6-9, 1988; a special inspection was conducted to assess the licensee's unreviewed safety question determination program and implementation. (88-43)

- September 25 - November 21, 1988; a series of special inspections of the Unit 1 heatup and restart effort were conducted by the NRC Sequoyah Restart Task Force. These inspections included control room observation and reviews of activities associated with the restart effort. (88-40,88-46, 88-47,88-48,88-49,88-51, 88-52,88-55)

- December 12, 1988 - January 26, 1989; a special quality verification inspection was conducted in the areas of maintenance, modifications, operations, radwaste processing, and corrective actions. (88-50)

The staff spent more effort on Sequoyah than on any other operating plant and also expended more effort than during the basis period. Reviews by the staff included TVA's Corporate and Sequoyah Nuclear Performance Plan (NPP) programs; the Employee Concern Task Group (ECTG) element reports; sixty-five amendments to the Unit 1 and 2 Technical Specifications including an exigent amendment, an emergency amendment, and a waiver of compliance; and four exemptions. The NPP reviews were documented in the NRC Safety Evaluation Report NUREG-1232 Volume 1 and 2 and its supplement, and included reviews in the major areas of adequacy of design, special programs, restart readiness, employee concerns, and allegations. The areas of adequacy of design, special programs, and restart readiness were further broken down as follows:

Adequacy of Design

1. Plant Modification and Design Control
2. Design Baseline Verification Program
3. Design Calculations Program
4. Alternately Analyzed Piping and Supports
5. Cable Tray Supports
6. Concrete Quality
7. Miscellaneous Civil Engineering Calculations

Special Programs

1. Fire Protection
2. Environmental Qualification of Electrical Equipment Important to Safety
3. Piece Part Qualification (Procurement)
4. Sensing Line Issues
5. Welding
6. Containment Isolation
7. Containment Coatings

8. Moderate-Energy Line Breaks
9. ECCS Water Loss Outside Crane Wall/Air Return Fan Operability
10. Platform Thermal Growth
11. Pipe Wall Thinning Assessment
12. Cable Installation
13. Fuse Replacement

Restart Readiness

1. Operational Readiness
2. Management
3. Quality Assurance
4. Operating Experience Improvement
5. Post-Modification Testing
6. Surveillance Instruction Review
7. Operability "Look Back"
8. Maintenance
9. Restart Test Program
10. Training
11. Security
12. Emergency Preparedness
13. Radiological Controls
14. Restart Activities List

II. SUMMARY OF RESULTS

A comparison of the present SALP ratings to the previous SALP ratings of 4 years ago (1984 to 1985) would be of little benefit in determining the current trend of the licensee. In order to evaluate the current trend of the licensee from the preassessment period to the assessment period, an additional summary is provided below of the NRC staff evaluation for the period from January 1, 1987 until the start of the assessment period (February 4, 1988) to be used as a basis for comparison.

The NRC established an Office of Special Projects (OSP) in February 1987 to address the particularly complex regulatory problems of TVA and one other utility. Part of the OSP goal was to assess whether identified problems to the licensee were on a path to an acceptable solution, and where not, to identify acceptable solutions necessary to enable the staff to complete its licensing reviews of these facilities, consistent with the NRC's statutory mandate to protect the health and safety of the public.

A. Basis Period Summary (January 1, 1987 - February 3, 1988)

1. Plant Operations

During the entire basis period both units were in the shutdown mode. Weaknesses were identified in the adequacy of Abnormal and Emergency Operating procedures, emergency contingency action procedures, compensatory operator actions, configuration control, the clearance process, investigation and resolution of event related issues, involvement of first line and upper level management in the day-to-day operation of the plant, and control and authority over plant activities impacting schedule. Some reportability/operability determinations were classified as unknown while awaiting Division of Nuclear Engineering (DNE) review which was not always timely or responsive. In addition, there was a reluctance by the licensee to report items that they felt were minor. As a result, several events were not properly classified and reported. Material condition, drawing adequacy and configuration management training were acceptable.

These issues indicated a lack of management attention to and involvement in the operational aspects of the plant. Control room operators were burdened with the work control management function. Their decisions in controlling these activities were often reversed by management. This resulted in limiting the amount of time senior reactor operators spent in the plant, a reduction in the amount of time reactor operators spent observing control panel indications, and a feeling that management did not respect their ability to make decisions.

Several management changes occurred during the basis period which contributed to major improvements in plant activities. The new managers included the Deputy Site Director, Plant Manager, Operations Superintendent, and Corporate Outage/Maintenance Managers.

The operations section was adequately staffed to support plant operations. Control room and plant shift rotation was increased to a six shift rotation late in the basis period. Overtime was routinely used to augment normal shift staffing with several occasions identified where administrative limits were exceeded without receiving prior plant manager approval. The 1987 NRC replacement examinations for licensed operators indicated satisfactory results (5 out of 5 passed).

Measures were implemented to revise and control primary drawings in the control room. These drawings were redrawn and maintained by computer-aided drafting systems which resulted in improved accuracy and a more timely revision process. System logic drawings were removed from the primary drawing list during 1986 because they were not routinely updated and revised as plant systems were modified.

Procedural compliance by Operations personnel was judged to be marginally better than the plant staff as a whole. Instances of procedure deviations and non-compliances occurred at an unacceptable frequency, and resulted in several reportable events.

The licensee made considerable progress in resolving the several hundred technical issues encountered after the 1985 shutdown of both units. Issues that remained to be resolved at the end of the basis period included the evaluation of containment sump level transmitters, lower containment coolers, and Senior Operator manning.

2. Radiological Controls

Inspections conducted during the basis period of the Sequoyah radiation protection program, indicated that the actions taken by the licensee, including correction of previous weaknesses in its program for maintaining exposure as-low-as-reasonably-achievable (ALARA), were sufficient to support plant restart. One significant event involved an exothermic reaction during a radwaste solidification process which caused personnel contaminations and higher than expected radiation levels.

Considerable organizational changes had taken place in the Chemistry Group during the period. These revisions assured close management involvement in maintenance of quality, storage of radioactive waste, and effluent releases. Close coordination with the Corporate Chemistry group resulted in resolution of technical issues in a timely manner.

The organizations were responsive to NRC initiatives in that open items were being closed out as the organization prepared for Unit 2 startup. Staffing had been reviewed, and several new management personnel were added to the Chemistry Group.

3. Maintenance/Surveillance

During the SALP basis period the Sequoyah maintenance program experienced numerous weaknesses. These weaknesses were in procedural compliance, corporate maintenance guidance, maintenance trending, root cause analysis, first line management involvement, training for maintenance planners, work control, maintenance coordination, equipment classification (Q-list), maintenance history tracking and trending, maintenance procedure adequacy, plant drawing use, the preventive maintenance program, accountability of maintenance tools and equipment, post modification testing, quality assurance involvement with maintenance activities, temporary alterations, and corrective action. In addition, there were significant backlogs in the modifications, temporary modifications, and maintenance areas. There was significant overlap between those issues identified by the NRC and those issues identified by TVA's Nuclear Manager's Review Group maintenance inspections. Tracking, trending and scheduling were improved and craft reviews were implemented which improved the quality of maintenance activities. Areas that did not demonstrate active direction during the basis period were the maintenance instruction enhancement project which was resolved during the SALP assessment period, and composite maintenance crews which were identified by the Nuclear Maintenance Review Group (NMRG) as having implementation problems but were not acted upon by TVA management. Institute for Nuclear Power Operations (INPO) accreditation of the training for nine previously selected maintenance craft areas was received during the SALP basis period.

The NRC identified significant problems in the area of procurement of safety-related parts and equipment at Sequoyah and was considering escalated enforcement action. Based on the NRC findings, TVA in general and Sequoyah in particular initiated an extensive Replacement Items Program (RIP) to ensure that appropriate parts and equipment were installed in the plant for EQ and seismic qualification of equipment prior to the restart of the Sequoyah units. This included training in repair part and procurement control which was considered one of the causes of the problem. Based on the shutdown plant enforcement policy and successful implementation prior to unit restart, these issues were given discretionary enforcement. The program also established controls to ensure that future procurement of safety-related equipment met the appropriate requirements.

Sequoyah was completing the documentation and field work for their EQ program. Sequoyah was found to have an excellent EQ program which had proper management attention and proposed sound technical resolutions as problems arose. TVA management was found to be knowledgeable of NRC and industry standards and requirements in this area.

Licensee management recognized that storage of equipment did not meet the requirements of American National Standard Institute (ANSI) 45.2.2 and initiated an improvement program to correct this problem. The equipment storage upgrade program initiated by licensee management was adequate and well implemented. The implementation included a computerized tracking system to identify the exact location of each part, and well organized, clearly marked storage areas that met the ANSI 45.2.2 storage class requirements, even at remote on-site locations. At the close of the SALP basis period safety related component storage was in excellent condition, as a result of several energetic knowledgeable managers who were personally involved in the resolution of this industry wide issue.

As a result of significant NRC concerns with surveillance instruction inadequacies which were under consideration for escalated enforcement, the licensee established a surveillance instruction review team to compare existing surveillance instructions to TS surveillance requirements. This review effort identified a significant number of additional issues that resulted in approximately 15 Licensee Event Reports (LERs) being written. A number of significant revisions and management changes were made to the surveillance instruction review and update program to achieve technically adequate surveillance instructions that met the surveillance requirements. Management involvement in the final effort was aggressive and included an independent validation process which was particularly well managed and ensured that the surveillance instructions produced were of high quality and technically adequate. Based on the shutdown plant enforcement policy and implementation of an acceptable surveillance program prior to restart, these issues were given discretionary enforcement.

The licensee established a Nuclear Performance Plan Restart Test Program in order to ensure the operability of safety related equipment which had been modified. A review matrix of component functions and previously performed surveillances was established to ensure the testing of functions that had not been tested. This program was considered adequately staffed with trained individuals and was determined to be acceptable. Only the closure of Mode 3 and 2 related items was deferred into the SALP period.

A problem was identified in the Inservice Test (IST) valve test program in that essentially all category A and B valves were included in one Surveillance Instruction (SI) and scheduling was based on the issue date for the SI package, not the test date for individual valves in the package. The test dates for individual valves were not controlled resulting in a number of valves exceeding their test frequency.

Procedural adherence was a weakness which contributed to several events and enforcement actions and indicated a lack of management involvement in and attention to this area. In addition, corrective actions were not effective in reducing the results of this weakness until well into the SALP assessment period.

Conduct of testing was identified as an area of weakness during the activities leading up to the restart of Unit 2. The licensee took strong corrective action with the issuance of special conduct of testing administrative controls which resulted in a significant improvement in plant operations.

The effectiveness of the short term layup of the steam and power conversion system (the secondary water system) was adversely affected due to uncertainties in the startup schedule. The uncertainties were directly related to the inability of management to control restart activity schedules. Continuous maintenance and modifications of systems created a condition where the desired controls did not in some cases maintain the parameters for minimizing corrosion and degradation of the car‑n steel systems. The licensee was responsive to NRC cor ns expressed during inspections and to NRC information not s. Actions were taken to enhance the protection of systems during the extended short term layup.

Organizational changes in the water chemistry program were a strengthening factor for water chemistry control. Qualifications of the chemistry management and staff were adequate with a sufficient number of chemists and analysts to maintain chemistry control. Other elements of the water chemistry program (procedures, training, and equipment) were maintained at a sufficient level to achieve chemistry control during plant startup.

During the basis period the licensee made progress in changing its maintenance philosophy from reactive to preventive and was trying to reinforce procedural compliance.

4. Emergency Preparedness

The Emergency Preparedness program was adequately maintained during the basis period. Two routine inspections and an emergency exercise indicated the licensee was maintaining an effective emergency preparedness program. Licensee management attention to the program was adequate The two violations identified during the routine inspections addressed an inadequacy in the training for licensed operators and a failure to conduct required monthly communications checks for three months.

5. Security

Four routine security inspections, one material control inspection and two special inspections relative to Fitness for Duty and pre-employment screening were conducted. Two violations were cited for failure to adequately post a compensatory officer, and for failure to maintain a bullet-resistant barrier. The Fitness for Duty program was judged adequate with both a few noteable strengths and one significant weakness. The NRC exercised discretionary enforcement in not issuing a violation regarding numerous pre-employment screening errors due to the significant corrective action initiated and that the program was examined and determined acceptable prior to plant startup. During this period the licensee, although non-operational, did not reduce its security program nor did it "devitalize" any of its security areas. The NRC inspection program also included various allegations, Employee Concerns and the licensee's Regulatory Improvement Plan.

A licensee Quality Assurance Audit (QSS-A87-0010) was performed and no regulatory issues were raised. With respect to Safeguards Event Reports, there were four relative to expired badges not being voided and various visitor/escort deficiencies. Of the 225 security incident reports per 10 CFR 73.71 requirements, the vast majority (nearly 95%) resulted from the failure of equipment (hardware and systems) and not human errors.

Midway through this period, the licensee reorganized its security organization which resulted in security officers working for and being accountable to the Corporate Nuclear Security Support Branch, as oppose to the previous multi-management level structure criticized in prior SALP Reports. A new site Security Manager was assigned to the site in July 1987.

The extended use of numerous compensatory measures needed because of failed equipment remained the most significant regulatory issue throughout this period. However, the licensee was judged as adequately meeting requirements and providing security for the facility.

