Enclosure 4

SUPPLEMENT NO. 1

TO THE

SAFETY EVALUATION REPORT

BY THE

OFFICE OF NUCLEAR REACTOR REGULATION

U. S. NUCLEAR REGULATORY COMMISSION

IN THE MATTER OF

TENNESSEE VALLEY AUTHORITY

SEQUOYAH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-327 AND 50-328

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FOREWORD

Supplement No. 1 to the Safety Evaluation Report for Sequoyah consists of two parts:

PART I - Review and Evaluation of Pre-TMI-2 Issues.

PART II - Review and Evaluation of TMI-2 Issues Related to Fuel Load and Low Power Test Program.

PART I

1.0 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

The Nuclear Regulatory Commission's Safety Evaluation Report in the matter of Tennessee Valley Authority's application to operate the Sequoyah Nuclear Plant, Units 1 and 2, was issued in March 1979. At that time we identified issues which were not resolved with the applicant. They were categorized as:

a. Outstanding issues which needed resolution prior to the issuance of an operating license.

b. Issues for which we had completed our review and had determined positions for which there appeared to be no significant disagreement between the applicant and the staff. Further information was needed, however, to confirm these positions.

c. Issues for which we had taken position and would require implementation and/or documentation after the issuance of the operating license. These would be conditions to the license.

The staff's review of the operating license application, as reflected in the SER issued in March 1979, focused on the requisite findings to support issuance of an operating license authorizing full power operation. This assessment was governed by the Commission requirements in effect at the time. However, following the TMI-2 accident, the Commission "paused" in its licensing activities to assess the impact of TMI-2. During this "pause" the recommendations of several groups established to investigate the lessons learned from TMI-2 became available. Tese groups included the Presidential Commission to Investigate TMI-2, the NRC Special Inquiry Group and several staff task forces, such as the Lessons Learned Task Force and the Bulletins and Orders Task Force. All available recommendatios were correlated and assimalated into a "TMI Action Plan Prerequisites for Resumption of Licensing."

Although the Commission has, as recently as February 7, 1980, reviewed this Action Plan, it has not fully approved the prerequisites for resumption of licensing. But, it has indicated it would consider, in the interim, a proposal by TVA for issuance of an operating licensing authorizing TVA to conduct Special Tests at power levels not exceeding five percent of full power.

This supplement which addressess the requirements for operation of the facility up to a power level of five percent of full power (1) discusses resolution or current status of the above issues, and (2) identifies new non-TMI-2 issues and their status since the issuance of the Safety Evaluation Report. Each of the following sections of the supplement is numbered the same as the corresponding sections of the Safety Evaluation Report. Except where noted, this supplement is an addition to the discussion in the Safety Evaluation Report.

It should be noted that the scope of review for Part I was performed by the normal NRR technical branches and is based on existing regulations which are described in the Standard Review Plan, Branch Technical Positions, Regulatory Guides and Standards, and the unresolved Safety Issues documents.

The review for Part II is based on draft revisions of the NRC Action Plan which includes the requirements derived from the Lessons Learned, Bulletins and Orders Task Forces and the recommendations of the Presidential (Kemeny) Commission to investigate TMI-2 and NRC Special Inquiry Group reports. The evaluation of the applicant's submittals in response to the Action Plan requirements was for the most part conducted by special interdisciplinary terms drawn from the general technical staff and managed by DPM. In special instances the evaluation was conducted by joint NRR/I&E teams. This Supplemental Safety Evaluation Report was then reviewed by the relevent NRR and I&E staffs to assure completeness and technical acceptability of the conclusions.

TMI-2 matters are discussed separately in Part II of this supplement.

1.6 Outstanding Issues

In the Safety Evaluation Report, we had identified five outstanding issues. Since that time, we have identified 13 new items. These are resolved to the extent identified below, and further discussed in the supplement under the appropriate sections. Please note that exemptions are required for appendices "G," "H," and "J" of 10 CFR Part 50 and are discussed in the applicable sections of the SER.

Items Identified in SER

1. Bolted Connections in Component Supports (Section 3.9.2)

   The applicant had not furnished sufficient information on bolted connections in linear component supports in safety-related systems regarding support plate flexibility considerations in determining maximum bolt loads. This item will be reported at a later date. However, based on our results thus far, the supports using concrete expansion anchor bolts are acceptable for the low power test program.

2. Seismic Qualification of Instrumentation and Electrical Equipment (Sections 7.2.2, 7.8.1)

We had not yet fully completed our review of the Westinghouse-supplied Class 1E instrumentation and electrical equipment. This item is resolved as far as it relates to fuel load and the special test program. For balance of plant equipment this matter is resolved.

3. Fire Protection (Section 9.5)

We had completed our review of the applicant's fire protection program and find it acceptable. The applicant has fully complied with our test requirements and this matter is resolved.

4. Radiological Emergency Plan (Section 13.3)

The applicant has provided responses to our request for additional information on this matter and meets the requirements for the fuel load and special test program phase.

5. Acceptance Criteria for Plant Trip Test (Section 14.0)

The applicant has provided information we requested on acceptance criteria for the turbine trip and generator load reject portions of the plant trip test from 100 percent power. This item is resolved.

New Items

1. ATWS Interim Procedures (Section 15.2)

The applicant has not provided fully acceptable procedures for postulated ATWS events, but must do so prior to full power operation. We have determined that it is acceptable to operate the plant at low power prior to completion of this activity. (See discussion)

2. Foundations (Section 2.6)

The review of the foundation design of seismic Category I structures is completed and all our concerns are resolved.

3. Reactor Vessel Closure Head (Section 3.2)

The reinspection ultrasonic inspection of the Sequoyah Unit 1 vessel closure head revealed a flaw that exceeded code requirements. after close study we have determined that the flow is not an immediate safety concern. But, to insure safety are augmented an inservice inspection program will be instituted to inspect the flaw.

4. Guide Thimble Tubes (Section 4.2)

Wear on the guide thimble tube walls has been observed on other operating pressurized water reactors. This item is resolved by a commitment to perform a surveillance program.

5. Grid Straps (Section 4.2)

Grid strap damage has been observed on discharged assemblies from other nuclear plants. Based on certain procedural changes, we find this matter satisfactorily resolved.

6. Control Spiders (Section 4.2)

Control rod spiders have failed at other plants which prompted a review pertaining to Sequoyah. This matter is resolved to our satisfaction.

7. Rod Drop Transient (Section 4.2)

Analysis indicated the possibility that a rod drop could cause a power overshoot when the reactor is in the automatic mode. This matter is resolved by establishing restrictive control rod insertion limits when the reactor is in automatic control above 90 percent power.

8. Operator Training (Section 13.2)

The operators are qualified to carry out the low power testing program.

9. Bypass Leakage (Section 15.4.1)

The applicant requested an additional 5 minutes of bypass leakage of an increased leak rate of 25 percent of the total contained leakage through the auxiliary building. The applicants request is resolved in accordance with our requirements.

10. Secondary Water Chemistry (Section 5.3.1)

As part of the steam generator tube integrity issue, a proposed secondary water chemistry program was reviewed. A few additional requirements were added by the staff and the item was resolved.

11. Steam Generator Level Instrumentation (Section 7.2)

The staff has required that limitations be made on the minimum low-low steam generator level set-point. This item is resolved.

12. Containment Overpressurization Due to MSLB (Section 15.3.3)

The applicant's analysis has correctly accounted for the potential case where auxiliary feedwater pump run-out flow could overpressure the containment. This item is resolved.

13. Nonsafety Systems (Section 15.2)

The applicant has recently provided additional information on this subject which meets our requirements for fuel load and conduction of the special test program.

1.7. Confirmatory Issues

In the Safety Evaluation Report we identified a number of matters for which we had completed our review and for which there appeared to be no significant disagreement between the applicant and the staff. The applicant was advised of our positions and confirmation of the applicant's commitment to comply with these positions and to provide appropriate information was required. These items are discussed below.

1. Single Failure in the Residual Heat Removal System (Section 5.3.2)

The applicant has agreed to provide a dedicated operator to monitor flow to the residual heat removal pumps during decay heat removal operations. In addition, the applicant will install a flow alarm. This is acceptable.

2. Pressure-Temperature Limits for Heatup and Cooldown (Section 5.2.3)

The applicant has provided an analysis that confirmed its statement that the proposed pressure-temperature limits for reactor vessel heatup and cooldown use is an acceptable prediction for temperature shift.

3. Inservice Inspection of Steam Generator Tubes (Section 5.2.6)

The applicant has formally documented his inservice inspection program for steam generator tubes. This item is resolved.

4. Cold Shutdown Using Safety-Grade Equipment (Section 5.3.2)

The applicant has submitted information on the capability of the system to achieve cold shutdown using only safety-grade equipment. As indicated in Section 5.3.2, the item is resolved subject to the Diablo Canyon test program.

5. Design of Steam Generator and Pressurizer Supports (Sections 3.9.1, 6.2)

The applicant has shown that, the pressure response to line breaks in the steam generator and pressurizer subcompartments has been accomadated in the design of the equipment supports. This item is resolved.

6. Containment Response to Steam Line Break and Environmental Qualifications of Westinghouse Equipment (Sections 6.2.1, 7.2.2, 7.8.2)

Westinghouse has provided an analysis to show that the containment temperature response to the small line break already analyzed will bound the response for the additional breaks we have requested be examined. Review of the environmental qualification of Westinghouse equipment is not fully completed, but the review is completed to the extent that the equipment is sufficiently adequate to load fuel and conduct the special test program.

7. Upper Head Injection Preoperational Tests (Section 6.3.4)

The applicant has submitted confirmatory documentation on tests already performed which demonstrated acceptable flow performance of the upper head injection system. This item is resolved.

8. Containment Sump (Section 6.3.4)

In fulfillment of the applicable requirements of Regulatory Guide 1.79 "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors", the applicant has performed scale model performance tests of the containment emergency sump and submitted reports which we reviewed. The applicant successfully verified acceptable sump performance in the event of certain line breaks. While this issue is resolved for Sequoyah generic studies are continuing on sump debris in PWRs to assure that core blockage would not occur from the material in the sump water.

9. Bypassed Safety Injection Signal (Section 6.3.5)

The applicant provided data to demonstrate that sufficient time is available to respond effectively to postulated line breaks in the residual heat removal system with the plant in the normal shutdown cooling mode with the safety injection signal blocked. This issue was acceptably resolved.

10. Loss-of-Coolant Accident Analysis (Sections 6.3.5, 15.3.2)

We have reviewed the additional loss-of-coolant accident analysis provided by the applicant and conclude that this item is resolved.

11. Response Time Testing (Section 7.2.2)

The applicant has committed to measure channel response time including the sensors, and has submitted the confirmatory information requested to assure acceptable implementation of this commitment. This item is resolved.

12. Isolation Valve Interlocks and Position Indication (Section 7.3.2)

The applicant is committed to a modification such that position indication of two safety-related valves will be maintained when power is removed from the valves. This is resolved.

13. Post-Accident Monitoring Separation Criteria (Section 7.5.2)

The applicant has provided information verifying that he meets the criteria for separation and independence of post-accident monitoring channels. This is resolved.

14. Environmental Qualification of Balance-of-Plant Equipment (Section 7.8.2)

The applicant has provided confirmatory information on an environmental monitoring system and corrected of errors in several tables in the Final Safety Analysis Report. This item is resolved.

15. Diesel Generator and Remote Shutdown Testing (Section 14.0)

We required that the applicant perform tests in accordance with regulatory guides covering diesel generators and remote shutdown capability, or provide justification for exceptions to these guides. Confirmatory information has been provided by the applicant. This item is resolved.

16. Boron Dilution (Section 15.2)

The applicant has documented his procedures associated with alarm setpoints for the high flux alarm which provides protection against a boron dilution event during startup or shutdown. This item is resolved.

17. Long-Term Effects of Steam Line Break (Section 14.3.3)

The applicant has provided information requested to verify operator actions related to long-term reactor vessel repressurization. This item is resolved.

1.8 Staff Positions

The staff had taken positions on certain issues in the Safety Evaluation Report. These items are listed below and are discussed further in this supplement.

1. Seismic Design of Structures and Components (Section 2.5)

The applicant has provided sufficient information to satisfy the staff that margins available in structures and components are adequate to maintain function effectivess during and after a design basis earthquake. The ACRS requested further staff audit calculation be made in this matter and we shall continue to pursue the issue with the applicant. The ACRs did not consider this concern to be prohibitive for low power operation.

2. Inservice Testing After Commercial Operation (Section 3.9.1)

The operating license will be conditioned to assure implementation of an acceptable inservice testing program for pumps and valves during commercial operation.

3. Reactor Vessel Overpressurization (Section 5.2.2)

The operating license will be conditioned to require installation of additional equipment to protect against overpressurization transients during the next fuel cycle.

4. Loose Parts Monitor (Section 5.2.8)

The applicant will to install an acceptable loose parts monitoring system prior to the low power test program.

1.9 Unresolved Safety Issues

In the Safety Evaluation Report we stated that a response on unresolved safety issues would be provided in a supplement. The response is in Appendix D.

2.0 SITE CHARACTERISTICS

2.5 Geology and Seismology

In the "Findings" section of the Safety Evaluation Report, we stated that because the design spectra do fall below the site-specific spectrum in a particular frequency range, and to verify our judgment regarding structural margins, we would initiate a review to quantify the additional margin in representative critical sections of the reactor building, auxiliary building structures, and in representative components required for safe shutdown. The results of our review are reported in this section. They also constitute a supplement to Section 3.7 of the Safety Evaluation Report.

Seismic Category I Structures

The design review was carried out to determine the margins present in the seismic Category I structures with a 84th percentile site-specific spectrum as a seismic input criterion.

The first part of the review considered those Sequoyah seismic Category I structures supported on rock (shield building, internal containment structures and auxiliary/control building). It was determined after considering all critical sections of these structures that, although the calculated loads on these structures increased, an overstress situation under combined loads existed only in the shield building. This overstress, which occurred at the base of the structure, was only 0.3 percent for the reinforcing steel and 5 percent for the concrete. For the internal containment structures and the auxiliary/control building, substantial remaining margins were identified for the critical sections. The staff considers the 0.3 percent overstress of the reinforcing steel and the 5 percent overstress of the concrete at the base of the shield building as insignificant. Normal engineering computations allow for a variation of a least a level of 5 percent In addition, the applicant utilized normal design values for the structural material properties. The use of in-situ material properties would reduce and/or eliminate the minor overstress condition.

The second part of the review considered the seismic Category I structures founded on soil. The staff ascertained that they were designed using a design response spectrum which enveloped the 84th percentile site-specific response spectrum for the frequencies of interest. This was determined by comparing the 84th percentile site-specific spectrum and the maximum and minimum design response spectra used in the design of the seismic Category I soil-supported structures.

The third part of the review assured the staff that the applicant would use an acceptable procedure for the followup qualification of safety equipment and components. The applicant developed a floor response spectra for specific equipment mounting locations using the best fit of the original four design earthquakes increased by a factor such that its response spectrum would envelope the 84th percentile site-specific response spectrum.

The fourth part of the review considered the effect of the new 84th percentile site-specific spectrum on the steel containment. The staff ascertained that the limiting design of the steel containment is not controlled by seismic loads, but instead, by loss-of-coolant accident pressure loads. It was determined that the seismic load introduced, for the worst loading situation, was less than 20 percent of the load produced by the loss-of-coolant accident.

The staff concludes, as a result of our review, that the seismic Category I structures are acceptable for seismic loadings calculated on the basis of the 84th percentile site-specific response spectra when used in conjunction with the damping values recommended by Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants."

Safety Components and Systems

To determine the seismic design margins, defined as the ratio seismic stress/allowable stress based on the 84 percentile earthquake response spectra and damping values in accordance with Regulatory Guide 1.61, selected piping systems were reanalyzed and selected mechanical and electrical equipment in safe shutdown systems were evaluated against the revised floor response spectra. The auxiliary feedwater and essential raw cooling water piping systems were selected for reanalysis on the basis of their significance in achieving a safe shutdown. Regions of high SSE stress level were identified in these piping systems and the SSE stresses combined with stresses resulting from pressure and deadweight. Seismic margins were determined in these regions of high stress based on the revised floor response spectra and damping values in accordance with Regulatory Guide 1.61. These margins were found to be adequate.

The seismic margins were not quantified for selected mechanical and electrical equipment in safe shutdown systems but the equipment was evaluated against the revised floor response spectra and is considered qualified. Based on the results of the reanalysis of the selected systems and the reevaluation of the electrical and mechanical equipment, we concluded that the piping systems and mechanical equipment in safe shutdown systems are sufficiently conservative in design to meet current licensing criteria.

However, in a letter from M. Carbon to J. Ahearne, "Interim Low Power Operation of Sequoyah Nuclear Power Plant, Unit 1," dated December 11, 1979, the Advisory Committee on Reactor Safeguards although improving issuance of a low power license recommended that the above seismic margin program be continued and expanded to the extent necessary to determine the seismic design margin of all structures and equipment necessary to accomplish safe shutdown. The staff has accepted this recommendation and will continue to pursue this issue with the applicant. The results of this program will be reported in a future supplement to this Safety Evaluation Report.

2.6 Foundations

In Section 2.5 of the March 1979 Safety Evaluation Report, the Geology and Seismology Section provided an evaluation of the region and site geological and seismological conditions for the Sequoyah site, Unit 1 and 2. The applicant has subsequently submitted by amendments (No. 60 through No. 62) to the Final Safety Analysis Report, additional geotechnical engineering information on the soils and foundation design of seismic Category I structures. We have completed our review of the submitted information including the results of subsurface explorations completed in January 1980, and the following sections present the results of our evaluation.

2.6.1 Foundation Description

The proposed nuclear plant site is located in south central Tennessee on the west shore of Chickamauga Lake approximately fifteen miles northeast of Chattanooga, Tennessee. The lake was formed by the construction of Chickamauga Dam on the Tennessee River and has a normal pool elevation of 682.5 feet above mean sea level. Plant grade in the area of the major power building complex has an average elevation of 705 feet. The general topography near the plant site above the formed lake is gently rolling hills with elevations ranging to 775 feet.

Subsurface explorations at the site were completed in several phases of investigation that began as early as 1953 with the last phase being completed in January 1980. For convenience, the description of foundation conditions indicated by these explorations will be separated into the three sites areas where seismic Category I structures have been constructed. These areas include:

1. The <u>Main Power Building complex</u> (Reactor Building, Auxiliary Building, Additional Equipment Building, Control Building, East Steam Valve Rooms (2), Condenser Cooling Water Intake Pumping Station, Refueling Water Storage Tanks (2), Waste Packaging Building and Condensate Demineralizer Waste Evaporator Building).

2. <u>The Diesel Generator Building area</u> (Diesel Generator Building, Auxiliary Essential Raw Cooling Water Towers and Pumping Station).

3. <u>The Essential Raw Cooling (ERCW) Station area</u> (Intake Pumping Station, Access Dike and Sheet Pile Cells that support safety related conduits and pipes).

2.6.1.1 Main Power Building Complex

Subsurface explorations in the main power building area revealed residual soils consisting of silts and clays and varying in thickness from 3 feet to 35 feet. The residual soils were derived from complete decomposition of the shale and limestone rock. Beneath the residium, explorations revealed highly weathered, soft shales and limestone with recognizable rock structure but with material properties closer to those of a soil. The bottom elevation of the highly weathered rock was at an average elevation of 680 feet. Below elevation 680 feet the complexly folded foundation bedrock consists of relatively unweathered interbedded light gray limestone and dark gray to green fissile shales of the Conasauga Formation. The dip of beds widely vary because of the folding but generally vary between 50°SE to vertical. Because the bedrock is highly contorted, the soft, highly weathered rock was known to extend to depths below elevation 680 feet in a few localized pockets, however, competent unweathered rock was generally present below elevation 665 feet. Six of the eleven safety-related structures in the main building complex have concrete mat foundations bearing on essentially unweathered rock at or below elevation 665 feet.

Unconfined compressive strength testing on unweathered foundation rock core samples indicated compressive strengths ranging from 11,900 psi to 16,800 psi for the limestone and 5700 psi for the shale. The results of the seismic surveys indicated a range in shear wave velocities in the rock foundation materials from 4800 to 9700 feet per second.

The foundation description and design of structures not supported on rock (East Steam Valve Rooms, Waste Packing Building, Condensate Demineralizer Waste Evaporator Building and the Refueling Water Storage Tanks) are discussed in the following sections.

2.6.1.2 Diesel Generator Building Area

The seismic Category I safety-related structures in this area have concrete mat foundations founded on natural soils except for a short length of the Diesel Generator Building that is founded on controlled compacted fill. The bottoms of foundations are located between elevation 710 to 717 feet. The depth of soil above bedrock beneath these structures varies between 35 feet to 85 feet. The foundation soils consist predominantly of silts ranging in plasticity from low to high and some layers of silty gravels and sands. These lightly loaded structures have maximum bearing pressures less than 2000 psf.

2.6.1.3 Essential Raw Cooling Water (ERCW) Station Area

Subsurface conditions for the ERCW Pipes and seismic Category I Electrical Conduits that extend approximately 2400 feet between the main plant area and the ERCW Pumping Station in Chickamauga Reservoir were shown to consist of residual soils, described as dense silty gravels, hard clays and soft to medium silts. Alluvial clay soils averaging 13 feet in thickness existed on the reservoir bank and reached thicknesses of 30 feet beneath the ERCW Pumping Station. Beneath the alluvial clay soils, the weathered shale zone was shown by explorations to average 10 feet in thickness.

2.6.2 Foundation Treatment

2.6.2.1 Main Power Building Complex

Excavation to foundation grades in this area resulted in the removal of the residual and highly weathered rock materials and known cavities that were known to be limited to the upper few feet of rock where solutioning had developed in the limestone near the overburden-rock interface. Following excavation and exposure of the rock to original foundation grades, two zones in the foundations of the Auxiliary and Reactor Buildings required additional removal of soft, deeply weathered rock pockets. This over-excavation was generally less than 10 feet except in the south area of the Auxiliary Building where soft rock as deep as 30 feet was removed. Approved foundation surfaces were protected with fill concrete. Other suspected cavity areas at depths deeper than established foundation grades, where rock core recovery in explorations had been poor, were inspected by borehole television and shown to be actually softer shale zones which had been ground during drilling between more competent limestone beds. A consolidation grouting program was conducted between February and June 1970 in the foundations of the Reactor, Auxiliary and Control Buildings. The purpose of the grouting program was to fill and close near-surface rock fractures that had been caused predominantly by blasting and to treat localized rock openings and small cavities which pre-construction exploratory drilling had indicated might exist to a maximum depth of 45 feet below foundation grade. The grouting program was completed in two stages (initially 10 feet, then 45 feet deep into rock). The applicant has concluded that the low grout takes which were measured in the grouting program gave further evidence that openings in the rock foundation existed only in localized areas. The staff concurs with this conclusion. The staff also agrees that the operations following rock excavation (including surface cleaning, inspection, additional removal of softer and weathered rock materials and placement of fill concrete) did produce an acceptable rock foundation capable of safely supporting the structures under maximum design loads.

A settlement problem developed during construction with the two soil supported East Steam Valve Rooms. The problem was reported to the NRC on June 2, 1975. Bored caisson foundations were added to these rooms during construction to correct for the settlement problem. The settlement experience at the East Steam Valve Rooms also resulted in other foundation design changes that lead to pile supported structures which was subsequently discussed.

The East Steam Valve Rooms house and protect the steam and feedwater valves and have a common wall with the reactor buildings that is separated by a 1-inch thick compressible joint material. These reinforced concrete rooms each measures 55 feet long, 23 feet wide and 52 feet high and were originally supported on a 4 foot thick reinforced concrete spread footing founded at elevation 699 feet. The valve home structure footings tested on plastic clay and silt backfill that had been previously placed in the peripherial excavation adjacent to the reactor buildings. The maximum static bearing pressure for these rooms is estimated at 3300 psf. Settlement monitoring readings from April 1974 through May 1975 had indicated significant total and differential settlements at the corners of the Valve Rooms. The maximum total settlement recorded (March 1976) reached approximately 6.6 inches in the northwest corner of Unit 2 East Steam Valve Room. The applicant's concern that unacceptable pipe stresses could be introduced because of continuing settlement after completion of piping connections resulted in their decision to underpin both Valve Rooms.

Underpinning of the Valve Rooms consisted of installing eight reinforced concrete caissons that were drilled into rock through the completed 4-foot thick spread footing. The caissons each measured 48 inches in diameter when in the soil backfill and are reduced to 42 inches in diameter for the sections socketed into bedrock. The drilling depth into sound rock varied from 8 feet to 15 feet depending on the requirements for safe bearing and needed resistance against uplift loads. The 42-inch calyx holes in rock were cleaned of loose material, inspected and logged prior to the placement of the caisson reinforcement and concrete. A large 4-foot thick mat which tied into the existing spread footings and a massive thrust block anchored to bedrock were constructed to assist in resisting large horizontal loads assumed to develop from a postulated steam pipe rupture.

Underpinning was completed in April 1976 and June 1976 for Units 1 and 2 Steam Valve Rooms, respectively. Monitoring for settlement of the Steam Valve rooms since completion of the underpinning work has indicated negligible settlement. The staff considers the applicant's foundation underpinning program to be a reasonable solution to the unanticipated settlement problem. We consider the measures taken to assure a successful caisson installation to be prudent and the completed foundation modifications to be conservative which should result in a stable foundation.

Because of the settlement experienced by the East Steam Valve Rooms, the originally-designed mat foundation for the Waste Packaging area (WPA) was changed to a pile foundation to be supported on H-piles driven to rock. A later structure, the Condensate Demineralizer Waste Evaporator Building (CDWEB) was also designed to be supported on H-piles driven to bedrock. The maximum compressive pile loads on the 12 x 74 H-piles are significant and reach 181 tons and 193 tons for the WPA and CDWEB, respectively. The pile driving criteria was 3 blows per inch of a 41,300 ft-lb diesel hammer. A considerable amount of interaction between the staffs of the applicant and the NRC has been necessary to resolve differences on the acceptability of these pile foundation designs.

The staff considers the major cause for these differences to have resulted from the scarce documentation of essential pile design information in the FSAR, an inadequate pile driving criteria, the omission of pile load testing and the failure to record meaningful driving records. Our concern on inadequate documentation has been resolved with the submittal of amendments 61 and 62. The inadequacy of the pile driving criteria has been resolved by evaluation of recently provided information on construction operations and additional subsurface investigations which lessened the importance of having field records that demonstrated high resistance to pile penetration.

Our initial concern was that in situ very stiff soils and weathered shales would produce enough resistance to permit stopping the 12 x 74 H-piles under the inadequate driving criteria without providing sufficient capacity to carry the high load concentration at the pile tips; however, during construction, the foundation areas of the WPA and CDWEB had been excavated to top of rock to provide an acceptable temporary foundation for a heavy gantry crane used in the construction of the reactor buildings. Cohesive silt and clay materials were then backfilled for the foundations of these two structures after removal of the gantry crane. These materials, unlike the weathered shale, would not have provided sufficient driving resistance to stop the piles using the adopted driving criteria.

The piles which were actually driven through the cohesive backfill soils did reach sound rock as verified by a series of vertical and inclined borings drilled in January 1980. Core recovery in the drilled holes beneath the recorded pile tip elevations showed predominantly hard, competent gray limestone. Thin layers and lenses of less competent gray and green shales do exist, however, in the steeply dipping rock beneath the pile tips. The applicant has concluded that the interlayered rock mass which is predominantly hard limestone with very high compressive strengths is a suitable foundation layer to carry the high pile loads. Following our inspection of the recovered rock core beneath the pile tips and our evaluation of the drill logs, the staff finds it unnecessary to perform pile load tests for the WPA and CDWEB structures. We concur with the applicant's conclusion that the foundation rock to which the piles have been driven is capable of safely carrying the imposed design pile loads.

Other structures in the main power building complex supported on soil include the two Refueling Water Storage Tanks. These tanks rest on a minimum 2.5-foot thick concrete mat, 53.5 feet in diameter, which was constructed over a 13-foot thick layer of compacted crushed stone backfill above 15 feet of weathered shale overlying the unweathered bedrock. The bottom of the crushed stone, at elevation 690 feet, required the removal of the upper residual soils.

Three types of backfill were used during construction and included Type A Backfill, Crushed Stone Fill, and Limestone Sand Fill. Type A Backfill consisted of cohesive silt and clay soils which were required to be compacted to 95 percent maximum dry density (Standard, ASTM D-698) after placement in 6-inch layers. Type A backfill was the major type of fill placed around seismic Category I structures when backfilling the deeper excavations. Crushed Stone fill was a sandy gravel with a maximum particle size of 1-1/4 inch and was compacted to an average relative density of 85 percent or greater (ASTM D-2049). This granular fill, in addition to being placed in the foundations of the Refueling Water Storage tanks, was also placed beneath safety-related piping. Limestone Sand F'‌:l is a cement sand placed around ERCW piping and was compacted to an average relative density of 75 percent or greater (ASTM D-2049).

2.6.2.2 Diesel Generator Building Area

The Diesel Generator Building and AERCW Towers are located southeast of the main plant area and have foundations supported predominantly on in situ cohesive soils. No special foundation treatment was required for these lightly loaded structures. Settlement of the Diesel Generator Building was conservatively predicted in design to be not greater than 3.25 inches. Settlement monitoring of the Diesel Generator Building was initiated after construction of the base slab and the start of the exterior walls in January 1973. Readings to date on the completed structure indicate a maximum recorded total settlement of 0.84 inches at the southwest corner. A small depth of Type A backfill was placed beneath the west wall foundation where the established foundation level caused a change in support from natural soils to backfill material. The measured maximum settlement is not considered excessive and the soil supported foundations are considered stable and acceptable to the staff.

2.6.2.3 Essential Raw Cooling Water (ERCW) Station Area

Seismic Category I electrical conduits and ERCW piping leaving the main plant area are founded on natural soils and travel approximately 2100 feet up to the concrete supporting slab that is founded on H-piles driven to rock. The supporting slab, founded on piles, then carries the piping, the electrical conduits and the access road to six interlocking sheet pile cells that approach the ERCW Pumping Station in Chickamauga Reservoir. The pumping station is also founded on interlocking sheet pile cells. All sheet pile cells were constructed by driving the sheet piling to bedrock and then excavating to bedrock within the cell, prior to backfilling with tremie concrete. The height of sheet piling beneath the Pumping Station averaged 65 feet. The maximum normal reservoir pool is at elevation 683 feet. The method employed to construct the sheet pile cells resulted in the removal of the potentially compressible alluvial clay soils and the founding of the structures on competent rock.

The alluvial clay soils landward of the cells were removed by dredging down to top of weathered rock in the stretch of conduit and piping that is supported on H-piles. The open trench which resulted from dredging on the reservoir bank was backfilled by end dumping rockfill. Grading and compacting the rockfill was then required using a vibratory roller on the surface at approximately elevation 677 feet. The 8 x 36 H-piles that are capped by the concrete supporting slab were then driven to rock through the 3 inch maximum size rockfill.

The staff concurs with the applicant that the required pile driving criteria and the results of completed pile load testing do indicate an acceptable foundation for the ERCW Piping and Electrical Conduit Support Slab. The staff expressed a concern for the length of conduit and piping immediately landward of the pile supported slab where the conduits are not pile supported but are founded on in situ soils consisting of soft to medium silts (Boring SS-69). This concern has been resolved by the applicant's commitment to monitor settlement and is discussed in more detail in subsequent paragraphs.

2.6.3 Foundation Evaluations

We conclude that the foundation soils supporting seismic Category I safety-related structures have been shown to be competent in bearing with acceptable margins of safety and will adequately support the proposed structure loads. We also conclude that the laboratory and field operations employed by the applicant has provided reasonable assurance that the rock foundations are capable of safely supporting the structures founded either directly on the rock or on pile supports driven to rock.

In our review we had expressed a concern for detrimental settlement along the ERCW pipe and electrical conduit alignment in the stretch where in situ soft to medium silts were shown to be located in the foundation. This length extended beyond where the conduits and pipes were supported on piles and where a maximum fill height of 13 feet had been placed over the pipes. The applicant has addressed this concern by initiating a settlement monitoring program along the ERCW alignment up to and including the piping station. The proposed program details covering the locations to be monitored, the frequency of readings and the applicant's commitment to submit the program results to NRR for evaluation are acceptable to the staff. The proposed program is required to address any settlement which may have already occurred by extrapolating back to original as-built elevations.

Continued monitoring of the Diesel Generator Building settlement is required and the results will be submitted for NRR review. Settlement of structures founded on competent rock should be negligible and no additional monitoring has been required.

No additional studies concerning liquifaction, slope stability and the development of lateral earth pressures have been required of the applicant since the PSAR review. We accept the results of the original studies and conclude that adequate stability has been demonstrated by conformance with PSAR criteria.

The applicant has committed for formally documenting, by amendment to the FSAR, a description of the soil parameters and procedures used in the seismic analysis of the pile supported WPA and CDWEB structures. Our understanding, which is based on verbal submittal of information from the applicant, is that a conservative design approach was followed. We will evaluate the applicant's formal submittal but do not, at this time, feel an additional supplement to the SER will be necessary.

In summary, based on our review of the information provided, we conclude that the site and plant foundations are acceptable for safe operation of Units 1 and 2.

3.0 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.2 Classification of Structures, Components, and Systems

The preservice ultrasonic inspection of the Sequoyah Unit 1 reactor vessel closure head revealed a flaw indication exceeding the ASME Boiler and Pressure Vessel Code, Section XI, Division 1, acceptance criteria. The flaw indication is at weld W09-10, which is located between the closure head dome (dollar plate) and ring. Reevaluation of the fabrication weld joint radiograph characterized the flaw as a subsurface elliptical discontinuity with a major axis of 1.625 inches and a minor axis of 1.25 inches. One way in which the reactor vessel closure head may be made acceptable for service is to remove the flaw and replace repaire the area to the extent necessary to meet the acceptance standards or the portion of the reactor vessel closure head containing the flaw. The applicant has determined that these acceptance procedures are not practical and proposed an analytical evaluation of the flaw as an alternative acceptance standard as allowed by ASME Code Case N-209. The intent of the analytical evaluation, which is based upon the methods of Appendix A to Section XI of the ASME Code, was to demonstrate the acceptability of the flaw throughout the service life of Unit 1.

The analysis submitted by the applicant used the linear elastic fracture mechanics methods recommended in Appendix A to Section XI of the ASME Code. The procedure of Appendix A was followed step-by-step, as described below:

(1) The preservice ultrasonic and fabrication radiograph results were evaluated to determine the flaw configuration.

(2) The flaw was resolved into a simple geometric shape.

(3) The stresses at the flaw location were obtained from the manufacturer's stress report (Reference 1).

(4) Stress intensity factors at the flaw location were calculated.

(5) Material properties were obtained from the manufacturer's stress report.

(6) The analytical procedures of Article A-5000 were used to determine the critical flaw parameters.

(7) The flaw evaluation criteria of Paragraph IWB-3600 were used to determine if the observed flaw indication is acceptable.

Additional guidance was obtained from the flaw evaluation procedure examples in EPRI Report NP-719-SR (Reference 2).

The applicant shown in its analysis that:

(1) The hydrostatic test condition produces the greatest stress intensity at the crack location.

(2) Flaw growth determined by using Section XI calculational methods and crack growth rates will be negligible.

(3) Using crack growth rates much more conservative than those contained in Section XI, a final flaw having major axis of 2.69 inches and a minor axis of 2.07 inches was calculated. The calculated stress intensity associated with this very conservative flaw size is less than the allowable stress intensity and meets the acceptance criteria of Section XI, Paragraph IWB-3600 at a hydrostatic test temperature of $(RT_{NDT})_{maximum} + 60°F = 133°F$.

The staff's evaluation included the review of the assumed cyclic loading of the reactor vessel due to changes in the applied stress level caused during normal operations including test and anticipated transient conditions. We determined that the analysis used limiting values for the flaw shape parameter, stress correction factors, available fracture toughness, reference temperatures and crack growth rate, such that the flaw size calculated at the end of service life is likely to be larger than the size of the flaw that will actually be present. Further, because a threshold value for the range of stress intensities that will produce flaw growth was omitted, much of the predicted crack growth calculated for the stress intensity ranges would likely not occur. Our independent calculations of flaw growth indicate that the applicant analysis methods are conservative and that the predicted crack growth is negligible.

The applicant also demonstrated that if the crack growth rate was one thousand times greater than that used in the analysis, the resultant crack would still meet the acceptance criteria of IWB-3600.

Based upon our independent calculations and review, we agree with the conclusions reached in the applicant's report concerning the predicted crack growth during normal operating conditions, including test and anticipated transient conditions. Therefore, it is our position (1) that the flaw in the reactor vessel closure head is acceptable, and (2) that the affected component may be placed into service if the following requirements are incorporated into the inservice inspection program for Sequoyah Nuclear Plant, Unit 1.

(1) In order to verify the predictions made in the analysis, we require an augmented inservice inspection program to monitor possible flaw growth during the service life of Unit 1. This augmented inservice inspection program shall examine the area of the flaw in weld W09-10 during the next three inspection

periods using the examination methods and evaluation criteria required by Section XI of the ASME Code. If it is found that the flaw is growing faster than predicted in the analysis, the applicant will be required to either:

(a) Remove the flaw and repair the affected area to meet the acceptance criteria; or

(b) Replace the flawed portion of the component; or

(c) Reanalyze the flaw, using the crack growth rate data acquired from the augmented inservice inspection program, to demonstrate the acceptability of the flawed component for continued service.

(2) If the results of the augmented inservice inspection program indicate that the flaw remained virtually unchanged during the three inspections periods, the reactor vessel closure head examination schedule may revert to the original Section XI required schedule for subsequent inspections.

3.9.1 Inservice Testing of Pumps and Valves

In the Safety Evaluation Report we stated that the license will be appropriately conditioned to assure implementation. The applicant has provided additional information on the proposed program for inservice testing of ASME Code Class 1, 2, and 3 pumps and valves in Final Safety Analysis Report Amendment 63 dated December 7, 1979. The program includes both baseline preservice testing and periodic inservice testing. It provides for both functional testing of components in the operating state and for visual inspection of leaks and other signs of degradation.

The date of the applicant's construction permit (May 27, 1970) places this plant under 10 CFR 50.55a(g)(1) which permits compliance to the extent practical with later editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code. The inservice testing requirements of pumps and valves were not included in the Code until the Summer 1973 addenda of the 1971 Edition of Section XI, well after the design of the plant was largely complete. The applicant cannot in all cases meet the requirements of the 1974 Edition and the Summer 1975 Addenda of Section XI, which he has optionally selected to meet, and has requested relief from certain Code requirements.

The applicant proposed the period for which the program is applicable as follows:

From the issuance of the operating license inservice testing of pumps and valves will be performed in accordance with the ASME Section XI Code and applicable addenda as required by 10 CFR Part 50, Section 50.55a(g)(6)(i).

We have not completed our detailed review of the applicant's submittal. However, based on our review, we find that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain of the ASME

Code requirements. Imposition of those requirements would, in our view, result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. Therefore, pursuant to 10 CFR 50.55a(g)(1), we recommend that the relief that the applicant has requested from the pump and valve testing requirements of the 1974 Edition of ASME Section XI through the Summer 1975 Addenda be granted for that portion of the initial 120-month testing period during which we complete our review. Following completion of our detailed review of the applicant's program, we will issue our evaluation in a supplement to the Sequoyah Units 1 and 2 Safety Evaluation Report.

3.9.2 Bolted Connections in Component Supports

Inservice inspections conducted at an operating nuclear power plant in 1978 revealed that several anchor bolts in some safety-related pipe supports were not properly embedded. In some cases the anchor bolts were completely pulled out and no supporting function was provided.

Deficiency reports filed by an applicant for an operating license for a nuclear power plant in 1978 indicated that pipe support base plates with drilled anchor bolts which were designed by assuming the plate to be completely rigid had underestimated the loads on some anchor bolts.

The above two issues resulted in IE Bulletin 79-02, "Pipe Support Base Plate Designs Using Concrete Anchor Bolts."

A team composed of representatives from IE, DOR, and DSS is reviewing this matter for Sequoyah and other plants. This item will be reported at a later date; however, it is concluded that based on our results thus far, the supports using concrete expansion anchor bolts are conservatively designed and are acceptable for issuance of a low power license.

3.10 Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment

3.10.3 Qualification Program

The applicant has conducted a seismic qualification program for the balance-of-plant seismic Category I instrumentation and electrical equipment and the associated supports to provide assurance that such equipment can be expected to function properly and that structural integrity of the supports will not be impaired during the excitation and vibratory forces imposed by the safe shutdown earthquake and the conditions of post-accident operation. The seismic qualification program described by the applicant is in compliance with IEEE Standard 344-1971, "Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations."

In addition, to address our previously stated concern of whether or not the original testing or analysis can be justified in light of our current criteria (IEEE Standard 344-1975, as supplemented by Regulatory Guide 1.100, "Seismic Qualification of

Electrical Equipment for Nuclear Power Plants"), we have established a seismic qualification review team. This team visited the Sequoyah plant in 1976. The team inspected selected vital mechanical and electrical equipment as installed and identified concerns about the adequacy of the original qualification per IEEE 344-1971 for some of the items that were inspected. The applicant has provided additional information regarding these items to justify the original testing in the light of our current criteria. To evaluate the adequacy of the vendor's qualification program for the nuclear steam supply system instrumentation and electrical equipment, the staff conducted a generic review of Westinghouse supplied equipment.

Based on the results of the reviews described above, we concluded that the seismic qualification testing program which has been implemented for seismic Category I instrumentation and electrical equipment will provide adequate assurance that such equipment will functional properly during the excitation from vibratory forces imposed by the safe shutdown earthquake and under the conditions of post-accident operation. We further concluded that this program constitutes an acceptable basis for satisfying the applicable requirements of General Design Criterion 2.

However, as stated in the last paragraph of Section 2.5 in this Safety Evaluation Report, the Advisory Committee on Reactor Safeguards has recommended that the seismic margin program be expanded. Since seismic qualification of seismic Category I instrumentation and electrical equipment is an integral part of the seismic margin program, these two issues will be pursued simultaneously with the applicant. The results of this program will be reported in a future supplement to this Safety Evaluation Report.

4.0 REACTOR

4.2 Mechanical Design

Guide Thimble Tubes

Unexpected degradation of guide thimble tube walls has been observed during post-irradiation examinations of irradiated fuel assemblies taken from several operating pressurized water reactors. Subsequently, it has been determined that coolant flow up through the guide thimble tubes and turbulent cross flow above the fuel assemblies have been responsible for inducing vibratory motion in the normally fully withdrawn ("parked") control rods. When these vibrating rods are in contact with the inner surface of the thimble wall, a fretting wear of the thimble wall occurs. Significant wear has been found to be confined to the relatively soft zircaloy-4 thimble tubes because the control rod claddings--stainless steel for Westinghouse-NSSS designs--provide a relatively hard wear surface. The extent of the observed wear is both time and NSSS-design dependent and has, in some non-Westinghouse cases, been observed to extend completely through the guide thimble tube walls, thus resulting in the formation of holes.

Guide thimble tubes function principally as the main structural members of the fuel assembly and as channels to guide and decelerate control rod motion. Significant loss of mechanical integrity due to wear or hole formation could (1) result in the inability of the guide thimble tubes to withstand their anticipated loadings for fuel handling accidents and condition 1-4 events, and (2) hinder scramability.

In response to the staff's attempt to assess the susceptibility and impact of guide thimble tube wear in Westinghouse plants, Westinghouse and the applicant have submitted information on their experience and understanding of the issue. This information consisted of guide thimble tube wear measurements taken on irradiated fuel assemblies from Point Beach Units 1 and 2 (two-loop plants using 14 x 14 fuel assemblies).

Also described was a mechanistic wear model (developed from the Point Beach data) and the impact of the model's wear predictions on the safety analyses of plant designs such as those utilizing 17 x 17 fuel assemblies.

Westinghouse believes that their fuel designs will experience less wear than that reported in other NSSS designs because the Westinghouse designs use thinner, more flexible control rods that have relatively more lateral support in the guide tube assembly of the upper core structure. Such construction provides the housing and guide path of the RCCA's above the core and thus restricts control rod vibration due to lateral exit flow. Also, Westinghouse believes that their wear model conservatively predicts guide thimble tube wear and that even with the worst anticipated wear conditions (both in the degree of wear and the location of wear) their guide thimble tube walls will be able to fulfill their design functions.

The staff concludes that the Westinghouse analysis probably accounts for all of the major variables that control this wear process. However, because of the complexities and uncertainties in (a) determining contact forces, (b) surface-to-surface wear rates, (c) forcing functions, and (d) extrapolations of these variables to other fuel designs (such as the 17 x 17 design used in Sequoyah), we believe that it is prudent for the applicant to make a commitment, before issuance of the OL, to submit for review a surveillance plan and schedule for the examination of guide thimble tube wear.

The specifics of such a surveillance program have not yet been determined, but since the wear phenomenon is a time-dependent process the details of such an inspection program do not need to be specified prior to the first Sequoyah refueling outage. Furthermore, such inspection may not have to be conducted at Sequoyah. For example, the applicant could join in a cooperative owner's group and thereby submit applicable information derived from a similar type of plant using 17 x 17 fuel assemblies. For acceptability, the minimum objective of such a program should be to demonstrate that there is no occurrence of hole formation in rodded guide thimble tubes.

The applicant has committed to the performance of the surveillance described above and this issue is adequately resolved for the first cycle of operation. This issue will be resolved for later cycles of operation provided that surveillance results confirm the predictions of the analysis described above.

Grid Straps

During a recent refueling at a similar Westinghouse 17 x 17 plant (Salem 1), strap damage on a number of spacer grids was observed on discharged assemblies. Similar damage has been reported previously (WCAP-8183, Rev. 1 through 8) but never to the extent observed at Salem 1, where 31 fuel assemblies suffered some damage. The damage ranged from deformed edges and small chips to loss of full strap width pieces and was usually confined to 1 or 2 of the eight grids per assembly. An evaluation for Salem Unit 1 showed that such grid-strap damage was unimportant to the operation of the reactor (see Amendment No. 20, October 1979, to the Salem Unit 1 operating license, Docket No. 50-272). This evaluation considered thermal-hydraulics, neutronics, fuel space grid-cell deformation, flow blockage from loose pieces, and control rod interference; the effects of all of these were found to be insignificant.

Westinghouse has recommended certain procedural changes that are designed to minimize or eliminate damage during fuel handling. These recommendations are based on the following: (1) loading sequence as to the buildup of rows and corner positions in the core, (2) offset into the open regions for vertical movement of assemblies, and (3) revised load cell limits on the refueling crane to increase the sensitivity in detecting spacer grid interference. TVA has agreed to follow these recommendations at Sequoyah 1 and 2 (letter from L. N. Mills, TVA, to L. S. Rubenstein, NRC, dated August 31, 1979). DOR Information Memorandum No. 19 issued on October 26, 1979 also requests all licencees of 17 x 17 plants to visually inspect their discharged fuel for grid strap damage. Should these inspections reveal significant strap damage, further changes to the fuel handling procedures will be made. On the basis that grid strap damage is relatively unimportant and that steps will be taken to minimize its occurrence, we find that this matter is satisfactorily resolved.

Control Spiders

Another core component failure, involving control rod spiders, was also observed at Salem 1. Eight alignment fingers on six spiders failed during plant operation. Thus, eight control rodlets became detached and were inserted into the core producing an observed flux tilt. This failure was traced to a manufacturing procedure that introduced a contaminant that led to stress-corrosion cracking of the fingers. This manufacturing procedure was primarily used for two lots of fingers, and the procedure has since been corrected to eliminate the problem. A complete evaluation of this problem and its safety implications is contained in Amendment 20 to the Salem Unit 1 operating license (October 1979, Docket No. 50-272).

That evaluation agrees with the Westinghouse conclusions that:

(a) Failures do not represent a structural inadequacy or generic design weakness.

(b) Failures are the result of stress-corrosion cracking and were contained within the two receiving lots of outer fingers.

(c) Elimination of all rod cluster control assemblies containing fingers from the suspect lots should prevent recurrence.

That evaluation goes on to show that if rodlets were dropped, the safety effects for the core would depend upon the number of dropped rodlets. A few dropped rodlets (about 10) could cause a flux tilt but the core parameters could be maintained within the Technical Specifications limits. A larger number of dropped rodlets (about 50) would be needed to cancel the excess shutdown margin or significantly affect peaking factors, but such a quantity would be easily detected and appropriate actions taken. In light of the low probability of the future occurrence of dropped rodlets and the fact that the dropping of significant number of rodlets would be detected, this matter is adequately resolved.

Rod Drop Transient

We recently completed changes to the negative rate trip Technical Specification for Sequoyah to provide protection against potential power overshoots (and, hence, possibly DNB) in the event of single rod drop incidents. We had taken that action as a result of a Part 21 notification and recommendations from Westinghouse.[1] As part of their continuing analysis of single rod drops being performed for a topical report, Westinghouse has found several new nonconservatisms which indicate that the trip setpoint changes made earlier do not necessarily provide the desired protection. This was discussed at a meeting with Westinghouse on November 19, 1979 in Bethesda. At the meeting Westinghouse suggested an interim procedural position which would provide protection in single rod drops. This position which the staff approved was offered until a long term solution to the problem can be developed, and is as follows:

(a) The plant may operate in manual control from 0 percent to 100 percent power with no changes in the current rod insertion limits.

(b) The plant may operate in automatic control from 0 percent to 90 percent power with no changes in the current rod insertion limits; above 90 percent power the D control rod bank would have to be withdrawn to 215 steps or greater.

[1]We will require that Sequoyah adopt these operating restrictions until a long-term generic solution to the problem is developed by Westinghouse.

5.0 REACTOR COOLANT SYSTEM

5.2.2 Low Temperature Overpressure Protection

Several instances of reactor vessel overpressurization have occurred in pressurized water reactors in which the Technical Specifications implementing 10 CFR Part 50, Appendix G, limits have been exceeded. The majority of cases have occurred during startup or shutdown operations while the primary coolant system was in a water solid condition. The Tennessee Valley Authority, owner of Sequoyah Nuclear Plant, is a participant in a task group of utilities formed to determine a solution to the low temperature overpressurization protection problem. The solution proposed for Sequoyah Unit 1 includes (a) administrative procedures modification, (b) operator training, and (c) design modifications. The proposed administrative procedure modifications and the operator training are intended to reduce the probability of an overpressurization event from taking place. The proposed design modifications are intended to activate an appropriate alarm and/or to mitigate the consequences of an overpressurization event.

The implementation of the proposed solution has been divided into two time periods: (a) partial implementation prior to initial fuel loading, and (b) completion during the first refueling. This separation was necessitated by procurement and construction schedules. Partial implementation for the first time period was found adequate based on a staff evaluation which indicated that due to minimal neutron damage suffered by the reactor vessel during its first operating cycle, no credible event could damage the pressure vessel due to overpressurization during this period.

The present safety evaluation is applicable for the period of operation prior to the first refueling. During this time administrative procedure changes and operator training will be implemented. In addition, an alarm will be installed to notify the operator in the control room of water solid conditions when the reactor coolant pressure is above 380 psig.

The staff will require that an overpressure mitigation system that meets all the staff requirements and in particular Reactor Systems Branch Technical Position 5-2, be installed prior to operation after the first refueling.

The staff concludes that the applicant's interim proposal is acceptable for operation during the first cycle. This conclusion is based on staff safety evaluation which indicates that no credible event could cause vessel rupture during this time period. As noted above, the staff will require implementation of an overpressure mitigation system which meets the staff requirements prior to allowing operation during the second and subsequent fuel cycles.

5.2.3 Reactor Vessel Materials

Fracture Toughness Materials

General Design Criterion 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires, in part, that the reactor coolant pressure boundary be designed with sufficient margin to ensure that, when stressed under operating, maintenance, testing, and postulated accident conditions, the boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A, 10 CFR Part 50, requires, in part, that the reactor coolant pressure boundary be designed to permit an appropriate material surveillance program for the reactor pressure vessel.

We have reviewed the materials selection, toughness requirements, and extent of materials testing proposed by the applicant to provide assurance that the ferritic materials used for pressure retaining components of the reactor coolant pressure boundary possess adequate toughness under operating, maintenance, testing and anticipated transient conditions. The ferritic materials were specified to meet the toughness requirements of the 1968 Edition of the ASME Boiler and Pressure Vessel Code Section III, "Rules for Construction of Nuclear Power Plant Components."

The guidelines specified for the fracture toughness requirements for the ferritic materials of the reactor coolant pressure boundary are defined in Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Requirements," of 10 CFR Part 50. The ferritic pressure boundary material of the Sequoyah Nuclear Plant was qualified by impact testing in accordance with Section III of the 1968 Edition of the ASME Code and evaluated in accordance with Appendix G, Section III, of the 1971 Edition, 1972 Summer Addenda of the ASME Code.

We have evaluated the applicant's degree of compliance with the fracture toughness requirements of Appendix G of 10 CFR Part 50. The results of our evaluation indicate that the applicant meets the requirements of this appendix, except that the requirement stated in Paragraph IV.b of Appendix G has not been met by the Unit 1 reactor vessel. This paragraph requires that the reactor vessel beltline materials have a specified minimum Charpy V-notch upper-shelf energy unless it can be demonstrated to the Commission that a lower value will still provide an adequate margin against deterioration from irradiation. The specific areas of noncompliance, our evaluation and recommendation for an exemption to the requirements of Paragraph IV.b of Appendix G for the Sequoyah Nuclear Plant Unit 1 are described in this supplement. Because of this item of noncompliance with the regulations, the reactor vessel of Unit 1 has been classified as one covered by NRC Generic Category A Technical Activity A-11, "Reactor Vessel Materials Toughness."

The toughness properties of the reactor vessel beltline materials will be monitored throughout the service life of the Sequoyah Nuclear Plant by a materials surveillance prog   that will meet the requirements of ASTM Standard E187-73, "Standard Recomme d Practice for Surveillance Tests for Nuclear Reactor Vessels," and Appendix H, 10 CFR Part 50. The applicant has stated that should the results of the materials surveillance tests indicate that excessive deterioration of the toughness of the reactor vessel beltline materials due to neutron irradiation has occurred, the reactor vessel can be annealed to restore material toughness.

Appendix G, "Protection Against Non-Ductile Failure," Section III of the ASME Boiler and Pressure Vessel Code, will be used, together with the fracture toughness test results required by Appendices G and H, 10 CFR Part 50, to calculate the reactor coolant pressure boundary pressure-temperature limitations for Unit 1 and 2 at the Sequoyah Nuclear Plant.

The fracture toughness tests required by the ASME Code and by Appendix G of 10 CFR Part 50 provide reasonable assurance that adequate safety margins against the possibility of nonductile behavior or rapidly propagating fracture can be established for all pressure retaining components of the reactor coolant boundary. The use of Appendix G of the ASME Code as a guide in establishing safe operating procedures, and use of the results of the fracture toughness tests performed in accordance with the the ASME Code and NRC regulat ons, will provide adequate safety margins during operating, testing, maintenance, and anticipated transient conditions. Compliance with these Code provisions and NRC regulations constitutes an acceptable basis for satisfying the requirements of General Design Criterion 31.

The materials surveillance program, required by Appendix H, 10 CFR Part 50, will provide information on material properties and the effects of irradiation on material properties so that changes in the fracture toughness of the material in the reactor vessel beltline caused by exposure to neutron radiation can be properly assessed, and adequate safety margins against the possibility of vessel failure can be provided.

Compliance with ASTM E 185-73 and Appendix H, 10 CFR Part 50, assures that the surveillance program constitutes an acceptable basis for monitoring radiation induced changes in the fracture toughness of the reactor vessel material and satisfies the requirements of General Design Criteria 31 and 32.

Operating Limitations

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Program Requirements," 10 CFR Part 50, describe the conditions that require pressure-temperature limits and provide the general bases for these limits. These appendices specifically require that pressure-temperature limits must provide safety margins at least as great as those recommended in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G, "Protection Against

Non-Ductile Failure." Appendix G, 10 CFR Part 50, requires additional safety margins whenever the reactor core is critical, except for low-level physics tests.

The following pressure-temperature limits imposed on the reactor coolant pressure boundary during operation and tests are reviewed to ensure that they provide adequate safety margins against nonductile behavior or rapidly propagating failure of ferritic components, as required by General Design Criterion 31:

(a) Preservice hydrostatic tests,

(b) Inservice leak and hydrostatic tests,

(c) Heatup and cooldown operations, and

(d) Core operation.

The applicant has proposed the use of an alternative method of calculating the shift in the reference temperature, as required by Appendices G and H, 10 CFR Part 50. This method, based upon Westinghouse Topical Report WCAP-7924, which has been approved by the NRC staff, estimates the shift in the reference temperature for the first 9.2 effective full-power years as conservatively as using the methods in Regulatory Guide 1.99, "Effect of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials," Revision 1. This period of time corresponds to that specified in the proposed exemption to Appendix G, 10 CFR Part 50, described in this supplement. After this period of time, the actual shift in the reference temperature will be calculated from the results of the materials surveillance program.

The pressure-temperature limits imposed on the Sequoyah reactor coolant system for all operating and testing conditions to assure adequate safety margins against nonductile or rapidly propagating failure are in conformance with established criteria, codes and standards acceptable to the staff. The use of operating limits based on these criteria, as defined by applicable regulations, codes, and standards, provides reasonable assurance that nonductile or rapidly propagating failure will not occur, and constitutes an acceptable basis for satisfying the applicable requirements of General Design Criterion 31.

5.2.5 Reactor Vessel Integrity

The portions of the applicant's SAR listed below are reviewed. These portions are all related to the integrity of the reactor vessel. Although these areas are reviewed separately, the integrity of the reactor vessel is of such importance that a special summary review of all factors relating to the integrity of the reactor vessel is warranted.

The information in each area is reviewed to ensure that the information is complete and that no inconsistencies in information or requirements exist that would reduce the certainty of vessel integrity. The areas reviewed are:

(a) Design (SER § 5.3.1),

(b) Materials of construction (SER § 5.2.3 and § 5.3.1),

(c) Fabrication methods (SER § 5.2.3 and § 5.3.1),

(d) Inspection requirements (SER § 5.2.4), and

(e) Operating conditions (SER § 5.3.2).

We have reviewed all factors contributing to the structural integrity of the Sequoyah Nuclear Plant reactor vessels and conclude there are no special considerations that make it necessary to consider potential reactor vessel failure for this plant. The bases for our conclusion are that the design, materials, fabrication, inspection, and quality assurance requirements for the plant will conform to applicable NRC regulations and Regulatory Guides, and to the rules of the ASME Boiler and Pressure Vessel Code, Section III, except that a beltline material of the Unit 1 reactor vessel does not meet the minimum upper-shelf fracture toughness requirement of Appendix G, 10 CFR Part 50. However, based on our analysis we have determined that an exemption from this requirement of Appendix G, 10 CFR Part 50, is justified. The properties of the reactor vessel beltline materials will be monitored by a materials surveillance program throughout service life. Operating limitations on temperature and pressure will be established for the Sequoyah Nuclear Plant in accordance with Appendix G, of the ASME Code Section III, and Appendix G, 10 CFR Part 50. Further, upon completion of NRC Generic Task A-11, "Reactor Vessel Materials Toughness," the marginal upper-shelf fracture toughness of the Unit No. 1 reactor vessel beltline material will be reevaluated and all pertinent recommendations of this task will be implemented.

The integrity of the reactor vessel is assured because the vessel:

(1) Is designed and fabricated to the high standards of quality required by the ASME Boiler and Pressure Vessel Code and pertinent code cases.

(2) Is made from materials of controlled and demonstrated high quality.

(3) Was subjected to extensive preservice inspection and testing to provide assurance that the vessel will not fail because of material or fabrication deficiencies.

(4) Will be operated under conditions and procedures and with protective devices that provide assurance that the reactor vessel design conditions will not be

exceeded during normal reactor operation, and that the vessel will not fail under the anticipated transient conditions.

(5) Will be subjected to periodic inspection to demonstrate that the high initial quality of the reactor vessel has not deteriorated significantly under service conditions.

(6) Marginal upper-shelf fracture toughness will be monitored with a surveillance program and will be reevaluated in terms of the conclusions and recommendations of NRC Generic Task A-11, when this task is completed.

(7) May be annealed to restore the material toughness properties if this becomes necessary.

With approval of the exemptions from Appendix G cited above, we conclude that this item is resolved.

5.2.6 Inservice Inspection Program

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity.

To ensure that no deleterious defects develop during service, selected welds and weld heat-affected zones will be inspected periodically at the Sequoyah Nuclear Plant. The design of the ASME Code Class A components of the reactor coolant pressure boundary in the Sequoyah Nuclear Plant incorporates provisions for access for inservice inspection in accordance with Section XI of the ASME Code. Methods will be developed to facilitate the remote inspection of those areas of the reactor vessel not readily accessible to inspection personnel.

Section 50.55a(g), 10 CFR Part 50, defines the detailed requirements for the preservice and inservice inspection programs for light water cooled nuclear power facility components. Based upon a construction permit date of May 27, 1970, this section of the Code of Federal Regulations does not require a preservice inspection program for this facility; however, the Tennessee Valley Authority is required to conduct inservice inspections at the Sequoyah Nuclear Plant at periodic intervals throughout the service life of the facility.

The Tennessee Valley Authority has made a commitment to use the Edition and Addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10 CFR Part 50, Section 50.55a, to the extent practical in formulating the inservice inspection program for Sequoyah Nuclear Plant. Since this part of the regulation requires that the initial inservice inspection program comply with the Edition and Addenda of the ASME Code in effect no more than 6 months prior to the date of the start of commercial operation, detailed evaluation of the inservice inspection program cannot be performed at this time. However, the inservice inspection program will be evaluated after the applicable ASME Code Edition and Addenda have been determined and before the initial inservice inspection. Therefore, the applicant has satisfied the inspection requirements of 10 CFR Part 50, Section 50.55a and has made a commitment to meet the requirements of 10 CFR Part 50, Section 50.55a for subsequent inservice inspections.

The conduct of periodic inspections and hydrostatic testing of pressure retaining components of the reactor coolant pressure boundary in accordance with the requirements of Section XI of the ASME Boiler and Pressure Vessel Code will provide reasonable assurance that evidence of structural degradation or loss of leaktight integrity occurring during service will be detected in time to permit corrective action before the safety functions of a component are compromised. Compliance with the inservice inspections required by this Code constitutes an acceptable basis for satisfying the requirements of General Design Criterion 32.

General Design Criterion 32, "Inspection of Reactor Coolant Pressure Boundary," Appendix A of 10 CFR Part 50, requires, in part, that components which are part of the reactor coolant pressure boundary or other components important to safety be designed to permit periodic inspection and testing of critical areas for structural and leaktight integrity.

The components in the steam generator are classified as ASME Boiler and Pressure Vessel Code Class 1 and 2, depending on their location in either the primary or secondary coolant systems, respectively. The Sequoyah steam generators are designed to permit inservice inspection of the Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program follow the recommendations of Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," Revision 1, and comply with the requirements of Section XI of the ASME Code, with respect to the inspection methods to be used, provisions for a baseline inspection, selection and sampling of tubes, inspection intervals, and actions to be taken in the event defects are identified.

Conformance with Regulatory Guide 1.83 and ASME Code Section XI constitutes an acceptable basis for meeting, in part, the requirements of General Design Criterion 32.

General Design Criterion 36, "Inspection of Emergency Core Cooling Systems;" Criterion 39, "Inspection of Containment Heat Removal System;" Criterion 42, "Inspection of Containment Atmosphere Cleanup Systems;" and Criterion 45, "Inspection of Cooling Water System," Appendix A of 10 CFR Part 50, require, in part, that the subject systems be designed to permit appropriate periodic inspection of important component parts to assure system integrity and capability.

The inservice inspection program for ASME Boiler and Pressure Vessel Code Class 2 and 3 systems and components will be submitted by the applicant as part of the Sequoyah Nuclear Plant inspection program. As discussed in Section 5.2.4 of the Safety Evaluation Report, the inspection of Class 2 and 3 components will comply to the Edition and Addenda of Section XI of the ASME Code, as required by 10 CFR Part 50, Section 50.55a, and will be evaluated when the applicable Edition and Addenda of the ASME Code has been determined.

Compliance with the inservice inspections required by the ASME Code and staff technical positions constitutes an acceptable basis for satisfying applicable requirements of General Design Criteria 36, 39, 42, and 45.

Check valves in the discharge side of the high head safety injection, low head safety injection, RHR, and boron injection systems perform a pressure isolation function in that they protect low pressure systems from full reactor pressure. The applicant has conformed to the staff requirement that these valves be classified as ASME Section XI Category AC, and has agreed to the appropriate leak testing criteria.

The staff has reviewed the valves which are to be included in the leak testing program, and believes that the testing of these valves provides assurance that proper pressure isolation will be maintained. The applicant plans to conduct check valve leak tests immediately prior to returning to power, after an outage. If leak rates between 1 and 9 gallons per minute are observed, the valve will be removed at the next available cold shutdown and repaired so that it exhibits a leak rate below 1 gallon per minute. If during the leak testing process, valve leakage above 9 gallons per minute is observed, the plant will be depressurized and the valve repaired before the plant can be restarted.

The staff finds the leak rate criteria being applied by the applicant to be acceptable, due to the presently installed safety valve relief capacity which is sufficient to relieve fluid in excess of 9 gallons per minute.

5.2.7 Reactor Coolant Pump Flywheel Integrity

General Design Criterion 4, "Environmental and Missile Design Bases," requires, in part, that structures, systems, and components of nuclear power plants important to safety be protected against the effects of missiles that might result from equipment failures. Because flywheels have large masses and rotate at speeds of approximately 1200 revolutions per minute during normal reactor operation, a loss of flywheel integrity could result in high energy missiles and excessive vibration of the reactor coolant pump assembly. The safety consequences could be significant because of possible damage to the reactor coolant system, the containment, or the engineered safety features.

Adequate margins of safety and protection against the potential for damage from flywheel missiles can be achieved by the use of suitable material, adequate design, and inservice inspection. The flywheels have been fabricated from SA-533, Grade B, Class 1 steel, produced by a process that will minimize flaws and improve fracture toughness, and be cut, machined, finished, and inspected in accordance with Section III of the ASME Boiler and Pressure Vessel Code and Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," Revision 1. The inservice inspection program will be in accordance with the recommendations of Regulatory Guide 1.14, Revision 1, and examination techniques of Section XI of the ASME Code.

The integrity of the reactor coolant pump flywheel will be provided by designing it to 125 percent of the normal synchronous speed of the motor (approximately 1500 revolutions per minute). The lowest design operating temperature is specified to be 120 degrees Fahrenheit. The applicant has stated that the RT_{NDT} will be no higher than 10 degrees Fahrenheit. Thus, the normal operating temperature of the pump flywheel will be at least 100 degrees Fahrenheit above the RT_{NDT} which satisfies the acceptance criteria for fracture toughness of Regulatory Guide 1.14.

Based on our evaluation, we conclude that the applicant is in compliance with NRC Regulatory Guide 1.14. Compliance with the recommendations of NRC Regulatory Guide 1.14 constitutes an acceptable basis for satisfying the requirements of General Design Criterion 4, Appendix A of 10 CFR Part 50.

5.2.8 Loose Parts Monitor

In the Safety Evaluation Report, we stated that an acceptable loose parts monitoring system is required.

The applicant has installed a loose parts monitoring (LPM) system on the Sequoyah units prior to initial startup after fuel loading. The design includes two sensors on the incore detector guide tubes on the bottom of the reactor vessel and two sensors near the primary coolant inlet of each steam generator. The system is capable of detecting a loose part with an energy of 0.6 joules (0.44 ft.-lbs.) and impacting within 3 feet of a sensor during plant shutdown. During startup and operation the detector discriminates against background noise. The applicant has shown that the system is designed to remain operational for all seismic events up to the operating basis earthquake and that the sensors are to remain operable under normal environmental conditions of the plant. The applicant intends to utilize the services of the LPM system vendor to provide operator training until plant startup. The LPM system described in the Sequoyah FSAR is acceptable to the staff.

5.3.1 Steam Generator Tube Integrity

The applicant was requested to implement a water chemistry monitoring and control program including the following:

(1) Identification of a sampling schedule for the critical parameters and of control points for these parameters.

(2) Identification of the procedures used to measure the value of the critical parameters.

(3) identification of process sampling points.

(4) Procedure for the recording and management of data.

(5) Procedures defining corrective actions for off-control point chemistry conditions.

(6) A procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

The applicant has stated that all volatile chemical treatment (AVT) of secondary water systems for control of dissolved oxygen and corrosion of ferritic metals and copper alloys will be used. Chemical treatment along with operation of condensate polishing and steam generator blowdown systems and a maintenance program will be used to control the three primary sources of secondary contamination (primary to secondary steam generator tube leakage, raw water inleakage across the condenser tubes, and air inleakage into the system). A sampling and analyses program in conjunction with inline monitors will provide the means of detecting and correcting out-of-limit chemistry conditions. Procedures will be instituted to provide instructions for the prompt notification of responsible plant personnel of out-of-limit secondary system chemistry and the steps to be taken to correct the situation. Records will be kept and maintained pertaining to secondary water chemistry to be used for evaluating past conditions in relation to possible subsequent chemical operations.

We find these provisions to be acceptable, however, in addition to the proposed secondary water chemistry monitoring and control program, it will be necessary to require monitoring of the steam condensate at the effluent of the condensate pump. The monitoring of the condensate is for the purpose of detecting condenser leakage. When condenser leakage is confirmed the applicant should repair or plug the leak in accordance with MTEB Branch Technical Position MTEB 5-3 attached to Standard Review Plan 5.4.2.1.

It should be noted that the steam generators of the Sequoyah Power Plant Units 1 and 2 are of the Westinghouse "51" series design having carbon steel supporting plates with drilled flow holes. Steam generators of this design in operating plants have experienced denting and cracking. Although an effective secondary water chemistry control program can reduce the rate of tube degradation, there is no assurance that a 40-year steam generator lifetime can be obtained.

In spite of the possibility of tube cracking, we have concluded that operation of the steam generators will not constitute an undue risk to the health and safety of the public for the following reasons:

(1) Primary to secondary leakage rate limits, and associated surveillance requirements will be established to provide assurance that the occurrence of tube

cracking during operation will be detected and appropriate corrective action, such as tube plugging, will be taken such that any individual crack present will not become unstable under normal operating, transient or accident conditions.

(2) Augmented inservice inspection requirements and preventative tube plugging criteria will be established to provide assurance that the great majority of degraded tubes will be identified and removed from service before leakage develops.

5.3.2 Residual Heat Removal System

In the Safety Evaluation Report, we stated that further confirmatory documentation was necessary on the capability of the Residual Heat Removal System to meet our Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal Systems."

Four processes are involved in taking the plant from hot standby to cold shutdown conditions. These are: (1) removal of residual heat and stored energy; (2) circulation of the reactor coolant; (3) boration of the reactor coolant to the cold shutdown boron concentration and coolant makeup; and (4) depressurization. With loss of offsite power, the reactor coolant pumps, main condenser and the main feedwater pumps are unavailable. Heat removal and coolant circulation under natural circulation conditions is then controlled by use of the steam generator atmospheric dump valves and the auxiliary feedwater system.

The four air-operated atmospheric dump valves at Sequoyah (one per steam generator) are seismic Category I. Air is supplied from plant safety-grade auxiliary control air systems. Electrical power is obtained from the 125-volt vital battery system. There are two independent trains of air supply and of electrical power (two dump valves per train). The most limiting single failure would be loss of one train of air supply or one train of vital power which prevents actuation of two dump valves from the main control room. The valves could be operated by manual action (outside or containment) to correct for this single failure. Since this is a control function, the applicant has committed to perform tests to confirm the feasibility of this type of manual action. Mechanical failure could prevent opening of a single dump valve. Manual action to correct for this failure would involve closing of an upstream isolation valve and replacement or repair of the dump valve. Alternatively, the natural circulation tests may justify plant cooldown with one failed dump valve.

The water supply to the auxiliary feedwater system is provided initially from the nonseismic condensate storage tank which has a minimum reserve of 190,000 gallons. This supply is backed up by the seismic Category I essential raw cooling water (ERCW) system. The supply is transferred automatically to the ERCW system via fully qualified automatic admission valves in order to maintain adequate net positive suction head at the auxiliary feedwater pumps. Analyses and tests were performed to verify proper operation of this transfer scheme.

During a normal plant cooldown from hot standby conditions, the CVCS letdown line from the RCS would be used during both the initial boration to the required boron shutdown concentration and while the RCS inventory is controlled during the cooldown. Loss of the nonseismic air supply results in loss of letdown due to air-operated valves failing closed in the letdown line. The CVCS makeup control system could also be unavailable due to loss of nonsafety-grade control circuits or the nonseismic air supply. Under these conditions, boration without letdown could still be accomplished using safety-grade equipment. Borated water (12 w/o boric acid) could be supplied to the suction of the centrifugal charging pumps from one of the three boric acid tanks using one of the four boric acid transfer pumps. The tanks, pumps, and associated piping are seismic Category I. The capacity of one boric acid tank is sufficient to provide boration to the required shutdown concentration. Makeup above that provided by the boric acid tanks is obtained from the refueling water storage tank. Borated water from the centrifugal charging pumps can be supplied to the RCS via the normal charging, and reactor coolant pump seal injection flow paths or via the boron injection tank path. The effect of valve failures due either to loss of air supply or postulated single failure is mitigated either by manual actions to correct the failure or use of an alternate injection path.