6. Engineering/Technical Support

The licensee's performance in the engineering/technical support area was greatly affected by the many changes which were being experienced by the engineering/technical support staff. Early in the baseline period, the licensee was trying to obtain a clear definition of the scope of effort required to resolve many technical and design issues which had been identified through licensee sponsored evaluations and audits and NRC inspections; however, the engineering and technical support staff was hampered by changes in organization structures and changes in key personnel as well as major changes to the internal engineering procedures.

While the above changes hampered early baseline period performance in engineering/technical support, the licensee had established many special programs to address and resolve previously identified issues as well as new issues identified during the baseline period (e.g. discrepancies identified during the NRC integrated design inspection (IDI)). Some of the issues for which special programs had been established included EQ of safety-related electrical equipment; design and configuration control (design baseline verification program); design calculations review - electrical, mechanical, nuclear, and civil; electrical issues; instrument sense line issues; component and piece part qualification; Appendix R; and restart testing.

The licensee performance in the engineering/technical support area was satisfactory for some of the programs; however, other programs were satisfactory only after corrections were made based on NRC input. Examples of programs where the licensee's performance was satisfactory and the program implementation was considered acceptable were: EQ; civil calculations; cable tray supports; technical drawings; Design Baseline and Verification Program (DBVP); and heat code traceability.

Examples of programs where program implementation was initially considered inadequate included: component and piece part qualification (inadequate seismic qualification and dedication of commercial grade parts for use in safety related equipment); pipe hangers and supports (inadequate calculations and documentation to demonstrate that installed pipe hangers and supports met plant design criteria); and instrument sense lines and instrumentation accuracy calculations (lack of sufficient conservatism). While the licensee's implementation of some programs was initially judged to be unsatisfactory or inadequate relative to engineering/technical support, once problems or concerns were identified, the licensee satisfactorily resolved the problems and completed the programs.

7. Safety Assessment/Quality Verification

For the basis period, there was an extensive review effort on Sequoyah. The review effort included the following significant items:

1. review of the Corporate Nuclear Performance Plan was completed and NUREG-1232, Volume 1 was issued;

2. most of the review of the Sequoyah Nuclear Performance Plan was completed;

3. most of the Employee Concerns Task Group (ECTG) element reports on Sequoyah were reviewed;

4. thirty amendments to the Units 1 and 2 TS were issued; and

5. twenty-one meetings were held with TVA on various technical issues.

Overall, the work submitted by TVA was reasonably good. The submittals generally showed evidence of prior planning by management. An understanding of the technical issues was generally apparent. The resolutions of issues were generally viable, timely, sound and well thought out with conservatism exhibited by the licensee's approach. This was generally true in the basis period except for the issues of cable testing and the transition of senior nuclear power management from contract employees to permanent employees.

The issue of cable testing which included the issue of testing 10 CFR 50.49 silicone rubber insulated cable which was inside containment was protracted and drawn out. The issue was discussed throughout the basis period and was not resolved for Unit 1 until the staff letter of May 25, 1988 in the rating period. The resolution of this issue was not timely and the technical issues were not well thought out.

The TVA response to the staff's concerns on the transition of TVA senior nuclear management was acceptable and the safety evaluation on the TVA's Corporate Nuclear Performance Plan was issued on July 28, 1987; but, TVA was not responsive to the issues raised by the staff pertaining to the transition from contract managers to TVA permanent managers. As a result, the staff was compelled to request TVA to notify the staff 30 days in advance of any permanent changes of the senior nuclear managers.

In January 1987, the NRC approved (for a period of two years) TVA's Quality Assurance Topical Report, TVA-TR75-1A, Revision 9, which was developed to resolve past problems relating to the inability of management to take prompt effective corrective action to prevent recurrence of problems. The past problems were under consideration for escalated enforcement at the start of the basis period. During the basis period, Sequoyah began implementing the new topical requirements which involved hiring the additional staff required, training them to appropriately implement the program, and then monitoring the implementation to ensure that the desired results were achieved. During this transition period Sequoyah experienced significant implementation problems especially with the conditions adverse to quality (CAQR) program which was the subject of several TVA audits and NRC inspections. The TVA audits concluded that the root cause of the failure of the program to not fully process any significant CAQRs was due to a lack of line management and Quality Assurance (QA) management involvement and attention. This was the same reason the previous corrective action program hadn't been effective. Sequoyah responded by deeply involving upper level managers in the corrective action program implementation. While problems still existed in the QA program implementation, the staff concluded that the program began moving in a positive direction toward the end of the basis period after upper level management involvement had significantly increased. Based on the shutdown plant enforcement policy and implementation of an acceptable corrective action program prior to restart, the past problems were given discretionary enforcement.

The three safety committees which functioned during the basis period [Plant Operations Review Committee (PORC), Nuclear Safety Review Board (NSRB), Independent Safety Engineering Group (ISEG)] went through a change process due to TS changes and charter reviews, which were for the most part a result of NRC initiatives. PORC was initially ineffective, however, improvement was observed near the end of the basis period due to both the qualified reviewer TS change and a new plant manager. The NSRB and ISEG did not independently identify issues which produced substantive changes to the site.

During the basis period, 88 LERs were issued of which 26 were classified as significant. These resulted primarily from the design reviews which TVA had initiated. Some LERs were unclear with respect to the root cause determination of events or differed from the staff determinations. The licensee established an ISEG audit, identified similar concerns, and was implementing ISEG and NRC recommendations at the end of the basis period.

Both the Special Employee Concerns Task Group (ECTG) and the new Employee Concerns Program (ECP) were in existence during the basis period. The ECTG was working on resolution of the concerns which it received in the 1985 to early 1986 time frame. Numerous revisions to the ECTG reports and their corrective actions occurred as a result of NRC review. All employee concerns received during the basis period were processed through the ECP. The NRC identified weaknesses relating to resolution of generic concerns, administrative issues, and restart determinations which were promptly addressed and corrected by the ECP management. NRC reviews of both programs indicated that concerns were being adequately addressed at the end of the basis period.

TVA Nuclear Power corporate management was usually involved in Sequoyah site activities in an effective manner during the basis period. There were several management changes at the site which contributed to major improvements in operation, security and radiological controls during this period. There were corporate audits made in the radiological controls and maintenance areas where actions were taken by corporate management to strengthen these programs. Although many significant problems in programs at the site were not being identified by TVA prior to NRC inspections, usually strong corrective actions from the corporate level were taken when it was needed to correct the identified problems.

For the basis period, corporate management was generally responsive to NRC initiatives. Responses to NRC were generally timely and generally sound and thorough. This is shown in the significant amount of work completed by the staff and TVA in the basis period.

The staff conducted an inspection of management effectiveness related to licensing activities in the basis period. The inspection was conducted in key areas of responsibility at both the plant site and corporate offices. The staff concluded that corporate management processes in the areas inspected were functioning adequately.

B. Assessment Period Summary (February 4, 1988 - February 3, 1989)

Sequoyah has been operated in an overall safe manner during the assessment period. Management involvement in and attention to the operations and support of the plant has significantly improved as a result of the strong leadership exhibited by the new plant manager and new site director.

The plant operations area matured during the assessment period. After starting the assessment period with five reactor trips, Unit 2 was on line for 210 continuous days which established a TVA single unit record. Unit 1 experienced two reactor trips during startup with full availability for the rest of the assessment period. Strengths included the procedures upgrade programs, the emphasis on procedural compliance, and the ownership concept for the operators. Corrective actions for problems once the root cause was identified were considered a strength. Weaknesses included operation of the radwaste system; root cause analysis in relation to the post-trip cooldown shutdown margin issues; and the performance of fire watches. Control of plant activities by the control room operators improved during the latter half of the assessment period.

The overall quality and experience level of the health physics staff is a program strength, and the licensee's health physics, radwaste, and chemistry staffing levels are adequate and compare well with other utilities having facilities of similar size. Management provides adequate support and is involved in matters related to radiation protection.

The maintenance/surveillance area also matured during the assessment period. Strengths included the leadership exhibited by the new maintenance superintendent, the establishment of the work control group, the establishment of a preventive maintenance upgrade program, implementation of the system and train outage concept for scheduling maintenance, and implementation of the system of the month review program. Weaknesses included the large number of personnel errors or inadequate procedures which resulted in Engineered Safety Feature or reactor protection system actuations; the inability to produce realistic schedules; and the inability to correct problems associated with the feedwater control system.

During a full participation exercise, the licensee demonstrated that they could satisfactorily respond to an emergency at the facility. However, weaknesses were noted in that the licensee had on two occasions failed to promptly report a Notice of Unusual Event (NOUE) and also failed to recognize an explosion as requiring entry into the emergency classification logic during the emergency exercise.

In the security area, a high number of hardware equipment inadequacies exist. These inadequacies, which are a result of the security equipment being obsolete, have lead to a continuous dependence on compensatory measures. Corporate support was weak because of a high turnover rate; however, the licensee has finalized a reorganization of its Corporate Nuclear Security Service Branch which has resulted in some improvements. The site management has been instrumental in dedicating site support to help the security branch reduce the number of security compensatory measures.

The Engineering/Technical Support activities did not significantly exceed minimum regulatory requirements. While numerous issues were resolved during the assessment period, many of the issues were resolved only after considerable NRC input. Support for operations of the plant was initially viewed as a weakness but improved late in the assessment period.

In the Safety Assessment/Quality Verification area, the most important improvement was in the corrective action program which made significant strides during the assessment period. Strengths included the significant management attention to and involvement in the corrective action process, the strong leadership provided by the plant manager and new site director in getting employees to accept responsibility for doing quality work, the quality monitoring and audit program, and the employee concerns program. Weaknesses included the 10 CFR 50.59 safety evaluation program and the slipping of the dates and scope changes for commitments made to the NRC.

C. Overview

February 4, 1988 - February 3, 1989

Functional Area	Rating	Trend
Plant Operations	2	None
Radiological Controls	2	None
Maintenance/Surveillance	2	None
Emergency Preparedness	2	None
Security	2	None
Engineering/Technical Support	3	Improving
Safety Assessment/ Quality Verification	2	None

III. CRITERIA

Licensee performance is assessed in selected functional areas, depending on whether the facility is in a construction or operational phase. Functional areas normally represent areas significant to nuclear safety and the environment. Some functional areas may not be assessed because of little or no licensee activities or lack of meaningful observations. Special areas may be added to highlight significant observations.

The following evaluation criteria were used, as applicable, to assess each functional area:

1. Assurance of quality, including management involvement and control;

2. Approach to the resolution of technical issues from a safety standpoint;

3. Responsiveness to NRC initiatives;

4. Enforcement history;

5. Operational and construction events (including response to, analyses of, reporting of, and corrective actions for);

6. Staffing (including management); and

7. Effectiveness of the training and qualification program.

However, the NRC is not limited to these criteria and others may have been used where appropriate.

On the basis of the NRC assessment, each functional area evaluated is rated according to three performance categories. The definitions of these performance categories are as follows:

1. Category 1. Licensee management attention and involvement are readily evident and place emphasis on superior performance of nuclear safety or safeguards activities, with the resulting performance substantially exceeding regulatory requirements. Licensee resources are ample and effectively used so that a high level of plant and personnel performance is being achieved. Reduced NRC attention may be appropriate.

2. Category 2. Licensee management attention to and involvement in the performance of nuclear safety or safeguards activities is good. The licensee has attained a level of performance above that needed to meet regulatory requirements. Licensee resources are adequate and reasonably allocated so that good plant and personnel performance is being achieved. NRC attention may be maintained at normal levels.

3. Category 3. Licensee management attention to and involvement in the performance of nuclear safety or safeguards activities are not sufficient. The licensee's performance does not significantly exceed that needed to meet minimal regulatory requirements. Licensee resources appear to be strained or not effectively used. NRC attention should be increased above normal levels.

The SALP Board may also include an appraisal of the performance trend of a functional area. This performance trend will only be used when both a definite trend of performance within the evaluation period is discernable and the Board believes that continuation of the trend may result in a change of performance level. The trend, if used, is defined as:

Improving: Licensee performance was determined to be improving near the close of the assessment period.

Declining: Licensee performance was determined to be declining near the close of the assessment period and the licensee had not taken meaningful steps to address this pattern.

IV. PERFORMANCE ANALYSIS

A. Plant Operations

1. Analysis

The quality of operations at Sequoyah improved during the SALP assessment period based on the results of routine and special inspections. During the first half of the assessment period, several plant trips and operational events occurred which demonstrated that the operations area required further improvement. Following an NRC/TVA management meeting to discuss the root causes of the poor performance which caused the trips, the Sequoyah plant staff exhibited increased responsiveness to NRC issues, attention to detail, and commitment to quality. Increased management attention to and involvement in the operation of the plant contributed to a Unit 2 record power run following the management conference. Management initiatives included revisions to the root cause assessment procedures, establishment of a requirement for PORC approval of post trip reviews prior to restart, increased attention to control of plant activities, and a conscientious effort to reduce the number of inoperable or out of service components.