Calculations, based on injection of borated water with 12 w/o boric acid, indicate that the available volume in the pressurizer steam space is greater than that needed to achieve a cold shutdown boron concentration in the RCS without taking credit for letdown or contraction of the primary coolant in cooldown. In addition, the available volume for borated water injection without letdown which results from the contraction of the primary coolant is much larger than that required to cool and, hence, depressurize the pressurizer to 425 psig by injection of borated water through the pressurizer spray. This pressure must be reached to permit shutdown cooling with the RHR system.

Under natural circulation conditions the normal supply for the pressurizer spray from the cold legs of two coolant loops is lost. In this case, the pressurizer spray can be supplied by flow from the centrifugal charging pumps through a line branching off from the charging line of the CVCS. This supply could be lost by a single failure involving either closing of a single valve in the supply line or opening of one of several valves in lines connected to the supply line. If manual actions to correct for such failures were not successful, a backup method of depressurization would involve opening either of the two seismic Category I power-operated relief valves of the pressurizer which discharge to the pressurizer relief tank. The pressurizer relief tank is not designed for continuous operation and does not have safety grade equipment to provide for intermittent operation. Hence, these actions might result in rupture of the tank rupture disc and a release to containment. The isolation valves in the suction line from the RCS to the RHR pumps, which must be opened to get on long-term cooling with the RHR system, are designed to withstand the environmental conditions following a steam line break inside containment and, hence would be qualified to withstand the less severe conditions resulting from this type of operation.

BTP RSB 5-1 requires that a natural circulation test with supporting analysis be conducted to demonstrate the ability to cooldown and depressurize the plant and to demonstrate that boron mixing is sufficient under such circumstances. Comparison with performance of previously tested plants of similar design may be substituted for these tests, if justified. The applicant plans to reference tests to be conducted at Diablo Canyon to meet this requirement. Hence, the applicant reviewed differences between Diablo Canyon and Sequoyah which might affect boron mixing under natural circulation.

Both plants have the same general piping size and configuration, elevation difference between heat source and sink and use Model 93A pumps and Model 51 steam generators. The core, lower reactor internals and vessel outlet nozzle configurations for both plants are the same. However, the Diablo Canyon plant has pump weirs and a smaller radius on the vessel inlet nozzle/vessel downcomer juncture which result in higher flow resistance. The plants also differ with respect to the upper reactor internals. The Sequoyah plant, which has an upper head injection (UHI) system, is designed to maintain upper fluid temperature close to the cold leg temperature. This is achieved by passing a significant portion of the vessel inlet flow (~3 percent) to the upper head. Hence, for the same loop flow rates in both plants, the hydraulic resistance of the reactor internals for the Sequoyah plant would be less than that for Diablo Canyon

One of the staff concerns has been the ability to cool the upper head region of the reactor vessel under natural circulation conditions. Low density, hot water would tend to remain in this region under these conditions. Flow paths in this region for Sequoyah consist of (a) the control rod guide tubes and support columns connecting the upper head region with the core exit plenum region, and (b) the head cooling spray nozzles connecting the upper head region with the downcomer region. For Diablo Canyon the support columns are not flow paths. Flow communication to the upper head regions of Sequoyah and Diablo Canyon was compared in terms of the overall hydraulic resistance of these flow paths when assumed to act in parallel. The overall hydraulic resistance of Diablo Canyon is about nine times larger than that for Sequoyah. Since there is better flow communication, the upper head cooling capability at Sequoyah should be no worse and will probably be better than that demonstrated by the Diablo Canyon tests. Although Sequoyah has a larger mass of metal in the upper region, the ratio of water volume to metal volume is significantly larger.

The applicant's comparisons of system and upper head region characteristics for Sequoyah and Diablo Canyon suggest that the results of the Diablo Canyon test and supporting analysis should satisfy the BTP RSB 5-1 requirement. However, the staff plans to defer reaching a conclusion on this matter until the Diablo Canyon results have been reviewed. If the Diablo Canyon tests are not completed or do not provide satisfactory results, the applicant has committed to conduct such tests at Sequoyah Unit 1 prior to startup following the first refueling.

Residual Heat Flow Alarm

In the Safety Evaluation Report, we stated that the operating license would be conditional pending the installation of a flow alarm. We were concerned about spurious isolation of the RHR system.

The applicant will install RHR low-flow alarm during the first refueling outage and will provide a dedicated operator to monitor RHR flow during RHR operation until the alarm is functional. The applicant has also provided a schematic drawing of the alarm function, procedures which account for detection and correction of spurious RHR isolation, and analyses to support the adequacy of these measures. We find these provisions acceptable. However, we require the following actions prior to startup after the first refueling outage:

(1) The applicant to provide a detailed description of the sensors which activate the alarm.

(2) Installation of the alarm.

(3) The applicant to provide test procedures which will be used to verify alarm functional adequacy.

(4) The applicant to identify settings for alarm sensors.

(5) The applicant to provide results from the tests demonstrating the functional adequacy of the alarm system.

(6) NRC staff review and approval of items (1) through (5).

6.0 ENGINEERED SAFETY FEATURES

6.2.1 Containment Functional Design

In the Safety Evaluation Report, we reported the following relative to the effects of postulated main steam line break accidents inside the containment building.

> The applicant has calculated the containment response to a postulated double-ended circumferential steam line break using the LOTIC-3 computer program. This program has been described in Supplement 2 to the Westinghouse Electric Corporation Topical Report WCAP-8354, "Long-Term Ice Condenser Containment Code - LOTIC Code." We have completed a generic review of the LOTIC-3 code and have concluded that the LOTIC-3 code is acceptable for the calculation of long-term ice condenser containment response to postulated secondary system pipe break accidents (see our letter to Westinghouse dated May 3, 1978). The applicant has also presented information to show that the calculated temperature transient inside the Sequoyah containment following a small postulated main steam line break accident is conservatively predicted by the analyses presented in Supplement 2 to WCAP-8354. These analyses were performed for a "generic" ice condenser plant using the LOTIC-3 computer code to demonstrate the adequacy of the code for ice condenser long-term transient analyses for secondary system ruptures. While we have accepted Supplement 2 to WCAP-8354 and approved the LOTIC-3 code, we do not believe that a sufficient spectrum of small split breaks were analyzed in the topical report to permit us to conclude that the most severe temperature transient for the "generic" ice condenser plant has been determined. Westinghouse has indicated that the temperature response for the small break analyzed in WCAP-8354 will bound the expected temperature responses for the spectrum of small breaks for which we have requested the applicant to provide results.

The applicant provided the results of analyses of the "generic" ice condenser plant for the spectrum of small steam line breaks. Specifically the applicant has analyzed the containment response to postulated 0.6 ft^2, 0.35 ft^2 and 0.1 ft^2 main steam line split breaks. In all cases the effects of containment spray and return air fan operation were considered in the analyses. In all cases a containment lower compartment pressure high enough to initiate automatic operation o the sprays and fans was calculated in the LOTIC-3 analysis of the postulated event.

Mass and energy release for a spectrum of steam line breaks were calculated using the MARVEL code described in Topical Report WCAP-8822, "Mass and Energy Release Following a Main Steam Line Break."

The MARVEL code describes the primary and secondary systems of a PWR including the power excursion which may occur in the core following a main steam line break. The code calculates heat flow from the core and intact steam generators into the primary system, and heat flow from the primary system into the broken steam generator. The primary system heat flow produces additional steam which is added to the containment. No liquid entrainment is assumed to flow from the break so that the break flow is all steam. This assumption permits the secondary liquid to remain in the steam generator until it is boiled by heat flow from the primary system, and maximizes the energy release. The analysis includes additional steam from the intact steam generators before closure of the isolation valves and the unisolated steam in the steam lines and turbine plant piping. Feedwater flow is added to the affected steam generator based on the reduction in discharge pressure calculated by the MARVEL code. No credit is taken for any feedwater flow reduction during the valve closure period. The isolated feedwater mass is added steam generator inventory during the blowdown. We have concluded that the mass and energy release calculation results are acceptable for containment analysis of Sequoyah Units 1 and 2.

WCAP-8822 which describes MARVEL is currently under review. Our review at this time indicates that there is reasonable assurance that the calculated mass and energy release rates will not be appreciably altered by completion of the analytical review.

The applicant presented data which showed a comparison of the containment input parameters assumed in the analysis of the "generic" plant to the same parameters for the Sequoyah Nuclear Plant. The comparison shows that the "generic" plant analysis was performed using parameters (i.e., lower and upper compartment volumes, lower compartment passive heat sinks, and containment spray flow rate and temperature) which conservatively bound the corresponding plant specific parameters for the Sequoyah Nuclear Plant. We therefore conclude that the "generic" plant steam line break temperature transients are more conservative (result in higher containment calculated temperatures) than those which would be calculated specifically for the Sequoyah Nuclear Plant.

The maximum calculated containment atmosphere temperature occurs in the lower compartment since all steam is effectively removed in the ice condenser. The maximum calculated lower compartment temperature for the "generic" plant is 327 degrees Fahrenheit and results from a postulated small split break of about 0.9 ft^2 area at 30 percent power level with the assumed failure of the auxiliary feedwater system. This is the break originally identified by the applicants as the worst break; i.e., the largest break that would not result in liquid entrainment in the blowdown and would not generate a feedwater isolation and trip signal from the high steam flow/low steam line pressure protection system. The results of analyses of the spectrum of breaks smaller than this break have shown that the peak calculated temperatures are slightly less for these breaks but that superheated conditions in the containment lower compartment are slightly prolonged.

We have concluded that the results of the LOTIC-3 analyses for the "generic" ice condenser plant will result in higher containment temperatures than would be calculated specifically for the Sequoyah Nuclear Plant. We have used the results of the complete spectrum of steam line breaks to assess the equipment qualification tests performed on those instruments and equipment located in the containment lower compartment which are required to detect a steam line break, initiate safety system functions, and monitor the course of the accident. The results of our review of equipment qualification for the steam line break is reported in Section 7.2 of this supplement to the Sequoyah Nuclear Plant Safety Evaluation Report.

In the Safety Evaluation Report we also reported that the applicant used the TMD code to analyze the dynamic response of the steam generator enclosures to a double-ended steam line rupture and the pressurizer enclosure to a double-ended rupture of the pressurizer spray line, using a 10-node subcompartment model and a four-node subcompartment model, respectively. We reported, however, that the information provided by the applicant did not confirm that the calculated pressure response for these subcompartments has been used in the evaluation of the adequacy of the design of the steam generator and pressurizer supports.

The applicant provided further information regarding the subcompartment analyses for the steam generator and pressurizer enclosures. The applicant provided figures showing the differential pressures acting across the steam generator and pressurizer vessels as a function of time. We have performed confirmatory analyses of the steam generator and pressurizer enclosures using the COMPARE subcompartment code. The results of our analyses show acceptable agreement with the results of the applicant.

The applicant has also provided figures showing the asymmetric loads (forces and moments) acting across the steam generator and pressurizer vessels as a function of time and the geometric information used in developing the force/moment time histories from the subcompartment pressure time histories. The applicant assumed the peak forces and moments multiplied by a dynamic load factor of 2.0 to be constantly applied to the steam generator and pressurizer supports for the duration of the pipe break accident. These loads were directly added to the thrust and hydraulic forces produced by the postulated pipe breaks. The maximum stresses for the steam generator upper supports are 90 percent of the faulted condition allowable stresses, 92 percent for the steam generator lower supports, 73 percent for the pressurizer upper support, and very small for the pressurizer lower support. The peak calculated differential pressure acting across the steam generator enclosure wall is 19.2 psi while the minimum design differential pressure for the steam generator enclosure wall is 24 psi. The peak calculated differential pressure acting across the pressurizer enclosure wall is about 13.5 psi compared to a design differential pressure of 20.2 psi.

We find the applicant's method of analysis, modeling assumptions and results acceptab for the evaluation of both the steam generator and pressurizer enclosure structures and the steam generator and pressurizer supports. We also find the applicant's analytical methods used to evaluate the steam generator and pressurizer supports as well as the results of the anlaysis to be acceptable. Comparison of the peak calculate differential pressure to the design differential pressure for the steam generator and pressurizer enclosure structures demonstrates the design adequacy of the subcompartment structures. We therefore conclude that the applicant has acceptably demonstrated the design adequacy of both the steam generator and pressurizer enclosure structures and vessel supports.

6.2.3 Containment Air Purification and Cleanup Systems
Auxiliary Building Gas Treatment System

In Section 6.2.3 of our Safety Evaluation Report (SER), we stated the following: "The containment systems of Sequoyah Nuclear Plant also include the auxiliary building gas treatment system. The auxiliary building gas treatment system is used to maintain portions of the auxiliary building which contain emergency safeguards systems and fuel handling systems at a negative pressure of 0.25 inch of water following a loss-of-coolant accident. Exhaust from the auxiliary building gas treatment system is filtered prior to release to the atmosphere."

The portion of the auxiliary building served by the auxiliary building gas treatment system is known as the Auxiliary Building Secondary Containment Enclosure (ABSCE). The applicant has defined an interim ABSCE to separate Unit 1 operations from Unit 2 construction during the interim period between startup of Unit 1 and the completion of construction of Unit 2. This interim ABSCE is smaller than the final ABSCE and its boundary is generally inside that defined for the final ABSCE.

The applicant has found, by test, that some portions of the interim ABSCE cannot be maintained by the auxiliary building gas treatment system at the required negative pressure of 0.25 inch water gauge. In particular, the rooms containing the engineered safety feature pumps (RHR, safety injection, charging, and containment spray pumps) can be maintained, at best, at negative pressures in the range of 0.04 to 0.07 inch water gauge. This is the result of the interim configuration, in which the ducting that will draw air from these rooms will not be able to draw sufficient flow to draw down the rooms to the required negative pressure. The refueling floor, on the other hand, can be maintained at the required negative pressure of 0.25 inch water gauge. The applicant's analysis indicates that the entire ABSCE (interim and final) could be drawn down to and maintained at the required negative pressure of 0.25 inch water gauge were it not encumbered by the flow restrictions mentioned above. Since additional flow paths will become available in the final ABSCE configuration, we find that it should be possible to achieve the required negative pressur in the final configuration for the ABSCE.

The acceptability of the interim pressures in the ESF pump rooms is dissussed in Section 15.4.1 of this supplement to the Sequoyah SER. When the final ABSCE is established, the applicant will be required to demonstrate that a negative pressure of 0.25 inch water gauge can be maintained in the spent fuel storage area and in the ESF pump rooms by testing in the manner detailed in the Technical Specifications. We find this approach acceptable on the basis of th satisfactory finding relative to this matter in Section 15.4.1 of this Supplement.

Containment Leakage Testing Program

In the Safety Evaluation Report we reported that in performing the containment airlock door seal leak rate tests the applicant would pressurize the volume between the door seals to Pa, the peak calculated containment pressure. We have recently been informed by the applicant that the airlock door seal leak rate test cannot be performed at Pa (12 psig).

The applicant has described in the FSAR and associated Technical Specifications its proposed leak testing procedure for the containment airlocks, and proposes an exemption from the associated requirements of Appendix J to 10 CFR Part 50. Based on our review, we find the proposed leak testing procedures and the proposed exemption to Appendix J acceptable. The rationale for our finding acceptable the applicant's proposed leak testing practices for the personnel airlocks and the proposed exemption from the associated requirements of Appendix J to 10 CFR Part 50, is discussed below.

Appendix J to 10 CFR Part 50 requires the containment personnel airlocks to be leak tested at six-month intervals and after each opening during such intervals (III.D.2). Appendix J further requires that the test be conducted at the peak calculated containment pressure related to the design basis accident, i.e., Pa (III.B.2).

Considering that a full pressure airlock test is to be performed every 6 months, it is our judgment that testing airlocks within 3 days after each opening or after the initial opening in a series of openings, at 1/2 Pa, will adequately demonstrate the continuing integrity of the airlock door seals such that the public health and safety will be ensured. The effect on accident consequences of testing after each opening versus testing within 3 days of an opening is judged to be insignificant. Furthermore, if an airlock door seal is damaged, it will be manifested during testing at 1/2 Pa (6 psig). This is an adequate demonstration of continuing airlock integrity for the period between the 6-month tests.

We find that leak testing an airlock in the manner described above is an acceptable alternative to the requirements of Appendix J. Accordingly, the proposed exemption from the requirements of Appendix J is acceptable.

In Section 6.2.6 of the SER we reported that we had identified 21 additional fluid lines which we believed to be potential paths for through line leakage from the containment to the auxiliary building. We stated that we would complete our review of these with the applicant and include them as necessary in the tabulation of potential bypass leakage paths to the auxiliary building gas treatment system during the development of the Technical Specifications for the operation of the plant.

We have completed our review of these fluid lines and have determined that twelve of the lines are potential through line leakage paths to the auxiliary building and have added them to the tabulation of through-line leak paths to the auxiliary building (Table 3.6-1) in Technical Specification 3.4.6.1, "Primary Containment - Containment Integrity." This brings the total number of bypass leakage paths to the auxiliary building to 50.

It should also be noted that when the Safety Evaluation Report was prepared the applicant had intended to maintain the bypass leakage fraction to the auxiliary building to 10 percent of the containment design leakage rate (La). The applicant has recently increased the allowable bypass fraction to 25 percent of La.

The applicant has analyzed the offsite dose consequence of this increase in the bypass fraction. The results of our review of the applicant's dose consequence analysis is reported in Section 15 of this supplement to the SER.

The applicant has recently identified 27 containment fluid penetrations (lines) which were designed to be local leakage rate tested with water as the test fluid, and which cannot be pneumatically tested as required by Appendix J without modifications to the systems. The Sequoyah Nuclear Plant design was completed and construction started before Appendix J to 10 CFR Part 50 was published.

The applicant intends to upgrade the design of the leakage test connections for these 27 lines. However, it is not possible to perform the necessary modifications for Unit 1 without delaying the initial operation of the plant because of the long lead time for procurement of necessary safety-grade valves (Unit 2 will be discussed below). The applicant proposes, for Unit 1, to perform the preoperational leakage rate tests with water and convert the measured leakage to an equivalent air leakage, and to perform the necessary modifications during the first plant refueling outage so that all subsequent Type C local leak rate tests may be performed in full compliance with Appendix J. The applicant will use test data developed for use at their Browns Ferry Nuclear Plant, Unit 2, to convert measured water leakage to an equivalent air leakage.

We maintain that the conversion of liquid leakage rates to equivalent air leakage rates is not desirable because it cannot be shown to provide a conservative estimate of air leakage for all possible types of leak paths, which is reflected in the requirements of paragraph III.C.2.(a) of Appendix J. However, since (1) the 27 penetrations comprise only a small fraction of the total containment penetrations and, therefore, contribute only a small fraction of the total allowable local leakage, (2) the applicant has committed to include a representative (if not conservative) assessment of the local leakage from these 27 fluid penetrations in the total measure of local leakage rate, and (3) the applicant has committed to procure and install the necessary hardware to permit pneumatic leakage rate testing for all future tests, we find the applicant's proposed preoperational hydrostatic testing of the isolation valves in these lines and the commitment for subsequent pneumatic leak testing to be an acceptable alternative for Unit 1 to the requirements of Paragraph III.C.2.(a) of Appendix J to 10 CFR Part 50.

For Unit 2, the applicant has committed to perform all Type C local leak rate tests, including the preoperational ones, in full compliance with Appendix J.

Based on our review of the applicant's proposed containment leak testing program, and subject to approval of the exemption of the matter cited above, we conclude that it meets the requirements of Appendix J to 10 CFR Part 50 and is, therefore, acceptable.

6.3 Emergency Core Cooling System

6.3.3 Evaluation

Functional Design

The applicant submitted an analysis of net positive suction head available to ECCS pumps. A worst case was identified as an RHR pump, drawing suction from the reactor containment sump during the recirculation mode after the loss-of-coolant accident, while supplying water directly to the reactor vessel and indirectly via high head pumps, and while containment spray pumps are drawing water from the same pump. The flow rate assumed for the RHR pumps was 5500 gallons per minute, conservatively higher than the expected pump runout flowrate. Because Sequoyah has an ice-condenser containment the applicant has been allowed to assume a subcooled temperature for the sump water. In his analysis, the applicant has assumed the sump water to be at 160 degrees Fahrenheit, based on the design basis LOCA calculation. He calculates that he has 13.4 feet of excess NPSH available.

Because of the possibility of a break in the area of the sump (not the design basis event) which would yield higher water temperatures in the sump locale, we feel that 190 degrees Fahrenheit is a more appropriate assumption. This assumption would increase the vapor pressure of the liquid by about 10.6 feet and thereby reduce the excess NPSH available to about 2.8 feet.

The applicant has performed preoperational RHR runout flow tests for the worst-case flow condition. For these tests the flow was measured to be less than 5300 gallons per minute, verifying the conservatism in the NPSH analysis assumption.

Because suitable analytical techniques have been used, suitably conserative assumptions have been made, in-plant testing has verified the conservatism of the assumed flow rate, and results indicate that at least 2.8 feet of excess NPSH are available for a worst flow case we conclude that the ECCS pumps will be provided with adequate NPSH for all modes of operation. The NPSH design of Sequoyah ECCS pumps is, therefore, acceptable.

Regulatory Guide 1.82, "Sump for Emergency Core Cooling and Containment Spray Systems", states that the size of openings in the fine screen of the containment sump should be determined by the physical restrictions that may exist in the systems which are supplied with coolant from the emergency sump. Regarding the core, the guide states that if the coolant channel openings in the core represent the smallest flow restriction, the minimum opening in the core channels which will allow design operation of the ECCS should be sued in sizing the fine screen mesh size.

In the course of its review of another plant, the staff became aware that the fine screen for the sump was designed with 0.040 inch openings, smaller than has been proposed for other plants. The size of the screen mesh was based on a minimum restriction in the as-built core of 0.080 inches, and the (limited) use of foam glass insulation, which could crumble into fine granules following a LOCA. Based on the consideration that local blockage of the open lattice of the PWR cores would not be detrimental to large areas, anticipation that a limited amount of debris would penetrate the fine screens, and the projection that the recirculation mode of cooling using sump water would take place at low decay heat levels where limited core blockage is more tolerable, we have normally found that the most restrictive flow path involves the containment sprays. The TVA fine screens have 0.25 inch openings, which are adequate protection for the containment spray nozzles, but which might not protect the core from significant blockage.

The Sequoyah plant has primarily mirrored insulation, which is not subject to breakage into small particles, in containment. The limited foam glass insulation has been covered with stainless steel, so its potential for blockage has been minimized.

The staff has not determined that additional protection core blockage by containment debris needs to be provided. However, considering the Sequoyah plant conditions noted above, and the low decay heat levels associated with low power operation, we conclude that the low power operation program can safely proceed while additional information and positions are developed.

6.3.4 Tests and Inspections

Upper Head Injection

In the Safety Evaluation Report, we stated that confirmatory documentation was required on the flow performance of the upper head injection system.

The applicant's preoperational tests of the upper head injection system are to demonstrate:

1. Hydraulic resistances in the UHI system are consistent with those used in the LOCA analyses.

2. No nitrogen entraining vortices are obtained during active UHI injection.

3. The level setpoints on the UHI accumulator are consistent with the UHI injection quantities used in the LOCA analyses.

4. The isolation valves on the UHI lines will function as expected.

These tests are conducted in accordance with Regulatory Guides 1.68 and 1.79. Tests to determine hydraulic resistance, level setpoints, and isolation valve performance are similar to corresponding preoperational tests performed on other ECC systems.

The original response on preoperational testing of the UHI system was judged to be insufficient because of the lack of a description of methods and acceptance criteria for determining entrained nitrogen, and the lack of justification that the test was conservative.

Since that time, the applicant has submitted additional material covering the methods of sampling and the acceptance criteria for total nitrogen in the samples. The licensee's proposed acceptance criterion ($\leq$ 4.38 percent entrained plus dissolved nitrogen) permits a maximum of 80 standard cubic feet of nitrogen to be injected. Preoperational test results have been well within the criterion (1.6-1.7 percent). The applicant points out that this volume is small compared to the volumes of the upper head, the reactor vessel or the reactor cooling system. The applicant states that there is no mechanism for the nitrogen to be accumulated anywhere in the system other than the upper head.

The staff was concerned that injected nitrogen might collect in the steam generators and thus interfere with natural circulation and heat transfer. Small break LOCA's, for which natural circulation and heat transfer from the steam generators are needed, are currently under review. Effects of the presence of noncondensibles will be studied. The amount of noncondensible gas introduced via the UHI system is small compared to the amounts in question under the current review, however. It is not expected that the 80 ft^3 of nitrogen introduced with UHI will be significant with respect to LOCA analyses.

The applicant has confirmed that preoperational tests were performed in accordance with Regulatory Guides 1.68 and 1.79. This requires the testing of both primary and backup isolation valves under the most adverse conditions. Although the applicant has not provided discussion of testing for nitrogen in the case that a train of isolation valves remains open as requested by the staff, it is now concluded that this system meets the single failure criterion, as there are two separate isolation valves, each with its own power supply and sensing signal, in each train. The performance of the tests according to the appropriate Regulatory Guides assures a degree of reliability so that this situation need not be tested further.

The tests were performed with the reactor vessel at one atmosphere rather than at operating pressure. This is conservative with respect to testing the operation of the valves against the maximum pressure differential for which they will be required to function. It is also conservative with respect to providing the maximum injection velocity for promoting the maximum entrainment of nitrogen.

Therefore, taking into account the applicant's preoperational testing and the samplin procedure and criteria for nitrogen content, the staff concludes that the issue of testing for nitrogen injection via the UHI system has been satisfactorily resolved.

We conclude that the preoperational test program described for the Sequoyah upper head injection system, conducted in accordance with Regulatory Guides 1.68 and 1.79, will accomplish its objectives associated with hydraulic resistance, level setpoints, isolation valve performance, and nitrogen entrainment. We therefore find the preoperational test program for the Sequoyah upper head injection system acceptable.

Containment Sump Tests

In the Safety Evaluation Report, we stated that the applicant had not verified the containment sump performance in the event of certain line breaks.

As part of the preoperational test program, the staff has required demonstration that recirculation from the containment sump with the low pressure coolant injection system would occur without any adverse hydraulic phenomena which could impede long-term cooling of the core following a loss-of-coolant accident. The applicant performed out-of-plant scale model tests of the containment sump at the TVA Norris Engineering Laboratory. These tests are described in TVA Report #WM28-1-45-102, "Model Study of the Sequoyah RHR Sump," October 1978.

The test facility was a one-quarter scale model of the Sequoyah sump. Initial testing showed some tendency for air entrapment in the sump, and small vortex formation. The applicant modified the sump design by sloping and venting the sump cover plate, installing vortex suppression grids, and increasing the water depth above the sump expected at the time of recirculation switchover. A comprehensive testing program conducted after the design was modified, indicated that for a range of both modeled and prototypical flow velocities, air entrapment and vortex formation had been eliminated.

In order to prevent air entrapment into the sump, nearby ice-condenser drains were rerouted, so that they did not discharge above the sump. Additionally, a jet deflector was installed so that nearby high pressure piping could not, upon rupturing, direct a steam/water stream toward the sump.

As part of their sump modification program, the applicant increased the containment water level as discussed above. This was accomplished by sealing a number of crane wall penetrations, so that the sump would be covered by 13 feet of water at switchover. The sealing methods have been tested by the applicant on prototypical penetration assemblies. Tests have shown that the sealing materials will withstand the post-LOCA containment pressure surge and still maintain their leak integrity.

The staff finds the present recirculation sump design to be acceptable, and believes that the applicant has demonstrated reasonable assurance that it will perform as expected following a LOCA.

6.3.5 Performance Evaluation

The applicant has provided loss-of-coolant analyses to demonstrate conformance with the requirements of 10 CFR 50.46 for emergency core cooling systems. These analyses identify the limiting location, type, discharge coefficient, and size break for Sequoyah Units 1 and 2. Additional analyses confirm conservatism in inputs and demonstrate sensitivity of calculated peak cladding temperature to uncertainty in input parameters.

The applicant has cited spectrum analyses performed for the Floating Nuclear Plant to show the most limiting break location to be in the pump discharge line. The Floating Nuclear Plant analyses include the effect of upper head injection, and we find them an acceptable reference to determine worst break location.

The applicant performed a break spectrum study for large ruptures in reactor coolant pump discharge piping using an appropriate metal/water reaction model, and which is in conformance with 10 CFR Part 50, Appendix K. The applicant presented its input values for a number of primary system initial conditions and emergency core cooling system parameters. It indicated whether those parameters were maximum, minimum, or nominal values expected during plant operation. It stated that the net effect of these input parameters is conservative for the loss-of-coolant accident analyses.

The analyses were performed with an assumed containment backpressure which has been reviewed and found acceptable as discussed in Safety Evaluation Report Section 6.2.1.

The study identified that large guillotine breaks are more limiting than large split breaks and that the most limiting break is a double-ended guillotine rupture in pump discharge piping with a discharge coefficient of 0.6 (DECLG, Cd=0.6). All guillotine ruptures were analyzed with both perfect and imperfect mixing as required by the staff in our approval of the model.

The applicant has submitted analyses for a spectrum of small break loss-of-coolant analyses (4 inch, 6 inch, 8 inch, 1/2 ft^3 breaks; Ref. 2 and 7). These identify that the 8-inch break is the limiting small break; the calculated peak cladding temperature is 1486 degrees Fahrenheit, the local metal water reaction is 0.532 percent, and the core wide oxidation is less than 0.3 percent. Of these small break analyses, only the 1/2 ft^2 break was anlayzed with a model properly accounting for metal/water reaction. Because of the magnitude of the cladding temperature for these small breaks would be far below that for large breaks and clearly would not be limiting.

Most of the study was performed using input describing an internally pressurized type of fuel and yielded a peak cladding temperature of 2190 degrees Fahrenheit.

The worst break (DECLG, Cd=0.6 imp.) was reanalyzed refining the input data to describe the fuel actually used in Sequoyah having a lower internal pressure. This refinement does not change identification of the worst break, but does define the peak cladding temperature for the Sequoyah as-fueled reactor.

The break spectrum study has shown that for the as-fueled Sequoyah reactor the worst break is a double-ended cold leg guillotine rupture, calculated assuming imperfect mixing and a coefficient of discharge equal to 0.6 (DECLG, Cd0.6, Imp). The calculated peak cladding temperature for this case is 2143 degrees Fahrenheit which is below the acceptable limit of 2200 degrees Fahrenheit, as specified in 10 CFR 50.46(b the calculated maximum local metal/water reaction of 6.6 percent and calculated total core-wide metal/water reaction of less than 0.3 percent are well below the allowable limits specified in 10 CFR 50.46(b) of 17 percent and 1 percent, respectively. The analysis were performed based on a total peaking factor of 2.25 (a peak linear power of 12.50 kilowatts per foot) at 102 percent of the rated core power level qf 3411 megawatts thermal.

The applicant has provided additional analyses and information to satisfy the plant-specific conditions specified in the staff approval of the UHI evaluation model.

The applicant has shown by analysis that, for a worst-case break at Sequoyah, a 4-degree Fahrenheit reduction in inlet temperature results in a calculated peak cladding temperature increase of 5 degrees Fahrenheit. The applicant will be required to compare his plant operating data for inlet and average temperatures with those assumed for the analysis and if these temperatures do not verify the range assumed for this sensitivity, he must provide additional analyses to justify the difference.

The minimum upper head injection accumulator pressure is higher than the saturation pressure based on the maximum allowable upper head temperature. Therefore, upper head injection will occur prior to flashing in the upper head as required by the staff's acceptance of the evaluation model.

In its analyses, the applicant assumed that the initial upper head temperature was equal to the cold leg temperature. Westinghouse has performed scale model tests simulating a reactor upper head region with upper head injection hardware. These tests have shown that 4-percent bypass flow into the upper head is sufficient to maintain the temperature in this region at the cold leg temperature. We have concluded that the scale model tests provide reasonable assurance that cold leg temperature will be achieved and, therefore, finds this upper head temperature assumption acceptable. We will require plant data to confirm the upper head temperature. The applicant has performed a sensitivity analysis to determine the effect of cold leg accumulator uncertainties on calculated peak cladding temperature. This analyses indicate that there is less than 20 degrees Fahrenheit impact on calculated peak cladding temperature for the worst case break due to cold leg accumulator uncertainties.

The applicant has assumed the most severe active single failure for the large break loss-of-coolant accident analyses is the loss of a residual heat removal pump. Potential consequences of losing an engineered safety features train were assessed. It was concluded that the loss of an engineered safety features train was less limiting because of the benefits of increased containment pressure with only one containment spray train available.

The applicant has demonstrated the conservatism in the assumption of loss of offsite power for these studies by performing an analysis of the worst case assuming continual running of reactor coolant pumps. The calculated peak cladding temperature (1907 degrees Fahrenheit) was below the identified design basis loss-of-coolant analysis.

Recently, the staff has requested information concerning the rupture and blockage models used in loss-of-coolant analyses from Westinghouse and operating plants. As a result of this review it is expected that modification to the Westinghouse ECCS evaluation model will be required. An interim assessment of the impact of potential model changes has been made for operating plants. Clearly there is no impact for power operating levels of less than or equal to fifty percent of full power. We will require generic resolution of this issue and appropriate implementation by the applicant prior to ascension to full power operation.

The applicant has provisions for maintaining long-term cooling of the core. The loss-of-coolant accident analyses presented show that the peak clad temperatures do not exceed the allowable limit and that clad temperatures are reduced as the core is reflooded. Therefore, these clad temperature trends, which include effects of rod ballooning, and available long-term cooling show that a coolable core geometry will be maintained as required by 10 CFR 50.46(b).

Based on this review and other SER sections describing the staff review of the emergency core cooling system for Sequoyah Units 1 and 2, we conclude that, subject to the conditions stated above, the emergency core cooling system performance conforms to the acceptance criteria in paragraph 50.46 of 10 CFR Part 50.

In the Safety Evaluation Report, we stated further information was needed to verify that time was available for an operator to respond to its consequences of a postulated moderate energy line break in the residual heat removal system while operating in the shutdown cooling mode.

For a moderate energy line break area of 0.01 ft^2 (based on staff criteria for this particular pipe size), a pressurizer low level alarm occurs within 30 seconds after the break occurrence and the operator has about 58 minutes to take appropriate action to ensure core coverage. Either one centrifugal charging pump or one safety injection pump would provide sufficient flow to keep the system in a safe condition. Assuming failure of the operating charging pump, manual action to unlock the breakers for either of the two safety injection pumps or the remaining centrifugal charging pump would be required. The applicant stated that these breakers are located immediately outside of the control room. On the basis of our review we find that there is adequate time for manual actions to prevent core damage following the postulated moderate energy line breaks in the RHRs at Sequoyah, Units 1 and 2.

7.0 INSTRUMENTATION AND CONTROL

7.2 Reactor Trip Systems

7.2.2 Process Analog System

Seismic Qualification of Westinghouse-Supplied Class 1E Equipment

We stated in the SER that, based on the review of previous applications, some aspects of the generic Westinghouse program for seismic qualification were not acceptable and that we were reviewing the acceptability of seismic qualification with the applicant. We requested that the applicant provide a table to identify Class 1E equipment by supplier and model number, its function and the number of units installed in the plant, and the documents and test reports for the seismic qualification of the equipment. The responses and information received to date remains incomplete in some respects which we are pursuing and will report on in a future supplement.

Response Time Testing

In the SER we stated that the applicant had committed to include measurement of the sensor response time in the determination of the response time of the reactor trip system and engineered safety features actuation system channels. This would ensure that the actual response times of the channels remain conservative with respect to those assumed in the safety analyses. We have reviewed typical procedures for preoperational and periodic tests that measure the response time from the instrument loop through the actuated device in a series of overlapping tests and have concluded that the testing for these sections of the system is acceptable.

For the sensor response times, we have reviewed preoperational test procedures for measuring the response times of pressure, differential pressure and resistance temperature transmitters used in the safety systems. The periodic sensor response time test procedures will use the same basic sensor test procedures as those used in the preoperational tests. Based on the similarity of these procedures and the availability of appropriate test equipment designed specifically for measuring the response times of these sensors, we conclude that sensor response time testing is acceptable.

Environmental Qualification of Westinghouse-Supplied Class 1E Equipment

In the SER we reported that Topical Report WCAP 7744, "Environmental Testing of Engineered Safety Features Related Equipment," was still being reviewed for acceptability as the basis for environmental qualification of safety-related Class 1E instrumentation and control equipment. We have completed our review of this information and find it acceptable for that equipment for which Sequoyah references this report as the basis of its qualification. For other unresolved concerns we requested additional information to identify Class 1E equipment by supplier and model number, its function and the number of units installed in the plant, and the documents and test reports for the environmental qualification of this equipment. The responses and information received to date remain incomplete in some respects.

In September 1978, Westinghouse provided test results for the environmental qualification of Barton Models 763 and 764 Lot 1 transmitters (Letter Report NS-TMA-1950). Our conclusion, based on these tests, was the instruments would perform their short-term safety functions. However, we required that additional testing be conducted to confirm their capability for longer term post-accident monitoring. In September 1979, Westinghouse provided the results of these supplemental tests.