Management attention to and involvement in the upgrading of operating procedures were focused both by results from NRC inspections, which occurred near the end of the basis period and during the assessment period, and by licensee initiatives. Operating procedures were included in the licensee's ongoing procedure enhancement program. Standardizing the procedure format and clarifying instruction steps as part of the enhancement program were elements of the program initiated during the latter part of the assessment period. This is a long-term program and is not expected to be complete during the next SALP rating period. System Operating Instruction (SOI) checklists were reviewed and revised by the licensee after NRC inspections during the basis period revealed problems with the system alignment processes. After the licensee completed these revisions, system operating instructions were workable and adequate. However, the procedure change process was difficult and cumbersome. The use of night orders to circumvent the need to revise operating procedures was stopped. TS interpretations were upgraded and now require specific approval prior to their entry into the TS Interpretations log. The Emergency Operating Procedures (EOPs) were determined to be adequate and the corrective actions initiated by the licensee from a basis period inspection were determined to be appropriate. The Administrative Instruction for controlling Hold Orders was revised to require more control by the Operations staff and more responsibility by the persons performing the work resulting in an improved hold order process. Upgrading of the system logic drawings for those systems described by the Design Baseline and Verification Program (DBVP) boundary was completed during the assessment period and the drawings were returned to the control room for use by the operators. Also, drawings essential for safe plant operations were available in the control room. At the end of the assessment period, a long-term effort was in progress to restore other system logics to the primary drawing list and return them to the control room.

The licensee's approach to the resolution of technical issues from an operational safety standpoint was technically sound. An understanding of the safety aspects was apparent, and conservatism was usually exhibited when responding to safety-significant events and issues. Notable exceptions to this generalization were the poor planning and management ineffectiveness in dealing with the system alignment and operability determination in support of UHI valve repair, and in the resin transfer operations which occurred near the end of the assessment period. Several operational plant events that occurred during the restart of both Units 2 and 1 identified that a poor feedwater control system design and operating philosophy existed. Changes to procedures and specific operator training to eliminate trips and transients in this area were not initially effective. Root cause determinations did not involve sufficient first line operations management efforts which resulted in a protracted resolution process.

Improvements in the area of communications were instituted following an incident involving manipulation of the wrong valve by an auxiliary unit operator which resulted in a loss of RHR suction. Control room professionalism was adequate and showed continued improvement during the assessment period. The control room was upgraded through extensive cosmetic improvements such as new carpeting, painting, and repair of deficiencies such as roof leaks. However, several functional deficiencies exist which affect operator performance and effectiveness. Nuisance alarms, long-standing hold orders and Temporary Alterations (TACFs), and human factors problems associated with steam generator level controls continued to cause an unwarranted number of problems for the operators. Management was aware of these problems and is addressing them in the form of a System Engineering concept and a detailed control room design review.

Problems continued in the configuration control area (system alignment) through the startup of Unit 2 particularly in the area of waste water systems. The program for controlling the configuration and operations of the waste water systems was changed to provide the same level of control for these systems as was applied to other plant systems that are under the authority of operations. This proved to be a positive step in reducing configuration control errors associated with the waste water systems. Additional changes made in the configuration control program consisted of repeat back communication, and separating the first and second verification by time and distance. The latter change had been previously recommended during the basis period by the licensee's Unit 2 operational readiness review team, but had not yet been implemented by management. Once implemented, these changes significantly reduced configuration control problems.

The licensee performed evaluations to confirm that compensatory measures which had previously been established for disabled safety functions were properly documented and were collectively and individually capable of being performed with normal staffing levels. Operator awareness and control of long standing TACFs in relation to their effect on plant configuration was a matter of concern to the NRC during the basis period and continued to be an issue during the assessment period. The licensee took action to reduce the number of TACFs to approximately 80, which was 50% of the level at the beginning of the period, with a goal of having no more than approximately 30 TACFs.

Operators were well informed in the use of emergency operating procedures. Because of the long duration shutdown period (approximately 2½ years), the number of reactor operators experienced in power operations was low and additional support personnel were made available in preparation for Unit 2 restart. These included additional management presence in the control room, additional control room Senior Reactor Operators, and temporary Operating Shift Advisors. Operator actions for most events that occurred during the Unit 2 startup were appropriate.

Licensed operators responded effectively to plant transients on most occasions during Unit 1 startup including a reactor trip of Unit 1 caused by feedwater control problems, a turbine trip of Unit 1, a reactor trip of Unit 1 caused by a generator ground, and a lightning strike of a switchyard transformer during a thunderstorm.

Operators were observed to be disciplined professionals with adequate communication skills. However, occasional lapses which were exemplified by one instance of inadequate action by an operator during routine plant activities occurred. This example involved the placement of a centrifugal charging pump in the pull to lock position which resulted in a failure to comply with a technical specification action statement.

Control room activities were generally conducted in an effective and professional manner. Formal communications were observed in most cases. Operators were attentive, aware of plant conditions and responsive to changes in plant conditions. Senior plant management actively supported the above operator activities and was deeply involved in the day-to-day operation of the plant. In addition senior plant management maintained a detailed account of and tracked the status of known equipment deficiencies, CAQRs, and plant parameters in daily plant meetings. Active involvement by plant management and support of the ownership concept by the operations department had a positive effect on plant operations and morale. This was exhibited by the absence of significant events or operating problems during the extended power run of Unit 2. Facility operations reflected improvements in planning and assignment of priorities during the period. The forced outage rate for both units during the period was extremely high as a result of the extended shutdown. However, following the five Unit 2 trips which occurred early in the Unit 2 startup process, Unit 2 had no forced outages for a period of approximately 210 days. Unit 1 experienced two reactor trips during its startup period, followed by full availability for the remainder of the assessment period.

Management support and insistence on the ownership concept has strengthened the authority and role of the Operations group in general and the control room shift supervisor in particular. Operations personnel have demonstrated on many occasions their willingness to suspend or delay surveillance, maintenance and other schedule impacting activities until they were satisfied that the plant was in a safe stable condition and that other plant activities in progress would not interact with the scheduled activities to produce safety system actuations. The absolute authority of the operations staff in these matters has been fully supported by plant management.

During the assessment period the licensee administered requalification examinations. The results from the examinations indicated a large percentage success rate (approximately 69 out of 70). Nonlicensed operators were judged to be extensively trained receiving both detailed classroom training and thorough in plant on the job training. The percentage success rate for new operating license candidates was determined to be below average (7 out of 11 passed).

Operations shift training for newly installed plant modifications and for correction of operating deficiencies or events was adequate. However, occasional lapses were exemplified by the shutdown margin/excessive cooldown events and rod control demand counter problems.

During the assessment period Operating shift manning was adequate and maintained at the levels established during the basis period. Several management positions were eliminated to streamline the Operations organization which resulted in a more effective organization.

Management stressed procedural compliance by operations personnel throughout the assessment period. This had a side effect of improving procedures by forcing operators to have inadequate procedures revised before they could be used. However, instances of procedural non-compliance and deviation continued during Unit 2 startup, such as the MSIV closures, configuration control deviations, and Upper Head Injection (UHI) accumulator venting events. Management was very aggressive in responding to the above issues and by the middle of the assessment period procedural adherence was adequate and improving.

In an event involving the discharge of highly-radioactive spent resin that occurred during the latter portion of the SALP assessment period, it was determined that the intense management attention given to power operations had not been applied to the waste processing portion of the power plant and the attendant operations support staff. This event highlighted, in that area alone, inadequate procedures, a casual attitude toward following procedures, inadequate drawing control, and failure to aggressively correct design problems that make operations awkward or could create personnel or radiological hazards. In addition, plant management in this specific area appeared to be poorly trained and very weak with respect to the operating and physical characteristics of their assigned system. Finally, interactions between the waste and water management group and other plant management that were observed following this event did not demonstrate a cooperative, quality-oriented approach to the resolution of technical issues within the waste and water management group. Plant management is currently taking strong corrective action to improve the waste water processing area.

Logkeeping by licensed operators continued to exhibit weaknesses particularly in the areas of detailed entries, entry and exit from Limiting Condition for Operation (LCOs), and descriptive explanations and rationales for decisions made and actions conducted by the operators and SROs. During the last two months of the assessment period, Operations management implemented corrective actions in these areas by having Operations supervisors review logs for completeness, stand-alone entries and supportable explanations for LCO entries, exits and changes to plant and equipment status. The NRC identified during the latter portion of the assessment period a significant improvement in the level of detail supporting log entries. The corrective actions were effective.

Operational events in general were promptly and accurately identified. Exceptions were the failure of the operations staff to recognize problems with the excessive post-trip cooldowns, and having a centrifugal charging pump in pull-to-lock while the other pump was inoperable, both of which resulted in escalated enforcement.

Emergency Notification System (ENS) reports occurred at a high rate as a result of the special outage conditions and system configurations. Notifications were generally conservatively made and technically correct. ENS notification was not made initially for the centrifugal charging pump in pull-to-lock event, and for an unidentified RCS leakage above allowable incident. DNE support of Operations in making Operability determinations improved during the assessment period. This improvement was the result of management initiatives and personnel changes.

As a result of the change in licensee management that occurred at the end of the basis period, PORC reviews became aggressive and technically involved in the resolution of issues affecting the safe operation of the unit. Changes in PORC activities which resulted in improved performance included consistency in personnel staffing and the high expectations established by the new plant manager. The elevated expectations were also strongly supported by the new site director and upper TVA management. As a result of the TVA management initiatives, the Plant Operations Review Staff was established as a part time support group for PORC. PORS employed specialized training and skills to perform root cause evaluations and determine corrective action plans associated with plant events, which were then submitted as completed projects to PORC. The use of the Plant Operations Review Staff has involved the PORC deeply in day-to-day plant operations.

At the close of the SALP assessment period Sequoyah upper line management was found to be strongly committed to obtaining quality in plant operations. There was also a general increase in management attention toward the conduct of operations and management awareness of plant conditions. These, coupled with organizational changes to reduce both management resistance to change and the number of management levels, resulted in continuing improvement in the performance of the operating staff and the resolution of technically diverse and complex issues throughout the year.

During this assessment period the entire fire protection staff at Sequoyah was reorganized into a Fire Operations Unit. The Fire Operations Unit consists of a dedicated fire brigade which is responsible for fire suppression and fire prevention activities. The dedicated fire brigade replaced the preexisting system of a fire brigade composed of unit operations personnel. Fire brigade training at TVA's Nickajack Fire Training Center was found to be excellent and brigade manning was determined to be adequate. Reorganization of the fire protection staff greatly improved fire brigade effectiveness and fire prevention activities during this assessment period. Organizational planning and assignment of priorities was demonstrated in the fire brigade reorganization. In general, policies and procedures were well stated and understood. Under the reorganized fire operations unit, decision making was usually at a level that ensured adequate management review. Involvement by corporate management in the fire protection area was evident.

Two Fire Protection QA Audits were performed during the SALP assessment period, one of which was by the licensee's insurer, American Nuclear Insurers (ANI). These audits identified a number of unsatisfactory conditions and findings and recommended several program improvements. The licensee either implemented the corrective actions associated with these findings or evaluated the issues to develop a schedule date for completion of the corrective actions. The NRC identified weaknesses in the areas of procedural implementation of fire penetration barrier requirements and control of combustibles. The new fire protection management was aggressive in the resolution of these issues and appeared to take appropriate corrective actions.

The condition of Fire Barriers, surveillance of fire protection systems and components, emergency lighting, manual equipment and QA audits were satisfactory in terms of the low number of deficiencies noted. Housekeeping practices and conditions relative to fire protection were found to be adequate.

During the SALP assessment period inadequacies in the performance of fire watches were noted. The inadequacies consisted of inadequate management oversight in regard to fire watch personnel and failure of management to provide concise guidance on how fire watch individuals must perform their duties. This issue occurred at the time that the new organization was being put into place and was aggressively pursued by the new fire organization management.

Five violations and one deviation were identified:

a. Severity Level III violation for failure to comply with TS 3.0.3 involving loss of safety functions and for failure to notify the NRC in a timely manner. (88-20-03 & 88-20-04)

b. Severity Level IV violation for failure to implement configuration controls. (88-26-01)

c. Severity Level IV violation for failure to meet requirements of TS 3.3.1 and 3.3.2 to place OTDT and OPDT in trip. (88-39-02)

d. Severity Level IV violation for failure to perform fire watch patrols. (88-46-01)

e. Severity Level IV violation for performing a test of the TDAFW pump without a written procedure. (88-48-02)

f. Deviation for failure to comply with a commitment made concerning the control of combustibles (wood) in safety-related areas. (88-54-01)

2. <u>Performance Rating</u>:

Category 2

3. <u>Recommendations</u>:

The Board recognized that significant experience was gained through the plant events and activities which occurred during the assessment period and resulted in an improvement in the plant operations area.

B. <u>Radiological Controls</u>

1. <u>Analysis</u>

During the assessment period, inspections were performed by the resident and Regional office staff in the areas of radiation protection, radiological effluent, and confirmatory measurements. Included in the inspection program was a special team inspection for restart of Unit 1 and a special team inspection to assess the performance of health physics, chemistry, and radioactive waste processing during the recent outage.

The qualifications of the new Superintendent of Radiological Controls position were determined to have met the requirements discussed in Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants.

The licensee's health physics, radwaste, and chemistry staffing levels were adequate and compared well with other utilities having facilities of similar size. An adequate number of ANSI qualified licensee health physics (HP) technicians were available to support routine operations. During outage operations, additional contract health physics technicians were used to supplement the permanent health physics staff. The overall quality and experience level of the health physics staff is viewed as a program strength. Radiation protection training was considered good. The licensee's general employee training (GET) in radiation protection was well defined. The GET training/retraining program not only included standard topics as outlined in 10 CFR 19, but findings of licensee audits and NRC inspections were factored into the training. Management support of and commitment to training was evident in that sufficient time was allowed for training and employees were encouraged to attend.

Management support and involvement in matters related to radiation protection were demonstrated by: (1) purchasing an automated laundry monitor to control the potential for "hot particles" in order to reduce exposure to personnel; (2) installing seven sensitive portal monitors at the exit to the radiation controlled area (RCA) to be more effective in detecting personnel contaminations; (3) establishing an ALARA incentive program; and (4) providing corporate support in resolving technical issues as related to the radiation protection program.

Resolution of technical issues was generally adequate; however, a special team inspection observed, during the Unit 2 refueling outage at the end of the assessment period, that the licensee experienced problems in containment such as high iodine airborne radioactivity, an unexpected increase of beta radiation levels in steam generators, and heat stress to personnel while wearing supplied air hoods. These problems appeared to be caused by a failure of licensee management to communicate and evaluate these problems adequately. Early identification and technical resolution of the root causes were not performed in a timely manner, which created the need for increased radiological attention, resources, and demand for support from the radiological controls program.

During the assessment period, a special NRC inspection team reviewed the licensee's controls for high radiation areas and determined that these controls were generally adequate.

However, one violation was identified pertaining to two Assistant Unit Operators (AUOs) who were unknowingly working in a high radiation area in the Unit 1 Auxiliary Building created by an inadvertent introduction of reactor coolant and resin into the CVCS demineralizer resin transfer piping. The AUOs received doses of between 400 and 500 mrem and did not exceed any administrative or NRC exposure limits. It was determined that the area was posted as a radiation area instead of a high radiation area and that the workers had neither an integrating dose rate monitoring device nor an individual present with a dose rate monitoring device to provide radiological protection job coverage. The licensee's immediate corrective action was to post and lock the concerned high radiation area and to reconfirm that other radiation and high radiation areas were adequately controlled.

The respiratory protection program was reviewed by the NRC during the assessment period and it was determined that the program was well defined and implemented in accordance with appropriate regulations.

The 1987 collective radiation dose was 206 person-rem which was approximately 56% of the national average of 368 person-rem per pressurized water reactor (PWR). In 1988, the station's collective radiation dose was 382 person-rem, compared to 345 person-rem per unit national average, which when combined with the 1986 and 1987 collective radiation dose averaged 284 person-rem for three years. However, since the unit has been inoperative for an extended period, the three year average is not necessarily comparable to similar intervals for other units.

At the end of 1987, the area of the plant controlled as radioactively contaminated was approximately 15% of the total area which potentially could become contaminated. At the end of 1988, the area contaminated was still approximately 15% and slightly above other facilities similar in design, however, this did not create a significant personnel exposure or personnel contamination problem.

The licensee experienced 130 personnel contaminations in 1987. The number of personnel contaminations in 1987 was among the lowest in Region II. However, in 1988, the number of personnel contaminations increased to 409 and 155 of these were skin contaminations. The increase in personnel contaminations was due in part to startup activity at the plant, increasing radiation levels and the increased detection sensitivity of the new, more sensitive, portal monitors at the exit of the RCA.

Effluent summary data for 1985, 1986, and 1987, are contained under Supporting Data and Summaries, Section I of this report. These releases are consistent with the plant being shut down from mid-1985 through 1987, and consequently no basis exists to establish any trends during the assessment period.

During the assessment period, the licensee's program for packaging, shipping, and storage of low level radioactive waste was determined to be adequate. The licensee demonstrated good radioanalytical trend capability by showing close agreement with NRC results for both beta-emitting and gamma-emitting samples. However, weaknesses were identified in the radiological waste water processing area as described in the operations section of this assessment.

Two violations were identified:

a. Severity Level IV violation for failure to adhere to or establish procedures for performing breathing zone air samples and for exposure control during steam generator work. (88-31-02)

b. Severity Level IV violation for failure to evaluate the radiation hazards present in the 690 foot elevation Pipe Chase in the Auxiliary Building. (89-05-04)

2. <u>Performance Rating</u>:

Category 2

3. <u>Recommendations</u>:

None

C. <u>Maintenance/Surveillance</u>

1. <u>Analysis</u>

During the assessment period, the technical quality of maintenance and surveillance at Sequoyah was good as a result of the many technical and programmatic upgrades which occurred. These programs experienced substantial organizational and personnel changes resulting in a large number of licensee initiatives. The addition of a new maintenance superintendent at the beginning of the assessment period resulted in licensee initiatives in the maintenance area which included; increasing the use of system engineers, the use of new vibration monitoring equipment techniques, maintenance procedure enhancement, extensive Motor Operated Valve Actuators (MOVATS) testing of primary and balance-of-plant valves, establishment of a 24 hour Outage Manager to coordinate maintenance and modification work, and the organization of maintenance and modification activities into train and system outages. Management of the Maintenance Program was very effective as demonstrated by positive trends in industry indicators such as maintenance backlog, tagging, overtime use, CAQR and LER generation, QA document rejection, Post Modification Testing (PMT) rejection requiring maintenance rework, personnel contamination, industrial safety practices, and delinquent safety-related preventive maintenance. Line management increased its presence in the operating and work spaces, became more aware of plant status and technical issues and demonstrated a commitment to the program and associated improvements implemented during the assessment period.

The licensee developed a detailed program for completed maintenance record review, which is quite thorough and effective in identifying and correcting deficiencies. The use of procedures in accomplishing maintenance activities was adequate and improving. The quality of procedures and work requests, and their associated review, steadily increased as a result of Maintenance Section upper and middle level management involvement in the licensee's program for removal, repair and restoration of safety-related equipment. The licensee initiated a system/train outage concept which was coordinated with unique site electrical distribution and TS requirements. In addition, the licensee instituted a standard maintenance practice which established the method for managing, tracking, planning, scheduling, post work evaluation of and documentation of maintenance work activities. This establishment of administrative control over maintenance work activities reduced open-ended "Troubleshoot and Repair" type work orders and provided clearer direction to the personnel performing work in the field. Operability determination was also added to the administrative control process prior to closing out work orders.

The licensee's action with regard to NRC maintenance related initiatives was generally good. The response varied depending on the organizations involved and the time during the assessment period when the NRC initiatives occurred. Licensee response improved in all areas throughout the assessment period. Responses from onsite maintenance and modifications organizations were usually quick, professional and technically accurate. During the initial portion of the SALP assessment period, support for onsite maintenance related issues from the TVA DNE organization took long periods of time. This caused issue resolution and operability determination to lag. However, by the middle of the assessment period DNE support for maintenance and modification activities was much improved. Licensee resolution of maintenance related technical issues usually indicated technical understanding of the issues, operational conservatism, and was generally well thought out. Examples of well thought out maintenance activities were; RCP trip bus troubleshooting and repair, and steam generator tube leak resolution and preventive plugging. Those maintenance activities that were less professionally addressed by the licensee included pressurizer safety valve trip setpoint calibrations which occurred at the beginning of the assessment period.

The maintenance staff is generally well qualified and trained. Special training was given to maintenance personnel following issues related to the maintenance management system, EQ, conduct of testing, and configuration control. Training also included management training for all levels of Maintenance Department management and specific technical training for first and second line managers to increase in-craft and cross-craft supervisory expertise. The experience levels of maintenance department first line supervisors averaged approximately 10 years of craft related experience, which included several hundred hours of craft and engineering training. The site maintained the INPO training accreditation received during the basis period for maintenance training.

During the assessment period, outage and work control processes were established and implemented. Performance immediately improved due to planning and assignment of priorities. Procedures for control of these processes were well defined, and appeared to be understood by the personnel involved in their implementation. The technical background and level of plant systems knowledge of the planners, coordinators and managers in the work control/outage organization was excellent. These positions were filled with operators, engineers, and managers that were deeply involved in the day-to-day operations of the plant and demonstrated excellent communications and organizational skills.

While maintenance tracking and planning was considered a strength, maintenance outage scheduling was considered to be a weakness. The licensee demonstrated it was capable of drafting detailed corrective and diagnostic maintenance plans, and implementing those plans in the field. However, outage and maintenance schedules rarely had any realistic relation to the actual work being performed in the plant and exhibited continual and predictable schedule slips.

The licensee used the composite maintenance crew concept for MOVATS testing, refrigeration, and general maintenance. An NRC review of the implementation of the composite crew process at the begining of the assessement period revealed that no procedures addressed the training and qualifications requirements for foremen supervising personnel in other crafts, for craftsmen performing work outside of their craft, or for craftsmen performing independent verification outside of their craft. Although no plant events were attributable to composite crews during the assessment period, composite maintenance crews existed in contradiction to the training and qualification requirements for maintenance foremen and craftsmen. This indicated insufficient management attention to and involvement with the composite crew concept and represented a failure by management to recognize that minimum regulatory requirements were not being met. Once management attention was focused on the problem, a comprehensive procedure was developed to address the composite maintenance crew concept. Corrective actions that were initiated appeared to have resolved problems with the composite crew concept.

The control and use of calibrated equipment met regulatory requirements and purchase receipt inspection and traceability of installed materials was found to be acceptable. Additionally, post maintenance testing was found to be satisfactorily accomplished.

During the assessment period the material condition of plant components steadily improved. A review of system failures did not indicate any adverse management or maintenance practices. Several conditions that did not constitute failures but did affect plant operations were: leaking pressurizer safety valves on both units, a leaking reactor vessel flange O-ring on Unit 1, and unstable feedwater automatic controls for both units. In the case of the Unit 1 pressurizer safeties and the Unit 1 vessel flange O-ring, plant activities were well controlled and personnel involved were technically astute and receptive to NRC initiatives. However, in reference to feedwater controls, less than cohesive disciplined management activities were noted.

The plant's material condition, preservation, and housekeeping status was adequate. Occasionally maintenance debris and other material/housekeeping deficiencies existed in the auxiliary building and other plant spaces. Additionally, work in progress was often left open, uncovered, and unattended during work crew breaks and turnover periods. Examples of these conditions were; ice condenser cleanliness prior to Unit 2 initial heatup, loose items and debris found by the NRC in safety-related electrical panels and distribution boards.

During the assessment period the Preventive Maintenance (PM) program at Sequoyah was in the midst of a significant amount of change. The licensee initiated a PM Upgrade Program which was very detailed and resulted in a significant increase in the number of PMs required for plant equipment. This PM upgrade effort was in place for the majority of the assessment period and the developmental stage will last another year. Weaknesses were identified in the number of outstanding delinquent PMs, and the existence of a significant percentage of recently developed PMs that had never actually been performed on plant equipment. The overall conclusion in the PM area was that a very strong PM program was being developed with involved management support. The program is being developed as a quality activity and will improve the safety and reliability of plant equipment when it is fully impleme ed. The results of this effort, in the form of benefit to ant equipment, has not yet been realized.

Predictive analysis techniques were well integrated into the licensee's maintenance program. Vibration analysis and MOVATS testing were active at the site and were found to be instrumental in the identification of much of the corrective maintenance. These two techniques were also found to be used as an integral part of the licensee's post-maintenance surveillance activities. In addition, the licensee implemented a system performance monitoring program to improve station reliability. The program includes vibration monitoring, system and component parameter trending, System of the Month reviews, and performance walkdowns. Upper plant management is very attuned to the results from these maintenance techniques and plant operational decisions were made using this data.

At the beginning of the assessment period, management continued to experience a lack of full understanding of the technical requirements necessary to fully resolve some NRC identified procurement issues. Following NRC identified adjustments to the program, Sequoyah established an acceptable program for resolving replacement part issues. Following the NRC findings, management demonstrated a clear understanding of the issues involved, proposed timely resolution of the findings, and proposed resolutions which were technically sound. In a specific case (e.g., molded case circuit breakers), Sequoyah exceeded the bulletin response requirements which enabled the NRC to provide up-to-date guidance to other licensees. In addition, procurement and maintenance management coordinated closely during the second half of the assessment period to reduce, by approximately 50 percent, the outage work that could not be performed due to outstanding material items.

Safety-related equipment storage continued to be well managed throughout the assessment period. Several cases existed where detailed storage and material information was necessary to support plant operability determinations. In each case the information was retrieved, clearly supported operability and demonstrated a service related role for the storage and procurement organizations.

Staffing in the procurement and storage areas was adequate. Staffing of the contract engineering group (CEG) was generally good. While site and corporate management had the expertise for the procurement operation, potential impacts on continued performance were identified as a result of their possible involvement in other TVA site procurement activities.

During this assessment period, Sequoyah transitioned from a separate dedicated EQ organization to a matrix organization within the site DNE organization. This transition occured without interruption or degradation of the quality of EQ corrective and preventive maintenance implementation. EQ maintenance decisions were made at appropriate levels. Additionally, plant organizations had well stated policies to guide them in completing field work. Management authority and responsibilities were defined and understood in the EQ area.