In the original tests, it was attempted to demonstrate the qualification of these transmitters by subjecting them to high readiation levels corresponding to post LOCA conditions and subsequently exposing them to the high temperature steam conditions, typical of main steam line break (MSLB) accidents. This combined test was performed to circumvent the need for separate LOCA and MSLB tests. This combination of high radiation and temperature while causing the transmitters to fail, resulted in excessive instrument error.

The supplemental tests which followed were based upon radiation levels and subsequent exposure to a steam environment corresponding to LOCA and MSLB conditions separately. Additional tests were also conducted to investigate the effects of radiation and temperature separately and in combination. This was done to promote an understanding of the phenomena which caused the errors and to provide a bases to support the conclusion that the transmitters are qualified to operate satisfactorily under the required service conditions. While the supplemental tests results support the conclusions that the Lot 1 instruments will function in an accident environment, we do not believe that these instruments provide a sufficient margin of safety to justify their use throughout the life of the plant. Further improvements to obtain an additional margin of safety are warranted due to the safety significance of the information provided for post accident recovery by these instruments. Accordingly, we will condition the operating licenses to permit the use of the Lot 1 Barton Transmitters until the second refueling outage. At that time, modified or replacement transmitters, that have been demonstrated to have a greater tolerance to harsh environments, will be required.

The Sequoyah plant also employs Barton Lot 2 Transmitters. These instruments use a circuit board design that differs slightly from that used in the Lot 1 instruments. In December 1979, Westinghouse provided test results for the environmental qualification of these Lot 2 transmitters. The test results demonstrate that the acceptance criteria for these units were satisfied when these units were subject to a single set of environmental condition which envelop the LOCA and SLB accidents.

We conclude from these results that the safety margins for these instruments are acceptable. While we still have concerns related to some aspects of the test report, informal discussions with Westinghouse inuicate that those concerns can be resolved and that plant operation in the interim is acceptable.

We questioned the qualification of the Foxboro differential pressure transmitters that provide input to the reactor coolant low flow trip. These transmitters are not required to function in harsh environments other than the radiation dose received during normal operation. The total radiation dose received during fuel loading and subsequent testing and operation at 5 percent power or less will not exceed that which the equipment could withstand without suffering unacceptable effects. We will require information for the qualification of these instruments to survive the normal radiation environment be provided prior operation beyond 5 percent power.

We reviewed Westinghouse Topical Report WCAP-9157 which contains the environmental qualification results for the main coolant loop resistance temperature detectors (RTD). These temperature sensors provided data to confirm natural circulation cooling we well as data to ensure an adequate margin of subcooling to prevent steam formation in the reactor coolant system. We questioned the basis for the assessment that the normal and post accident radiation exposure would be limited to a radiation dose for which the RTDs were qualified. The applicant provided a response to our concern which concluded that the RTDs used for post accident monitoring are adequate if replaced after eleven years of operation. We conclude that this evaluation did not include assumptions which contained an adequate degree of conservatism. Therefore, we will condition the operating license to require the replacement of RTDs used for post accident monitoring at each refueling outage pending requalification of the sensor to a higher radiation dose which is established based on a conservative assessment of post accident radiation levels and the normal radiation dose for the RTD service life.

We have recently published staff guidance to be used in environmentally qualifying electrical equipment (see NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"). Recognizing that the equipment qualification review for the Sequoyah plant has been a long-term effort spanning several years, we recently required that TVA reassess their qualification documentation for equipment installed at Sequoyah with the purpose of establishing that the qualification methods used and results obtained are in conformance with the staff positions contained in NUREG-0588. We believe that this additional review will confirm our earlier conclusions regarding the adequacy of the qualification documentation, and therefore that it need not be completed prior to licensing Sequoyah for lower power operation. We will require that, prior to full power operations, TVA confirm the adequacy of qualification for all safety-related electrical equipment that could be exposed to a harsh environment.

Steam Generator Level Instrumentation

In June of 1979 Westinghouse reported a potential safety hazard under 10 CFR Part 21. This report addressed errors generated in steam generator level indication following high energy pipe breaks inside containment. High ambient temperatures due to accidents can result in a decreased in the density of water in the level instrument reference leg with a consequent increase in the indicated steam generator water level (i.e., the indicated water level exceeds actual level). We requested that the applicant evaluate the effects of such errors for all level measurement systems in containment. This evaluation led to a decision to insulate the reference legs for steam generator level measurements.

The applicant also assessed the method for establishing the low-low steam generator level trip setpoint. This setpoint is adjusted above zero-measured level by an amount which just equals the accumulation of all system errors, including temperature effects on the reference legs. We do not find this approach to evaluating errors and establishing the setpoint for safety action to be acceptable. The choice of zero-measured level, as a reference point for establishing the setpoint, does not provide an adequate margin of safety since these level transmitters do not respond to a reduction of water level below this point in the steam generators. Accordingly, we will condition operation to require a minimum low-low steam generator level setpoint of 21 percent (a margin of 3 percent in addition to identified errors of 18 percent) until such time as it can be demonstrated that this method establishes that an adequate margin of safety exists.

7.2.3 Solid-State Protection System General Warning Alarm Circuits

We stated in the SER that a defect existed in the General Warning Alarm circuit of the Solid State Protection System that constituted an unacceptable compromise of the reactor trip system independence. Further, Westinghouse had issued a field modification to eliminate this problem. We have reviewed this modification, which has been implemented at Sequoyah, and find this action acceptable.

7.2.5 Control Room Rack Wiring

In the SER we reported that the design for separation and independence of control room rack wiring presented in the FSAR was acceptable. On the first site visit we were unable to determine that this design was properly implemented and had noted an apparent lack of separation between redundant circuit wiring in some areas. On a followup site visit we completed our review of these and other areas and found that adequate separation has been provided between redundant trains and channels. Where separation of 6 inches or more could not be maintained, barriers were provided. We find thse actions to implement the separation criteria acceptable.

7.3.2 Isolation Valve Interlocks and Position Indication

We stated in the SER that removal of power to the motor control centers of selected isolation valves resulted in loss of power to their position indication circuits which we found unacceptable. The applicant has modified the design to provide separate power sources for the control portions of the motor control centers for those valves. This modification allows motive power to be removed from the valve operators without disturbing the power for the position indication systems. We find that this modification meets our requirements for both preventing spurious actuation and maintaining the redundant position indication and is, therefore, acceptable.

Effect of Power Transients on Safety-Related Equipment

In the SER, we discussed the applicant's compliance with four generic staff positions which arose as a result of power system transients that occurred at Millstone Plant, Unit 2 in July 1976. We stated that we would require that the applicant provide an additional level of under and/or over voltage protection (Position I). The applicant has now documented his agreement to comply with this position no later than the first refueling outage. We find this acceptable and will condition the operating license accordingly.

We also concluded in the SER that the applicant's justification for exception to testing of the standby power source (Position III) was inadequate. The preoperational test program and the Technical Specifications require the performance of specific preoperational periodic testing that meets the staff position by confirming the overall operability of the standby power system including its source. This action closes this matter.

7.5.2 Post-Accident Monitoring Criteria

We stated in the SER that the applicant had committed to providing separation and independence between redundant post-accident monitoring channels and that we would report further on the implementation in a supplement report.

On a followup site visit we reviewed the implementation of these criteria. The post-accident monitoring channels are identified by color coding and train one cables run in rigid conduit while train two cables run in nondivisional, enclosed, signal-level raceways. Separation between meters is provided by metal barriers surrounding the terminals. The meter cases serve as the barrier between adjacent meters not separated by 6 inches or more. The use of the meter cases as barriers is acceptable because they are made of fire-retardant plastic materials (phenolic or fiberglass) and the energy levels available to initiate and maintain damaging events are low. We find that the applicant has properly implemented the separation criteria.

7.8.1 Seismic Qualification of Balance-of-Plant Class 1E Instrumentation, Control, and Electrical Equipment

In the SER we stated that we had reviewed additional documentation regarding seismic qualification of selected representative BOP items and found them acceptable. However, the applicant was to submit additional seismic qualification information on the outboard containment isolation valves. We reviewed this additional information and find it acceptable. We consider this matter closed.

7.8.2 Environmental Qualification of Balance-of-Plant Class 1E Equipment

We stated in the SER that the applicant relied on environmental qualification information based on ANSI and NEMA standards to qualify the BOP Class 1E equipment for a narrow range of environmental conditions. We questioned the adequacy of environmental control systems to assure that this equipment would not be exposed to environmental conditions more severe than those used for its qualification. The applicant has provided redundant environmental control systems and we find this acceptable.

We had further required that the applicant install a temperature monitoring system for those plant areas that contain safety-related equipment. The applicant has stated that this system will be in operation prior to the end of the first refueling outage and we will condition the operating license accordingly. In the interim the applicant had agreed to implement a program of daily surveillance that will limit the potential for exposure of safety-related equipment to unacceptable temperature extremes. If such an exposure occurs, it will be reported as an abnormal occurrence and an analyses of the fitness of the affected equipment for continued service will be made. We find the commitment to these actions acceptable.

We stated in the SER that we found omissions, discrepancies, and, in some cases, lack of justification for entries made in FSAR Tables 3.11-2 and 3.11-3. The applicant has revised portions of these tables and portions of FSAR Section 3.11 to remedy these deficiencies. Our review shows that while we still have some minor concerns with the applicant's response, we believe that they will be acceptably resolved. We require that these concerns be acceptably resolved prior to escalation of power beyond 5 percent.

In the SER we stated that we would find the BOP Limitorque valve motor operators for use inside the containment acceptable, conditioned on our acceptance of the Westinghouse environmental tests made on valves of the same type. We have reviewed the Westinghouse test reports (NS-CE 692, NS-CE 756, F-C 3441) and have concluded that the environmental testing and results adequately envelopes the most severe set of environmental conditions postulated during and after an accident. We find these operators to be acceptably qualified.

8.0 ELECTRICAL POWER SYSTEMS

8.2.4 Unit Start Buses

We stated in the SER that the close proximity of the two-unit start buses to a shield wire system support tower was a concern as the tower could fall in such a way as to damage both buses. In responses to this concern, the applicant anchored the shield wire system to the turbine building wall and removed the tower. We find these actions acceptable.

8.3.1 Diesel Generator Reliability

The reliability of the installed diesel generators has been demonstrated by performance of the applicant's preoperational testing specified in Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems." This includes performance of 69 consecutive start and load tests with zero failures, and a 24-hour full-load carrying capability test. A continuing demonstration of reliability will be obtained by inclusion in the Technical Specifications of the periodic testing provisions of Regulatory Guide 1.108. To provide further assurance of the long-term reliability of the diesel generators, the applicant has been requested to review the design with regard to the recommendations of NUREG/CR-0660, "Enhancement of Onsite Emergency Diesel Generator Reliability," and to report the conformance to or plans for implementation of these recommendations. The staff finds this program acceptable for low power operation of the Sequoyah facility. We will review this report and require implementation of these recommendations as deemed necessary to assure long-term reliability of the installed diesel generators prior to full power operation.

9.0 AUXILIARY SYSTEMS

9.5 Fire Protection System

I. INTRODUCTION

We have reviewed the Sequoyah fire protection program and fire hazards analysis submitted by the applicant. The submittal, including Revisions 1, 2 and 3, was in response to our request to evaluate their fire protection program against the guidelines of Appendix A to BTP APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." As part of the review, we visited the plant site to examine the relationship of safety-related components, systems, and structures in specific plant areas to both combustible materials and to associated fire detection ad suppression systems. The overall objective of our review of the Sequoyah Nuclear Plant fire protection program was to ensure that in the event of a fire at the facility, Units 1 and 2 would maintain the ability to safely shutdown, remain in a safe shutdown condition, and be able to minimize the release of radioactivity to the environment.

Our review included an evaluation of the automatic and manually operated water and gas fire suppression systems, the fire detection systems, fire barriers, fire doors and dampers and fire protection technical specifications.

Since Unit 1 and Unit 2 are of the same design, except where noted, the comments made in this report apply to both Units.

Our conclusion, given in Section VII, is that the Fire Protection Program at the Sequoyah plant is adequate at the present time and meets General Design Criterion 3. However, to further ensure the ability of the plant to withstand the damaging effects of fires that could occur, we required and the applicant provided additional fire protection system improvements. These additional fire protection features have been completed for both Unit 1 and Unit 2.

Until the committed fire protection system improvements are operational, we consider the existing fire detection and suppression systems; the existing barriers between fire areas; improved administrative procedures for control of combustibles and ignition sources; the trained onsite fire brigade; the capability to extinguish fires manually; implementation of temporary damage control; and the fire protection technical specifications provide adequate interim protection against a fire that could threaten safe shutdown.

This report summarizes the results of our evaluation of the Fire Protection Program for the Sequoyah Nuclear Plant.

II. FIRE PROTECTION SYSTEMS DESCRIPTION

A. Water Supply Systems

The water supply system is common to both units and consists of four seismic Category I high pressure submersible motor-driven pumps each rated at 1500 gpm at 410 ft head. The pumps are located in the seismic Category I intake pump station. Three-hour fire rated barriers are provided to separate each pump from each other and from the other equipment.

The fire pump motors are powered by the Class 1E 480V shutdown boards. In the event of loss of offsite power, the fire pump power supply is automatically connected to the emergency diesel generators. Alarms indicating the fire pump motor running condition and alarms indicating loss of line power on the line side of the switchgear are provided in the main control room.

We were concerned that an exposure fire in the control building EL 685 might damage the relays for the fire pumps and prevent automatic operation of the pumps. At our request, the applicant has agreed to relocate one of the relays and separate them by at least 20 feet or provide ½-hour rated fire barriers around the relays.

Water supply for the fire pumps is taken from Chickamauga Reservoir and is considered as an unlimited supply for fire protection purposes. An underground fire main loop is provided to serve both units. Sectional isolation valves are provided such that maintenance may be performed on the loop or portions of the loop for one Unit without affecting fire fighting capability of either Unit. The isolation valves are mechanically locked in position and Technical Specification surveillance is placed upon supervision of valve position to ensure proper system alignment. The yard fire main loop is cross-tied between Units. The fire protection headers are pressurized through an interconnection with the raw water system, with the pressure being maintained by two 10,000-gallon tanks on the auxiliary building roof. The raw water system is automatically isolated when the fire pumps start.

Automatic sprinkler systems and hose station standpipe systems are separately connected to the yard main or to headers within buildings fed from each end of the building; therefore, a single failure cannot impair both sprinkler systems and hose stations. Fixed water spray systems and sprinkler systems are designed according to the requirements of NFPA Standard No. 13, "Standard for Installation of Sprinkler Systems," and NFPA Standard No. 15, "Standard for Water Spray Fixed System." Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety-related area in the plant. The system is designed according to the requirements of NFPA Standard No. 14, "Standpipe and Hose System for Sizing, Spacing, and Pipe Support Requirements." Portions of the fire protection water system piping necessary to protect safety-related equipment in the auxiliary, control and reactor buildings are designed to seismic Category I requirements. Pipe and pipe hangers of the fire protection system located in seismic Category I structures are designed for seismic requirements to ensure the integrity of other essential equipment in the same area.

Valves in the fire protection system are not electrically supervised, however, all valves will be mechanically locked in their normal position. Technical Specification surveillance is placed upon supervision of valve position to assure proper system alignment.

Areas that have been or will be equipped with water suppression systems are:

(a) Control rod drive equipment rooms
(b) 480V shutdown board transformer rooms
(c) 480V shutdown board rooms
(d) Mechanical equipment rooms (EL 749)
(e) 125V vital battery rooms
(f) Emergency gas treatment filter room
(g) Record storage room
(h) Reactor coolant pumps
(i) Auxiliary control room
(j) 6.9 kV shutdown board rooms
(l) Reactor building equipment hatch act (EL 734)
(m) Refueling room
(n) Cable spreading room
(o) Heating and ventilation equipment room
(p) Pipe gallery (EL 690)
(q) Component cooling pump area (EL 690)*
(r) Motor-driven auxiliary feedwater pump area (EL 690)
(s) Boric acid transfer pump rooms
(t) Decontamination area
(u) 250V battery room
(v) RHR valve room
(x) Safety injection pump room
(y) Charging pump room
(z) Diesel generator building corridor
(aa) Main turbine oil storage tank area
(bb) Radwaste building waste packaging area

We have reviewed the design criteria and bases for the water suppression systems and conclude that these systems with the additional sprinkler systems

*Additional sprinklers to be installed - see schedule in Conclusions section.

to be installed meet the guidelines of Appendix A to Branch Technical Position 9.5-1 and are in accordance with the applicable portions of the National Fire Protection Association (NFPA) codes, and are, therefore, acceptable.

B. Gas Suppression System

A low pressure CO_2 system is provided for the following areas:

(a) Standby diesel generator rooms (automatic fixed total flooding)
(b) Turbine lube oil purification room (automatic fixed total flooding)
(c) Computer room (automatic fixed total flooding)
(d) Paint storage room

The CO_2 system for the diesel generator building is automatically actuated by thermal rate compensated detectors. The system can also be actuated manually. A 20-second time delay gives personnel time to clear the area before CO_2 is discharged. Actuation of the system provides alarms and annuciates in tbe main control room. Fire dampers, provided in each air supply and exhaust to the room, will automatically close to isolate the room in the event of a fire. A manually-operated total flooding CO_2 system, with a 2-minute delay, is also provided for the cable spreading room, which will be used only as a backup system to the automatic sprinkler system. Actuation of the system will alarm locally.

The CO_2 systems are designed and installed according to NFPA Standard No. 12, "Carbon Dioxide Extinguishing Systems." We have reviewed the design criteria and basis for these fire suppression systems. We conclude that these systems satisfy the provisions of Appendix A to Branch Technical Position 9.5-1 and are, therefore, acceptable.

C. Fire Detection System

The fire detection system consists of initiating devices, local control panels, remote transmitter-receiver providing remote multiplex (MUX) function, computerized multiplex central control equipment and power supply. The types of detectors used are ionization (products of combustion), and thermal (heat sensors). Fire detection systems will give an audible and visual, and also annunciation in the control room. Local audible and/or visual alarms are also provided.

The system is electrically supervised for ground open wiring faults in the detection, power supply, alarm, and MUX data transmission circuits. Supervision is Class A in the detection and data transmission circuits and Class B is local audible alarm circuits. A wiring fault in the above circuits results in an audible and visual trouble indication at both the local and control locations. The fire detection system is powered from a single 102V ac distribution panel. The panel is provided with a manual transfer switch to allow normal or alternate power feed from the Class IE 480V ac control and auxiliary building ventilation boards. The ventilation boards are automatically connected to the emergency diesel generators on loss of offsite power. The applicant has committed to specify in the Sequoyah fire protection technical specifications to call for 6 months surveillance testing of detection circuits from the local panel to the actuated devices, i.e., fire dampers, fire door holders, ventilation equipment or pre-action valves.

The fire detection systems have been installed or will be installed according to NFPA No. 72D, "Standard for the Installation, Maintenance, and Use of Propriety Protection Signalling Systems."

We have reviewed the fire detection systems to ensure that fire detectors are adequate to provide detection and alarm of fires that could occur. We have also reviewed the fire detection system's design criteria to ensure that it conforms to the applicable sections of NFPA No. 72D. We conclude that the design and the installation of the fire detection systems coupled with the additional detectors to be installed, meet the guidelines of Appendix A to Branch Technical Position ASB 9.5-1 and are, therefore, acceptable.

III. OTHER ITEMS RELATING TO THE STATION FIRE PROTECTION PROGRAM

A. Fire Barriers

Three-hour fire rated barriers are provided between the reactor building and auxiliary building, control building and auxiliary building, service building and auxiliary building, control building and turbine building. All floors, walls and ceiling enclosing the control room, cable spreading room and the diesel generator building are rated at a minimum of 3-hour fire rating. The main control room area contains peripheral rooms which are located within the main control room 3-hour fire barrier. These peripheral rooms are provided with detectors and alarms and 1½-hour fire rated barriers. A minimum 3-hour fire rated coating of Pyrocrete 102 is applied to all exposed structural steel within the cable spreading room. Other fire areas having low or minimal fire loadings are provided with 1½-hour fire rated barriers. We have reviewed the fire hazard analysis including the fire loading, fire detection system, and fire suppression system in these areas and found that a postulated fire in these areas would not be sufficient to breach the fire barrier integrity. We, therefore, conclude that this is an acceptable alternative to the guidelines of Appendix A to Branch Technical Position ASB 9.5-1. The applicant has also provided acceptable documentation to substantiate the fire rating of the barriers.

B. Fire Doors, Dampers, and Fire Barrier Penetrations

We have also reviewed the placement of the fire doors to ensure that fire doors of proper fire rating have been provided.

All doors which separate safety-related redundant divisions are alarmed through the security system's primary alarm station in the gate house and secondary alarm station in the control building. Doors separating the control building from the turbine building are normally closed. Heavy equipment doors are locked and operated by card readers. Operation of these doors is alarmed in the main control room. Strict administrative procedures will be used to ensure that the doors are not left open or propped open during maintenance or plant operation. The applicant, at our request, will replace the sliding fire doors in adjacent diesel generator rooms in the diesel generator which would have closed if a fire melted a fusible link with hinged-type Class A fire doors which will be normally closed.

Fire doors in most of the fire cell and fire area boundaries are UL-labeled. The special purpose doors in the auxiliary building such as flood doors and pressure doors are not UL-labeled; however, these doors are designed to ASME Standard and are of heavy welded steel construction. In addition, the applicant has evaluated these doors and determined that they will provide an equivalent fire rating commensurate to the fire loading in the areas or cells they separate. The security doors in the main control room are made of bullet-resistent heavy gauge steel and have not been tested by UL. However, the door manufacturer has certified that the doors are equivalent to UL tested fire doors rated for 3 hours. We concur with the applicant's finding in this regard. At our request, the applicant has agreed to install additional fire doors in the auxiliary building fire barrier openings presently containing nonrated doors or no doors. Modifications will be implemented prior to initial fuel loading of the associated unit.

Penetrations, including electrical penetration seals, through rated barriers are sealed to provide fire resistance equivalent to the barrier itself.

Ventilation penetrations through barriers are protected by standard fire door dampers. Most of the fire damper/doors are UL listed. Those nonlabeled fire dampers have either been certified by the manufacturer to be equivalent to the presently manufactured UL-listed and labeled models or verified by the applicant through a detailed comparison of construction features with the certified damper. We have reviewed the available information and agreed with the applicant's findings. The applicant has also agreed to install additional fire dampers in ventilation ducts penetrating fire barriers presently containing nonrated dampers or no dampers.

The design of the electrical penetration fire stops for cables and cable trays and their installation is based on the applicant's tests and tests by Factory Mutual of full scale mockups.

We have reviewed the construction features of the electrical penetrations and conclude that the applicant has provided acceptable documentation to demonstrate the fire resistability of the electrical penetrations. However, we requested that the bare steel plate in the cable tray penetration seals be coated with fire resistance coating equivalent to the fire barrier rating and the applicant has agreed to do so.

We have reviewed the fire barriers, fire doors, dampers and fire barrier penetrations and conclude that their design and installation, with the additional fire doors and dampers to be installed, meet the guidelines of Appendix A to Branch Technical Postion ASB 9.5-1 and are, therefore, acceptable.

IV. FIRE PROTECTION FOR SPECIFIC AREAS

A. Essential Raw Cooling Water (ERCW) System Junction Box and Conduits EL 690 and EL 734)

On EL 690 of the auxiliary building, all four power cables (both trains of both units) of the ERCW pump from the yard pump house come into a metal enclosure mounted on the concrete wall approximately 10 feet above the floor. Each cable within the junction box is separated by a metal baffle. From the enclosure, the cables are run in conduits and go up the wall, through the ceiling to EL 734. On EL 734, the conduits terminate in cable trays that extend to the switchgear. We were concerned that an exposure fire could damage all the power cables within the metal enclosure or the conduits on the wall thus eliminating the ERCW function which is necessary for safe shutdown for both units. At our request, the applicant is committed to:

(i) Apply a 1½-hour fire rated coating (Pyrocrete or equivalent) on the outside of the ERCW pump power cable metal enclosure (junction box).

(ii) Fully enclose the four redundant ERCW pump power cable conduits in a 1½-hour rated barrier to the ceiling of EL 690 and into EL 734 to a point where the conduit trains are at least 20 feet apart.

(iii) Provide additional area sprinklers around the ERCW pump cable junction box on EL 690 an on EL 734 where the 1½-hour barrier extends.

We have reviewed the applicant's fire hazards analysis and fire protection provided for the ERCW pump power cable trains and the area of concern. We conclude that appropriate fire protection has been provided and with the modifications conforms to the provisions of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

B. Component Cooling Water (CCW) Pump Area (EL 690)

On elevation 690 feet of the auxiliary building all five (two from each unit and one swing) component cooling water pumps are located together. Adjacent to these safety-related pumps are the two motor-driven auxiliary feedwater pumps (both trains), of Unit 1, which are also safety-related. Both Unit 2 auxiliary feedwater pumps are located approximately 125 feet away down the corridor. Power-operated control valves for the component cooling water (CCW) pumps are located immediately above the CCW pumps on an open granting mezzanine. Various safety-related cable trays are also located in the area. A preaction sprinkler system is proposed for the ceiling level only and would not offer adequate protection against an exposure fire due to the many obstructions between the ceiling level sprinkler and the floor below.

At our request, the applicant has agreed to provide:

(i) Automatic sprinkler under the pipe break barrier for the Units 1 and 2 motor-driven auxiliary feedwater pumps.

(ii) Automatic sprinkler coverage under the mezzanine for all five CCW pumps.

(iii) A ½-hour fire rated barrier separating each CCW pump from one another such that the barrier will extend approximately 3 feet above the highest point of each pump.

(iv) Control and power supply cables that are required for safe shutdown and are presently located on the mezzanine level above the CCW pump will be protected according to Item IV A of this report.

(v) Additional smoke detectors will be installed to actuate the proposed sprinkler systems and to ensure early warning of a fire.

We have reviewed the applicant's fire hazards analysis and fire protection provided for the CCW pump area and motor-driven auxiliary feedwater pump area. We conclude that appropriate fire protection has been provided and with the modifications meets the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

C. Cable Spreading Room

The cable spreading room is shared by both units. The walls, floors and ceiling are designed to have a fire rating of three hours. An automatic preaction sprinkler system has been provided. The system has two horizontal levels in the cable spreading room (i) an upper level near the ceiling, and (ii) an intermediate level approximately halfway between the floor and ceiling. The sprinklers in the intermediate level are staggered horizontally between the upper level sprinkler grid. A manual total flooding CO_2 system has also been provided as a backup system. Hose stations are also provided. Cross-zoned ionization smoke detection system is installed in this area.

The exposed cable in the room has been coated with a flame retardant to minimize fire propagation. In the event of a fire in the control room or cable spreading room, plant shutdown capability can be maintained from the auxiliary control room which is completely separate and independent of these areas. As discussed in Section IV E of this report, the applicant will establish and implement, by initial fuel loading, emergency procedures to assure safe plant cold shutdown.

We have reviewed the applicant's fire hazards analysis and fire protection provided for the cable spreading room and consider that fire protection and emergency shutdown procedures have been provided and conform to the provisions of Appendix A to BTP 9.5-1 and are, therefore, acceptable.

D. Fire Protection Inside Containment

The major fire hazard within the containment is the reactor coolant (RC) pump lube oil system. To prevent a fire due to oil leakage the applicant has provided a noncombustible housing for each RC pump. The housing is designed to contain a pressurized leak of RC pump lube oil, but will not jeopardize the ventilation air flow to the RC pump motor. This housing will also act as a heat collector to reduce the response time of the thermal detectors and the thermal actuated water spray nozzles installed inside the housing. The fixed automatic water spray system is designed in accordance with NFPA 15. Drainage has been provided for the RC pump motor so that water and oil will not build up at the bottom of the noncombustible housing.

An automatic fixed water spray system has been provided for the charcoal HEPA filters in the lower containment air cleaning units. The water spray system is designed according to NFPA 15.

Areas of divisional interaction within the annulus area will be protected by an automatic fixed water spray system designed according to NFPA 15. In addition all exposed cables within this area will be coated with a flame retardant.

A standpipe and hose system, designed according to NFPA 14, has been provided in order to complement the fixed water suppression system in the reactor building. The standpipe system within its containment will be normally dry and arranged to admit water to the system through manual operation of remote control devices located at each hose station.

The fire detection system is designed according to NFPA 72D with Class A supervision. Thermal detectors are provided for the charcoal filters and HEPA filters. Thermal-rate compensated and flame detectors are provided for the RC pump motors. Smoke, photoelectric and/or thermal-rate compensated detectors are provided for divisional cable interaction areas.

In lieu of detectors throughout primary containment, photoelectric smoke duct detectors are provided for each lower contaiment cooling unit and each upper compartment cooling unit. In addition, photoelectric smoke duct detectors are provided for the exhaust ducts serving the containment purge air exhaust systems and the emergency gas treatment system. In the annulus area, heat and smoke collectors are provided for fire detection so that a quick response can be obtained.

We have reviewed the applicant's fire hazard analysis and fire protection provided for the area inside containment. We conclude that appropriate fire protection is provided for this area and meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

E. Other Plant Areas

During our site visit we noticed numerous places where redundant safety-related cable trays as well as conduits were in close proximity such that an exposure fire could damage both divisions. This was noticed on almost all elevations. The applicant proposed that they apply a fire retardant coating on the exposed cable and install preaction sprinkler systems at the interaction location. At the time of the site visit, the function of these various cable-conduits could not be determined at these interactions.

At our request, the applicant has performed a fire interaction analysis of redundant divisions of the plant systems necessary for safe shutdown but were not separated by a fire barrier. The analysis postulated an exposure fire between divisions and failure of any primary fixed automatic fire suppression system. The applicant has identified where additional protection and/or separation is required to assure a safe shutdown condition. As a result, the applicant has committed to:

(i) Relocate one or both divisions to maintain a minimum of 20 feet separation between divisions, or

(ii) Provide a ½-hour fire rated barrier such as 1 inch of mineral wool separating one safety-related train from the other or from a common exposure fire.

Also, area automatic sprinkler systems will be provided to afford protection against exposure fire at the interactions.

(iii) Establishing damage control measures which cannot be considered typical of normal plant operation. Manual operation of some of the component/equipment may be required to achieve cold shutdown within 72 hours.

The applicant has implemented all the modifications and damage control measures for Unit 1. For Unit 2, the program will be implemented prior to initial fuel loading of that unit. Meanwhile, the applicant has established interim procedures to assure plant shutdown capability in the event of a fire. We have reviewed the interim procedures and found that the plant can be shut-down and maintained in cold shutdown condition with these procedures, and is, therefore, acceptable.

To enhance plant shutdown capability, the applicant has provided an auxiliary control room (ACR) which is completely separated and independent of the main control room. In the event of a damaging fire in the main control room or cable spreading room, plant shutdown capability can be maintained from the ACR. We were concerned that a spilled flammable liquid fire could affect the auxiliary control room and the adjacent auxiliary control instrument rooms. At our request, the applicant has agreed to install a curb on all four auxiliary control instrument room openings to prevent such an accident.

We have reviewed the fire interaction analysis, the fire hazard analysis and fire protection provided for interaction areas and conclude that hot shutdown condition can be achieved through the auxiliary control room using existing hardware. Cold shutdown condition can be achieved within 72 hours through the implementation of damage control measures and some operator actions.

The applicant's fire hazards analysis addresses other plant areas not specifically discussed in this report. The applicant committed to install additional water sprinklers, detectors, fire doors, fire dampers as identified in the applicant's installation schedule.

We have also reviewed the emergency lighting system and the communication system and found that they meet the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

In conclusion, we find the fire protection measures provided for these areas with the modifications made by the applicant are in accordance with the guidelines of Appendix A to BTP ASB 9.5-1 and the applicable sections of the National Fire Protection Association Code and are, therefore, acceptable.

V. ADMINISTRATIVE CONTROLS

The administrative controls for fire protection consists of the fire protection organization, the fire brigade training, the controls over combustibles and ignition sources, the prefire plans procedures for fighting fires and quality assurance.

In response to Appendix A to Branch Technical Position ASB 9.5-1, the applicant described those procedures and controls that were in existence at that time.

The applicant has agreed to revise his administrative controls and training procedures to follow supplemental staff guidelines contained in "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated 6/14/77.

A plant fire brigade of at least five members is organized to provide immediate response to fires that may occur at the site. The plant fire brigade will also be equipped with pressure demand breathing apparatus, portable communications equipment, portable lanterns, and other necessary fire fighting equipment. Spare city cylinders and recharge capability are provided to satisfy the guidelines of Appendix A to Branch Technical Position ASB 9.5-1.

The fire fighting brigade participates in periodic drills. Liaison between the plant fire brigade and the local fire departments has been established. The local fire departments have been on plant tours and have also been involved in training sessions with the plant fire brigade.

We conclude that the fire brigade equipment and training conform to the recommendations of the National Fire Protection Association, Appendix A to Branch Technical Position ASB 9.5-1 and supplemental staff guidelines and are, therefore, acceptable.

VI. TECHNICAL SPECIFICATIONS

We have reviewed the plant Technical Specifications issued for Sequoyah Units 1 and 2, and find that they are consistent with our Standard Technical Specifications for fire protection and find them acceptable.

VII. CONCLUSION

As a result of investigations conducted by the staff on the fire protection systems, fire protection criteria were developed and further requirements were imposed to improve the capability of the fire protection system to prevent unacceptable damage that may result from a fire. At our request, the applicant conducted a reevaluation of the proposed fire protection system for Sequoyah Units 1 and 2. The applicant submitted, in January 1977, a Fire Hazards Analysis and subsequently three revisions in response to our positions. The applicant also has compared the system, in detail, with the guidelines of Appendix A to Branch Technical Position ASB 9.5-1, "Guidelines for Fire Protection for Nuclear Plants."

During the course of our review we have reviewed the applicant's submittals and responses to our requests for additional information. In addition, we have made a site visit to evaluate the fire hazards that exist in the Sequoyah Nuclear Plant, Units 1 and 2, and the design features and protection systems provided to minimize these hazards.

The applicant has completed all the modifications to improve the fire resistance capability for fire doors, dampers, fire barriers and barrier penetration seals.

The applicant has also installed additional sprinkler systems for areas such as the motor-driven auxiliary feedwater pump area, component cooling water pump area, and various other areas. To ensure that fires can be detected rapidly and the plant operators informed promptly, additional detectors have been installed in various areas of the plant.

In addition, the applicant established emergency shutdown procedures to bring the plant to hot shutdown and safe cold shutdown condition in the event of a damaging fire in the cable spreading room, the main control room or the divisional cable interaction areas.

Our overall conclusion is that a fire occurring in any area of the Sequoyah Nuclear Plant will not prevent the plant from being brought to a controlled safe cold shutdown, and further, that such a fire would not cause the release of significant amounts of radiation. We find that the Fire Protection Program for Sequoyah Units 1 and 2 with the improvements made meets the guidelines contained in Appendix A to Branch Technical Position BTP ASB 9.5-1 and meets General Design Criterion 3 and is, therefore, acceptable.

13.0 CONDUCT OF OPFRATIONS

13.2 Training Program

The Reactor Operator and Senior Reactor Operators commenced training in 1971. At the time of examination, approximately 3000 hours of academic training had been received in addition to substantial practical training on a PWR simulator and at an operating PWR.

In the period of January to March 1979, an initial group of applicants was examined in accordance with the requirements of 10 CFR Part 55 and found to have the requisite qualifications for manipulations of the reactor controls. The examination grade criterion used at that time was 70% overall.

No licenses were issued due to TMI-2 and the shippage in the Sequoyah fuel load date. However, the licensed operator requalification program was instituted immediately following the examinations.

A second group of applicants was affirmed in September 1979. These applicants was founded in September 1979. These applicants had received special additional training in TMI-2 related topics. The NRC examination included specific questions addressing the TMI-2 material. A revised criteria was used to determinc a passing grade. Applicants had to inclusive 70% overall and at least 80% as TMI-2 related material.

Subsequent to the second set of examinations the NRC required that the first group of applicants be examined on TMI-2 related material. THE NRC required TVA to prepare and administer a TMI-2 related examination. A passing grade of 90% was required. Any individual scoring less than 90% would be examined by the NRC. All aopplicants scored better than 90%. The NRC audited both the examinstion TVA had prepared and the grading of the examinations. No deficiencies were noted.

A third group of applicants have been undergoing examination. All TMI-2 related material has been factored into their training program. They, and all subsequent groups of applicants, will be held to a new NRC criteria for passing grades of 80% overall and at least 70% in each category of the examination.

NRC licenses have been issued to 18 Senior Reactor Operators and 6 Reactor Operators. We find the number of licensed operators sufficient to meet the manning requirements of Technical Specificaiton Section 6.2, Minimum Shift Crew Composition, in all operating modes.

The applicant has modified his training program in accordance with Action Plan requirement IA31 by including appropriate courses in thermodynamics and related subjects.

13.3 Emergency Planning

Our evaluation of emergency preparedness is included in Part II of this supplement under Section III.A.3.

13.6 Industrial Security

The Security Plan was revised on April 2, 1979, June 29, 1979, and September 19, 1979 in accordance with the provisions of 10 CFR 50.54(p). Implementation of its modified plan will ensure that the health and safety of the public will not be endangered.

In addition, we require that the applicant fully comply with the requirements which states that all keys, locks, combinations, and related equipment used to control access to protected and vital areas shall be controlled to reduce the probability of compromise. Whenever there is evide--- *hat there is compromise, changes in locks, keys, etc. shall be made. Also, termination of any employee who had access to keys, locks, etc., changes s'all be made.

14.0 INITIAL TESTS AND OPERATION

The Safety Evaluation Report stated that the applicant's description of the initial test program was acceptable with two exceptions. Both of these items have been resolved as discussed below.

The first exception was that the applicant had not provided adequate acceptance criteria for the turbine trip test and the generator load rejection test for us to conclude that acceptable tests would be conducted. The applicant submitted information in a letter dated March 16, 1979 which assures that the test results for both the 100 percent power turbine trip test and the 100 percent power generator load rejection test will be compared with expected results for the transients based on normal system performance and realistic test conditions. The results also will be compared to results of similar transients as described in the accident analysis. Based on the applicant's commitment to conduct both of these tests at 100 percent power and to evaluate the results against realistic criteria, we consider this item resolved.

The other exception was that the applicant had not addressed whether its tests of the emergency diesel generators or remote shutdown demonstration would be conducted in accordance with Regulatory Guides 1.108 and 1.68.2, respectively. In a letter dated March 23, 1979, the applicant stated that tests would be conducted in accordance with these regulatory guides. We will review the applicant's revised test descriptions to verify this when they are submitted. We consider this item resolved.

We conclude that the initial test progrε described by the applicant is acceptable.

15.0 ACCIDENT ANALYSIS

15.2 Normal Operation and Anticipated Operational Transients

Boron Dilution

In the Safety Evaluation Report we stated the reliance upon an audible rate count to alert the operator of postulated boron dilution events during refueling was not justified.

The applicant provided justification for maintaining the alarm set point within one-half decade of the source flux level. Based on this margin and on the maximum possible rates of dilution, the applicant's analysis showed that the event would be detected and announced by the high flux at shutdown alarm within a time period that left sufficient margin for the operator to correct the situation before criticality occurred. Fifteen minutes is the required minimum time margin at these conditions in accordance with our Standard Review Plan.

The applicant has committed to a schedule for setting and monitoring the gap between the high flux at the shutdown alarm level and the shutdown source flux level that is consistent with the analysis presented. The setting is to be no higher than 1/2 decade above the count rate, and the margin is to be verified (or reset if necessary) every 30 minutes for the first 2 hours, every 2 hours for the next 6 hours, and once per shift thereafter until the flux level has stabilized. The required procedures and schedule for verification of the set point are to be incorporated in the operator's Surveillance Instructions.

The staff finds that the analysis, the reactivity changes in the boron dilution event are accounted for satisfactorily. The applicant's analysis defines a region of reactor conditions for the event that are considered safe, according to NRC criteria. The procedures adopted by the applicant will assure that the reactor remains within the boundaries of the safe conditions. The staff, therefore, regards the question of the boron dilution event immediately following shutdown as having been satisfactorily resolved.

ATWS

We have reviewed the TVA submittal of October 17, 1979 on Emergency Operating Procedures for the postulated anticipated transients without scram (ATWS) events. We provided our comments on the proposed procedures and made recommendations for changes. The proposed procedures must be modified in accordance with our comments and instructions to be acceptable for full power operation. However, the Sequoyah plant may be operated at low power (less than or equal to five percent of full power) prior to completion of procedures modifications without undue risk to the health and safety of the public. Our conclusion that low power operation is acceptable is based on our understanding of the expected plant response to the most relevant ATWS events under these operating conditions.

Normal Operation and Anticipated Operational Transients

Section 15.2 of the Sequoyah SER referred to our generic review of the Westinghouse Topical Reports WCAP-9226, WCAP-9236, and WCAP-9230 as the licensing bases for the analysis methods and sensitivity studies for postulated main steamline and feedline breaks. The steamline break information is contained in WCAP-9226. The feedwater line break information was provided in WCAP-9230 and in WCAP-9236, which discusses the NOTRUMP computer program used in the analyses. At that time, our review was scheduled for completion in late 1979.

For review of the steamline break topical, the staff requested additional information from Westinghouse in September 1978. Westinghouse responded with answers to some of our questions in May 1979. In response to staff inquiries, Westinghouse has attributed their failure to answer the balance of our questions to higher priority TMI-2 analyses requirements.

The staff has previously accepted steamline and feedline break analyses described in plant applications for PWRs designed by Westinghouse and other reactor vendors. It has been our position that a more detailed account of analytical methods for steamline and feedline break is required from the vendors for generic review and that the outcome of this review would be applied to licensed reactors. Our generic review includes the performance of in-house audit calculations and calculations by technical assistance contractors.

While our review is not sufficiently advanced to provide assurance that the Sequoyah analysis methods are acceptable, it does provide evidence that substantial thermal margin exists under postulated steamline and feedline break accident conditions to preclude core damage leading to unacceptable consequences. Therefore, we conclude that the steamline and feedline break accident analyses for Sequoyah are acceptable while our more detailed review continues. However, our approval is predicated on the assumption that our generic review can proceed on a reasonable schedule. To assure that this assumption is valid, we will require a response to our outstanding questions on the topical reports discussed above and a new commitment for prompt response to any additional information requirements prior to approval of a full power operating license.

15.3 Accidents and Infrequent Transients

15.3.3 Steam Line Break

Long-Term Effects of Steam Line Break

Because the primary system pressure may have an effect on pressure vessel integrity following a steamline break or a small break loss-of-coolant accident, the staff requested additional information regarding the long-term scenarios, and effects of these events. Using techniques similar to those reviewed and approved for the D. C. Cook, Unit 2, plant, the applicant has conservatively calculated pressure and temperature conditions for a bounding spectrum of steamline break and small break LOCA events. Using fracture mechanics techniques the applicant has estimated that, for those accident conditions, reactor vessel integrity can be assured for 17 effective full-power years.

Category A Task A-11, upon completion, will specify requirements for the applicant to evaluate reactor vessel integrity for the design life of the plant, for both normal transient, and accident conditions including consideration of SLB and small break LOCA.

Based on our review and evaluation, we conclude that the analyses performed by the applicant provide acceptable assurance of vessel integrity for the present time until the requirements of completed Task A-11, vessel integrity under steam line break and small break LOCA conditions be explicitly addressed by the applicant.

Because the applicant has predicted post-accident conditions using previously reviewed methods and assumptions, because reactor vessel integrity is reasonably assured until compliance with Task A-11, and because we require that steam line break and small break LOCA events be explicitly considered in implementing the Task A-11 requirements for Sequoyah, we find the analyses and provisions acceptable, subject to the conditions stated above.

Auxiliary Feedwater Runout Flow Following a Steam Line Break

The applicant was requested to address the potential for containment overpressurization due to the anticipated continuous addition, at pump runout flow, of auxiliary feedwater to the affected steam generator following a postulated main steam line break (MSLB) accident.

Our interest in this issue resulted from the Part 21 report filed by the Virginia Electric and Power Company (VEPCO) dated September 4, 1979. In that report, the NRC was informed by VEPCO that overpressurization of the continment at North Anna, Units 3 and 4, could occur in the event of a postulated MSLB inside containment. VEPCO indicated that, due to the anticipated continuous addition of auxiliary feedwater to the broken loop steam generator, at the pump runout flow condition, following a MSLB accident, the containment pressure will reach the containment design pressure in about 10 minutes.

To determine if the issue under consideration was generic for all pressurized water reactors (PWRs), we initiated a review of all "near-term" operating license applications for PWR plants. The object of the review was to determine if auxiliary feedwater flow was considered in the MSLB analyses and, if so, whether pump runout flow conditions were used.

The applicant indicated that the auxiliary feedwater system utilizes runout flow control equipment to limit the flow. Therefore, in the original MSLB analysis, the auxiliary feedwater flow to the faulted steam generator was assumed to exist at maximum capacity from the time of the rupture until realignment of the system is completed by the operator, 10 minutes after the onset of the postulated accident. The applicant's original submittal, that in one of the postulated analyses performed a failure of the auxiliary feedwater runout protection system was assumed. In this analysis, it was assumed that flow to the broken loop steam generator at pump runout flow conditions continued from onset of the accident until the operator manually terminates flow 10 minutes later. It was concluded by the applicant, and the staff concurs, that the peak containment pressure will remain below the containment design pressure. The applicant also indicated that information for use in deciding to terminate the auxiliary feedwater flow to the affected steam generator will be available to the operator immediately after onset of the accident.

We find that the applicant's analyses have correctly accounted for the auxiliary feedwater flow and that no further analysis is required.

Normal Operation and Anticipated Operational Transients

We have reviewed the TVA submittal of November 9, 1979 responding to IE Information Notice 79-22 on qualification of control systems for Sequoyah Units 1 and 2. The submittal identifies plant systems required for safety and states for each safety function that adequate instrumentation would alert the operator to an event, adequate time is available for operator action, and control system design permits operator action. Based on the information provided by the applicant, our review of the Sequoyah Final Safety Analysis Report, our related reviews of equipment qualification, and similar reviews for operating reactors, we have found no event sequence that leads to an unacceptable consequence.

We have concluded that the Sequoyah applicant has satisfied the standards set for operating reactors and that this issue presents no concerns which would restrict operation of the plant.

15.4 Radiological Consequences of Accidents

15.4.1 Loss-of-Coolant Accident

This section of the supplement revises in its entirety the material that was present in the Safety Evaluation Report. The Sequoyah Nuclear Plant includes a double containment design to collect and filter the leakage of fission products from a postulated design basis loss-of-coolant accident. The double containment consists of a free-standing steel primary containment vessel surrounded by a reinforced concrete shield building. The reinforced concrete auxiliary building is also a part of the secondary containment barrier. Leakage which enters the secondary containment is treated by either the emergency gas treatment system or the auxiliary building gas treatment system prior to release to the atmosphere. Both of these systems are engineered safety features. Another engineered safety feature is the ice condenser with a sodium tetraborate additive to the ice to enhance the removal of iodine in the containment following a loss-of-coolant accident. The dose model and dose conversion parameters are consistent with those given in Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors."

In the analysis of the design basis loss-of-coolant accident, the primary containment was assumed to leak at the design leak rate of 0.25 percent per day for the first 24 hours following the accident and at 0.125 percent per day thereafter. The applicant established to the staff's satisfaction that the shield building annulus pressure would not exceed -0.25 inch water gauge pressure and that no leakage would bypass the gas treatment system throughout the course of the accident (see Section 6.2 of this report for further discussion of these items). The applicant has increased the amount of leakage which enters the auxiliary building following the accident from 10 percent to 25 percent of the primary containment leakage. Assuming that this leakage was exhausted directly to the atmosphere during the first 10 minutes of the accident. After 10 minutes the leakage is processed through the auxiliary building gas treatment system without credit for holdup or mixing.

Seventy-five percent of the leakage from the primary containment enters the shield building annulus where we assumed that it went directly to the intake of the shield building annulus recirculation/exhaust system. Following passage through the emergency gas treatment system filters, a fraction of this leakage was assumed in our analysis to be exhausted to the atmosphere with the remainder recirculated to the shield building annulus where credit was given for mixing in 50 percent of the annulus free volume. The split between the exhaust and recirculation fractions was assumed to be proportional to the air flow rates in the exhaust and recirculation paths of the systems.

The applicant assumed in his dose analysis that it takes 10 minutes to isolate the auxiliary building rather than the previous assumption of 5 minutes (the applicant's analysis of the auxiliary building gas treatment system indicated that the system is designed to draw down the building to a -0.25 inch water gauge pressure within 170 seconds). Therefore, our analysis assumes that all leakage into the auxiliary building for the first 10 minutes into the accident is immediately released to the environment. For all times after the first 10 minutes into the accident we assume the leakage is exhausted through the gas treatment system.

The doses we calculate for the postulated design basis loss-of-coolant accident for the Sequoyah Nuclear Plant, shown in Table 15-1, are within the exposure guidelines of 10 CFR Part 100.

As part of the loss-of-coolant accident, we have also evaluated the consequences of leakage of containment sump water which is circulated by the emergency core cooling system after that postulated accident. We have assumed the sump water contains a mixture of iodine fission products in agreement with Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident." During the recirculation mode of operation the sump water is circulated outside of the containment to the auxiliary building. If a source of leakage should develop, such as from a pump seal failure, a fraction of the iodine in the water could become airborne in the auxiliary building and exit to the atmosphere. Since the emergency core cooling system area in the auxiliary building is served by an engineered safety features air filtration system (the auxiliary building gas treatment system), we conclude that the doses resulting from the postulated leakage of recirculation water would be low and, when added to the direct leakage loss-of-coolant accident doses, would result in total doses that are within the guideline values of 10 CFR Part 100.

As discussed in Section 6.2.3 of this report, the applicant recently informed us that during the ongoing Unit 2 construction activities, the minimum pressure that can be achieved in some of the ESF pump rooms will be approximately -0.04 inches water gauge as compared to the -0.25 inches required by the Technical Specifications. We determined that this pressure is not sufficiently low to assure the removal of airborne iodine activity by the auxiliary building gas treatment system following a postulated accident. We, therefore, have evaluated the 30-day dose at the LPZ distance for a postulated ESF pump seal failure following a loss-of-coolant accident. We conservatively assumed no holdup, mixing or removal of the associated airborne iodine activity in the auxiliary building. We also assumed that the Unit 1 reactor will be operated during this interim period of unit construction at a power level not in excess of 5 percent of the rated power of 3582 Mw thermal. Other assumptions of our analyses are listed in Table 15.3.

Based on our evaluation we conclude that the radiological consequences associated with an ESF pump seal failure in conjunction with the doses resulting from a design basis accident are within the guidelines of 10 CFR Part 100. We also conclude that the Unit 1 reactor shall not be operated at a power level in excess of 5 percent of the rated power level unless the applicant can demonstrate, by test, that the ESF pump room can achieve and maintain a pressure not higher than the -0.25 inch water gauge identified in the Technical Specifications.

The applicant may purge the containment periodically during reactor operation. Should a loss-of-coolant accident occur when the purge lines are open, a portion of the containment atmosphere plus a portion of any flashed reactor coolant containing radioactive iodine fission products would be released to the environment in the short interval before the purge isolation valves close and isolate the containment. We have estimated the radiological consequences of this event using conservative assumptions regarding the radioactive iodine concentration in the primary coolant, the amount of reactor coolant inventory released, and the flow rate through the valves. We conclude that the consequences are such that, even when added to the calculated doses from containment leakage, the total is within the guideline values of 10 CFR Part 100.

The applicant has provided redundant hydrogen recombiners for the purpose of controlling any accumulation of hydrogen within the primary containment following a loss-of-coolant accident. In the event of failure of both recombiners, the applicant has provided a backup system. The purged containment effluent would flow to the shield building annulus where it would be subsequently discharged to the atmosphere through the emergency gas treatment system filters. We find the combination of redundant recombiners plus a backup purge capability to be an acceptable method for controlling the potential contribution to the offsite doses from hydrogen purging following a loss-of-coolant accident.

While Unit 2 is under construction the equipment hatch of the Unit 2 containment building will be closed off from the interim auxiliary building by two steel roll-up doors. These doors must be closed in the case of an accident in order to draw down the interim auxiliary building to a negative pressure of 0.25 inch water gauge. These doors will be locked shut or alarmed in the Unit 1 control room under normal conditions and plant personnel will be stationed at the doors when they are in use in order to initiate their immediate closing in the case of an accident. The staff concludes that this control will provide adequate assurance that the interim auxiliary building can be drawn down to the required negative pressure.

TABLE 15-1

RADIOLOGICAL CONSEQUENCES OF DESIGN BASIS ACCIDENTS

Accident	Exclusion Area* 2-Hour Dose, Rem Thyroid	Exclusion Area* 2-Hour Dose, Rem Whole Body	Low Population Zone** 30-Day Dose, Rem Thyroid	Low Population Zone** 30-Day Dose, Rem Whole Body
Loss of Coolant	194	9	28	1
Fuel Handling	20	1	<1	<1
Steam Line Break				
1) I-131 at 1 microcurie per gram	13	<0.1	<1	<0.1
2) I-131 at 60 microcuries per gram	26	<0.1	1	<0.1
Steam Generator Tube Rupture				
1) I-131 at 1 microcurie per gram	19	<0.1	1	<0.1
2) I-131 at 60 microcuries per gram	214	<0.1	10	<0.1
Control Rod Ejection				
1) Leakage through secondary side	42	<0.1	2	<0.1
2) Leakage through containment	97	<0.1	4	<0.1

*Exclusion area minimum boundary distance = 556 meters
**Low population zone distance = 4828 meters

TABLE 15-2

ASSUMPTIONS USED IN THE CALCULATION OF LOSS-OF-COOLANT ACCIDENT DOSES

Power Level	3582 Megawatts thermal
Operating Time	3 years
Fraction of Core Inventory Available for Leakage	
Iodines	25 percent
Noble Gases	100 percent
Initial Iodine Composition in Containment	
Elemental	91 percent
Organic	4 percent
Particulate	5 percent
Primary Containment Volumes	
Upper Containment	7.16×10^5 cubic feet
Lower compartment (including ice condenser)	5.25×10^5 cubic feet
Shield Building Annulus Volume	3.75×10^5 cubic feet
Mixing Fraction in Annulus	50 percent
Annulus Ventilation Flow Distribution	

TABLE 15-2 (Con't)

Time Step	Recirculation Flow Cubic Feet Per Minute	Exhaust Flow, Cubic Feet Per Minute
0-46 seconds	0	0
46-200 seconds	500	3500
200-400 seconds	1500	2500
400-1000 seconds	3000	1000
1000 seconds - 30 days	3900	100

Filter Efficiencies	
Elemental Iodine	95 percent
Organic Iodine	95 percent
Particulate Iodine	95 percent
Ice Condenser Removal Efficiency Elemental Iodine	30 percent
Flow Rate through Ice Condenser	40,000 cubic feet per minute
Period of Ice Condenser Effectiveness	10-60 minutes
Primary Containment Leak Rates	
0 - 24 Hours	0.25 percent per day
> 24 Hours	0.125 percent per day
Bypassing Leakage Fraction (Auxiliary Building Pathway)	
0-10 Minutes	25 percent
>10 Minutes	0 percent
Minimum Exclusion Area Boundary Distance	556 meters
Low Population Zone Distance	4828 meters
Atmospheric Diffusion (X/Q) Values	
0-2 Hours	1.4×10^{-3} sec per cubic meter
0-8 Hours	6.4×10^{-5} sec per cubic meter
8-24 Hours	4.5×10^{-5} sec per cubic meter
1-4 Days	2.1×10^{-5} sec per cubic meter
4-30 Days	6.9×10^{-6} sec per cubic meter

TABLE 15-3

ASSUMPTIONS USED IN THE CALCULATION OF ESF PUMP SEAL FAILURE

Power Level	180 Megawatt thermal (5 percent of rated)
Atmospheric Diffusion Values	See Table 15-2
Liquid Volume in Primary Containment	500,000 gallons
Time of Pump Seal Failure After LOCA	24 hrs.
Pump Seal Failure Flowrate	60 gallons/minute
Isolation of Pump Seal Failure	30 minutes
Evaporation Fraction	0.1

20.0 FINANCIAL QUALIFICATIONS

Introduction

The Nuclear Regulatory Commission's regulations relating to the determination of an applicant's financial qualifications for a facility operating license appear in Section 50.33(f) and Appendix C to 10 CFR Part 50. At our request, the Tennessee Valley Authority has submitted financial information regarding estimated operating and decommissioning costs for the Sequoyah Nuclear Plant, Units 1 and 2, along with the additional material covering the applicant's financial status. The following analysis summarizes our review of this submittal and addresses the applicant's financial qualifications to operate, and if necessary, permanently shut down and safely maintain the subject facility.

Estimated Operating and Shutdown Costs

For the purpose of estimating the facility's operating costs, the applicant assumed that 1981 would be the first full year of commercial operation. Estimates of the total annual cost of operating each unit for the first 5 years are presented in Tables 1 and 2. The unit costs (mills per kWh) are based on a net electrical capacity of 1129 MWe.

The estimates of operating costs cover operating and maintenance expenses (including fuel expense), depreciation and other expenses associated with the operation of the plant.

For planning purposes, estimates have been prepared for both the temporary mothballing and the dismantling concepts as defined in the Atomic Industrial Forum/NESP-0095R report. TVA estimated it would cost $72,000,000 for complete dismantling of the facility and restoration of the site to its original condition. The estimated cost of mothballing the facility would be $6,500,000, with an additional $292,000 per year required to maintain the facility after completion of the permanent shutdown. All costs are expressed in terms of 1979 dollars.

Sources of Funds

The permanent shutdown would be financed with a combustion of internally generated and borrowed funds. The annual cost associated with maintaining the facility would be financed from the revenues of the utility. For the calendar year 1978, the unit price per kilowatt-hour from the system-wide scale of electric power was 20.59 mills. This price is in excess of the projected operating cost presented in Tables 1 and 2 and does not reflect possible rate increases during the first

TABLE 20-1

SEQUOYAH UNIT 1
PLANT CAPACITY FACTOR

50% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	59,743	12.14
1982	66,177	13.45
1983	67,316	13.68
1984	68,080	13.84
1985	76,154	15.48
5 Year Average	67,494	13.72

60% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	65,025	11.02
1982	68,408	11.59
1983	73,013	12.37
1984	82,610	14.00
1985	77,770	13.17
5 Year Average	73,365	12.43

70% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	72,376	10.51
1982	75,777	11.00
1983	79,880	11.60
1984	[illegible],142	11.93
1985	83,172	12.08
5 Year Average	78,669	11.42

TABLE 20-2

SEQUOYAH UNIT 2
PLANT CAPACITY FACTOR

50% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	58,865	11.97
1982	55,415	11.27
1983	56,098	11.41
1984	65,749	13.37
1985	60,509	12.30
5 Year Average	59,327	12.06

60% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	58,134	9.85
1982	62,219	10.54
1983	63,314	10.73
1984	64,810	10.98
1985	66,235	11.22
5 Year Average	62,942	10.66

70% Plant Capacity Factor

	Operating Cost Estimate	Mills/kWh
1981	63,274	9.18
1982	65,169	9.46
1983	70,202	10,19
1984	72,013	10,46
1985	73,402	10.66
5 Year Average	68,812	9.99

5 years of Sequoyah's commercial operation. Revenues and net income for the 12-month period ending June 1978 were $2,252 million and $184 million, respectively, compared with $1,881 million and $131 million in 1977.

The TVA Act delegates to the board the sole responsibility for establishing the rates which TVA charges and authorizes it to include in power contracts such terms and conditions as in its judgment may be necessary or desirable for carrying out the purposes of the Act.

It is further stipulated in Section 15(f) of the Act that the Board of Directors set rates that are sufficient to meet the total financial obligations of TVA, to protect its bondholders, and to protect the equity of the Federal Government. In January 1979, the fuel adjustment clause was removed from rates and replaced by a fixed amount. In addition, a $2.2 million rate adjustment was made to recover the lag between collected revenues and projected fuel adjustment costs projected for the year. Before this action, the most recent rate adjustment was made in July 1978. This was an 8½ percent rate adjustment on an annual basis.

Conclusion

In accordance with the regulations cited above, an applicant must demonstrate that it has reasonable assurance of obtaining the necessary funds to cover the estimated costs of the activities contemplated under the license. Based on the preceding analysis, the Tennessee Valley Authority has satisfied the reasonable assurance standard and is therefore, financially qualified to operate and, if necessary, shut down and safely maintain the Sequoyah Nuclear Plant, Units 1 and 2. Our conclusion is based upon the applicant's demonstrated ability to achieve revenues sufficient to cover all operating costs and interest charges, and the favorable comparison between TVA's current and unit prices of electricity and the projected unit costs of this facility.

APPENDIX A

CHRONOLOGY FOR RADIOLOGICAL SAFETY REVIEW
SEQUOYAH NUCLEAR PLANT

Date	Item
January 24, 1979	Letter from TVA Transmitting Amendment 59 to application.
January 26, 1976	Letter from TVA forwarding response to QA Branch Question 2.
January 25, 1979	Letter from TVA forwarding draft revisions to FSAR.
February 2, 1979	Letter responding to 1-11-79 phone request... Submits preoperational response time limit procedures & revised response to question Q8.33 in FSAR re effects of sustained high or low grid voltage conditions on safety-related electrical equipment....
February 5, 1979	Letter from TVA forwarding revised response to NRC 6-28-78 letter re loss of flow to either residual heat removal pump.
February 7, 1979	Letter from TVA presenting schedule for response to 1-19-79 request for additional information.
February 8, 1979	Letter from TVA forwarding results of Westinghouse analyses of total core peaking factor as function of core height for normal operations during Cycle 1.
February 14, 1979	Letter from TVA forwarding drawings re interlock & position indication design features for isolation valves.
February 14, 1979	Letter from TVA forwarding responses to 12-8-78 letter... Provides list of all Class IE safety-related equipment with identification of basis for qualification.
February 14, 1979	Letter from TVA forwarding responses to Materials Engineering Branch questions on preservice & inservice inspection.
February 14, 1979	Letter from TVA responding to 1-24-79 telephone request and submits information on fluence level received by lower shell weld reactor vessel after one fuel power year.

February 14, 1979	Letter from TVA forwarding revision to Radiological Emergency Plan.
February 16, 1979	Letter to TVA concerning contents of the offsite dose calculation manual.
February 16, 1979	Letter from TVA providing interim report on deficiency in RHR pump 1A natural frequency.
February 16, 1979	Letter from TVA forwarding final report on reactor coolant pump tie rod embedments.
February 20, 1979	Letter from TVA forwarding final deficiency report re fire dampers & fire doors in control & auxiliary buildings.
February 20, 1979	Letter forwarding responses to 12-29-78 request for additional financial information.
February 22, 1979	Letter from TVA forwarding final report on deficiency re possible unconservative pressurizer relief and safety line blowdown analysis.
February 24, 1979	Letter from TVA forwarding first interim report on potential excessive water hammer forces in main feedwater system initially report on 1-15-79.
February 28, 1979	Letter from TVA forwarding deficiency report "High Flow Alarm in Essential Raw Cooling Water Piping-NRC MEB 79-4.
March 2, 1979	Letter from TVA transmitting Amendment 60 to FSAR.
March 2, 1979	Letter from TVA forwarding requested information re piping system support base plates.
March 7, 1979	Letter from TVA forwarding qualification data on limitorque valve operators.
March 8, 1979	Letter from TVA transmitting Revision 3 to responses to NRC Questions re Fire Protection Review.
March 6, 1979	Letter from TVA forwarding response to items 11-15 of NRC 1-19-79 request for additional information...Responses will be included in Amdt. 61 of FSAR....Loose parts monitoring system will be installed during 4-30-79 refueling outage....
March 9, 1979	Letter from TVA forwarding proposed environmental tech specs for facility operating license DPR.

March 12, 1979	Letter from TVA transmitting draft Radiological Effluent Tech Specs Modified to reflect plant design.
March 14, 1979	Letter to TVA transmitting Safety Evaluation Report for Sequoyah plant.
March 16, 1979	Letter from TVA forwarding revised response to questions 2 of 9-20-78 request for additional information re monitoring requirements of reactor cooling system trip test.
March 16, 1979	Letter from TVA transmitting Annual Financial Report for 1978.
March 21, 1979	Letter from TVA forwarding Safeguards Contingency Plans...
March 23, 1979	Letter from TVA forwarding responses to questions 3 and 10 of 1-19-79 request for additional information, completes utilities' response.
March 23, 1979	Letter from TVA with scheduled fuel load dates for units 1 and 2 being June 1979 & Feb. 1980, respectively....
March 22, 1979	Letter to TVA transmitting request for additional information concerning the foundation engineering for Sequoyah.
April 11, 1979	Letter from TVA forwarding FSAR revisions to Section 13.2... Incorporating responses to Item 11 thru 15 of letter to N. Hughes...
April 11, 1979	Letter from TVA forwarding responses to items 8-16 of 12-29-78 letter to N. Hughes..
April 19, 1979	Letter from TVA forwarding Revision 5 to "Preservice Baseline Inspection and Inservice Inspection Program."
April 27, 1979	Letter from TVA concerning the Sequoyah Modified Amended Security Plan for the plant...
May 1, 1979	Letter from TVA forwarding revisions to Physical Security Plan...
May 7, 1979	Letter from TVA submitting requested information on Radiological Emergency Plan.
May 8, 1979	Letter from TVA forwarding TVA's responses to 5 SER outstanding confirmatory items.
May 17, 1979	Letter from TVA fo[illegible] comments from review of March 1979 SER.
May 22, 1979	Letter from TVA forwarding Revision 7 to "Preservice Baseline Inspection & Inservice Inspection Program for TVA".

May 25, 1979	Letter from TVA transmitting Amendment 61 to FSAR.
May 30, 1979	Letter from TVA notifying that responses to five geotechnical engineering questions transmitted in 3-22-79 letter are included in Amendment 61 of FSAR....
June 6, 1979	Letter from TVA transmitting Latest Revisions (Unnumbered) to Radiological Emergency Plan....
June 22, 1979	Letter from TVA submitting additional information re seismic qualification data package...
June 28, 1979	Letter from TVA requesting extension to 1-1-80 for construction completion...
June 28, 1979	Letter from TVA transmitting "Southern Appalachian Tectonic Study" to provide additional information to seismic design basis for plants....
July 10, 1979	Letter from TVA transmitting "Preliminary Evaluation of Sequoyah #1 Flaw Indication" & "Analytical Evaluation of a Flaw Indication in Unit 1 Reactor Vessel Closure Head"....
July 18, 1979	Letter from TVA transmitting "Reactor Bldg. Containment Integrated Lek Rate Test" performed Mar. 13-16, 1979....
July 10, 1979	Letter to TVA concerning use of ASME Code N-192 for Sequoyah & Watts Bar nuclear plants....
July 12, 1979	Letter to TVA concerning upgraded standard tech specs bases program for Sequoyah 1-2...
July 30, 1979	Letter from TVA forwarding Revision to Physical Security Plan for Sequoyah.
August 1, 1979	Letter to TVA concerning secondary water chemistry control on Standard Tech Specs....
August 7, 1979	Letter to TVA transmitting requests for information on Sequoyah from several branches
August 9, 1979	Letter from TVA transmitting "Earthquake Ground Motion Study in Vicinity of Facility".
August 10, 1979	Letter to TVA concerning requests for information on Sequoyah...

August 13, 1979	Letter to TVA transmitting IE Bulletin 79-21, about temperature effects on level measurements....
August 17, 1979	Letter to TVA concerning interim actions needed for plant operation pending final resolution of anticipated transients with failure to scram...
August 23, 1979	Letter to TVA concerning the use of Dupont Tefezel 200 for snubber seal material....
August 23, 1979	Letter to TVA requesting additional information for Sequoyah from Reactor Systems Branch...
August 23, 1979	Letter to TVA concerning site visit to Sequoyah for Sept. 4-5, 1979 on fire protection review...
August 23, 1979	Letter from TVA submitting revised fuel load schedule for all TVA plants under construction.
August 23, 1979	Letter from TVA discussing anticipated problems & design deficiencies of Westinghouse waste encansulation system.
August 31, 1979	Letter from TVA forwarding responses to Reactor System & Radiological Assessment Branch questions to 8-779 letter to H. Parris.
August 31, 1979	Letter from TVA forwarding financial statements for FY1978 power quarterly report.
September 1979	Letter from TVA forwarding Utility evaluation of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report & Short-Term Recommendations"... Commits to implementation of recommendations.
September 7, 1979	Letter from TVA responding to 8-23-79 question re net positive suction heat calculations for ECCS pumps.
September 20, 1979	Letter from TVA forwarding responses to two operator licensing branch questions.
September 11, 1979	Letter from TVA transmitting Rev. 40 to FSAR tables re diesel generator preopertional & startup tests.
September 11, 1979	Letter from TVA forwarding response to our 8-10-79 letter re bypass leakage.
September 12, 1979	Letter from TVA forwarding responses to Geosciences Branch questions transmitted by 8-10-79 ltr.

September 13, 1979	Letter from TVA forwarding "General Description of Loose Parts Monitoring System TEC Model 1430" installed at site.
September 13, 1979	Letter to TVA concerning followup actions resulting from NRC Staff reviews regarding the TMI-2 accident....
September 14, 1979	Letter from TVA responding request for documentation of utility position re containment penetration testing.
September 14, 1979	Letter to TVA concerning requests for additional information on Sequoyah...& guide thimble tube wear in Westinghouse fuel assemblies...
September 17, 1979	Letter from TVA acknowledging receipt of lette granting approval for use of Tefzel 200 as snubber material.
September 21, 1979	Letter to TVA concerning qualification of inspectors, inspection specialists, & inspection agencies for Sequoyah....
September 27, 1979	Letter to TVA concerning followup actions resulting from NRC Staff reviews regarding the TMI-2 accident....
September 27, 1979	Letter to TVA concerning containment pressures for Sequoyah.
October 1, 1979	Letter to TVA responding to 9-14-79 requests for information re possible guide thimble wear in Westinghouse assemblies.
October 2, 1979	Letter to TVA concerning emergency planning task force site visit & meeting on Sequoyah....
October 2, 1979	Letter from TVA forwards responses to Reactor System Branch questions re LOCA.
October 5, 1979	Letter to TVA concerning request for additional information for Sequoyah on level measurement systems.
October 10, 1979	Letter from TVA transmitting "Secondary Water Chemistry Control Program"...
October 10, 1979	Letter from TVA forwards description of secondary water chemistry control program.
October 10, 1979	Letter from TVA forwarding description of secondary water chemistry control program.

September 13, 1979	Letter from TVA forwarding "General Description of Loose Parts Monitoring System TEC Model 1430" installed at site.
September 13, 1979	Letter to TVA concerning followup actions resulting from NRC Staff reviews regarding the TMI-2 accident....
September 14, 1979	Letter from TVA responding request for documentation of utility position re containment penetration testing.
September 14, 1979	Letter to TVA concerning requests for additional information on Sequoyah...& guide thimble tube wear in Westinghouse fuel assemblies...
September 17, 1979	Letter from TVA acknowledging receipt of letter granting approval for use of Tefzel 200 as snubber material.
September 21, 1979	Letter to TVA concerning qualification of inspectors, inspection specialists, & inspection agencies for Sequoyah. ..
September 27, 1979	Letter to TVA concerning followup actions resulting from NRC Staff reviews regarding the TMI-2 accident....
September 27, 1979	Letter to TVA concerning containment pressures for Sequoyah.
October 1, 1979	Letter to TVA responding to 9-14-79 requests for information re possible guide thimble wear in Westinghouse assemblies.
October 2, 1979	Letter to TVA concerning emergency planning task force site visit & meeting on Sequoyah....
October 2, 1979	Letter from TVA forwards responses to Reactor System Branch questions re LOCA.
October 5, 1979	Letter to TVA concerning request for additional information for Sequoyah on level measurement systems.
October 10, 1979	Letter from TVA transmitting "Secondary Water Chemistry Control Program"...
October 10, 1979	Letter from TVA forwards description of secondary water chemistry control program.
October 10, 1979	Letter from TVA forwarding description of secondary water chemistry control program.

October 12, 1979	Letter from TVA forwarding revision to physical security plan.
October 12, 1979	Letter from TVA forwarding utility response to ACRS recommendations in 5-16-79 interim reports 2 & 3 re TMI-2 natural circulation, core exit thermocouples, containment radioactivity levels & reactor safety research.
October 12, 1979	Letter from TVA responding to our 8-21-79 ltr. re check valve leak testing.
October 12, 1979	Letter from TVA forwarding revised response to 9-24-79 request re detection of boron dilution event during reactor shutdown.
October 12, 1979	Letter from TVA responding to our 9-21-79 ltr. re position that facility could not provide independent review of Section XI program.
October 15, 1979	Letter from TVA transmitting latest Revision to Radiological Emergency Plan.
October 16, 1979	Letter to TVA concerning request for information needed by 10-26-79 for forthcoming meeting with ACRS in early November 1979....
October 17, 1979	Letter from TVA responding to H. G. Parris 9-17-79 request the utility develop emergency operating instructions & training for operators.
October 17, 1979	Letter to TVA concerning environmental qualification of Class IE instrumentation & electrical equipment...
October 17, 1979	Letter to TVA concerning Mar. 1979 submittal of Vol. 3 of NUREG-0460, "Anticipated Transients Without Scram for LWRs"...
October 18, 1979	Letter from TVA responding to our 9-27-79 ltr. re followup actions resultng from NRC review of TMI.
October 19, 1979	Letter from TVA forwarding response to 8-21-79 question re containment sump penetrations.
October 22, 1979	Letter from TVA forwarding Revision 8 to Preservice Baseline Inspection & Inservice Program.
October 23, 1979	Letter from TVA transmitting "Preliminary Results of Sequoyah #1 Internals Vibration Measurement Program"....
October 23, 1979	Letter from TVA forwarding confirmatory info on natural circulation per 9-25-79 telecon with C. Graves, Reactor System Branch reviewer.