Sequoyah management continued their resolution of technical issues in the maintenance area with conservative approaches during the assessment period. This was illustrated by the implementation of corrective maintenance activities to support the qualification of silicone rubber electric cable installed inside containment and the qualification of transmitter cable nylon butt splices. The maintenance department was adequately staffed with personnel having the appropriate expertise.

Surveillance performance and technical adequacy continued to improve through an extensive surveillance review and inplant validation process that continued throughout the assessment period. Surveillance scheduling was reorganized resulting in only one administratively late TS required surveillance occurring following the restart of Unit 1. This improvement in surveillance management was the result of the licensee's aggressive SI planning and scheduling program. The licensee's scheduling performance of non-TS required surveillances and preventive maintenance is less aggressive and appears to rely heavily on input from upper plant management rather than first and second line supervision.

In the vast majority of surveillances performed, implementation of the surveillance testing was excellent reflecting adequate planning and assignment of priorities, and indicating an aggressive level of management overview. However, surveillance procedural adherence problems continued throughout the assessment period, although improvement in this area was noted following the initial Unit 2 restart activities. Examples of procedural adherence problems were; surveillance of a Reactor Coolant System (RCS) flow indicator resulting in a reactor trip when the instrument was returned to service, and a power operated relief valve (PORV) opening when an RCS resistance temperature device (RTD) was returned to service. Licensee resolution of surveillance related technical issues reflected a thorough understanding of the appropriate issues. Management was responsive to NRC initiatives in that they established new surveillance instructions in response to NRC information notices and bulletins. Personnel performing as test directors while conducting surveillance testing activities appeared to have a good working knowledge of the surveillance procedures and were trained in the use of required instrumentation.

A management initiative, designed to minimize the recurrence of mispositioned valves, was to form a dedicated Operations Department surveillance instruction performance team. Forming such a team limited the number of people performing surveillance instructions, increased the exposure of each team member to the various instructions, and enhanced internal communications. The team appeared to be effective in improving efficiency and control. The SI team concept was a case of effective technical resolution and management involvement that occurred during the assessment period.

During the assessment period physics-related activities associated with the restart of Units 1 and 2 demonstrated the ability of the licensee to perform at a technical level above that required to meet regulatory requirements. A number of complications were experienced during startup testing, including significant differences between the measured and predicted critical boron concentrations on both units and a positive zero power moderator coefficient on Unit 1. Licensee management responded effectively to the complications which were encountered. Management ensured that adequate personnel resources were allocated to properly perform the test program and that an atmosphere existed which encouraged feedback from the ersonnel involved with the testing. This resulted in a continuing improvement of the reactor physics testing program.

A significant investment was made in the training of inexperienced personnel and in the cross training of design specialists, which should benefit future reactor engineering activities and result in further improvement of the program. Marked improvement in the control of nuclear design calculations and computer codes was observed during the assessment period.

Management involvement in assuring quality was demonstrated in that the chemistry program was very actively supported by the corporate chemistry staff. The staff was involved in developing a corporate policy statement and directive which established philosophy, directives and responsibilities for a chemistry program which endorsed the guidelines recommended by the steam generators owners group (SGOG) and Electric Power Research Institute (EPRI). Management emphasized the need for quality control in all aspects of the chemistry program to meet the stringent criteria recommended by SGOG and EPRI for prevention of corrosion.

Adequate resolution of technical issues was exhibited in the short term wet layup of Unit 2, the long term dry layup of Unit 1 and the startup of Unit 2. Modifications to the moisture separator reheaters replaced copper-nickel tubes with stainless steel tubes, reducing the potential source of copper corrosion products to the steam generators. Replacement of all resins in the polisher vessels prior to restart of Unit 2 was a contributing factor to the good water quality during restart. Consequently, a lengthy chemistry hold was not necessary. However, the shortage of demineralized water limits the number of polishers that can be used. The licensee has initiated investigatory programs to improve the all volatile treatment (AVT) chemistry control program. The areas of wet and dry layup of plant systems, and corrosion and erosion programs were determined to be acceptable.

Even though there were major changes in key staffing positions in the plant water chemistry program, the defined program was implemented with an adequate number of qualified, experienced supervisors in accordance with licensee procedures.

As determined at the end of the assessment period, the ISI program and procedures were acceptable and management involvement in the ISI process was apparent. Based on a review of ISI program submittals and program changes, TVA's responsiveness to NRC initiatives and staffing for ISI work was adequate. During the assessment period the Inservice Test (IST) program and records were greatly improved and preclude the problems identified during the basis period. Management appeared to be involved in assuring quality in IST activities. Responsiveness to NRC initiatives was evident. Based on observation of in-process testing and review of IST activities, staffing levels appeared to be adequate. IST personnel observed and interviewed in the field conducted themselves in a professional manner, and appeared to be well trained and qualified for their responsibilities.

Seventeen violations were identified:

a. Severity Level IV violation for failure to have a procedure for composite maintenance crews. (87-78-02)

b. Severity Level IV violation for failure to adequately implement surveillances involving RCS temperature, containment spray system flow, and ice condenser operability. (88-02-01)

c. Severity Level IV violation for failure to adequately implement work instructions involving resistance temperature detectors, a system hold order, and the safety-related air system. (88-17-01)

d. Severity Level IV violation for failure to have an adequate fire protection surveillance instruction for containment penetration sleeves. (88-19-01)

e. Severity Level IV violation for failure to have an adequate SI for fire barriers. (88-19-03)

f. Severity Level IV violation for failure to establish and implement plant instructions (TS interpretations) that complied with TS 3.7.1.2. (88-20-01)

g. Severity Level IV violation for failure to implement surveillance requirement 4.5.1.1.1.6 involving cold leg accumulator boron concentration. (88-20-02)

h. Severity Level IV violation for failure to control maintenance activities related to a steam gen: ator level indicator, and flow transmitter 2-FT-68-718 (88-28-01).

i. Severity Level IV violation for structural walkdown issues. (88-29-02)

j. Severity Level V violation for failure to control work practices involving the installation of beveled washers, spring cans and anchor bolt alignment. (88-29-03)

k. Severity Level IV violation for failure to perform an adequate ASME section XI test. (88-29-04)

l. Severity Level IV violation for UHI system inoperable due to failure to perform surveillance. (88-34-02)

m. Severity Level IV violation for EDG surveillance not performed when one EDG was made inoperable. (88-34-03)

n. Severity Level IV violation for two examples of failure to follow procedures for radiation monitor work. (88-39-01)

o. Severity Level IV violation for failure to have an adequate work plan. (88-39-03)

p. Severity Level IV violation for failure to follow AI-47 requirements. (88-40-01)

q. Severity Level IV violation for failure to follow incore flux detector withdrawal procedures. (88-44-02)

2. Performance Rating:

Category 2

3. Recommendations:

The Board recognized that improvements in the maintenance area were the direct result of initiatives instituted by the new maintenance management. The Board also recognizes that an aggressive PM program has been developed, but is not fully implemented, and that benefit to the equipment has not yet been realized.

D. Emergency Preparedness

1. Analysis

The inspections conducted during this assessment period included two routine Emergency Preparedness (EP) inspections and a full participation EP exercise.

The routine EP inspection performed March 7-11, 1988, disclosed that the licensee had revised its system for reviewing and approving changes to the Radiological Emergency Plan and Implementing Procedures. The inspection noted that the changes made under the new system were being properly approved and distributed in a timely manner. Emergency supplies and equipment met regulatory requirements. Although several key personnel changes had occurred, personnel had been properly trained prior to integration into the emergency response organization with one exception. The exception resulted in a violation for failure to provide annual retraining to an alternate Technical Support Center communicator. In the EP area, preparedness audits were found to meet regulatory requirements.

The routine EP inspection performed September 1-4, 1988, disclosed that the licensee had declared six Notification of Unusual Events (NOUE) since February 4, 1988. All events were promptly classified with the exception of a "seismic alarm received" on February 8, 1988. The licensee's failure to promptly report this event as an NOUE was identified as a violation for failure to adequately implement an emergency procedure. In addition, a second example of failure to promptly declare an NOUE on high RCS leak rate was also identified. The licensee was maintaining an adequate notifications and communications capability in the event of an emergency. The areas of shift staffing and augmentation, training, and dose calculation and assessment were found to be adequate.

The emergency exercise with full participation was conducted on December 14, 1988, and demonstrated that the licensee could satisfactorily respond to an emergency at the facility. The most significant of the negative observations was a failure of the Shift Operating Supervisor to recognize an explosion as an entry into the emergency classification logic. However, the licensee adequately demonstrated the ability to classify higher levels of emergency after entering the emergency classification logic. The overall performance was fully satisfactory and an adequate critique was conducted by the licensee.

Three violations were identified.

a. Severity Level V violation for failure to provide annual retraining to an alternate Technical Support Center communicator. (88-18-01)

b. Severity Level IV violation for failure to promptly report an NOUE when a seismic alarm was received. (88-33-01)

c. Severity Level IV violation for late reporting of a NOUE on high RCS leak rate. (88-34-04)

2. Performance Rating

Category 2

3. Recommendations

None

E. Security

1. Analysis

During the assessment period three routine security inspections and one special inspection resulted in the issuance of three licensee-identified-violations relative to key control, unescorted visitors and officers being found inattentive to duty. The reactive inspection reviewed the licensee's investigation of suspected or alleged drug abuse and found the licensee's investigation and resolution to be adequate.

In February 1988, the licensee performed both an Operational Readiness Review (NSB/CA 88-01) and its annual Quality Assurance Audit (SSA-88-06) which resulted in the identification of persistent hardware and equipment inadequacies and the continued dependence on compensatory measures. While no Conditions Adverse to Quality were identified, the Audit concluded that some of the equipment was obsolete and restricted the effectiveness of the security program. NRC has assessed the Safeguards Event Logs, pursuant to 10 CFR 73.71, and found that nearly 93% of the logged security incidents are attributable to failed alarms, cameras, computers and coded-key card readers. The same assessment noted a minor reduction in the number of compensatory measures, due to the correct prioritization of work requests and a relatively short turnaround time for repair of security equipment. It is noted that the licensee-identified violations for officers being found inattentive to duty have a direct relationship to the extensive use of compensatory measures. Much of the security equipment was poorly designed and installed, and has over the years fallen into a state of disrepair such that replacement parts are not always readily available. The NRC found several examples where vendor furnished parts needed to be extensively altered before being used in the current security system. In the interim, the licensee implemented appropriate compensatory measures.

At the Corporate level, the licensee continued to experience attrition at its senior security management level. During this assessment period the ninth manager in the last 10 years resigned. As a result of this continued turnover, numerous assessments, evaluations and studies have been conducted with correspondingly few corrective action programs reaching fruition. After appointment of the most recent and current managers the NRC can now begin to see significant progress made on several old projects, some of which have been successfully completed.

In July 1988, the licensee finalized the reorganization of its Corporate Nuclear Security Services Branch so that there now exists a centralized (and accountable) management system. Within this Branch there is a security compliance section, a consolidated plant access and screening unit, a separate section responsible for equipment upgrade and another section tasked with plans and procedures. A key element of the Branch is a Safeguards Information Network which will computerize all site and corporate data. Another indication of improvement is the upgrading of security training and increased tactical exercises, Multiple Integrated Laser Engagement System (MILES) is available to add to the realism of these drills. The licensee's canine corp is recognized by other federal and state agencies for its expertise in detecting contraband.

At the site level, there exists a direct management matrix from the Site Security Manager to the Corporate Manager of Protective Services within the Nuclear Power Group. The Site Director and the Plant Manager have been instrumental in dedicating site support to reduce the number of security compensatory measures. While technically there is a matrixed relationship between the site and its security organization there is a very strong matrixed interface.

Changes to Physical Security, Contingency, and Guard Training and Qualification Plans were generally well-prepared and coordinated, with one exception. The licensee withdrew one revision to the Physical Security Plan when it was discovered to contain a number of errors and omissions. The licensee has been very responsive to questions and concerns raised on licensing submittals.

The NRC has noticed an improvement in the quality of the security staff while the size of the staff has been reduced. This is evidenced in such key elements as training and procedural knowledge. There now appears to be a premeditated implementation of the security program, as opposed to a reactive security program.

No violations were identified:

2. Performance Rating:

Category 2

3. Recommendations:

The Board recommends that the licensee review it's security upgrade priorities at all three facilities to ensure that the Sequoyah security program continues to reduce its long term reliance on compensatory measures in lieu of reliable security equipment and systems.

F. Engineering/Technical Support

1. Analysis

NRC involvement in the engineering and technical support area was more comprehensive than normally applied to licensee activities. This resulted from interactions between NRC OSP and the licensee necessary to achieve acceptable engineering resolutions as described previously in the summary section and the technical complexity of many of the engineering issues.

The Engineering/Technical Support functional area addresses the adequacy of the technical and engineering support for all plant activities. To determine the adequacy of the support provided, specific attention was given to assurance of quality, including management involvement and control, the identification and approach to resolution of technical issues, responsiveness to NRC initiatives, enforcement history, operational and construction events, staffing, and effectiveness of training, and qualification. This area includes all licensee activities associated with design baseline evaluation implementation in terms of Sequoyah plant modifications, engineering and technical support provided for operations, maintenance, surveillance, training, procurement, and configuration management. This evaluation was based on Sequoyah site inspections conducted by the NRC staff in the above areas and on licensee technical submittals reviewed by the staff containing engineering evaluations supporting the Sequoyah Nuclear Performance Plan (SNPP).