October 23, 1979	Letter to TVA concerning potential unreviewed safety question on interaction between non-safety grade systems & safety grade systems....
October 26, 1979	Letter to TVA concerning environmental qualification of reactor coolant temperature detectors & containment pressure transmitters.
October 30, 1979	Letter from TVA transmitting "Preliminary Results of Internals Vibration Measurement Program."
October 31, 1979	Letter from TVA transmitting Amendment 62 to FSAR.
October 31, 1979	Letter from TVA forwarding revised response to NUREG-0578," Lessons Learned Requirements"....
November 1, 1979	Letter from TVA forwarding plant operating procedures TI-18, SI-400, SI-401 & SI-417....
November 1, 1979	Letter to TVA concerning requirements for individuals who have applied for operator & senior operator licenses.
November 2, 1979	Letter from TVA forwards response to containment system branch 9-27-79 questions re containment pressures. Material will be incorporated into FSAR by Amendment 63 as Question 6.56B.
November 2, 1979	Letter from TVA forwarding summary of investigation of facility chlorination practices.
November 2, 1979	Letter from TVA forwarding lists of all superseded material submitted to NRC facilities security, contingency, training & qualification plans.
November 7, 1979	Letter from TVA responding to 10-26-79 request for additional information re WCAP-9157, "Environmental Qualification of Safety-Related Class IE Process Instrumentation.
November 8, 1979	Letter to TVA concerning site visit to Sequoyah on 11-14-79 re assessment of ultimate strength of steel ice-condenser containments....
November 9, 1979	Letter to TVA concerning discussion of Lessons learned short term requirements...
November 9, 1979	Letter from TVA forwarding response to IE Bulletin 79-22.
November 13, 1979	Letter to TVA responding to our 10-17-79 ltr. re environmental qualification of IE instrumentation & electrical equipment.

November 16, 1979	Letter from TVA requesting further extension of CPPR-7 to provide sufficient contingency, until NRC resumes licensing new nuclear plants....
November 19, 1979	Letter from TVA notifying that results of operators exams requested in our 11-1-79 ltr. is being submitted directly to P. Collins on 11-20-79.
November 20, 1979	Letter to TVA concerning site visit to Sequoyah on 11-27-79 on preoperational assessment of security program...
November 21, 1979	Letter from TVA forwarding additional revision to utility revised response to NUREG-0578 re direct indication of power operated relief valve safety & safety valve position for PWRs & BWRs...
November 21, 1979	Letter to TVA concerning upgraded emergency plans...
November 23, 1979	Letter to TVA concerning proposed Revision #2 to Reg. Guide 1.97, "Instrument for Light-Water-Cooled Nuclear Power Plants to Assess Plant & Environs Conditions during & Following an Accident"....
November 23, 1979	Letter from TVA responding to our 11-1-79 ltr. re requirements for individuals applying for operator & senior operator licenses.
November 27, 1979	Letter from TVA forwarding prop & non-prop response to our 9-14-79 questions re guide thimble tube wear....
December 3, 1979	Letter from TVA forwarding responses to our 10-4-79 questions on water level measurement system inside containment.
December 3, 1979	Letter to TVA transmitting request for additional information in area of Instrumentation & Control Systems...
December 4, 1979	Letter from TVA forwarding response to 10-26-79 request for additional info re review of WCAP-9157.
December 5, 1979	Letter from TVA forwarding responses to J. Buzy 11-30-79 telecon questions.
December 7, 1979	Letter from TVA transmitting Amendment 63 to FSAR.
December 11, 1979	Letter to Honorable J. Ahearne....re interim low power operation of Sequoyah #1....

APPENDIX C

NUCLEAR REGULATORY COMMISSION
UNRESOLVED SAFETY ISSUES

C-1 Unresolved Safety Issues

The NRC staff continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors, research results, NRC staff and Advisory Committee on Reactor Safeguards safety reviews, and vendor, architect/engineer and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to assure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to assure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue prior to making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC staff requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called "generic safety issues" because they are related to a particular class or type of nuclear facility rather than a specific plant. These issues have also been referred to as "unresolved safety issues." However, as discussed above, such issues are considered on a generic basis only after the staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer-term generic review is underway.

ALAB-444 Requirements

These longer-term generic studies were the subject of a Decision by the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. The Decision was issued on November 23, 1977 (ALAB-444) in connection with the Appeal

Board's consideration of the Gulf States Utility Company application for the River Bend Station, Unit Nos. 1 and 2.

In the view of the Appeal Board (pp. 25-29):

> "The responsibilities of a licensing board in the radiological health and safety sphere are not confined to the consideration and disposition of those issues which may have been presented to it by a party or an "Interested State" with the required degree of specificity. To the contrary, irrespective of what matters may or may not have been properly placed in controversy, prior to authorizing the issuance of a construction permit the board must make the finding, *inter alia*, that there is "reasonable assurance" that "the proposed facility can be constructed and operated at the proposed location without undue risk to the health and safety of the public." 10 CFR 50.35(a)...Of necessity, this determination will entail an inquiry into whether the staff review satisfactorily has come to grips with any unresolved generic safety problems which might have an impact upon operation of the nuclear facility under consideration."
>
> "The SER is, of course, the principal document before the licensing board which reflects the content and outcome of the staff's safety review. The board should therefore be able to look to that document to ascertain the extent to which generic unresolved safety problems which have been previously identified in a TSAR item, a Task Action Plan, an ACRS report or elsewhere have been factored into the staff's analysis for the particular reactor -- and with what result. To this end, in our view, each SER should contain a summary description of those generic problems under continuing study which have both relevance to facilities of the type under review and potentially significant public safety implications."
>
> "This summary description should include information of the kind now contained in most Task Action Plans. More specifically, there should be an indication of the investigative program which has been or will be undertaken with regard to the problem, the program's anticipated timespan, whether (and if so, what) interim measures have been devised for dealing with the problem pending the completion of the investigation, and what alternative courses of action might be available should be program not produce the envisaged result."
>
> "In short, the board (and the public as well) should be in a position to ascertain from the SER itself -- without the need to resort to extrinsic documents -- the staff's perception of the nature and extent of the relationship between each significant unresolved generic safety question and the eventual operation of the reactor under scrutiny. Once again, this assessment might well have a direct bearing upon the ability of the licensing board to make the safety findings required of it on the construction permit level even though the generic answer to the question remains in the offing. Among other things, the furnished information would likely shed light on such alternatively

important considerations as whether: (1) the problem has already been resolved for the reactor under study; (2) there is a reasonable basis for concluding that a satisfactory solution will be obtained before the reactor is put in operation; or (3) the problem would have no safety implications until after several years of reactor operation and, should it not be resolved by then, alternative means will be available to insure that continued operation (if permitted at all) would not pose an undue risk to the public."

This appendix is specifically included to respond to the decision of the Atomic Safety and Licensing Appeal Board as enunciated in ALAB-444.

C-3 <u>"Unresolved Safety Issues"</u>

In a related matter, as a result of Congressional action on the Nuclear Regulatory Commission budget for Fiscal Year 1978, the Energy Reorganization Act of 1974 was amended (PL 95-209) on December 13, 1977 to include, among other things, a new Section 210 as follows:

<u>"UNRESOLVED SAFETY ISSUES PLAN"</u>

"SEC. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issued relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter."

The joint Explanatory Statement of the House-Senate Conference Committee for the FY 1978 Appropriations Bill (Bill S.1131) provided the following additional information regarding the Committee's deliberations on this portion of the bill: -

<u>"SECTION 3 - UNRESOLVED SAFETY ISSUES"</u>

"The House amendment required development of a plan to resolve generic safety issues. The conferees agreed to a requirement that the plan be submitted to the Congress on or before January 1, 1978. The conferees also expressed the intent that this plan should identify and describe those safety issues, relating to nuclear power reactors, which are unresolved on the date of enactment. It should set forth: (1) Commission actions taken directly or indirectly to develop and implement corrective measures; (2) further actions planned concerning such measures; and (3) timetables and cost estimates of such actions. The Commission should indicate the priority it has assigned to each issue, and the basis on which priorities have been assigned."

In response to the reporting requirements of the new Section 210, the NRC staff submitted to Congress on January 1, 1978, a report describing the NRC generic issues program (NUREG-0410).[1/] The NRC program was already in place when PL 95-209 was enacted and is of considerably broader scope than the "Unresolved Safety Issues Plan" required by Section 210. In the letter transmitting NUREG-0410 to the Congress on December 30, 1977, the Commission indicated that "the progress reports, which are required by Section 210 to be included in future NRC annual reports, may be more useful to Congress if they focus on the specific Section 210 safety items."

It is the NRC's view that the intent of Section 210 was to assure that plans were developed and implemented on issues with potentially significant public safety implications. In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program to determine which issues fit this description and quality as "Unresolved Safety Issues" for reporting to the Congress. The NRC review included the development of proposals by the NRC Staff and review and final approval by the NRC Commissioners.

This review is described in a report, NUREG-0510, entitled "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress" dated January 1979. The report provides the following definition of an "Unresolved Safety Issue:"

> "An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants it affects."

Further the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an "Unresolved Safety Issue" is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in NUREG-0510. As a result, 17 "Unresolved Safety Issues" addressed by 22 tasks in the NRC program were identified. The issues are listed below. Progress on these issues was discussed in the 1978 NRC Annual Report. The number(s) of the generic task(s) (e.g., A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

[1/] NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," issued on January 1, 1978.

"UNRESOLVED SAFETY ISSUES" (APPLICABLE TASK NOS.)

1. Water Hammer - (A-1)
2. Asymmetric Blowdown Loads on the Reactor Coolant System - (A-2)
3. Pressurized Water Reactor Steam Generator Tube Integrity - (A-3, A4, A-5)
4. BWR Mark I and Mark II Pressure Suppression Containments - (A-6, A-7, A-8, A-39)
5. Anticipated Transients Without Scram - (A-9)
6. BWR Nozzle Cracking - (A-10)
7. Reactor Vessel Materials Toughness - (A-11)
8. Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports - (A-12)
9. Systems Interaction in Nuclear Power Plants - (A-17)
10. Environmental Qualification of Safety-Related Electrical Equipment - (A-24)
11. Reactor Vessel Pressure Transient Protection - (A-26)
12. Residual Heat Removal Requirements - (A-31)
13. Control of Heavy Loads Near Spent Fuel - (A-36)
14. Seismic Design Criteria - (A40)
15. Pipe Cracks at Boiling Water Reactors - (A-42)
16. Containment Emergency Sump Reliability - (A43)
17. Station Blackout - (A-44)

In the view of the staff, the "Unresolved Safety Issues" listed above are the substantive safety issues referred to by the Appeal Board in ALAB-444 when it spoke of "...those generic problems under continuing study which have...potentially significant public safety implications" (page 27). Eight of the 22 tasks identified with the "Unresolved Safety Issues" are not applicable to Sequoyah Units 1 and 2. Six of these tasks (A-6, A-7, A-8, A-39, A-10 and A42) are peculiar to pressurized water reactors with Babcock & Wilcox and Combustion Engineering nuclear steam supply systems.[2/] With regard to the remaining 14 tasks that are applicable to Sequoyah Units 1 and 2, the NRC staff has issued NUREG reports providing its proposed resolution of three of the issues. These are listed below.

Task Number	NUREG Report and Title
A24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"
A-26	NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors"
A-31	Regulatory Guide 1.139, "Guidance for Residual Heat Removal"

[2/] Even though Tasks A-4 and A-5 address steam generator tube problems experienced in CE and B&W plants, there are many common task elements between these tasks and Task A-3 which addresses Westinghouse steam generator tube problems. For this reason, the Task Action Plans for all three tasks have been combined into a single Task Action Plan.

GENERIC TASKS ADDRESSING UNRESOLVED SAFETY ISSUES THAT ARE APPLICABLE TO THE SEQUOYAH NUCLEAR PLANT, UNITS 1 AND 2

1. A-1 Water Hammer
2. A-2 Asymmetric Blowdown Loads on PWR Primary Systems
3. A-3 Westinghouse Steam Generator Tube Integrity
4. A-9 ATWS
5. A-11 Reactor Vessel Materials Toughness
6. A-12 Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports
7. A-17 Systems Interactions in Nuclear Power Plants
8. A-36 Heavy Loads Near Spent Fuel
9. A-40 Seismic Design Criteria
10. A-43 Containment Emergency Sump Reliability
11. A-44 Station Blackout

With the exception of Tasks A-43 and A-44, the Task Action Plans include the generic tasks above. Task Action Plans for Tasks A-43 and A-44 are currently under development. The information provided meets most of the informational requirements of ALAB-444. Each Task Action Plan provides a description of the problem; the staff's approaches to its resolution; a general discussion of the bases upon which continued plant licensing or operation can proceed pending completion of the task; the technical organizations involved in the task and estimates of the manpower required; a description of the interactions with other NRC offices, the Advisory Committee on Reactor Safeguards and outside organizations; estimates of funding required for contractor supplied technical assistance; prospective dates for completing the task; and a description of potential problems that could alter the planned approach or schedule.

We have reviewed the 10 "Unresolved Safety Issues" listed above as they relate to Sequoyah Units 1 and 2. Discussion of each of these issues including references to related discussions in the Safety Evaluation Report and this supplement are provided below in Section C-5. Based on our review of these items, we have concluded, for the reasons set forth in Section C-5, that there is reasonable assurance that the Sequoyah Nuclear Generating Station Units 1 and 2 can be operated prior to the ultimate resolution of these generic issues without endangering the health and safety of the public.

C-4 New "Unresolved Safety Issues"

No new issues have been identified in 1979 for reporting as "Unresolved Safety Issues." However, the NRC staff has not been able to perform an in-depth review to identify and evaluate new issues. NRC efforts have been concentrated on implementing new TMI-related requirements on operating plants and on identifying, defining and scoping additional TMI-related issues and tasks. Several broad program areas where issues and tasks are being scoped will likely result in designation of new "Unresolved Safety Issues." These program areas include the following:

1. Man-machine interface and control-room design.

2. Qualification and training of operation, maintenance, and supervisory personnel.

3. Offsite emergency response, emergency planning, and action guidelines.

4. Siting policy, including compensatory design and operating provisions for plants in areas where evacuation would be difficult.

5. Systems reliability and interactions.

6. Consideration in licensing requirements of accidents involving degraded or melted fuel.

Nonetheless, the specific TMI-related requirements for licensing Sequoyah Units 1 and 2 have been identified and are discussed in Part 2 of this supplement. Many of these are related to the program areas listed above. Long-term "Unresolved Safety Issue" tasks that may be undertaken in the same program areas could provide a basis for further improvements that may or may not be applicable to the Sequoyah plant.

The NRC staff also performed a cursory review of a number of candidate issues from sources other than Three Mile Island accident investigations, including a review of events reported as Abnormal Occurrences in 1979. Based on this cursory review, none were judged to be of such safety importance to require reporting to the Congress in the 1979 Annual Report as "Unresolved Safety Issues." An in-depth and systematic review of all candidate issues will be performed by the staff and the Commission in the first half of 1980. A special report will be provided to the Congress by July 1, 1980, describing the review and new issues designated as "Unresolved Safety Issues." Their applicability to all plants will be determined at that time.

C-5 Discussion of Tasks as they Relate to Sequoyah Units 1 and 2

A-1 Water Hammer

Water hammer events are intense pressure pulses in fluid systems caused by any one of a number of mechanisms and system conditions. Since 1971 there have been over 100 incidents involving water hammer in pressurized water reactors and boiling water reactors. The water hammers have involved steam generator feedrings and piping, decay heat removal systems, emergency core cooling systems, containment spray lines, service water lines, feedwater lines and steam lines. However, the systems most frequently affected by water hammer effects are the feedwater systems. The most serious water hammer events have occurred in the steam generator feedrings of pressurized water reactors. These types of water hammer events are addressed in our SER for Sequoyah Units 1 and 2 in Section 10.4.2 at page 10-3. System design changes and testing requirements necessary to prevent this type of water hammer are discussed. In Section 10.4.2, we concluded that, subject to confirmation during the preoperational test program, the feedwater system and steam generator design for Sequoyah Units 1 and 2 with respect to this potential water hammer concern is acceptable.

Adequate protection from potential loss-of-coolant accidents, such as might be initiated by a water hammer event, is provided in plants by emergency core cooling systems. As indicated in Section 6.3.3 of our SER at page 6-30, the applicant will take steps to maintain ECCS lines full of water to minimize the potential for water hammer ocurring in these systems due to injection into dry lines. Since the probability of failure due to a water hammer is low and the consequences of postulated water hammer induced accidents would be adequately limited by currently installed redundant engineered safety features, continued operation and licensing of plants can proceed with reasonable assurance that the health and safety of the public is protected while this task is being conducted. We have concluded that the applicant has fulfilled the requirements necessary at the operating license stage of review. Accordingly, there is reasonable assurance that the Sequoyah Units 1 and 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-2 Asymmetric Blowdown Loads on Primary Coolant Systems

In the very unlikely event of a rupture of the primary coolant piping in light water reactors, large nonuniformly distributed loads would be imposed upon the reactor vessel, reactor vessel internals, and other components in the reactor coolant system. The potential for such asymmetric loads, which result from the rapid depressurization of the reactor coolant system, was only recently identified and was not considered in the original design of some facilities. The forces associated with a postulated break in the reactor coolant piping near the reactor vessel, for example, could affect the integrity of the reactor vessel supports and reactor pressure vessel internals. A significant failure of the reactor vessel support system, besides impacting the reactor internals, has a potential for (1) damaging systems designed to cool the core following the postulated piping break, (2) affecting the capability of the control rods to function properly, (3) damaging other reactor coolant system components, and (4) causing other ruptures in the initially unbroken reactor coolant system piping loops and attached systems.

As indicated in Section 3 of the Task Action Plan for Task A-2 in NUREG-0660, we currently require that this issue be resolved prior to issuing an operating license. This issue has been acceptably resolved for the Sequoyah facility. Our evaluation and conclusions are provided in Section 3.9.1 at pages 3-18 and 3-19 and in Section 6.2.1 at pages 6-10 of the Sequoyah SER and in Section 6.2.1 of this supplement. Accordingly, we have concluded that Sequoyah Units 1 and 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-3 Westinghouse Steam Generator Tube Integrity

The primary concern is the capability of steam generator tubes to maintain their integrity during normal operation and postulated accident conditions. In addition, the requirements for increased steam generator tube inspections and repairs have resulted in significant increases in occupational exposures to workers. Corrosion resulting in steam generator tube wall thinning has been observed in several Westinghouse and Combustion Engineering plants for a number of years. Major changes in their secondary water treatment process essentially eliminated this form of degradation. Another major corrosion-related phenomenon has also been observed in a number of plants in recent years, resulting from a buildup of support plate corrosion products in the annulus between the tubes and the support plates. This buildup eventually causes a diametral reduction of the tubes, called "denting," and deformation of the tube support plates. This phenomenon has led to other problems, including stress corrosion cracking, leaks at the tube/support plate intersections, and U-bend section cracking of tubes which were highly stressed because of support plate deformation.

Specific measures such as steam generator design features, a secondary water chemistry control and monitoring program, condensate demineralization and condenser tubing material selection, that the applicant has employed to minimize the onset of steam generator tube problems are described in Section 5.3.1 of the Sequoyah SER and this supplement. In addition, Section 5.2.6 of the SER and this supplement discuss the inservice inspection requirements for steam generator tubes. As described in these sections, the applicant has met all current requirements regarding steam generator tube integrity. The Technical Specifications will include requirements for actions to be taken in the event that steam generator tube leakage occurs during plant operation.

Task A-3 is expected to result in improvements in our current requirements for inservice inspection of steam generator tubes. These improvements will include a better statistical basis for inservice inspection program requirements and consideration of the cost/benefit of increased inspection. Pending completion of Task A-3, the measures taken at Sequoyah Units 1 and 2 should minimize the steam generator tube problems encountered. Further the inservice inspection and Technical Specification requirements will assure that the applicant and the NRC staff are alerted to tube degradation should it occur. Appropriate actions such as tube plugging, increased and more frequent inspections and power derating could be taken if necessary. Since the improvements that will result from Task A-3 will be procedural, i.e., an improved inservice inspection program, they can be implemented by the applicant at Sequoyah Units 1 and 2 after operation begins, if necessary.

Based on the foregoing, we have concluded that Sequoyah Units 1 and 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-9 Anticipated Transients Without Scram (ATWS)

Nuclear plants have safety and control systems to limit the consequences of temporary abnormal operating conditions or "anticipated transients." Some deviations from normal operating conditions may be minor; others, occurring less frequently, may impose significant demands on plant equipment. In some anticipated transients, rapidly shutting down the nuclear reaction (initiating a "scram"), and thus rapidly reducing the generation of heat in the reactor core, is an important safety measure. If there were a potentially severe "anticipated transient" and the reactor shutdown system did not "scram" as desired, then an "anticipated transient without scram," or ATWS, would have occurred.

The ATWS issue and the requirements that must be met by the applicant prior to operation of Sequoyah Units 1 and 2 are discussed in Section 15.3.8 at page 15-8 of our Safety Evaluation Report. The requirements set forth are for the interim period pending completion of Task A-9 and implementation of additional requirements if found to be necessary.

TVA has submitted some proposed ATWS procedures, which have been reviewed and commented on by the staff. The proposed procedures were not fully acceptable for full power operation, and are being modified by TVA. We have concluded that the plant may be safely operated at low power prior to completion of this effort, and that TVA can prepare adequate ATWS procedures, in accordance with our guidance, prior to full power operation.

Accordingly, we have concluded that Sequoyah Units 1 and 2 can be operated safely prior to the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-11 Reactor Vessel Materials Toughness

Resistance to brittle fracture, a rapidly propagating catastrophic failure mode for a component containing flaws, is described quantitatively by a material property generally denoted as "fracture toughness." Fracture toughness has different values and characteristics depending upon the material being considered. For steels used in nuclear reactor pressure vessels, three considerations are important. First, fracture toughness increases with increasing temperature. Second, fracture toughness decreases with increasing load rates. Third, fracture toughness decreases with neutron irradiation.

In recognition of these considerations, power reactors are operated within restrictions imposed by the Technical Specifications on the pressure during heatup and cooldown operations. These restrictions assure that the reactor vessel will not be subjected to that combination of pressure and temperature that could cause brittle fracture of the vessel if there were significant flaws in the vessel material. The effect of neutron radiation on the fracture toughness of the vessel material is accounted for in developing and revising these Technical Specification limitations over the life of the plant.

For the service times and operating conditions typical of current operating plants reactor vessel fracture toughness for most plants provides adequate margins of safety against vessel failure under operating testing, maintenance, and anticipated transient conditions over the life of the plant. In addition, conservative analyses indicate that adequate safety margins are available during accident conditions until after many years of operation. However, results from a reactor vessel surveillance program and analyses performed using currently available methods indicate that the reactor vessels for up to 20 older operating pressurized water reactors and those for some more recent vintage plants will have marginal toughness after comparatively short periods of operation. The principal objective of Task A-11 is to develop an improved engineering method and safety criteria to allow a more precise assessment of the safety margins that are available during normal operation and transients in older reactor vessels with marginal fracture toughness and of the safety margins available during accident conditions for all plants.

Our evaluation of the reactor vessel materials fracture toughness and reactor vessel integrity requirements of Appendix G of 10 CFR Part 50 for Sequoyah Units 1 and 2 during normal operation, testing, maintenance, and anticipated transient conditions is described in Sections 5.2.3 and 5.2.5 of the SER and this supplement. In Sections 5.2.3 of this supplement, we indicated that the applicant meets the fracture toughness requirements of Appendix G of 10 CFR Part 50 except that Paragraph IV.b of Appendix G has not been met by the Unit 1 reactor vessel. This paragraph requires that the reactor vessel beltline materials have a specified minimum Charpy V-notch upper shelf energy unless it can be demonstrated to the Commission that a lower value will still provide an adequate margin against deterioration from irradiation. On the basis of our evaluation, we have concluded that the calculated fracture toughness values are sufficiently high to assure the safety margins specified in Appendix G, Section III of the ASME Code, will be maintained at operating temperatures and pressure during the first 9.2 effective full-power years of plant life. The Unit 2 reactor vessel meets the fracture toughness requirements of Appendix G to 10 CFR Part 50. Therefore, it is expected to meet the specified safety margins throughout its life.

Since the Unit 1 reactor vessel will have marginal fracture toughness based on our current conservative assessment after 9.2 effective full power years of operation, its available fracture toughness will have to be reassessed before allowing operation beyond this point in plant life. The improved engineering method and safety criteria being developed under Task A-11 are expected to allow a more accurate assessment of the available safety margins over plant life and accordingly are expected to be used for the reassessment of the Unit 1 vessel. Task A-11 is currently expected to be completed by the end of 1980. Its results will, therefore, be available long before they are needed for application to the analysis of the Sequoyah Unit 1 vessel.

In addition to the evaluation for normal operating conditions, we have evaluated the integrity of the Unit 1 and 2 reactor vessels during accident conditions, as indicated in Section 15.3.3. A conservative assessment by the applicant indicates that reactor vessel integrity under accident conditions is assured for 17 effective full-power years. Again, the engineering methodology and safety criteria developed under Task A-11 are expected to provide the basis for assessing the acceptability of operation beyond this point in plant life. As indicated above, the results are expected to be available long before this assessment is necessary to assure safe operation.

Based on the foregoing, we have concluded that Sequoyah Units 1 and 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-12 Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports

As discussed in the Task Action Plan for Task A-12, this activity is concerned with fracture toughness properties and the possibility of lamellar tearing in steam generator and reactor coolant pump supports for pressurized water reactors. Section 3 of the Task Action Plan provides an evaluation indicating that continued licensing is acceptable pending completion of this task.

The draft recommendations for resolution of this task action plan are contained in NUREG-0577, which has been issued for public comment. Standard Review Plan revisions are being written that will contain supplementary guide ines to those in NUREG-0577. All applicants and licensees will be required to insure that the staff criteria are met or implement suitable alternative measures contained in NUREG-0577.

Based on the foregoing considerations, our ultimate conclusion in the Units 1 and 2 Safety Evaluation Report regarding issuance of operating licenses is unaffected by this ongoing generic task.

A-17 Systems Interactions In Nuclear Power Plants

The licensing requirements and procedures used in our safety review address many different types of systems interactions. Current licensing requirements are founded on the principle of defense-in-depth. Adherence to this principle results in requirements such as physical separation and independence of redundant safety systems, and protection against events such as high energy line ruptures, missiles, high winds, flooding, seismic events, fires, operator errors, and sabotage. These design provisions supplemented by the current review procedures of the Standard Review Plan (NUREG-75/087) which require interdisciplinary reviews and which account, of a large extent, for review of potential systems interactions, provide for an adequately safe situation with respect to such interactions. The quality assurance program which is followed during the design, construction, and operational phases for each plant is expected to provide added assurance against the potential for adverse systems interactions.

In November 1974, the Advisory Committee on Reactor Safeguards requested that the NRC staff give attention to the evaluation of safety systems from a multidisciplinary point of view, in order to identify potentially undesirable interactions between plant systems. The concern arises because the design and analysis of systems is frequently assigned to teams with functional engineering specialties--such as civil, electrical, mechanical, or nuclear. The question is whether the work of these functional specialists is sufficiently integrated in their design and analysis activities to enable them to identify adverse interactions between and among systems. Such adverse events might occur, for example, because designers did not assure that redundancy and independence of safety systems were provided under all conditions of operation required, which might happen if the functional teams were not adequately coordinated. Simply stated, the left hand may not know or understand what the right hand is doing in all cases where it is necessary for the hands to be coordinated.

In mid-1977, Task A-17 was initiated to confirm that present review procedures and safety criteria provide an acceptable level of redundancy and independence for systems required for safety by evaluating the potential for undesirable interactions between and among systems.

The NRC staff's current review procedures assign primary responsibility for review of various technical areas and safety systems to specific organizational units and assign secondary responsibility to other units where there is a functional or interdisciplinary relationship. Designers follow somewhat similar procedures and provide for interdisciplinary reviews and analyses of systems. Task A-17 will provide an independent investigation of safety functions--and systems required to perform these functions--in order to assess the adequacy of current review procedures. This investigation is being conducted by Sandia Laboratories under contract assistance to the NRC staff.

The contract effort, Phase I of the task, began in May 1978 and is nearing completion. The Phase I investigation is structured to identify areas where interactions are possible between and among systems and have the potential of negating or seriously degrading the performance of safety functions. The investigation will then identify where NRC review procedures may not have properly accounted for these interactions. Finally, a follow-on Phase II of the task will be scoped based on the results of Phase I and the status and scope of other related NRC activities.

The NRC staff believes that its review procedures and acceptance criteria currently provide reasonable assurance that an acceptable level of system redundancy and independence is provided in plant designs and this task is expected to confirm this belief. Therefore, we conclude that there is reasonable assurance that Sequoyah Units 1 and 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-36 Control of Heavy Loads Near Spent Fuel

Overhead cranes are used to lift heavy objects, sometimes in the vicinity of spent fuel, in both PWRs and BWRs. If a heavy object, such as a spent fuel shipping cask or shielding block, were to fall or tip onto spent fuel in the storage pool or in the reactor core during refueling and damage the fuel, there could be a release of radioactivity to the environment and a potential for radiation overexposures to in-plant personnel. If the dropped object is large, and is assumed to drop on fuel containing a large amount of fission products with minimal decay time, calculated offsite doses could exceed the siting guideline values in 10 CFR Part 100.

The applicant has complied with our requirements for the safe handling of fuel and spent fuel casks as discussed in Section 9.1 of the Sequoyah Units 1 and 2 SER. In addition, the Technical Specifications will include a prohibition on the movement of loads over spent fuel in the storage pool that weigh more than the equivalent weight of a fuel assembly. These measures provide reasonable assurance that the likelihood of a load handling accident damaging enough spent fuel to cause unacceptable consequences is small for Sequoyah Units 1 and 2.

Task A-36 may result in additional requirements applicable to Sequoyah Units 1 and 2 to further reduce the likelihood of such accidents. These additional requirements are expected to be procedural and therefore can be implemented at Sequoyah Units 1 and 2 after operation begins if found to be desirable.

In the interim period, the current design, administrative and procedural measures are acceptable as indicated above and in the referenced SER section. Accordingly, we have concluded that there is reasonable assurance that Sequoyah Units 1 and 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-40 Seismic Design Criteria - Short-Term Program

NRC regulations require that nuclear power plant structures, systems and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are provided in the NRC regulations and in Regulatory Guides issued by the Commission. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance were in place. For this reason, rereviews of the seismic design of various plants are being undertaken to assure that these plants do not present an undue risk to the public. Task A-40 is, in effect, a compendium of short-term efforts to support such reevaluation efforts of the NRC staff, especially those related to older operating plants. In addition, some revisions to SRP sections and Regulatory Guides to bring them more in line with the state-of-the-art will result.

As discussed in the SER and this supplement, the seismic design basis and seismic design of Sequoyah Units 1 and 2 have been reevaluated at the operating license stage and have been found acceptable. The results of Task A-40 will not affect these conclusions. Accordingly, we have concluded that Sequoyah Units 1 and 2 can be operated prior to ultimate resolution of this generic issue without endangering the health and safety of the public.

A-43 Containment Emergency Sump Reliability

Following a postulated loss-of-coolant accident, i.e, a break in the reactor coolant system piping, the water flowing from the break would be collected in the emergency sump at the low point in the containment. This water would be recirculated through the reactor system by the emergency core cooling pumps to maintain core cooling. This water would also be circulated through the containment spray system to remove heat and fission products from the containment. Loss of the ability to draw water from the emergency sump could disable the emergency core cooling and containment spray systems. The consequences of the resulting inability to cool the reactor core or the containment atmosphere could be melting of the core and/or loss of containment integrity.

One postulated means of losing the ability to draw water from the emergency sump could be blockage by debris. A principal source of such debris could be the thermal insulation on the reactor coolant system piping. In the event of a piping break, the subsequent violent release to the high pressure water in the reactor coolant system could rip off the insulation in the area of the break. This debris could then be swept into the sump, potentially causing blockage.

Currently, regulatory positions regarding sump design are presented in Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and Containment Spray Systems," which address debris (insulation). The Regulatory Guide recommends, in addition to providing redundant separated sumps, that two protective screens be provided. A low approach velocity in the vicinity of the sump is required to allow insulation to settle out before reaching the sump screening; and it is required that the sump remain functional assuming that one-half of the screen surface area is blocked.

A second postulated means of losing the ability to draw water from the emergency sump could be abnormal conditions in the sump or at the pump inlet such as air entrainment, vortices, or excessive pressure drops. These conditions could result in pump cavitation, reduced flow and possible damage to the pumps.

Currently, regulatory positions regarding sump testing are contained in Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," which addresses the testing of the recirculation function. Both in-plant and scale model tests have been performed by applicants to demonstrate that circulation through the sump can be reliably accomplished.

As indicated in Section 6.3.4 of this supplement, the applicant has performed out-of-plant scale model tests of the Sequoyah Units 1 and 2 containment sump design. The test identified the need for several design modifications that were subsequently incorporated into the plant design. We concluded that the applicant had demonstrated that there was reasonable assurance that the sump design would perform as expected following a LOCA and therefore was acceptable.

Task A-43 is principally concerned with the adequacy of emergency sump performance for plants licensed to operate before current design and testing requirements were imposed. The results of Task A-43 are not expected to alter our conclusions for the Sequoyah Units 1 and 2 sumps. Accordingly, we have concluded that Sequoyah Units 1 and 2 can be operated prior to ultimate resolution of this generic issue without endangering the health and safety of the public.

A-44 Station Blackout

Electrical power for safety systems at nuclear power plants must be supplied by at least two redundant and independent divisions. The systems used to remove decay heat to cool the reactor core cooling a reactor shutdown are included among the safety systems that must meet these requirements. Each electrical division for safety systems includes an offsite alternating current (ac) power connection, a standy emergency diesel generator ac power supply, and direct current (dc) sources.

Task A-44 involves a study of whether or not nuclear power plants should be designed to accommodate a complete loss of all ac power, i.e., a loss of both the offsite and the emergency diesel generator ac power supplies. A loss of all ac for an extended period of time in pressurized water reactors accompanied by loss of the auxiliary feedwater pumps (usually one of two redundant pumps is a steam turbine driven pump that is not dependent on ac power for actuation or operation) could result in an inability to cool the reactor core, with potentially serious consequences. This particular accident sequence was a significant contributor to the overall risk associated with the PWR analyzed in the Reactor Safety Study (WASH-1400). The steam turbine driven auxiliary feedwater pump for the PWR analyzed in WASH-1400 had no ac dependencies. If the auxiliary feedwater pumps are dependent on ac power to function, then a loss of all ac power could of itself result in an inability to cool the reactor core and accordingly, this event sequence would be expected to be more important to the overall risk posed by the facility.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

December 11, 1979

Honorable John F. Ahearne
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555

SUBJECT: INTERIM LOW POWER OPERATION OF SEQUOYAH NUCLEAR POWER PLANT, UNIT 1

Dear Dr. Ahearne:

During its 236th meeting, December 6-8, 1979, the Committee considered a proposal for interim, low power operation of the Sequoyah Nuclear Power Plant, Unit 1. At its 229th meeting, May 10-12, 1979 and also at its 228th meeting, April 5-7, 1979 the Committee had considered aspects of the application of the Tennessee Valley Authority (hereinafter referred to as the Applicant) for authorization to operate the Sequoyah Nuclear Power Plant, Units 1 and 2. A tour of the facility was made by members of the Subcommittee on January 24, 1976 and the application was considered at Subcommittee meetings on March 12, 1979 and on November 5, 1979. During its review, the Committee had the benefit of discussions with representatives and consultants of the Applicant, the Westinghouse Electric Corporation, and the Nuclear Regulatory Commission (NRC) Staff. The Committee also had the benefit of the documents listed. The Committee reported on the application for a construction permit for this plant on February 11, 1970.

The Sequoyah Nuclear Power Plant is located on the west bank of the Tennessee River in Hamilton County in southeastern Tennessee approximately 17 miles northeast of the center of Chattanooga, Tennessee. Construction on Unit 1 is essentially complete and construction of Unit 2 is about 90% complete. Each unit will utilize a four-loop pressurized water reactor nuclear steam supply system having a power level of 3411 MWt and an ice condenser system enclosed within a free-standing steel containment vessel which is surrounded by a reinforced concrete shield building. The ice condenser system is similar to that used in the McGuire Nuclear Station and the Donald C. Cook Nuclear Plant. The Applicant has modified the ice condenser system as a result of the operating experience gained in the Donald C. Cook Nuclear Plant. The Applicant and the NRC Staff have made plans to monitor the performance of the ice condenser containments at the Sequoyah Nuclear Power Plant (Generic Item 63 in the ACRS report, "Status of Generic Items Relating to Light-Water Reactors: Report No. 7," dated March 21, 1979). The Committee recommends that such plans be implemented.