Inadequacies during the basis period were in the areas of design analysis, modification control, engineering documentation, design basis utilization, and design verification. In order to correct these weaknesses, TVA senior management increased their involvement and control during this assessment period to improve the quality of engineering support. TVA management involvement was demonstrated through issues including; the Replacement Items Program, in which TVA Corporate and Sequoyah management were greatly involved in the program to ensure immediate and effective corrective action; the issuance and use of procedures in the civil/structural area, including pipe supports and restraints;

the drawing control process, which is considered now to be of high quality and accuracy; and the procedures for control of thermal expansion tests. The procedures used for the thermal expansion tests were well defined and explicit, demonstrating evidence of prior planning with a proper assignment of priorities.

In response to concerns expressed by the NRC, TVA revised Sequoyah's snubber surveillance program procedures, resulting in a more conservative selection of the number of snubbers to be tested upon occurrence of test failures.

TVA DNE continued the control of the EQ activities as had been established in 1986 and 1987. During this assessment period, Sequoyah transitioned from a separate dedicated EQ organization to a matrix organization within the site DNE organization. This transition appeared to occur without interruption or degradation of the quality of DNE support to the plant. Engineering decisions were made at appropriate levels. This is a clear example of TVA DNE management involvement and control in assuring quality.

Other issues in which DNE management oversight and involvement was strongly prevalent included DNE representation during the morning and outage planning meetings, the initiation of a duty DNE manager for weekend and back shift engineering support for Operations, and the direct management involvement in the organization and allocation of resources for the Restart Test Program.

TVA DNE management, however, has not been adequately involved to ensure quality in all cases. Specifically, the staff guidance provided in Generic Letter (GL) 86-10, for spurious actuations from high-impedance faults had not been followed by TVA. Similar problems with the implementation and applicability of other portions of GL 86-10 had been previously discussed with the licensee early in the assessment period. This instance indicated a reliance of the licensee on the NRC to establish an adequate scope and content for this generic letter with respect to the extent of applicability and indicated a lack of responsiveness to this NRC initiative.

TVA did not follow their design commitments made to the NRC involving criteria for pipe supports and piping analyses. These cases indicated a lack of management involvement in the activities they supervise and a lack of quality verification for commitments made to the NRC.

TVA experienced problems in engineering documentation adequacy and in the backlog of open plant change packages. For example, TVA did not properly document changes to the Emergency Diesel

Generator (EDG) 2B-B load analysis (SQN-E3-002) from Revision 7, which was used as the basis for Unit 2 restart, to Revision 10, in which all EDGs were analyzed for Unit 1 restart. Revision 10 which documented that EDG 2B-B had reduced diesel generator loading, lacked complete information and required additional supporting data to explain the loading changes. Furthermore, the summary letter of EDG load analysis dated August 11, 1988 contained three incorrect numbers, only one of which was later identified by TVA. NRC staff discussions with modification personnel revealed there were approximately 1300 engineering design change workplans remaining open, some dating back to 1980. All required physical work was completed on these workplans prior to plant startup, however, the workplans were left open for various reasons. These problems indicate lack of quality verification for submittals made to the NRC and a lack of management involvement.

The approaches taken by the site and corporate engineering staffs to resolve technical issues from a safety standpoint were adequate with improvement shown during the assessment period. For example, in the civil/structural area, the staff reviewed TVA's submittals for justifying the adequacy of Interim (or Restart) Criteria and design calculations for a field erected tank, cable tray supports, pipe supports, conduit and supports, ERCW pipe access cells, the ERCW pump station, masonry walls, the steel containment vessel, equipment supports and miscellaneous civil/structural issues, and found that the engineering records and design calculations were generally complete and documented. However, as a result of NRC reviews, some of the design calculations were regenerated two or three times by TVA before TVA was able to meet and implement restart requirement design criteria which was acceptable to the NRC. The evaluation results for the issues identified were reasonable, logical and met the Sequoyah restart requirements. In the area of pipe supports, cable tray supports, pipe restraints and equipment supports, staff review and evaluation found that there was a defined set of procedures for the control of engineering activities. It was concluded that engineering records were available, relatively easy to access and were clear. Minor errors were found in some of the specific calculation packages reviewed, however, the general assessment was that TVA had improved the quality of the results of the engineering and technical support groups.

TVA engineering personnel were found to have an understanding of the issues involved when evaluating changes to the facility. The staff audited the licensee's report required under 10 CFR 50.59 supporting the seismic qualification of the interim and final designs associated with the component cooling water (CCW) heat exchanger replacement and associated piping modifications.

The detailed analyses provided to the staff exhibited a comprehensive evaluation of the CCW system to justify continued operation of Unit 1 while the piping modifications were being implemented. The engineering records were extensively documented and readily available for staff audit. The licensee exhibited a thorough understanding of the technical analyses and clearly explained the rationale for allowing continued operation of Unit 1 during the CCW heat exchanger changeout.

Further examples of adequate TVA engineering reviews included the piping thermal expansion test program which demonstrated a sound and thorough approach to identifying potential interference to piping thermal growth as a result of implementation of plant modifications. Also, TVA's response to the staff's concerns regarding potential damage to the containment during the Sequoyah extended shutdown period demonstrated a sound approach to resolving the staff's concerns.

However, in several instances during the assessment period, TVA actions indicated an inconsistency in the thoroughness of technical resolutions and a lack of attention to detail. Examples of weak technical resolutions and lack of thoroughness included TVA's initial cable testing program, EDG voltage analysis (SQN-E3-011, Revision 2,) and a proposed TS change which applied to the Turbine Driven Auxiliary Feedwater Pump (TDAFWP). TVA demonstrated a general understanding of the safety issues involved, however, the engineering analysis accompanying these issues did not reflect an indepth review of all applicable safety aspects. The DNE effort supporting the Sequoyah Unit 2 pressurizer safety valve steam trim/leakage resolution was another example of a lack of effective DNE action to resolve plant problems.

The staff audited the licensee's modification to correct a deficiency in the seismic qualification of Bailey Meter electrical instrumentation cabinets involving the use of aircraft cable. The staff found the licensee's modification to be unacceptable. The licensee did not demonstrate an understanding of the seismic qualification requirements for the Bailey Meter cabinets and thus its fix, using aircraft cable, was not sound. In addition, only after the modification using the aircraft cable was found to be unacceptable, did the licensee establish that the electrical instrumentation was not required for safe shutdown.

While the level of cooperation between DNE and plant personnel has substantially improved, the technical adequacy of the engineering support has not been of a consistently high level. While progress over the assessment period was evident, errors and incomplete evaluations have continued.

During the assessment period, the licensee generally responded well to NRC initiatives. While NRC had to insist on cable type testing, TVA has since been responsive in all remaining areas of the cable testing program. Other examples of TVA's responsiveness were demonstrated in the area of procurement. In a few cases (e.g. molded case circuit breakers) Sequoyah engineering staff exceeded reporting requirements to the NRC with respect to reporting the scope of problems. This assisted the NRC in providing up-to-date guidance to other licensees. In the area of fire protection, responses to NRC requests have generally been timely as well as thorough except for certain provisions of GL 86-10. An exception was in the area of establishing welding inspector certification where records were not complete nor well maintained and corrective action was not timely. Other responsive efforts worth noting include the timely corrective action taken for problems identified during the pre-operational thermal expansion test program. These efforts represented timely corrective action implementation for an NRC initiative which went beyond minimum NRC requirements and, with TVA's proper completion of the test program, significantly enhanced the reliability of the Sequoyah piping systems.

During the assessment period two violations were issued in the Engineering/Technical Support area. The first violation was for failure to take adequate corrective action and follow procedures relative to dedication of commercial grade items for use in safety-related applications. While NRC had observed improvements in TVA's procurement of purchased parts due to previous corrective actions, the inspection determined that Sequoyah was still procuring commercial grade parts without adequate dedication of the parts for use in safety-related applications. The second violation documented that TVA did not have hydraulic and thermal design calculations for the containment spray system, which established the design basis for the pressure and temperature boundaries. Corrective actions for both of the above violations have been implemented and were determined adequate.

Operational and construction events which involved TVA engineering have been properly reported to the staff via the Licensee Event Reporting system. Engineering support for these occasions was adequate to support both proposed and implemented corrective actions.

TVA staffing levels in the engineering/technical support area, including management, were adequate. Position identifications and definitions of authority and responsibility were well established and managed during the assessment period. In the civil/structural engineering area, the items that required resolution by TVA engineering from the NRC's Safety System

Quality Evaluation, were in some instances delayed because of a lack of available staff. However, this was noted as an exception rather than the norm.

The effectiveness of TVA's training and qualification programs in engineering and technical support has generally been adequate with a few exceptions. Lack of adequate training was a major cause of a violation in the procurement area. A lack of adequate training in administrative procedures was found to be a major contributing factor in ISI training and documentation problems and in the reluctance by the ISI group members who performed radiography on welds to follow administrative requirements for procedure changes. These events were inconsistent with the observed results of training for other TVA organizations (e.g. plant modification training, maintenance craft training, and Shift Technical Advisor and Operator training). The pre-operational thermal expansion test program engineers were noted as being well trained and qualified for the performance of their required duties. In general, the training and qualification programs contributed to an adequate understanding of work and general adherence to procedures. The number of exceptions were acceptable. Management of the training and qualification program within the ISI area was inadequate in that adherence to administrative procedures was not enforced.

Two violations were identified:

a. Severity Level IV violation for failure to take adequate corrective action and follow procedures relative to dedication of commercial grade items for use in safety-related applications. (88-07-01)

b. Severity Level IV violation for failure to have hydraulic and thermal design calculations for the containment spray system. (88-29-01)

2. <u>Performance Rating</u>:

Category: 3 Improving

3. <u>Recommendations</u>:

The Board is encouraged by the initiative and efforts expended by TVA to improve the quality and effectiveness of its engineering support for the Sequoyah Nuclear Plant. The Board recognizes that a significant amount of complex engineering work was completed. Since considerable NRC effort and input was needed to obtain acceptable engineering resolutions, the Board concluded that TVA has not yet demonstrated independent performance at a level greater than that necessary to meet minimum regulatory requirements. The Board recommends that management attention to this area continue, that those long term commitments made to assure continued improvement after the initial restart of both units be completed as scheduled, and that adequate long term staffing and funding be maintained to support completion of the long term commitments.

G. Safety Assessment/Quality Verification

1. Analysis

The area of Safety Assessment/Quality Verification included quality assurance and the corrective action process, safety committees, the 10 CFR 50.59 safety evaluation program, event reporting and root cause assessment, the employee concerns program, licensing activities, and corporate support for quality verification. The most significant improvement was in the corrective action program which is now functioning adequately. Improvements were noted in safety committee performance and root cause assessment. Weaknesses were noted in the 10 CFR 50.59 safety evaluation program.

While both site and corporate management were involved in the QA area and the policies were adequately stated, NRC inspections and other NRC staff reviews and evaluations indicated that all new policies were not fully understood by Sequoyah personnel. Problems continued to exist during the early part of the rating period in the corrective action process and adequate corrective action was occasionally not effective resulting in repetitive CAQRs. In addition, CAQR resolutions were sometimes delayed. Changes to the QA topical report are required to be submitted to the NRC at least yearly. TVA made several extension requests for submittal of changes indicating a slow approval process and a reliance on the NRC to establish an adequate time frame for submittal. While the violations that occurred during the assessment period have not been directly related to the QA program, they have involved failure to follow procedures or failure to take adequate corrective action.

Key positions in the QA department were identified and authorities and responsibilities were well defined. The staff expertise level was considered excellent. Training contributed to an adequate understanding of the QA program.

The licensee continued the implementation of the CAQR program which was established during the basis period. Early in the assessment period CAQR reviews indicated weaknesses in operability and significance determinations, reviewer and management training, timeliness, documentation, and auditability of records. The Sequoyah Site Deputy Director personally took charge of the implementation of the Sequoyah CAQR program to ensure that implementation problems would be resolved. The CAQR process required an enormous amount of dedicated upper management effort to ensure that it continued to function adequately. One major reason that the dedicated management attention was necessary was that a large number of issues were identified at Sequoyah, and at other TVA plants which had implications on Sequoyah, that required resolution through the corrective action program, resulting in a significant CAQR backlog. A second reason was that time-sensitive equipment operabilty determinations on engineering issues required determinations prior to the completion of the CAQR technical evaluations resulting in the required use of large amounts of predecisional information. The corrective action process was determined to be adequate to allow the restart of both units. To this end an order, which dealt with a management breakdown in controls for safety concerns having generic implications to other TVA sites, was considered adequately resolved for Sequoyah.

In order to reduce the amount of dedicated upper management effort necessary to make the CAQR system work, the licensee developed a change to the CAQR process and implemented it in September 1988, immediately prior to the restart of Unit 1. The change provided several administrative control programs to act as corrective action screening processes. Those issues that did not meet the acceptance criteria for being a CAQR stayed in the administrative control programs for resolution. A Quality Verification Inspection (QVI) conducted near the end of the assessment period found that the changes were adequately implemented and strongly supported by senior line management. The changes appeared to have the desired effect of forcing insignificant and less significant issues down to the proper level for resolution, while keeping safety significant items at the senior management level.