The Sequoyah Nuclear Plant will utilize 17x17 fuel assemblies. A surveillance program has been developed by the NRC Staff to follow the behavior of these assemblies, and data are being obtained from several plants now in operation in which such assemblies have been installed for test. Experience to date has been satisfactory. The Committee wishes to be kept informed of the results of the various 17x17 assembly inspections and test programs now under way.

The Sequoyah site is considered by the NRC Staff to be within the Southern Valley and Ridge tectonic province. The maximum historic earthquake within this tectonic province is the 1897 Modified Mercalli Intensity (MMI) VIII earthquake in Giles County, Virginia. During the construction permit review, the NRC Staff concluded that a modified Housner response spectrum anchored at 0.18g was acceptable as the safe shutdown earthquake. Since that time, the NRC Staff has adopted methods which would characterize an MMI VIII earthquake with the more conservative response spectrum specified in Regulatory Guide 1.60 anchored at 0.25g.

The Applicant, in response to NRC Staff recommendations, has evaluated the Sequoyah design using a site-specific safe shutdown response spectrum developed from North American and Italian strong motion records of appropriate magnitude and epicentral distance and has compared the probability of the safe shutdown earthquake being exceeded at Sequoyah to that at other Tennessee Valley Authority plants that meet the Standard Review Plan. It has been concluded that the risk of exceeding the present design spectrum and the risk of exceeding the site-specific spectrum are comparable and that the probability of exceeding the safe shutdown earthquake is not appreciably different from that for other plants in this region. The NRC Staff has reviewed the Applicant's evaluation and has concluded that the Sequoyah plant is adequate to withstand the effects of the safe shutdown earthquake without loss of its capability to perform required safety functions. The NRC Staff, to verify their judgments regarding structural and component design margins, has performed an audit of the design margins in representative critical sections of the reactor and auxiliary building structures and in representative components required for safe shutdown.

The Committee recommends that this program for the quantification of the seismic design margin be continued and expanded to the extent necessary to ensure that all structures and equipment necessary to accomplish safe shutdown do indeed have some margin. Similar recommendations have been made by the Committee for the North Anna Power Station, Units 1 and 2, and the Davis-Besse Unit 1 in its reports dated January 17, 1977 and January 14, 1979. This matter should be resolved on a schedule and in a manner satisfactory to the Staff.

The Emergency Core Cooling Systems (ECCS) for the Sequoyah Nuclear Plant incorporate the Upper Head Injection (UHI) system. The NRC Staff has completed its review of the Westinghouse Electric Corporation ECCS evaluation model for plants equipped with UHI, and the Committee in its April 12, 1978 report on the McGuire Nuclear Station has concurred with the

Staff's conclusions. The NRC Staff has completed its review of the application of this approved evaluation model to the Sequoyah Nuclear Plant and concurs with the Applicant.

The Committee has been reviewing the circumstances relating to the recent accident at the Three Mile Island Nuclear Station Unit 2 and has made recommendations for improvements in plant design and operating procedures which should be considered for all pressurized water reactors. The Committee is continuing its review of the implications of this accident and expects to provide additional recommendations. It is expected that these recommendations will be considered and implemented as appropriate by the NRC Staff. The Committee wishes to be kept informed.

The NRC Staff has identified a number of outstanding issues, confirmatory issues, and licensing conditions, not related to TMI-2 accident considerations, which have not been specifically addressed in this report. These issues should be resolved in a manner satisfactory to the NRC Staff.

Various generic problems are discussed in the Committee's report, "Status of Generic Items Relating to Light-Water Reactors: Report No. 7," dated March 21, 1979. Those problems relevant to the Sequoyah Nuclear Plant should be dealt with by the NRC Staff and the Applicant as solutions are found. The relevant items are: 54-60, 63-65, 69, 71, 72, 74, and 76.

The NRC Staff has not completed its review of the Sequoyah Nuclear Power Plant application for a normal operating license at full power, and various implications of the Three Mile Island accident on the Sequoyah Plant remain to be decided. The ACRS has not completed its own review in regard to these matters.

The Applicant has proposed a program of interim low power operation to provide improved operator training and the development of additional experimental information on the behavior of a nuclear unit and its systems under transient conditions. The Applicant has proposed a special test series which includes the following:

1. Natural circulation following a simulated reactor trip.
2. Natural circulation following a simulated loss of offsite power.
3. Natural circulation with loss of pressurizer heaters.
4. Effect of steam generator isolation on natural circulation.
5. Natural circulation at reduced pressure.
6. Cooldown capability of the charging and letdown system.

7. Heat removal following a simulated loss of onsite and offsite AC power.

8. Establishment of natural circulation from stagnant flow conditions.

9. Boron mixing and cooldown.

The NRC Staff plans to review the proposed experimental program in detail to assure itself that all safety-related aspects are being dealt with appropriately. The Committee wishes to be kept informed.

The NRC Staff advised the Committee that it will require that TVA's emergency procedures for Sequoyah be reviewed by Westinghouse. The NRC Staff also stated that an acceptable emergency plan will exist prior to reactor operation.

The Committee believes that there is reasonable assurance that the Sequoyah Nuclear Power Plant, Unit 1 can be operated on an interim basis up to power levels of about five percent of full power without undue risk to the health and safety of the public. Subject to approval of the detailed test program by the NRC Staff, the Committee recommends approval of an interim low power license for the purposes proposed.

Sincerely,

Max W. Carbon

Max W. Carbon
Chairman

References:

1. Tennessee Valley Authority, "Final Safety Analysis Report, Sequoyah Nuclear Power Plant," Volumes 1 to 13, and Amendments 1 to 61.
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the operation of Sequoyah Nuclear Plant Units 1 and 2," NUREG-0011, March 1979.
3. Letter from L. M. Mills, TVA, to D. B. Vassallo, NRC, dated October 31, 1979, containing revised responses to the Lessons Learned Requirements.
4. Letter, L. M. Mills, TVA, to L. S. Rubinstein, NRC, dated October 30, 1979, containing responses to ACRS questions.
5. Letter from L. M. Mills, TVA, to L. S. Rubinstein, NRC, dated October 23, 1979, containing information on natural circulation in Sequoyah, Unit 1, and Diablo Canyon, Unit 1.
6. Letter from L. M. Mills, TVA, to D. B. Vassallo, NRC, dated October 12, 1979, containing responses to ACRS recommendations.

7. Letter from L. M. Mills, TVA, to D. B. Vassallo, NRC, dated September 7, 1979, containing responses to the Short-Term Recommendations of the Lessons Learned Task Force.
8. Letter from L. M. Mills, TVA, to D. B. Vassallo, NRC, dated July 12, 1979, containing responses to NRC-I&E Bulletin 79-06A and ACRS recommendations.

APPENDIX D

ADVISORY COMMITTEE ON REACTORS SAFEGUARDS - GENERIC MATTER AND LETTER

Letter to Commissioner Ahearne.

SEQUOYAH

SAFETY EVALUATION REPORT

PART II

TMI-2 ISSUES RELATED TO FUEL LOAD AND

LOW POWER TEST PROGRAM

TABLE OF CONTENTS

PART II

TMI-2 ISSUES

*(2-1) indicates Part 2 - Item 1 of Draft Action Revision 2/6/80

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**Indicates non-F. L. Action Plan item.

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PART II

Introduction

The TMI-2-related requirements for near-term operating license (NTOL) applications were initially identified in the January 5, 1980 memorandum from the Executive Director of Operations to the Commissioners, "TMI Action Plan Prerequisites for Resumption of Licensing." On February 6, 1980, a revision of this list of requirements based on the latest draft of the Task Action Plans as of February 6, 1980 was prepared and discussed with the Commission. These requirements were listed in two categories; those required prior to fuel load and low power testing operation up to five-percent power (designated as FL) and those required prior to operation above five-percent power (designated as FP).

This supplement addresses only those TMI-2-related requirements in the February 6, 1980 list of NTOL requirements as required prior to fuel load, identified therein as FL.

These requirements were developed from all available sources such as the recommendations of the Bulletins and Orders Task Force, the Presidential Commission to Investigate TMI-2, and the NRC Special Inquiry Group, and those which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578), and the Lessons Learned Task Force Final Report (NUREG-0585).

Those requirements of the February 6, 1980 list which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578) and those resulting from the Advisory Committee on Reactor Safeguards (ACRS) review of that document and the additional requirements of the Director, Office of Nuclear Reactor Regulation were previously approved by the Commission. On September 27, 1979, a letter was issued transmitting these requirements to all pending operating license applicants. On November 9, 1979, a letter clarifying these requirements was issued to all pending operating license applicants to assist in their understanding of our requirements.

The response of TVA to our letters has been the subject of staff review since October 1979. Meetings were held with TVA in Bethesda on November 6, November 15, November 20 and December 10, 1979. A site visit was made on November 28 and 29, 1979 to check hardware installation, review proposed support centers, and to review specific administrative procedures relating to operating personnel and accident response.

In addition, for all the remaining items of the February 6, 1980 listing of requirements, the staff and TVA have had ongoing reviews and meetings concerning these requirements and TVA responses to these additional items. Further site visits were held, for example, the January 28, 1980 visit by a team headed by an I&E leader and composed of the NRR licensing project manager, the I&E site representative, and technical members from NRR and I&E headquarters. They evaluated the onsite and offsite support cei ters and their staffing and the communications between the plant and NRC. This eval iation included the review of license managements organizational and managerial capa ilities.

Each applicable FL .:quirement of the February 6, 1980 listing is discussed below and follows the numbering sequence utilized therein. The Table of Contents of Part II of this SER consists of that action plan listing except for two items, dealing with Containment Inerting and Worker Protection which have been added because of their special interest. Those requirements arising from the previously approved NUREG-0578 are identified by appropriate reference. The discussion of these items includes sections titled Position and Clarification which are repeated from the generic letters to operating license applicants as discussed above.

The review is ongoing and the general status of the NURL. J578 issues under review is as follows:

I.A.1.1 Shift Technical Adviser - We concluded that TVA has met the short-term requirements for accident assessment. Additional information is required to conclude on the operating experience function. TVA has now supplemented their response and it will be reviewed with regard to this issue.

I.A.1.2 Shift Supervisor Duties - We have concluded that TVA's management directive, administrative procedures and training programs meet the staff requirements.

I.A.3.1 Licensing Examinations - Applicant is preparing operators for new examination in accordance with the revised criteria.

I.A.1.3 I.B.3.4
I.B.1.1 I.E.2
I.B.3.1 III.A.1.5

A joint I&E/NRR team is reviewing these items and their results will be reported the second week in February 1980, and published in a supplement to the Safety Evaluation Report.

I.C.1.1 Analysis and Procedure Modification - The schedules discussed in the SER for resolution of this item extend into March 1980. We are attempting to expedite resolution of this issue.

I.C.1.2 Shift and Relief Turnover Procedures - We have concluded that TVA meets the staff requirements for this item.

I.C.1.4 Control Room Access - We have concluded that TVA meets the staff requirements for this item.

II.D.1.1 Relief and Safety Valve Position - TVA has installed hardware to accomplish the required position indication. There are still several areas of documentation requirements.

II.E.1.3 Auxiliary Feedwater Initiation - The automatic initiation requirement has been met satisfactorily. The staff must resolve a difference between NUREG-0578 and RG 1.97 requirements to conclude that TVA's short-term flow indication is satisfactory.

II.E.4.1 Containment Penetrations - This item is not applicable to the Sequoyah design.

II.F.2 Inadequate Core Cooling - The subcooling meter installation is acceptable and they have met the requirements regarding submittal of a design for additional instrumentation. Inadequate core cooling procedures remains as an open issue.

II.G Emergency Power for Pressurizer Equipment - The Sequoyah design meets the NUREG-0578 requirements.

III.A.2.1 Technical Support Center - We have concluded that this item is satisfactory for fuel load.

III.A.2.2 Onsite Operational Support Center - We have concluded that TVA meets the staff requirements for this item.

III.D.1.3.a Area Radiation Monitors - We have concluded that TVA meets the staff requirements for this item.

IV. Bulletins and Orders - This is under review and TVA meets the five-percent power requirements for this item.

I. OPERATIONAL SAFETY

I.A.1 Operating Personnel and Staffing

I.A.1.1 Shift Technical Advisor (2.2.1.b - NUREG-0578)

POSITION

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multi-unit site if qualified to perform the advisor function for the various units.

The shift technical advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The shift technical advisor shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the shift technical advisors that pertain to the engineering aspects of assuring safe operation of the plant, including the review and evaluation of operating experience.

CLARIFICATION

1. Due to the similarity in the requirements for dedication to safety, training and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment functions. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

2. To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been that STA's must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor, to STA duties as defined herein.

3. It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the 10-minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence. We do not intend, at this time, to specify or advocate a minimum time onsite.

4. The implementation schedule for the STA requirements is to have the STA on duty by January 1, 1980, and to have STAs, who have all completed training requirements, on duty by January 1, 1981. While minimum training requirements have not been specified for January 1, 1980, the STAs on duty by that time should enhance the accident and operating experience assessment function at the plant.

DISCUSSION AND CONCLUSIONS

TVA has committed to provide an onshift technical advisor (STA). In order to meet the requirements for low power operation, TVA will place onshift degreed nuclear engineers to act as STAs. These interim STAs will receive additional training in nuclear plant systems, transient and accident recognition on a plant simulator, limiting conditions for operations and bases, TVA radiological emergency plan, and shift assignments and responsibilities. In addition, the interim STAs must have qualified as a shift nuclear engineer under the respective plant nuclear engineer training program.

STAs provided on shift to meet the long-term requirements will have the following minimum qualifications: (1) a bachelors degree in nuclear engineering or the equivalent; (2) must be a qualified shift nuclear engineer; (3) must have completed an extensive training program, the details of which are being developed (Elements of the training program will include basic engineering principles, extensive training in plant transient and accident response, technical specification training with emphasis on the basis for limiting conditions for operation and significant reactor training on systems and operating procedures); (4) must have been certified by a panel consisting of a licensed senior operator, a representative of the Reactor Engineering Branch, and a representation of the Nuclear Operations Staff.

Organizationally, the STA will work for the plant Reactor Engineer, thus maintaining independance from the operations staff.

In addition to the STA's advisory duties, the STA evaluates the operating history of the plant (equipment failures, design problems, operations errors, etc.) and Licensee Event Reports from other plants of similar design with suitable dissemination of the results of such evaluations to other members of the plant staff. The

STA serves as the station liaison with the corporate Nuclear Experience Review Panel, insuring that applicable operating events identified by the corporate engineering staff are funneled back into the onsite training programs.

All STAs will participate in an annual requalification training program. Based on our review of the material submitted, we have concluded that TVA has met this requirement. Qualified STAs will serve on shift who will perform both an accident assessment role and an operating experience role. The STAs will maintain their qualifications through an annual requalification program.

I.A.1.2 Shift Supervisor Duties (2.2.1.a - NUREG-0578)

POSITION

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

2. Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

   a. The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

   b. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

   c. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the shift supervisor is to provide for assuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

DISCUSSION AND CONCLUSIONS

TVA has identified the assistant shift engineer as the individual performing the duties of shift supervisor, as described in NUREG-0578.

TVA has issued a management memorandum from the Manager of Power Operations through the Director of Nuclear Power to the nuclear plant staffs which emphasizes the primary managerial responsibilities of the shift supervisor for safe operation. The memorandum also clearly establishes the shift supervisor's command duties. The responsibilities and authority of the shift supervisor are further defined in Administrative Instruction 2, "Authorities and Responsibilities for Safe Operation and Shutdown," and in Division of Nuclear Power Procedure DPM No. N7903, "Nuclear Plant Licensed Operating Shift Personnel Responsibilities."

The shift supervisor remains in the control room at all times during accident situations to direct the activities of the unit operator unless formally relieved of this function by the shift engineer. The shift engineer may, in turn, be formally relieved by the assistant operations supervisor or the operations supervisor (both also hold an SRO license).

In the event the shift supervisor is absent, the unit operator will be the lead operator on the unit to which he is assigned.

TVA is proposing a two-part training program for shift supervisors which would take approximately 80 hours to complete. The first part is a course in first-line management, which includes leadership, communication, problem analysis and decisional analysis among other associated subjects. The second part consists of a simulator course which is designed to place the trainee in conditions during which he must take a command position to assess problems, direct the actions of others during the emergency, and make decisions.

TVA has made a commitment to perform a review of the administrative duties of the shift supervisor. This review will be performed by the senior officer of TVA responsible for plant operations. Administrative functions that detract from or are subordinate to ensuring safe operation of the plant will be assigned to other personnel. TVA has already added a clerk to the shift engineer's office on each shift to perform administrative details. In addition, some of the routine "nonmanagement" duties of the assistant shift engineer have been assigned to other employees.

We have reviewed TVA's revised procedures discussed above, management memorandum, the proposed training program for shift supervisors, and commitment to review the administrative duties of the shift supervisor and conclude that TVA has met the objective of this requirement.

I.A.1.3 Shift Manning

POSITION

Assure that the necessary number and availability of personnel to man the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0585. Provisions should be made for an aide to the shift supervisor to assure that, over the long term, the shift supervisor is free of routine administrative duties.

DISCUSSION AND CONCLUSION

Status Report - This item and items I.B.1.1, I.B.1.2, I.B.2.2, I.C.5, and III.A.3.3 have been grouped together and are to be addressed by the joint I&E/NRR team which is reviewing the Sequoyah plant's and the TVA provisions for meeting originator's and management criteria. The integral evaluation of these six action plan requirements will form the basis for the team's conclusion regarding the TVA and Sequoyah staff's overall competency. The preliminary staff position and recommendations which are a requisite for fuel loading is available to the staff (Reference).

A summary of the applicant's deficiencies is noted below.

The staff organization that is in effect at the Sequoyah plant is different in several significant aspects from the organization described in the FSAR. TVA has been informed that if they wish to function under the new organization they will have to submit a revised Section 13.1 of their FSAR for review or revert to the old organization.

The plant staff organization personnel directly responsible or in the line of responsibility for the operation of the Sequoyah facility have in general minimal experience in the operation of PWR's except for that received on simulators. These positions are the Shift Engineer and operations supervision chain of command. TVA needs to augment their capability in this area with persons experienced in Westinghouse PWR operations.

Home office engineering type personnel provide backup to the plant staff in the event of emergencies and during normal operation. While they spent a portion of their time at the plant site in the normal course of their duties, we consider that they need specific preplanned training, such as systems training to provide the type of support we require.

TVA has committed to an onsite engineering group for the special test program. The functions, compositions and interfaces with other groups and the plant staff is not clear; nor is the long-term commitment to maintain this group on site been clarified.

TVA will have Westinghouse people on site for the startup tests and particularly the special tests. The role of Westinghouse people, their responsibilities and interfaces with the plant staff and other TVA groups supporting the startup of Sequoyah are apparently not clear and need to be established, preferably by written procedures.

TVA will assign a Shift Technical Advisor to each shift. These individuals will be relocated onto shift from an onsite nuclear engineering group. It is not clear, nor specific in writing how their roles change when they change from one position to another, particularly their responsibilities and authority as a Shift Technical Advisor.

The TVA Site Radiological Emergency Plan does not provide adequate definition of authorities and responsibilities for those persons or groups reporting onsite to provide technical support to the plant staff in the event of an emergency.

I.A.3.1 <u>Revised Scope and Criteria for Licensing Examinations</u>

Refer to Part I, Section 13.2, Training Program, for a discussion of this item.

I.B.1 Management for Operations

I.B.1.1 Organization and Management Criteria

POSITION

Assure that the applicant meets the requirements for onsite and offsite support personnel, [illegible] management and technical, that will assure safe operation of the plant during normal and abnormal conditions and provide the capability necessary to respond to accident situations.

Items to be considered include (a) competence of management and technical staff, both onsite and offsite; (b) size of offsite staff and degree of involvement in plant operations; (c) types of expertise needed; (d) pooling of resources among utilities; (e) organizational arrangements for both normal and accident situations; (f) training of management and technical personnel, both onsite and offsite, to assure full knowledge of plant operations and reactor safety; (g) staffing of control room personnel; (h) quality assurance program and staffing; (i) financial capability (in the event reliance is placed on outside contractual assistance during the accident situation); (j) requalification program for management and technical personnel; (k) procedures for normal operations, accident conditions, surveillance, and maintenance; (l) special requirements for accident situations including control room access, onsite technical support center, and onsite operational support center; (m) status of preestablished plans for using available resources in the event of unusual situations; and (n) reporting of unusual events; (o) policy for the consideration at management levels of safety issues identified at all levels, but unresolved.

DISCUSSION

See discussion of item I.A.1.3 for the status of this item which is being reviewed by the joint I&[illegible] team.

I.B.1.2 Safety Engineering Group

POSITION

Assure that an independent, onsite safety review group exists. Consider the interaction of the independent safety review group with other committees/groups already established to oversee certain plant operational aspects to assure the effectiveness of the group and to avoid duplication of review efforts. Consider the characteristics of the independent safety review group: number of people, areas of expertise, competence, assigned scope of work, organizational relationships, authority, and reporting requirements.

DISCUSSION

See discussion of item I.A.1.3 for the status of this item which is being reviewd by the joint I&E/NRR team.

I.B.1.4 Licensee Onsite Operating Experience Evaluation Capability

See Sections I.A.1.1 and I.C.5.

I.B.2.2 Resident Inspector

POSITION

This requires that an NRC resident inspector is stationed at each site for a new operating license.

DISCUSSION

Mr. William Cottle is currently the IE:RE senior resident inspector at the Sequoyah site. He has been at the site since May 1979, and is intimately knowledgeable of the plant design and the pertinent operating and emergency procedures. He has participated in the review and inspections of the plant design, construction and safety features. He is currently a member of the joint I&E/NRR team.

I.C Procedures

I.C.1 Short-Term Accident Analysis and Procedure Modifications (2.1.9 - NUREG-0578)

POSITION

Analyses, procedures, and training addressing the following are required:

1. Small break loss-of-coolant accidents;

2. Inadequate core cooling; and

3. Transients and accidents.

Some analysis requirements for small breaks have already been specified by the Bulletins and Order Task Force. These should be completed. In addition, pretest calculations of some of the Loss of Fluid Test (LOFT) small break tests (scheduled to start in September 1979) shall be performed as means to verify the analyses performed in support of the small break emergency procedures and in support of an eventual long-term verification of compliance with Appendix K of 10 CFR Part 50.

In the analysis of inadequate core cooling, the following conditions shall be analyzed using realistic (best-estimate) methods:

1. Low reactor coolant system inventory (two examples will be required - LOCA with forced flow, LOCA without forced flow).

2. Loss of natural circulation (due to loss of heat sink).

These calculations shall include the period of time during which inadequate core cooling is approached as well as the period of time during which inadequate core cooling exists. The calculations shall be carried out in real time far enough that all important phenomena and instrument indications are included. Each case should then be repeated taking credit for correct operator action. These additional cases will provide the basis for developing appropriate emergency procedures. These calculations should also provide the analytical basis for the design of any additional instrumentation needed to provide operators with an unambiguous indication of vessel water level and core cooling adequacy (see Section 2.1.3.b of NUREG-0578).

The analyses of transients and accidents shall include the design basis events specified in Section 15 of each FSAR. The analyses shall include a single active failure for each system called upon to function for a particular event. Consequential failures shall also be considered. Failures of the operators to perform required control manipulations shall be given consideration for permutations of the analyses. Operator actions that could cause the complete loss of function of a safety system shall also be considered. At present, these analyses need not address passive failures or multiple system failures in the short term. In the recent analysis of small break LOCAs, complete loss of auxiliary feedwater was considered. The complete loss of auxiliary feedwater may be added to the failures being considered in the analysis of transients and accidents if it is concluded that more is needed in operator training beyond the short-term actions to upgrade auxiliary feedwater system reliability. Similarly, in the long term, multiple failures and passive failures may be considered depending in part on staff review of the results of the short-term analyses.

The transient and accident analyses shall include event tree analyses, which are supplemented by computer calculations for those cases in which the system response to operator actions is unclear or these calculations could be used to provide important quantitative information not available from an event tree. For example, failure to initiate high-pressure injection could lead to core uncovery for some transients, and a computer calculation could provide information on the amount of time available for corrective action. Reactor simulators may provide some information in defining the event trees and would be useful in studying the information available to the operators. The transient and accident analyses are to be performed for the purpose of identifying appropriate and inappropriate operator actions relating to important safety considerations such as natural circulation, prevention of core uncovery, and prevention of more serious accidents.

The information derived from the preceding analyses shall be included in the plant emergency procedures and operator training. It is expected that analyses performed by the NSSS vendors will be put in the form of emergency procedure guidelines and that the changes in the procedures will be implemented by each licensee or applicant.

In addition to the analyses performed by the reactor vendors, analyses of selected transients should be performed by the NRC Office of Research, using the best available computer codes, to provide the basis for comparisons with the analytical methods being used by the reactor vendors. Th[illegible] comparisons together with comparisons to date, including LOFT small break tes[illegible] will constitute the short-term verification effort to assure the adequacy of [illegible]alytical methods being used to generate emergency procedures.

DISCUSSION AND CONCLUSIONS

This item requires analysis, procedure guidelines, emergency procedures, and operator training related to small break loss of coolant accidents, inadequate core cooling, and transients and non-LOCA accidents.

Westinghouse submitted analyses for small break accidents for non-UHI plants in Topical Report WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System," June 1979. Emergency procedure guidelines were then developed by the Westinghouse Owners Group. These guidelines were approved by NRC for non-UHI plants in November 1970. Analyses for small break accidents for UHI plants have been submitted in Topical Report WCAP-9639, "Report on Small Break Accidents for Westinghouse Nuclear Steam Supply System (NSSS) with Upper Head Injection (UHI)," December 1979. This analysis is presently under staff review and the review is expected to be completed by March 15, 1980. We expect that some changes in the guidelines for non-UHI plants will be necessary for UHI plants. The staff will review the revised Sequoyah emergency procedure for small break accidents. In addition, we require that TVA provide a pretest prediction of the semiscale small break UHI test.

Westinghouse submitted analyses of inadequate core cooling for non-UHI plants on October 30, 1979, "Analysis of Inadequate Core Cooling and Emergency Procedure Guidelines to Restore Core Cooling and Emergency Procedure Guidelines to Restore Core Cooling." The staff has discussed these analyses with TVA and Westinghouse, and Westinghouse indicated that additional information relating to inadequate core cooling specifically for UHI plants will be submitted by the end of January 1980. TVA has indicated that the revised emergency procedures to be submitted February 15, 1980, will address inadequate core cooling by incorporating appropriate concerns for core cooling in various emergency procedures. We require TVA to clearly indicate each and every addition to the emergency procedures which were made in accordance with the requirement 2.1.3 of NUREG-0578. The staff analyses of this requirement will be complete by March 15, 1980.

The third part of this item relates to analysis, procedure guidelines, emergency procedures, and operator training for transients and accidents. TVA has committed to providing all of the required items but has stated that it may not be possible to meet the schedule required for operating reactors, that is, analyses and guideline development due by March 31, 1980 and emergency procedures and operator training by June 30, 1980. We are continuing our discussions with the NSSS vendors and the owners groups and will continue to discourage any delays in the established schedule.

I.C.2 Shift Relief and Turnover Procedures (2.2.1.C - NUREG-0578)

POSITION

The licensee shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist.

    a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included on the checklist.

c. Identification systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

2. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of syst alignments).

DISCUSSION AND CONCLUSION

TVA has developed and will implement shift and relief turnover procedures that will provide assurance that the oncoming shift possesses adequate knowledge of critical plant status information and system availability. A checklist or similar hard copy will be completed by and signed by offgoing and oncoming shifts at each shift turnover. These checklists will be periodically reviewed by the operations supervisor or his assistant and will be held in the operations supervisor's office files for 1 month following review. TVA has committed to establish a system to evaluate the effectiveness of the turnover procedures.

We have reviewed the administrative procedures revised to implement this requirement and the pertinent checklists to be filled out by offgoing and oncoming shift personnel. We conclude that TVA has met this requirement.

I.C.3 Shift Personnel Responsibilities (2.2.1.a - NUREG-0578)

This item is included with I.A.1.2, Shift Supervisor Duties.

I.C.4 Control Room Access (2.2.2.a - NUREG-0578)

POSITION

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and the predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access, and

2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

DISCUSSION AND CONCLUSION

TVA has developed and will implement plant-specific administrative procedures that establish specific individual authority and responsibility as well as delineate various system or equipment functions related to controlling personnel access during normal and accident condition. During normal operations, permission is required from the unit operator or assistant shift engineer for entrance into the operating area of the control room. The unit operator, assistant shift engineer, or shift engineer has the authority to terminate activities and expel persons from the control room if the operation of the unit is being adversely affected by such activities.

During radiological emergencies, only those persons approved by the shift engineer or site emergency director may be present in the control room. TVA intends to post a public safety officer in the control room during radiological emergencies to ensure access restrictions are enforced.

A specific set of senior plant staff personnel are authorized control room access during plant transients and trips. Other personnel may be granted access at the request of the SRO licensed person in charge. The NRC resident inspector has access to the control room at all times.

TVA has delineated a clear line of authority and responsibility in the control room through revised administrative procedures. These administrative procedures address normal operations as well as emergencies and leave no doubt as to who is in charge.

We have reviewed the applicable administrative procedures revised to implement this requirement. We conclude that TVA has met this requirement. This item is closed.

I.C.5 Licensee Dissemination of Operating Experiences

POSITION

Description: Review the licensee's onsite capability to evaluate the operating history of the plnat and plants of similar design. This function should be part of the duties of the independent Onsite Safety Engineering group (see Task I.B.1.2) and may include some of the duties o the Shift Technical Advisor (see Task I.A.1.1)

This will include a review of administrative procedures to assure that operating experience from within and outside its organization is continually provided to operators and other operations personnel and is incorporated in training programs.

DISCUSSION

See discussion of items I.A.1.3 and I.A.1.1 for the status of this item.

I.C.7 NSSS Vendor Review of Low Power Test Procedures

The applicant's low power test procedures are currently under review by the NSSS Vendor, Westinghouse. This review will be completed and documented prior to startup of the low power test program.

I.G Training During Low Power Testing

Introduction

In a letter dated December 3, 1979 to Joseph Hendrie (NRC), S. David Freeman, Chairman of the Board of TVA, proposed "pursuing certain limited activities in the case of those power plants where construction has been completed during the Commission's pause..." One of the activities proposed was a series of natural circulation tests to be performed at power levels up to five percent of normal full power.

The NRC staff, immediately after receipt of the December 3, 1979 letter, began to review the low power test program proposed by TVA to be performed at Unit 1 of the Sequoyah Nuclear Plant. The staff established the following five criteria for the test program:

1. The tests should provide meaningful technical information beyond that obtained in the normal startup test program.

2. The tests should provide supplemental operator training.

3. The tests should not pose an undue risk to the public.

4. The risk of damage to the nuclear plant during the test program should be low.

5. The radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming from the NRR Lessons Learned Task Force, Kemeny Commission, Rogovin Commission or Task Action Plan.

I.G.1 Test Program

The low power test program proposed by TVA consists of nine tests, eight of which involve natural circulation in the reactor coolant system at low power conditions, but at normal, or nearly normal, operating pressures and temperatures.

The specific tests proposed are:

1. Natural circulation test;
2. Natural circulation with simulated loss of offsite ac power;
3. Natural circulation with loss of pressurizer heaters;
4. Effect of secondary side isolation on natural circulation;
5. Natural circulation at reduced pressure;
6. Cooldown capability of the charging and letdown system;
7. Simulated loss of all onsite and offsite ac power;
8. Establishment of natural circulation from stagnant conditions; and
9. Forced circulation cooldown (part A) and boron mixing and cooldown (part B).

The tests will not necessarily be performed in this order. In general the test program will progress from relatively simple tests to those that are more complex. Members of the NRC staff will observe the performance of selected tests.

On December 7, 1979, TVA submitted a document that very briefly stated the purpose, listed the major initial conditions, and outlined the test method for each test. Subsequently, on January 7, 1980, TVA submitted a draft of the special operating procedures for each of the nine proposed tests. These special procedures include the objectives, prerequisites, precautions, special test equipment, instructions, and acceptance criteria for each test.

The special procedures prepared by TVA are intended to be used in conjunction with, and in addition to, the normal plant operating procedures, the normal plant Technical Specifications, and the special Technical Specifications for each test. That is, the special procedures do not describe the status of plant systems that are not manipulated during the tests, nor do they describe any actions that may have to be taken on these systems during the tests. For example, the method of replenishing the inventory in the condensate storage tanks, if auxiliary feedwater is used to provide flow to the steam generators, is not covered in the special procedures. Thus the licensed plant operators and the test director must not only use the special procedures, but they also must refer back to the special Technical Specifications for each test and to the normal operating procedures.

STAFF EVALUATION

The staff is currently reviewing the procedures for the special tests that have been submitted by TVA. The staff review is concentrating on the overall approach proposed by TVA, not on the details of valve lineup and the designation of the instruments to be used to record data.

The staff has pointed out to TVA that here may be the need to perform some hot isothermal, zero power tests to measure such items as normal system heat loss and rate of pressure decay due to heat losses in the pressurizer in order to be able to correctly interpret the data from the test proposed. For example, in test 6, the experimentally-determined change in the temperature of the reactor coolant will reflect the algebraic sum of the pump energy input, the heat losses through the insulation, and the heat removal capability of the charging and letdown system. Thus, the determination of the cooldown capability of the charging and letdown system, the objective of test 6, cannot be determined directly from the test results.

The staff has also pointed out to TVA that the instruments for measuring hot leg and cold leg temperatures may be subject to significant errors at the low flow rates that will exist during natural circulation. Under these flow conditions, heat losses to the environment through the instrument mounts, combined with low heat transfer coefficients at the sensor, might lead to indicated temperature readings that are much slower than the actual bulk coolant temperature. This may make the control of the tests more difficult. We have asked TVA to investigate this matter further.

The staff is in the process of evaluating the low power test program proposed by TVA. The criteria listed above are being used as the basis of the evaluation. The status of the staff's review is described below for each of the criteria. However, the staff approves TVA and load fuel.

A. Criterion 1

Criterion 1 states that the tests should provide meaningful technical information beyond that obtained during the normal test program. By meaningful we mean information that adds to the understanding of the capabilities of a plant to remove heat from the reactor either by natural convection circulation of reactor coolant or by other heat transfer mechanisms considered in the analyses of small loss of coolant accidents. Although natural circulation tests have been performed on many reactors, they have not been done under degraded plant conditions, such as loss of electrical power or isolation of the secondary side of a steam generator.

The staff has reviewed each of the tests proposed by TVA relative to Criterion 1. We have concluded that the test program will provide meaningful technical information.

The earlier tests in the series are only expected to confirm that natural circulation can be obtained, and to develop the techniques needed to simulate decay heat using fission heat. As the program proceeds to the more complex tests, meaningful information is expected to be obtained. This is expecially true for the test in which loss of all alternating current electric power, both onsite and offsite, is simulated. This test is expected to demonstrate a design capability that has never previously been experimentally confirmed in a commercial nuclear power plant. Other tests that are expected to provide significant technical information are those that demonstrate that natural circulation can be established from stagnant conditions and that determine the degree of boron mixing that can be obtained under natural circulation conditions.

It should be noted that all of the natural circulation tests proposed by TVA will be single phase, liquid tests. That is, the tests will be initiated and conducted with the reactor coolant subcooled. Thus, the tests will not be representative of the two-phase conditions that might exist following an accident. TVA opposes two-phase testing because they believe that the potential risk of damage to the plant outweighs the benefits to be gained. Despite the lack of two-phase tests in the proposed test program, the staff concludes that the test program will provide meaningful information and is expected to confirm design features that have not been previously demonstrated in commercial, light-water nuclear power plants.

B. Criterion 2

Criterion 2 states that the tests should provide supplemental operator training. In regard to the training objectives of the test program, TVA plans to repeat each test several times so that each operating crew will have an opportunity to gain "hands-on" experience for each test. Some of the training that will be obtained during low power testing could also be provided by simulator training. However, simulator training is generally limited to operations that take place in the control room. The performance of the test program will aid in the check-out of procedures for those operations conducted outside the control room, and provide training in those operations. Therefore, the staff concludes that the proposed test program will provide valuable training not otherwise available for the Sequoyah operating crews.

However, the TVA must assure that consideration of two-phase conditions is provided. Without such an awareness the operators could be misled into believing that the single-phase natural circulation conditions they experience in performin the test program would be representative of the two-phase conditions they may encounter following an accident.