The QVI reviewed for quality and quality verification in the areas of plant operations, surveillance, maintenance, corrective actions, modifications, and implementation of commitments made to the NRC. The QVI concluded that site line management was strongly dedicated to quality and was convincing workers that quality work was what was expected. One exception to this attitude was in the radwaste processing area as revealed by a resin transfer event that occurred at the end of the assessment period. This event indicated that management attention had been lacking in the radwaste processing area and that overall site procedure upgrades had not had an effect on upgrading quality in this area.

The function of the quality monitoring organization was to assist site management in meeting quality objectives by identifying conditions adverse to quality on a real-time basis before they impacted on nuclear safety, reliability, or component operability. The quality monitoring organization was observed to be a well qualified and adequately staffed organization which was adequately performing its function.

The use of interfaces between groups, by the organization as a whole, to verify and accept quality when deliverables were transferred was not emphasized as a quality verification tool. For example, the maintenance department was using an interface organization between the shops and QA to ensure that completed surveillance tests represented quality work prior to their transfer to QA for review, however some of the problems that were being identified for correction had resulted because procedure changes had not been adequately communicated to the shop organization responsible for performing them. An interface problem was also identified between engineering and the plant in relation to vendor manuals having conflicting data and resulted from a lack of communication between the two organizations. Although interface problems between engineering and the plant were identified by the NRC staff during the basis period, interfaces were not actively used by site or corporate management for the purpose of quality verification.

The licensee identified that the percentage of Boron-10 isotope in the boron being added to the reactor coolant was outside of the established procurement and design specifications. Although this and related nonconforming conditions were identified by licensee personnel on at least three distinct occasions, the established corrective action process was not implemented in a timely manner and was only initiated after the issue was raised by the NRC. Once identified by the licensee, corrective actions were adequate.

The licensee's 10 CFR 50.59 program was reviewed and in most cases found to comply with minimum regulatory requirements, however weaknesses were identified. The first weakness was identified as a violation and related to non-conservative translation of regulatory requirements into procedures; the second weakness was related to the lack of qualification requirements for the performance of screening reviews; the third weakness was related to a lack of definition for when interdisciplinary reviews were required, and the fourth weakness was related to coordination of the reviews between groups. These weaknesses indicated minimal management involvement in assuring the quality of this function. In addition, a failure of the 10 CFR 50.59 process was identified in relation to the excessive post trip cooldown effect on shutdown margin which was identified early in the assessment period and issued after the end of the assessment period as a Severity Level III violation.

A reorganization of the Plant Operations Review Staff (PORS), which is responsible for reporting and investigating plant events, occurred at the beginning of the assessment period. NRC concerns about inadequate root cause analysis for plant events were addressed by providing training for the PORS staff. Root cause determinations and licensee corrective actions improved throughout the SALP period and have become more reliable and technically correct near the end of the period. One failure of the root cause reviews was in the area of excessive post trip cooldowns and the resulting effect on end-of-life shutdown margin which was issued after the end of the assessment period as a Severity Level III violation.

The objective for ISEG and the other safety review committees to identify underlying problems before they become issues was recognized by TVA management. The safety committee reorganizations which occurred near the end of the basis period began to have an effect in accomplishing that objective during the assessment period. PORC was more aggressive and technically involved in the resolution of issues affecting the safe operation of the units. PORC improvements were due to consistency in personnel staffing, strong leadership from the new plant manager, and use of the Plant Operations Review Staff (PORS) as a part-time support group for PORC. PORS employed specialized training and skills to perform root cause evaluations and determine corrective action plans associated with plant events, which were then submitted as completed projects to PORC. The use of the PORS to perform investigative data gathering and initial evaluations has allowed PORC to be more deeply involved in day-to-day plant oversight. The NSRB has continued to show a low profile with respect to onsite activities functioning principally in the areas of LER evaluation, TS change approval and other areas that allow for offsite review. The ISEG was reorganized as a result of a TS change and became more aware of industry issues, showed a greater presence in the plant, and by the end of the assessment period, was becoming an effective auditor of plant activities. Near the end of the period, ISEG and the other safety committees were working together better in understanding what each of their roles should be in accomplishing the overall objective.

A broad spectrum of safety issues was identified by TVA employees in the ECTG program which reflected a previous lack of management involvement with quality. The NRC staff review of the Sequoyah ECTG investigations, corrective actions, and planned programmatic improvements concluded that the evaluations were generally adequate and well documented.

The Employee Concerns Program (ECP) continued to be implemented in an impressive and professional manner. Several audits of ECP open files and concerns were completed with no significant findings or weaknesses. Restart determinations performed on open files and concerns were accurate and conservative. Followup on issues which were both NRC issues and ECP issues resulted in parallel, conservative conclusions. The ECP encouraged the return of issues to line management for resolution and in doing so, has strengthened line management responsiveness to issues identified by non-management employees.

There was a tremendous amount of activity in the licensing area. Supplemental information regarding licensing activity is provided in Section F, under Supporting Data and Summmaries.

Generally, the large majority of the work done by TVA on licensing issues was good and showed evidence of prior planning by management. However, TVA had a tendency to be optimistic in establishing submittal dates which has resulted in frequent requests for extensions. In addition, two examples, TSCR 87-47, Control Room Emergency Ventilation System, and TSCR 88-21, River Water Level and Temperature, were noted where TVA knew that a TS change would be needed and the submittals were not made on a timely basis.

Submittals by TVA generally showed an understanding of the technical issues being discussed. The approach to the technical issues exhibited conservatism and were viable, thorough, and generally sound as demonstrated in their quick response to a primary to secondary leak that developed in a Unit 2 steam generator during start-up, in their response to NRC Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes", and in their submittals requesting relief from ASME code Section XI, Inservice Inspection and Operating Plant Code. In addition, TVA's proposal to revise instrument accuracy calculations for the RCP undervoltage reactor protection channel in TSCR 87-18, RCP undervoltage reactor trip, could be considered illustrative of a rigorous evaluation of technical problems and a timely update consistent with industry practice. This, however, was not true for TSCR 88-20, Upper Head Injection Accumulator Level Switch Setpoint which was submitted without TVA understanding that its application did not meet 10 CFR 50.46(a)(1) and therefore required an exemption.

Conservatism in the licensee's alternate approach to problems was generally exhibited and decision making was usually at a level that ensured adequate management review. The technical reviews occasionally were lacking in detail and/or technical basis. Licensee statements at meetings were not always well thought out prior to presentation to the NRC indicating that communication between licensee organizations was not always clear.

TVA was generally responsive to NRC initiatives. NRC expectations regarding the issue of Steam Binding of Auxiliary Feedwater (AFW) pumps were met in the area of technical accuracy and were exceeded in the area of scheduling. The overall staffing to support operating activities was adequate with the licensing engineer being well qualified and adequately trained. The site licensing organization has been successful in improving the timeliness and quality of responses to NRC violations.

TVA Nuclear Power corporate management was usually involved in Sequoyah site activities in an effective manner. The corporate level was reorganized on July 1, 1988, as part of a general reorganization of TVA itself, and resulted in a reduction in the number of levels of management between the Senior Vice President-Nuclear Power, who is manager of the TVA nuclear power program, and the site. Also, the manager of the TVA nuclear power program, who was a contract employee, was replaced by a permanent TVA employee. The emphasis of TVA's nuclear power program has switched to operating the Sequoyah units within constrained TVA budgets, compared to past budgets, and reduction-in-force within TVA's nuclear power program including the site. The effects of the new emphasis is uncertain, however, the NRC has noted that TVA was reassessing the dates and scope for commitments.

Corporate support for site activities was observed in the areas of Operations, Quality Assurance, and outage management. The support in these areas was limited to activities and managers necessary to support the restart of Units 1 and 2 and the refueling of Unit 2. The support was not global in nature and consisted mainly of loaned corporate managers and specialists that met specified needs. Activities appeared to be well supported by corporate management and the managers supplied by corporate management were professional and well suited to the assigned tasks. A site Radiological Assessor position has been established. The position reports to the Manager of Radiological Control, a corporate position rather than to the Site Director. The position provides a programmatic overview of the Sequoyah radiological control program and an independent reporting path offsite. The Site/Corporate interface was adequate and programmatic overview of the site was occurring.

For the assessment period, corporate management continued to be generally responsive to NRC initiatives. The responses to NRC were generally timely, sound and thorough. Although Unit 1 was restarted in November 1988, the restart date was only three months later than originally scheduled by TVA, as compared to two years later for Unit 2, which showed evidence of improved planning and assignment of priorities.

The significant exceptions to TVA's general responsiveness to NRC initiatives and timely submittals in the rating period were the resolution of the silicone rubber insulated cable testing issue and the tardiness of TVA in submitting Revision 6 of the Corporate Nuclear Performance Plan to reflect the July 1, 1988 reorganization.

Seven violations were identified:

a. Severity Level IV violation for failure to follow procedures for authorization to exceed plant overtime limits. (327, 328/87-78-01)

b. Severity Level IV violation for failure to follow procedures for installation and inspection of seal table bolts. (327, 328/88-09-01)

c. Severity Level IV violation for failure to take prompt corrective action for deficiencies in QA record storage. (327, 328/88-09-02)

d. Severity Level IV violation for failure to properly translate 10 CFR 50.59 requirements into instructions or procedures. (327, 328/88-43-01)

e. Severity Level IV violation for failure to take adequate corrective action for prevention of reactivity changes while both trains of control room ventilation are inoperable. (88-27-01)

f. Severity Level IV violation for failure to take adequate corrective action to preclude repetition of violation 87-30-01 involving lack of control over plant evolutions, and system and equipment status in the radioactive waste area. (88-50-01)

g. Severity Level IV violation for three examples of failure to promptly identify and initiate adequate corrective action for Boron-10 procurement problems. (88-60-01)

2. Performance Rating

Category: 2

3. Recommendations

None

V. SUPPORTING DATA AND SUMMARIES

A. Investigation Review

The NRC's Office of Investigations closed fourteen cases which dealt with TVA during the assessment period. None of these involved enforcement action pertaining to Sequoyah.

B. Escalated Enforcement Action

1. Civil Penalties

Severity Level III violation issued on July 3, 1988, concerning failure to comply with TS when both centrifugal charging pumps were inoperable and failure to report this condition pursuant to 10 CFR 50.72. ($50,000 CP)

2. Discretionary Enforcement for Shutdown Plants

Failure to meet the 10 CFR 50.59 requirements for a 1984 auxiliary feedwater pump modification. No Notice of Violation or Civil Penalty was issued as discussed in a letter dated May 9, 1988.

C. Licensee Conferences Held During Appraisal Period

During the appraisal period, meetings were held with the licensee to discuss various issues, as follows:

1. Management Meetings

Date	Purpose
February 11, 1988	Meeting to discuss load sequencing of plant diesel generators.
March 09, 1988	Meeting to discuss technical issues related to 10 CFR 50 Appendix R.
April 14, 1988	Meeting to discuss differences between Sequoyah, Units 1 and 2 in the Sequoyah Nuclear Performance Plan.
April 29, 1988	Meeting to discuss (1) the Unit 2 steam generator tube leakage and (2) loop seals for the pressurizer safety valves.
June 13, 1988	Meeting to discuss the restart of Unit 2 in light of the five scrams from power in May 1988.
June 22, 1988	Meeting to discuss the TVA commitments for Unit 2.
July 21, 1988	Meeting to discuss Phase II of the Design Baseline and Verification Program for Sequoyah.
September 8, 1988	Meeting to discuss changes to the TVA Conditions Adverse to Quality Program at Sequoyah.

September 13, 1988	Meeting to discuss TVA's preparation for Unit 1 restart and the post-trip cooldown shutdown margin issue.
September 15, 1988	Meeting on TVA's Microbiologically Induced Corrosion Program at Sequoyah.
October 24, 1988	Meeting on the status of TVA's commitments to NRC on Sequoyah.
November 28, 1988	Meeting on the Essential Raw Cooling Water pumphouse formulation and roadway access cells.

2. Enforcement Conferences

March 17, 1988	Enforcement Conference at Sequoyah concerning centrifugal charging pump operability which resulted in EA 88-86. (IR 88-20)
July 28, 1988	Enforcement Conference at Sequoyah concerning upper head injection system operability. Issued as Severity Level IV. (IR 88-34)
December 19, 1988	Enforcement Conference at NRC Headquarters concerning the affect of excessive cooldowns following reactor trips on end-of-life shutdown margin which resulted in EA 88-307. (IR 88-35 & 88-55)

D. Confirmation of Action Letters

1.	April 26, 1988	Reinstatement of Hold Points for Unit 2 Restart from Steam Generator Outage
2.	June 16, 1988	Confirmation of Release from Unit 2 Hold Points
3.	November 7, 1988	Reinstatement of Unit 1 Mode 2 Hold Point

E. Review of Licensee Event Reports

During the assessment period, there were a total of 78 LERs analyzed for Units 1 & 2. The distribution of these reports by causes, as determined by the NRC staff was as follows:

LER CAUSES	UNIT 1	UNIT 2
Component failure	2	6
Design	2	1
Construction/Installation/ Fabrication	1	3
Inadequate Procedure	11	3
Test Calibration	7	3
Other	7	3
Personnel		
- operating activity	5	6
- maintenance activity	2	4
- test/calibration	2	6
- other	3	1
Total	42	36

F. Licensing Activities

The assessment of licensing activities was based, in part, upon licensing actions successfully completed during this period. These include the following:

1. Discretionary Enforcement/Waiver of Compliance

January 30, 1989	Emergency Diesel Generator Surveillance Testing

2. Reliefs Granted

February 8, 1988	American Society of Mechanical Engineers (ASME) Code Case N-411
May 11, 1988	ASME Code Section XI Relief for the Microbiologically Induced Corrosion (MIC) Program
August 18, 1988	Hydrogen Analyzer Sampling Valves, ASME Code Section XI Relief
September 15, 1988	ERCW Valves on CSS Heat Exchangers, ASME Code Section XI Relief
September 15, 1988	Generic Relief on Use of Ultrasonic Monitoring of Pump Flow
November 4, 1988	Temporary Deviation from Appendix R to to 10 CFR 50, Section III.G.

3. Exemptions

July 14, 1988	Schedular Exemption to Appendix J, Type B and C Testing
September 22, 1988	Exemption to Appendix J, Type C Testing for C/RHR Spray System Check Valves
October 26, 1988	Temporary Exemption to Appendix K ECCS Calculations to May 31, 1989
January 26, 1989	Exemption to 10 CFR 50.46(a)(1), Approved ECCS Analysis for Operating Cycle 4

4. Orders

March 31, 1988	Modification of Order 85-49 stating that Sequoyah had satisfied the requirements of the Order.

5. Emergency or Exigent Technical Specification (TS) Amendments

June 30, 1988	Exigent TS Amendment on Corporate Reorganization
January 30, 1989	Emergency TS Amendment on Diesel Generator Surveillance Testing

6. Multi-Plant Actions (MPA) Resolved

Date	MPA Description
March 21, 1988	F-05, Procedures Generation Package
May 5, 1988	A-21, Pressurized Thermal Shock
May 18, 1988	B-60, Environmental Qualification for Unit 2
July 20, 1988	B-98, Bulletin 85-01, Steam Binding of AFW Pumps
September 9, 1988	B-101, Boric Acid Corrosion of Carbon Steel RCS Components
November 28, 1988	B-81, GL 83-28, Items 4.2.1/4.2.2
February 3, 1989	B-60, Environmental Qualification for Unit 1

7. Significant Plant-Specific Issues Resolved

Date	Description
February 23, 1988	Sequoyah Pipe Support Criteria
February 23, 1988	Unit 2 Extended Heatup Prior to Restart
March 11, 1988	Unit 2 Restart Employee Concern Element Reports
March 14, 1988	Revised Sequoyah IST Program
March 21, 1988	Hydrogen Analyzer Operability
May 18, 1988	NUREG-1232, Volume 2, Review of Sequoyah Nuclear Performance Plan for Unit 2 Restart
May 25, 1988	Silicone Rubber Insulated Cable Inside Containment
June 23, 1988	Bulletin 86-02, Static-O-Ring Switches
July 6, 1988	GL 87-06, Periodic Verification of PIV Leak Tight Integrity
August 3, 1988	10 CFR 2.206 Petition on Emergency Diesel Generators
September 22, 1988	JCO for Operation with C/RHR Spray System Check Valves without Appendix J, Type C Testing
November 4, 1988	Unit 1 Restart and Both Units Non-Restart Employee Concern Element Reports
December 5, 1988	GL 87-12, Loss of RHR with RCS Partially Filled
February 3, 1989	NUREG-1232, Volume 2, Supplement 1 Review of Sequoyah Nuclear Performance Plan for Unit 1 Restart

8. License Amendments

AMENDMENT NO. UNIT 1	UNIT 2	DATE ISSUED	TS NUMBER	TITLE
67	59	2/11/88	TS 87-37	Lower Containment Vent Coolers
68	60	2/17/88	TS 87-47	Control Room Emergency Ventilation System
69	61	4/04/88	TS 87-03	Operability and Surveillance Rqmts For Residual Heat Removal Spray
70	62	5/16/88	TS 87-15	Addition of Two Containment Isolation Valves to Table 3.6.2
71	63	5/18/88	TS 87-33	Bypass Leakage Paths to the Auxiliary Building
72	64	5/24,88	TS 87-01	Administrative Controls
73	65	6/27/88	SGER	Modification of Paragraph 2.E of OL (Physical Security Plan)
74	66	6/30/88	TS 87-12 TS 87-44 TS 88-12	Twelve Changes to Section 6 (Administrative Controls)
75	-	7/06/88	TS 87-23	Delete License Condition 2.C.10 (Water Chemistry Program)
76	67	7/13/88	TS 79	Remote Shutdown Monitoring Instrumentation
77	68	08/5/88	TS 88-10	TDAFWP Response Time and Actuation Signal Testing
78	69	8/15/88	TS 88-05 TS 88-07	Amend Tables 3.6.1 and 3.6.2 and Implement GL 87-09
79	70	8/15/88	TS 88-21	River Water Level and Temperature
80	71	8/16/88	TS 87-42 TS 87-43 TS 87-36	Addition of 3 MOVS and Cont. Spray Pump Differential Pressure
81	72	09/1/88	TS 87-07 TS 87-31	Seismic Monitor Information; SR for Containment Isolation; Logic for Vacuum Relief Valves

8. License Amendments
(cont'd)

AMENDMENT NO. UNIT 1	UNIT 2	DATE ISSUED	TS NUMBER	TITLE
82	73	09/9/88	TS 88-01	Addition of 5 MOVs to Replace Check Valves.
83	74	9/21/88	TS 87-35 TS 68	Addition of RCS Pressure Isolation Valves
84	75	9/22/88	TS 82	Reactor Coolant Loop Required for Mode 3
85	76	9/22/88	TS 87-15	Reactor Coolant UnderVoltage Reactor Trip
86	-	10/14/88	TS 88-20 TS 74	Upper Head Injection Level Switch Setpoint.
87	-	10/14/88	TS 87-06	Deletion of Table 4.4-5
88	77	10/14/88	TS 87-10	Maximum Allowable Pressure Drop Across the HEPA and Charcoal Filters
89	78	10/14/88	TS 87-19	Ice Condenser Bed Temperature Monitoring System
90	79	10/14/88	TS 87-46 TS 88-09	Bypass Leakage Paths to Aux. Bldg. Table 3.6-1
-	80	11/28/88	TS 88-18	Weighing of Ice
91	81	12/5/88	TS 87-41	Crane Travel - Spent Fuel Pit Area
92	82	12/29/88	TS 87-27	Residual Heat Removal System Isolation
93	83	12/29/88	TS 88-23	Operating License Extension
94	84	12/29/88	TS 87-40	AFW Suction Pressure Low Setpoint and Allowable Value
95	-	01/23/89	TS 88-28	Heat Flux Hot Channel Factor
96	85	01/22/89	TS 87-09	Diesel Generator Bldg. Carbon Dioxide System
97	86	01/22/89	TS 87-45 TS 88-08	Fire Detection Instruments

8. License Amendments (cont'd)

AMENDMENT NO. UNIT 1	UNIT 2	DATE ISSUED	TS NUMBER	TITLE
98	87	01/30/89	TS 88-13	Ice Condenser Surveillance
99	88	01/30/89	TS 89-17	Change to Diesel Generator Surveillance Testing
100	89	01/31/89	TS 88-04	Diesel Generator Cold Fast Starts-2-

G. Enforcement Activity

All violations for the appraisal period were cited against Unit 1 and Unit 2.

NO. OF DEVIATIONS & VIOLATIONS IN SEVERITY LEVEL

FUNCTIONAL AREA	DEV	V	IV	III	II	I
PLANT OPERATIONS	1		4	1		
RADIOLOGICAL CONTROLS			2			
MAINTENANCE/ SURVEILLANCE		1	16			
EMERGENCY PREPAREDNESS		1	2			
SECURITY						
ENGINEERING/TECHNICAL SUPPORT			2			
SAFETY ASSESSMENT/ QUALITY VERIFICATION			7			
TOTAL	1	2	33	1		

H. Reactor Trips

A total of seven automatic reactor trips occurred during the assessment period, five above 15% power and two below 15% power. No manual trips were initiated and no trips occurred with the unit subcritical. In general, these reactor trips occurred during power escallation activities and were followed by extended periods of continued operation. The trips are described in more detail below:

May 19, 1988 - Unit 2 tripped from 73% power due to a steam/feed flow mismatch coincident with low steam generator level. This situation occurred due to maintenance being performed concurrently on two pieces of equipment which together could cause a reactor trip (one channel of steam generator level indication to replace an unqualified splice and the #3 heater drain tank level controller which resulted in plant oscillations).

May 23, 1988 - Unit 2 tripped from 70% power due to low flow on RCS Loop #4. This situation occurred due to a personnel error while performing a surveillance on the loop #4 flow transmitters.

June 6, 1988 - Unit 2 tripped from 98% power on steam/feed flow mismatch coincident with low level in #4 steam generator. The trip occurred while performing a surveillance on the feedwater regulating valves and resulted because a diode was missing in the block circuit.

June 8, 1988 - Unit 2 tripped from 12% power on low-low level in #2 steam generator due to an operator error when placing the feed pump controller in the automatic position resulting in steam generator level oscillations.

June 9, 1988 - Unit 2 tripped from 20% power on low-low level in #2 steam generator due to feedwater heater isolations which caused feed flow and steam generator level transients.

November 18, 1988 - Unit 1 tripped from 72% power due to an electrical ground in the main generator which tripped the main turbine.

December 26, 1988 - Unit 1 tripped from 7% power on low-low level in #4 steam generator. The trip was caused by a series of events that started with a manual trip of the main turbine due to generator seal rubbing. After the turbine trip, steam generator level was controlled using manual feedwater control which resulted in a feedwater isolation from high-high level in #2 steam generator followed by the reactor trip on low-low level in #4 steam generator.

I. Effluent Release Summary

Gases	1985 (Curies)	1986 (Curies)	1987 (Curies)
Fission and Activation Gases	4.57 E+03	1.21 E-00	0.0
Halogens and Particulates	6.63 E-03	1.56 E-03	5.04 E-04
Liquids			
Fission and Activation Products	2.08 E±00	1.65 E-01	4.66 E-01
Tritium	6.33 E+02	1.72 E+02	1.19 E+02

J. Acronyms

ALARA - As-Low-As-Reasonably-Achievable
ASME - American Society of Mechanical Engineers
ANSI - American National Standard Institute
ANI - American Nuclear Insurer
AUO - Assistant Unit Operator
AVT - All Volatile Treatment
CAQR - Condition Adverse to Quality
CCW - Component Cooling Water

CEG	-	Contract Engineering Group
NPP	-	Nuclear Performance Plan
DBVP	-	Design Baseline Verification Program
DNE	-	Division of Nuclear Engineering
EA	-	Escalated Enforcement Action
ECCS	-	Emergency Core Cooling System
ECP	-	Employee Concerns Program
ECTG	-	Employee Concerns Task Group
EDG	-	Emergency Diesel Generator
EOP	-	Emergency Operating Procedures
EP	-	Emergency Preparedness
EPRI	-	Electric Power Research Institute
EQ	-	Environmental Qualification
ERCW	-	Essential Raw Cooling Water
FT	-	Flow Transmitter
GET	-	General Employee Training
GL	-	Generic Letter
HP	-	Health Physics
IDI	-	Integrated Design Inspection
INPO	-	Institute for Nuclear Power Operations
IR	-	Inspection Report
ISEG	-	Independent Safety Engineering Group
ISI	-	Inservice Inspection
IST	-	Inservice Testing
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MIC	-	Microbiologically Induced Corrosion
MILES	-	Multiple Integrated Laser Engagement System
MOVAT	-	Motor Operated Valve Actuators
MSIV	-	Main Steam Isolation Valve
NMRG	-	Nuclear Maintenance Review Group
NOUE	-	Notice of Unusual Event
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSRB	-	Nuclear Safety Review Board
OPDT	-	Over Power Delta Temperature
OSP	-	Office of Special Projects
OTDT	-	Over Temperature Delta Temperature
PM	-	Preventive Maintenance
PMT	-	Post Modification Testing
PORC	-	Plant Operations Review Committee
PWR	-	Pressurized Water Reactor
QA	-	Quality Assurance
QMDS	-	Qualified Maintenance Document System
QVI	-	Quality Verification Inspection
RII	-	Region II
RCA	-	Radiation Controlled Area
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RIP	-	Replacement Items Program

RTD	-	Resistance Temperature Device
SALP	-	Systematic Assessment of Licensee Performance
SGOG	-	Steam Generators Owners Group
SI	-	Surveillance Instruction
SNPP	-	Sequoyah Nuclear Performance Plan
SOI	-	System Operating Instruction
TACFs	-	Temporary Alterations
TDAFW	-	Turbine Driven Auxiliary Feedwater Pump
TS	-	Technical Specifications
TSCR	-	Technical Specification Change Request
TVA	-	Tennessee Valley Authority
TVAPD	-	TVA Projects Division (NRC)
UHI	-	Upper Head Injection
VCT	-	Volume Control Tank