C. CRITERION 3

Criterion 3 requires that the tests should not pose an undue risk to the public. TVA has not submitted, for staff review, the safety analyses that demonstrate that the Criterion 3 will be satisfied. They intend to submit these analyses at least 4 weeks prior to the scheduled start of the low power test program.. Since the proposed test program will be performed at power levels of 5 percent or less, the decay heat in the event of a reactor trip or an accident will be about comparable to heat losses through the insulation at normal reactor coolant system (RCS) operating temperature. Therefore, we do not anticipate that the safety analysis to be prepared by TVA will uncover any significant safety problems. However, review of these safety analyses by the staff and issuance of a license amendment, along with the supporting safety evaluation report, will be required prior to beginning the test program.

As noted above, the procedures for the special low power tests submitted by TVA are not self-sufficient. Instead, the special procedures also require use of the normal plant operating procedures, the plant technical specifications, and special test exceptions to the technical specifications. This approach has the advantage of providing additional operator training in the use of these normal plant procedures, but does make the operators' duties more complex during the low power test program. Other potential difficulties include possible conflicts or ambiguities between the special procedures and the normal operating procedures, lack of clear instructions to the licensed operators regarding the actions they should take if specified limits are exceeded during testing, and any ambiguity as to the responsibility and authority of the licensed operators relative to that of the test director.

The staff has concluded that some type of lead or master document should be prepared by TVA. This document should outline the entire test program, defining the sequence in which the individual tests will be performed. For each individual test, the master document should specify which conditions should be established or maintained, and what orders or instructions apply during the period the test is being performed, including the applicable emergency procedures if limits are exceeded. At the conclusion of each individual test, the master document should specify that normal technical specifications and licensed plant conditions, including safety system settings, apply. The master document should also specify that the normal plant administrative procedures will be followed when tests are being conducted so there will be no doubt that the licensed senior operator has the authority and responsibility to direct the licensed operators in accordance with 10 CFR 55.4e.

Also, TVA should thoroughly review the special test procedures and test exemptions relative to the normal operating procedures and technical specifications to assure that there are no ambiguities that will rise during testing.

D. CRITERION 4

Criterion 4 states that the risk of damage to the nuclear power plant during the test program should be low. In this regard, TVA has not proposed any tests that they feel represent more than a minimal risk to Unit 1 of the Sequoyah plant. This is the major reason they have not proposed any natural circulation tests involving two-phase conditions.

E. CRITERION 5

Criterion 5 states that the radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming form the TMI-2 accident. TVA has evaluated the expected radiation levels following the completion of the low power test program. They have stated that they do not foresee that the radiation levels created by the low power testing will prevent implementation of any requirements for physical alterations dictated by the Lessons Learned Task Force, Kemeny Commission, Rogovin Commission, or Task Action Plan as presently understood. The radiation exposure from these tests will not preclude any currently identified changes, additions, or deletions from the plant.

ADDITIONAL TESTS

The staff has requested that TVA also obtain some base line data regarding differential pressure across the elbow pressure taps in each reactor coolant loop for various pump combinations. TVA has agreed to perform such tests.

These tests will be conducted with the core installed, but all control rod assemblies inserted. The reactor coolant system will be at about normal operating temperature and pressure. The tests will be performed with one pump, two pumps and three pumps operating. The differential pressure data will be obtained in all four loops; that is, the loops with flow in the normal direction and the loops having flow in the reverse direction. Pump data such as motor current and revolutions per minute (if possible to obtain) will also be recorded.

The purpose of the tests is to provide baseline data for an undamaged core. In the event that there is an accident sometime in the future involving core damage, similar data could be obtained and compared to the base line data to infer the extent of the core damage.

II. SITING AND DESIGN

II.B.4 Degraded Core - Training

Position

Operational procedures for the degraded core cooling which occurs during inadequate core cooling is an item which TVA is pursuing jointly with other utilities through the Westinghouse Electric Corporation Owners Group. TVA has upgraded their procedures by incorporating recommendations which have been made by the Owners Group. The procedures will be further modified with respect to inadequate core cooling after the final Owners Group recommendations are received. This information is expected in March 1980. Since the operational procedures are used as the basis for all operator training, an upgrading of the procedures is essentially an upgrading of the operator training. We consider the item resolved for the low power test program because the applicant has established a training program as required by the action plan.

II.B.7 Containment Inerting

Position

Licensees will be required to insert BWR Mark I and Mark II containment structures. Studies will be conducted for other designs to determine whether they should be inerted or additional hydrogen control and mitigation measures should be required. This is categorized as a full power issue.

Discussion and Conclusion

The present NRC regulations on emergency core cooling require that the calculated amount of hydrogen generated from a metal-water reaction involving the cladding not exceed one percent of the hypothetical amount that would be generated if all the cladding reacted. The present regulations on combustible gas control require an assumption that the hydrogen generated is five times that calculated from degraded ECCS performance, or that generated in a reaction involving one percent of the cladding, whichever is greater. In the Sequoyah ECCS analysis, a metal-water reaction involving 0.3 percent of the cladding was calculated, an the combustible gas control requirement was set based on a metal-water reaction involving 1.5 percent of the cladding.

The TMI-2 accident resulted in a greater amount of metal-water reaction than previously considered in degraded ECCS calculations, with the amount of metal-water reaction in the TMI-2 accidnet having been estimated in the range of 40 percent. The hydrogen generated in this reaction was released to the containment, the combustible limit was exceeded, and the hydrogen burned. Because of this lesson of the TMI-2 accident, the staff is evaluating whether additional measures should be takne regarding combustible gas control in all plants.

A metal-water reaction in the Sequoyah plant involving 40 percent of the cladding could result in a hydrogen concentration in containment of about 12 percent, well above the 1.5 percent design level, used to size recombiners, and well above the combustible level of about four percent hydrogen in air at 1 atmosphere. Although a much more thorough study must be performed to make final decisions on combustible gas control in ice condenser containments, the staff has performed and is continuing to perform evaluations of this problem for Sequoyah operation, particularly operations at low power. We have examined loss-of-coolant accident scenarios which involve steam in the containment and the operation of containment sprays. For these conditions it appears that a 40 percent metal-water reaction would not result in a combustible mixture because of the suppressing effects of steam. It also appears that the containment would not catastrophically fail even if the design pressure were to be exceeded by as much as a factor of three. Heat removal over a period of time would reduce the pressure loading, and the recombiners would reduce hydrogen levels.

In addition to the perspective regarding combustible gas control, we have considered whether a loss-of-coolant accident from low power operations is likely to lead to a significant metal-water reaction (and hydrogen generation) even under severely degraded ECCS conditions. We have concluded that there is time available to take corrective action to cool the core before there is any substantial hydrogen generation, and that the low power operation phase may proceed while the matter is more fully studied.

II.D.2 Relief and Safety Valve Test (2.1.2 - NUREG-0578)

POSITION

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

CLARIFICATION

1. Expected operating conditions can be determined through the use of analysis of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70.

2. This testing is intended to demonstrate valve operability under various flow conditions, that is, the ability of the valve to open and shut under the various flow conditions should be demonstrated.

3. Not all valves on all plants are required to be tested. The valve testing may be conducted on a prototypical basis.

4. The effect of piping on valve operability should be included in the test conditions. Not every piping configuration is required to be tested, but the configurations that are tested should produce the appropriate feedback effects as seen by the relief or safety valve.

5. Test data should include data that would permit an evaluation of discharge piping and supports if those components are not tested directly.

6. A description of the test program and the schedule for testing should be submitted by January 1, 1980.

7. Testing shall be complete by July 1, 1981.

DISCUSSION AND CONCLUSION

TVA has stated that they are actively pursuing a joint effort with other members of the utility industry which will develop requirements for a generic test facility and program for RCS releif and safety valve prototypical testing. This involves subscription to and participation in a program developed and managed by the Electric Power Research Institute (EPRI). The initial result of that joint industry effort (i.e., the EPRI "Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems") was presented to and discussed with representatives of the NRC staff at a meeting with EPRI personnel on December 17, 1979. TVA has certified separately to NRC that the generic program and schedule presented by EPRI is applicable to the Sequoyah design.

The staff will perform a detailed review of the generic program proposed by EPRI and of the certification by TVA of the applicability of that program to the Sequoyah design. We will report the final results of that review in a supplement to this evaluation. On the basis of our preliminary discussions to date with EPRI regarding the feasibility of meeting the clarified value testing requirements of NUREG-0578 (including discussions at the December 17 meeting), and on the basis of TVA's statements that the proposed EPRI program is applicable to the Sequoyah design and consistent with the NRC position in this regard, we believe that there is adequate assurance at this point that the NUREG-0578 requirement regarding performance verification of RCS relief and safety valves will be met satisfactorily for the Sequoyah unit.

II.D.5 Relief and Safety Valve Position (2.1.3.a - NUREG-0578)

POSITION

Reactor system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe.

CLARIFICATION

1. The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

3. The valve position indication may be safety grade. If the position indication is not safety-grade, a reliable single channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis and action.

4. The valve position indication should be seismically qualified consistent with the component or system to which it is attached. If the seismic qualification requirements cannot be met feasibly by January 1, 1980, a justification should be provided for less than seismic qualification and a schedule should be submitted for upgrade to the required seismic qualification.

5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift). If the environmental qualification program for this position

indication will not be completed by January 1, 1980, a proposed schedule for completion of the environment qualification program should be provided.

DISCUSSION AND CONCLUSIONS

Two power-operated relief valves (PORV) and three safety valves, connected to the top of the pressurizer are provided in the Sequoyah design to protect against overpressurization. Positive indication of PORV position is obtained by a direct, stem-mounted indicator which mechanically activate limit switches at the fully-open and fully-closed valve stem positions (single channel for each PORV). TVA has installed an accelerometer similar to those employed in the Sequoyah noise monitoring system on the discharge piping of each safety valve (also single channel for each valve). All valve positions are indicated in the main control room; and TVA has stated that these valve position indication systems will meet seismic and environmental qualification requirements as specified by NRC for Sequoyah. TVA has also indicated that an alarm in the main control room will indicate when any valve is not in the fully-closed position.

The Sequoyah design as described in TVA's submittal incorporates only a single channel of positive position indication for each safety valve. In accordance with the NRC position and clarification, therefore, TVA has described backup methods of determining valve positions; these include temperature sensors downstream of each valve, pressurizer relief tank temperature/pressure/level indicators and pressurizer high pressure sensors, already installed and all indicated and alarmed in the main control room.

On the bases of TVA's submittals to NRC describing these new systems, discussions with TVA engineering and operating staff representatives, and an inspection tour of the Sequoyah facility, the TVA approach to providing positive pressurizer relief and safety valve position indication, by use of direct stem-mounted devices on the PORVs and by use of accelerometers at the discharge of each safety valve appears acceptable.

The acoustic monitors are powered from a vital bus which is battery backed. The seismic and environmental qualifications have been completed with the exception of qualified life requirements to IEEE-323-1974 which are currently being tested. TVA is to provide a schedule for completion of the qualification work. Although TVA has stated that the backup indication methods have not been incorporated into operating procedures it is our understanding that they have now been incorporated following the NSSS review of emergency operating procedures. We will require that TVA document this fact. TVA has stated that the high frequency generated in the tailpipe for all levels of flow will provide an unambiguous indication of a valve opening as well as show valve position within 10 percent increments.

The basis for this statement has not been provided. Although the staff concludes at this time that the use of acoustic monitors is an acceptable method for providing valve position indication it appears that calibration of these devices is an important aspect of their usefulness. TVA is to provide the means by which these instruments will be calibrated particularly with respect to feedback from the common downstream piping. TVA must document the schedule for qualification of the acoustic monitors and the means of calibration prior to fuel load.

II.E.1.2 Auxiliary Feedwater Initiation and Indication (2.1.7.a - NUREG-0578)

POSITION

Consistent with satisfying the requirementsof General Design Criterion 20 of Appendix A to 10 CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system, the following requirements shall be implemented in the short term:

1. The design shall provide for the automatic initiation of the auxiliary feedwater system.

2. The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of auxiliary feedwater system function.

3. Testability of the initiating signals and circuits shall be a feature of the design.

4. The initiating signals and circuits shall be powered from the emergency buses.

5. Manual capability to initiate the auxiliary feedwater system from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

6. The ac motor-driven pumps and valves in the auxiliary feedwater system shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.

7. The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFWS from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety-grade requirements.

CLARIFICATION

Control Grade (Short-Term)

1. Provide automatic/manual initiation of AFWS.

2. Testability of the initiating signals and circuits is required.

3. Initiating signals and circuits shall be powered from the emergency buses.

4. Necessary pumps and valves shall be included in the automatic sequence of the loads to the emergency buses. Verify that the addition of these loads does not compromise the emergency diesel generating capacity.

5. Failure in the automatic circuits shall not result in the loss of manual capability to initiate the AFWS from the control room.

6. Other Considerations - For those designs where instrument air is needed for operation, the electric power supply requirement should be capable of being manually connected to emergency power sources.

DISCUSSION AND CONCLUSION

The auxiliary feedwater system for Sequoyah was designed as a safety-related system, aside and apart from any TMI-related requirements imposed subsequently by NRC. Consistent with that design intent, and as described in TVA's submittals to NRC and in discussions with TVA personnel in connection with this NUREG-0578 position, the AFW initiating circuitry for Sequoyah incorporates both automatic and manual system start capability, including manual initiation of the system from the main control room. Manual initiation capability is provided independent of automatic initiation, and the design of the automatic initiation circuitry is such that a single-failure cannot result in total loss of the AFW system function. Further, the Sequoyah design incorporates on-line testability, and the system is powered from reliable emergency buses as specified in NUREG-0578 (including automatic actuation of ac motor driven pumps and valve loads onto the emergency buses.

The Sequoyah AFW initiation circuitry design meets NUREG-0578 requirements.

Auxiliary Feedwater Initiation (2.1.7.b - NUREG-0578)

POSITION

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide the capability in the control room to ascertain the actual performance of the AFWS when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity

requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

CLARIFICATION

A. Control Grade (Short-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy the single failure criterion.

2. Testability of the auxiliary feedwater flow indication channels shall be a feature of the design.

3. Auxiliary feedwater flow instrument channels shall be powered from the vital instrument buses.

B. Safety-Grade (Long-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy safety-grade requirements.

C. Other

1. For the short-term the flow indication channels should by themselves satisfy the single failure criterion for each steam generator. As a fall-back position, one auxiliary feedwater flow channel may be backed up by a steam generator level channel.

2. Each auxiliary feedwater channel should provide an indicationof feed flow with an accuracy on the order of ±10 percent.

DISCUSSION AND CONCLUSIONS

Auxiliary feedwater flow indication for the Sequoyah unit is provided by a single flow indicating element (channel) in the individual AFW feed lines to each of the four steam generators. In additon, a single flow indicating element (channel) located in the discharge line of the steam driven AFW pump provides total flow indication from the steam driven pump into all steam generators (up to four) being fed by that pump when it is in operation. The flow channel associated with the steam driven pump is powered from either of two vital buses (uninterruptible, battery-backed); the other four flow channels are powered from reliable, nondivisional, emergency buses (but not from vital buses). The direct AFW flow indication arrangement for Sequoyah then is not safety grade nor does it satisfy the single failure criterion as specified in this NUREG-0578 position.

TVA has noted, however, that the direct flow indication arrangement provided is backed by safety grade steam generator water level indication. Taken together then, the combined (direct and indicrect) AFW flow indication capability does satisfy the single failure criterion. Further, the components (e.g., flow transmitters) and design employed in the direct flow indication channels are similar to those employed in safety grade systems. For example, flow transmitters are mounted on seismically qualified panels, and signal cabling is maintained separate from power cabling. Each direct AFW flow indication channel provides indication with an accuracy of approximately ±10 percent; and testability of all channels is a feature of the Sequoyah design.

The direct AFW flow indication arrangements provided for the Sequoyah unit does not by itself satisfy the "control grade" requirements specified in the NUREG-0578 position and clarifications, because the flow channels associated with the individual feed lines to each steam generator are not powered from a vital bus. They are, however, powered from either of two high-quality, nondivisional emergency power buses which satisfy the requirements of proposed Regulatory Guide 1.97, Revision 2, in this regard. Although the staff is now considering replacing the NUREG-0578 "vital bus" requirement with the Regulatory Guide 1.97 "emergency bus" requirement, the staff requires that the Sequoyah design satisfy the NUREG-0578 "control grade" AFW direct flow indication position and clarification.

II.E.4.1 Containment Penetrations (2.1.5.a - NUREG-0578)

POSITION

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment isolation systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR Part 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

CLARIFICATION

1. This requirement is only applicable to those plants whose licensing basis includes requirements for external recombiners or purge systems for post-accident combustible gas control of the containmbent atmosphere.

2. An acceptable alternative to the dedicated penetration is a combined design that is single-failure proof for containment isolation purposes and single-failure proof for operation of the recombiner or purge system.

3. The dedicated penetration or the combined single-failure proof alternative should be sized such that the flow requirements for the use of the recombiner or purge system are satisfied.

4. Components necessitated by this requirement should be safety grade.

5. A description of required design changes and a schedule for accomplishing these changes should be provided by January 1, 1980. Design changes should be completed by January 1, 1981.

DISCUSSION AND CONCLUSION

Sequoyah does not use external recombiners or purge systems for post-accident combustible gas control. The Sequoyah design has a manually actuated ESF recombiner system inside containment which is redundant and fully qualified.

This requirement is not applicable to Sequoyah.

II.F.1 Additional Accident Monitoring Instrumentation (2.1.8.b - NUREG-0578)

POSITION

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

1. Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions; multiple monitors are considered to be necessary to cover the ranges of interest.

   a. Noble gas effluent monitors with an upper range capacity of 10^5 µCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

   b. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (ALARA) concentrations to a maximum of 10^5 µCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

2. Since iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

3. In-containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be designed and qualified to function in an accident environment.

CLARIFICATION

The January 1, 1980 requirements were specifically added by the Commission and were not included in NUREG-0578. The purpose of the interim January 1, 1980 requirement is to assure that licensees have methods of quantifying radioactivity releases should the existing effluent instrumentation go offscale.

1. Radiological Noble Gas Effluent Monitors

A. January 1, 1980 Requirements

Until final implementation in January 1, 1981, all operating reactors must provide, by January 1, 1980, an interim method for quantifying high-level releases which meets the requirements of Table 2.1.8.b.1. This method is to serve only as a provisional fix with the more detailed, exact methods to follow. Methods are to be developed to quantify release rates of up to 10,000 Ci/sec for noble gases from all potential release points (e.g., auxiliary building, racwaste buidling, fuel handling building, reactor building, waste gas decay tank releases, main condenser air ejector, BWR main condenser vacuum pump exhaust, PWR steam safety valves and atmosphere steam dump valves and BWR turbine buildings) and any other areas that communicate directly with systems which may contain primary coolant or containment gases (e.g., letdown and emergency core cooling systems and external recombiners). Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such that measurements of individual sources which contribute to a common release point may not be necessary. For assessing radioiodine and particulate releases, special procedures must be developed for the removal and analysis of the radioiodine/particulate sampling media (i.e., charcoal canister/filter paper). Existing sampling locations are expected to be adequate; however, special procedures for retrieval and analysis of the sampling media under accident conditions (e.g., high air and surface contamination and direct radiation levels) are needed.

It is intended that the monitoring capabilities called for in the interim can be accomplished with existing instrumentation or readily available instrumentation. For noble gases, modifications to existing monitoring systems, such as the use of portable high-range survey instruments, set in shielded collimators so that they "see" small sections of sampling lines is an acceptable method for meeting the intent of this requirement. Conversion of the measured dose rate (mR/hr) into concentration (μCi/cc) can be performed using standard volume source calculations. A method must be developed with sufficient accuracy to quantify the iodine releases in the presence of high background radiation from noble gases collected on charcoal filters. Seismically qualified equipment and equipment meeting IEEE 279 is not required.

The licensee shall provide the following information on his methods to quantify gaseous releases of radioactivity from the plant during an accident.

TABLE 2.1.8.b.1

INTERIM PROCEDURES FOR QUANTIFYING
HIGH-LEVEL ACCIDENTAL RADIOACTIVITY RELEASES

. Licensees are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off-scale.

. Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.

- Provide shielding to minimize background interference.

- Use of an installed monitor (preferable) or dedicated portable monitor (acceptable) to measure the radiation.

- Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

1. Noble Gas Effluents

a. System/method description, including:

i. Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique.

ii. Monitoring/sampling locations, including methods to assure representative measurements and background radiation correction.

iii. A description of method to be employed to facilitate access to radiation readings. For January 1, 1980, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on iv., below.

iv. Capability to obtain radiation readings at least every 15 minutes during an accident.

v. Source of power to be used. If normal ac power is used, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

b. Procedures for conducting all aspects of the measurement/analysis, including:

i. Procedures for minimizing occupational exposures.

ii. Calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown.

iii. Procedures for dissemination of information.

iv. Procedures for calibration.

TABLE 2.1.8.b.2

HIGH RANGE EFFLUENT MONITOR

. Noble gases only

. Range (overlap with normal effluent instrument range):

- Undiluted containment exhaust	10^{+5} μCi/cc
- Diluted (> 10: 1) containment exhaust	10^{+4} μCi/cc
- Mark I BWR reactor building exhaust	10^{+4} μCi/cc
- PWR secondary containment exhaust	10^{+4} μCi/cc
- Buildings with systems containing primary coolant or gases	10^{+3} μCi/cc
- Other buildings (e.g., radwaste)	10^{+2} μCi/cc

. Not redundant - one per normal release point

. Seismic - no

. Power - vital instrument bus

. Specifications - per Regulatory Guide 1.97 and ANSI N320-1979

. Display;* continuous and recording with readouts in the technical support center (TSC) and emergency operations center (EOC)

. Qualifications - no

*Although not a present requirement, it is likely that this information may have to be transmitted to the NRC. Consequently, consideration should be given to this possible future requirement when designing the display interfaces.

2. Radioiodine and Particulate Effluents

A. For January 1, 1980 the licensee should provide the following:

1. System/method description, including:

   a. Instrumentation to be used for analysis of the sampling media with discussion on methods used to correct for potentially interfering background levels of radioactivity.

   b. Monitoring/sampling location.

   c. Method to be used for retrieval and handling of sampling media to minimize occupational exposure.

   d. Method to be used for data analysis of individual radionuclides in the presence of high levels of radioactive noble gases.

   e. If normal ac power is used for sampling collection and analysis equipment, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

2. Procedures for conducting all aspects of the measurement analysis, including:

   a. Minimizing occupational exposure.

   b. Calculational methods for determining release rates.

   c. Procedures for dissemination of information.

   d. Calibration frequency and technique.

DISCUSSION AND CONCLUSION

Monitors for radioactive effluents currently installed at Sequoyah are designed to detect and measure releases associated with normal reactor operations and anticipated operational occurrences. Such monitors are required to operate in radioactivity concentrations approaching the minimum concentration detectable with "state-of-the-art" sample collection and detection methods. These monitors comply with the criteria of Regulatory Guide 1.21 with respect to releases from normal operations and anticipated operational occurrences.

TABLE 2.1.8.b.3

HIGH RANGE CONTAINMENT RADIATION MONITOR

. Radiation: total radiation (alternate: photon only)

. Range:

- Up to 10^8 rad/hr (total radiation)
- Alternate: 10^7 R/hr (photon radiation only)
- Sensitive down to 60 keV photons*

. Redundant: two physically separated units

. Seismic: per Regulatory Guide 1.97

. Power: vital instrument bus

. Specifications: per Regulatory Guide 1.97, Rev. 2, and ANSI N320-1978

. Display: continuous and recording

. Calibration: laboratory calibration acceptable

*Monitors must not provide misleading information to the operators assuming delayed core damage when the 80 keV photon Xe-133 is the major noble gas present.

Radioactive gaseous effluent monitors designed to operate under conditions of normal operation and anticipated operational occurrences do not have sufficient dynamic range to function under release conditions associated with certain types of accident. General Design Criterion 64 of Appendix A to 10 CFR Part 50 requires that effluent discharge paths be monitored for radioactivity that may be released from postulated accidents.

The potential gaseous effluent release points at Sequoyah consist of the shield building vent, the steam safety valves, and the atmospheric steam dump valves.

As an interim measure for determination of high level noble gas releases, Sequoyah will place an area radiation monitor near the sample piping to the shield building vent monitor assembly. TVA will precalculate a relationship between noble gas concentrations in the sample piping, the observed monitor readings, and the observed air volume flow rate in the sield building vent to provide an estimate of gross radioactivity release rates. Procedures for the use of the interim monitoring system have now been submitted for staff review.

Interim procedures for monitoring of iodine and particulate gaseous effluents have now been provided to the staff.

The staff will review the interim procedures to determine their adequacy prior to approval of five-percent power.

II.F.2 Inadequate Core Cooling (2.1.3.b - NUREG-0578)

SUBCOOLING METER

POSITION

Licensees shall develop procedures to be used by the operator to recognize inadequate core cooling with currently available instrumentation. The licensee shall provide a description of the existing instrumentation for the operators to use to recognize these conditions. A detailed description of the analyses needed to form the basis for operator training and procedure development shall be provided pursuant to another short-term requirement, "Analysis of Off-Normal Conditions, Including Natural Circulation" (see Section 2.1.9 of NUREG-0578).

In addition, each PWR shall install a primary coolant saturation meter to provide on-line indication of coolant saturation condition. Operator instruction as to use of this meter shall include consideration that is not to be used exclusive of other related plant parameters.

CLARIFICATION

1. The analysis and procedures addressed in paragraph one above will be reviewed and should be submitted to the NRC "Bulletins and Orders Task Force" for review.

2. The purpose of the subcooling meter is to provide a continuous indication of margin to saturated conditions. This is an important diagnostic tool for the reactor operators.

3. Redundant safety-grade temperature input from each hot leg (or use of multiple core exit in T/C's) are required.

4. Redundant safety-grade system pressure measures should be provided.

5. Continuous display of the primary coolant saturation conditions should be provided.

6. Each PWR should have: (A) safety-grade calculational devices and display (minimum of two meters), or (B) a highly reliable single channel environmentally qualified, and testable system plus a backup procedure for use of steam tables. If the plant computer is to be used, its availability must be documented.

7. In the long term, the instrumentation qualifications must be required to be upgraded to meet the requirements of Regulatory Guide 1.97 (Instrumentation for Light Water Cooled Nuclear Plants to Assess Plant Conditions During and Following an Accident) which is under development.

8. In all cases appropriate steps (electrical, isolation, etc.) must be taken to assure that the addition of the subcooling meter does not adversely impact the reactor protection or engineered safety features systems.

9. The attachment provides a definition of information required on the subcooling meter.

ADDITIONAL INSTRUMENTATION

POSITION

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement those devices cited in the preceding section giving an unambiguous, easy-to-interpret indication of inadequate core cooling. A description of the functional design requirments for

INFORMATION REQUIRED ON THE SUBCOOLING METER

Display

Information Displayed (T-Tsat, Tsat, Press, etc.) ____________
Display Type (Analog, Digital, CRT) ____________
Continuous or on Demand ____________
Single or Redundant Display ____________
Location of Display ____________
Alarms (include setpoints) ____________
Overall uncertainty (°F, PSI) ____________
Range of Display ____________
Qualifications (seismic, environmental, IEEE 323) ____________

Calculator

Type (process computer, dedicated digital or analog calc.) ____________
If process computer is used specify availability, (% of time) ____________
Single or redundant calculators ____________
Selection Logic (highest T., lowest press) ____________
Qualifications (seismic, environmental, IEEE 323) ____________
Calculational Technique (Steam Tables, Functional Fit, ranges) ____________

Input

Temperature (RTD's or T/C's) ____________
Temperature (number of sensors and locations) ____________
Range of temperature sensors ____________
Uncertainty* of temperature sensors (°F at 1) ____________
Qualifications (seismic, environmental, IEEE 323) ____________
Pressure (specify instrument used) ____________
Pressure (number of sensors and locations) ____________
Range of Pressure sensors ____________
Uncertainty* of pressure sensors (PSI at 1) ____________
Qualifications (seismic, environmental, IEEE 323) ____________

Backup Capability

Availability of Temp & Press ____________
Availability of Steam Tables etc. ____________
Training of operators ____________
Procedures ____________

*Uncertainties must address conditions of forced flow and natural circulation.

the system shall also be included. A descriptic of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

CLARIFICATION

1. Design of new instrumentation should provide an unambiguous indication of inadequate core cooling. This may require new measurements to or a synthesis of existing measurements which meet safety-grade criteria.

2. The evaluation is to include reactor water level indication.

3. A commitment to provide the necessary analysis and to study advantages of various instruments to monitor water level core cooling is required in the response to the September 13, 1979 letter.

4. The indication of inadequate core cooling must be unambiguous, in that, it should have the following properties:

   a. It must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high void fraction pumped flow as well as stagnant boil off).

   b. It must not erroneously indicate inadequate core cooling because of the presence of an unrelated phenomenon.

5. The indication must give advanced warning of the approach of inadequate core cooling.

6. The indication must cover the full range from normal operation to complete core uncovering. For example, if water level is chosen as the unambiguous indication, then the range of the instrument (or instruments) must cover the full range from normal water level to the bottom of the core.

DISCUSSION AND CONCLUSIONS

This item requires: the addition of a subcooling meter; procedures and training related to the use of existing instrumentation to detect inadequate core cooling and new instrumentation and procedures to provide an unambiguous indication of inadequate core cooling.

TVA has committed to providing a subcooling meter which meets NRC requirements as stated in NUREG-0578 and in the October 30, 1979 clarification letter to all licensees and applicants. The TVA system will use the plant computer to calculate margin to saturation using input from the highest of four hot leg temperature measurements and the pressurizer pressure. The margin to saturation will be continuously displayed on a computer output trend recorder in the main control room. This system is acceptable. In our review of the Sequoyah Emergency Procedures and Abnormal Occurrence procedures we will assure that appropriate references to the use of the subcooling meter are included.

TVA has committed to providing emergency procedures to respond to a condition of inadequate core cooling. As the first step in the development of these procedures, the Westinghouse owners group has provided an analysis and guidelines for an inadequate core cooling procedure. This requirement is consistent with the position described in I.C.1. A number of steps remain before this item will be completed, specifically: (1) TVA must address staff concerns relative to the applicability of the owners group work to a UHI plant; (2) TVA must incorporate the owners group guidelines into the Sequoyah procedures and submit it for staff review; and (3) TVA must incorporate the new procedures into its training program.

In terms of new instrumentation to provide an unambiguous indication of inadequate core cooling, TVA has proposed to install a system of reactor vessel pressure drop measurements to be used in combination with the existing core exit thermocouples and is soon to be installed subcooling meter. TVA has proposed to measure differential pressure between the top of the reactor vessel and the bottom of two of the four hot legs. In addition, the pressure drop between the top of the reactor vessel and the bottom of the reactor vessel will be monitored on two narrow range and two wide range instruments. The system is intended to function as follows: with the reactor coolant pumps off, the pressure drop between the top of the vessel and the bottom of the hot legs will provide an indication of the collapsed liquid level (the equivalent liquid level without voids in the two-phase region) in the reactor vessel upper head; and the pressure drop between the top and the bottom of the vessel would indicate the collapsed liquid level in the vessel (this would be read on the narrow range instrument in terms of feet of liquid). With the reactor coolant pumps running, the pressure drop from the top to the bottom of the vessel would provide an approximate indication of the void fraction in the vessel (this would be read on the wide drange instrument as percent of full flow ΔP with the vessel filled with water).

The relationship between vessel differential pressure and core cooling involves complex phenomena, especially with one or more reactor coolant pumps operating. The adequacy of the system to indicate core cooling has not been demonstrated for conditions including: level swell, two-phase pumped flow; flow blockage; system dynamics (including blowdown). TVA has met our requirement to provide a commitment to installing instrumentation to detect inadequate core cooling and our requirement to provide a system design before fuel loading. However, we cannot find the design of that system acceptable at this time. The staff will continue to review the TVA design and will complete its review in sufficient time to allow for installation of an acceptable system by January 1981. The analyses and procedures related to the use of the new instrumentation must also be submitted and approved by NRC prior to January 1, 1981 which is the implementation date for the installation of the new instrumentation.

II.G Emergency Power For Pressurizer Equipment (2.1.1 - NUREG-0578)

POSITION

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 30 of Appendix A to 10 CFR Part 50 for the event of loss of offiste power, the following positions shall be implemented:

1. Motive and control components of the power-operated relief valves (PORVs) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

2. Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

3. Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.

4. The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

CLARIFICATION

1. While the prevalent consideration from TMI Lessons Learned is being able to close the PORV/block valves, the design should retain, to the extent practicable, the capability to open these valves.

2. The motive and control power for the block valve should be supplied from an emergency power bus different from that which supplies the PORV.

3. Any changeover of the PORV and block valve motive and control power from the normal offiste power to the emergency onsite power is to be accomplished manually in the control room.

4. For those designs where instrument air is needed for operation, the electrical power supply requirement should be capable of being manually connected to the emergency power sources.

DISCUSSION AND CONCLUSION

We have reviewed the applicants submittal and discussed the design details with them.

We find the current Sequoyah emergency power supply design for pressurizer level and relief and block valves to be in conformance with all requirements and clarifications of Lessons Learned Item 2.1.1 and is, therefore, acceptable.

II.K.1 IE Bulletins on Measures to Mitigate Small Break LOCAs and Loss of Feedwater

Following the Three Mile Island, Unit 2, (TMI-2) accident, the NRC issued a number of Office of Inspection and Enforcement (IE) bulletins, which specified actions to be taken by power reactor licensees to avoid occurrence of an event similar to that which occurred at TMI-2. By letters dated April 14 and April 18, 1979, we transmitted IE Bulletins 79-06A and 79-06A (Revision 1), respectively, to all licensees with Westinghouse-designed operating plants.

By letter dated June 1, 1979, S. A. Varga to H. G. Parris, the NRC staff requested TVA to provide responses to IE Bulletins 79-06A and 79-06A, Revision 1. In the July 12, 1979 letter, L. M. Mills to Dominic B. Vassallo, TVA provided responses to these two bulletins for the Sequoyah plant. Subsequent to its original response to these IE bulletins, TVA became a participating member of the Westinghouse Owners Group, which was formed to effect resolution of a number of TMI-2-related issues with the staff.

We have reviewed TVA's July 12, 1979 response to IE Bulletins 79-06A and 79-06A, Revision 1, along with additional information provided by TVA since their original response. The results of our review are summarized in this section.

Based on our review of TVA's July 12, 1979, response, we find that the management review of the TMI-2 accident and subsequent review program conducted for all licensed operators satisfactorily addressed the concerns expressed in Bulletin Action Item No. 1. TVA's response to this action item is therefore acceptable.

TVA's original response to Bulletin Action Item No. 2 regarding void formation recognition and the resulting effect on natural circulation capability has been supplemented by the TVA response to Item 2.1.9 of NUREG-0578 regarding inadequate core cooling and their January 25, 1980 response to Bulletins and Orders Task Force Report Item 3.2.3.b-Instrumentation to Verify Natural Circulation. Our evaluation of Item 2.1.9 of NUREG-0578 is contained in Section I.C.1 of this report. TVA is participating in the effort sponsored by the Westinghouse Owners Group to develop guidelines for emergency procedures regarding natural circulation for plants with upper head injection (UHI). TVA has incorporated the staff-approved Westinghouse generic guidelines for emergency procedures regarding small break LOCAs for non-UHI plants into the Sequoyah plant procedures. In addition, TVA will perform certain tests involving natural circulations as part of the Sequoyah special test program described in Section I.G.1 of this report. We find TVA's response to Bulletin Action Item No. 1 acceptable.

In response to Bulletin Action Item No. 3, TVA tripped the pressurizer low level bistables to permit safety injection on low pressurizer pressure alone. A design modification to be completed by fuel loading has been completed to modify the protective logic to initiate safety injection on 2 out of 3 low pressurizer pressure signals regardless of pressurizer level. In addition, all applicable instructions were revised to require manual initiation of safety injection when 2 out of 3 pressurizer pressure signals reach the actuation setpoint. We find that these actions constitute an acceptable response to Bulletin Action Item No. 3.

TVA has performed the review of containment isolation design and procedures required by Bulletin Action Item No. 4. They have determined that containment isolation is effected of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection. Based on our review of TVA's response to Action Item No. 4, we find it to be acceptable.

Since the auxiliary feedwater system at the Sequoyah plant is automatically initiated, Bulletin Item No. 5 is not applicable to Sequoyah.

TVA's response to Bulletin Action Item No. 6 described the indicators of power-operated relief valve (PORV) position available to the operators and the instructions given to the operators regarding their interpretation and use. This information has been augmented by TVA's response to Items 2.1.1 and 2.1.3.a of NUREG-0578 regarding PORV and block valve emergency power supplies and direct indication of PORVs. (See Sections II.D.5 and II.G of this report). We find that TVA has provided an acceptable response for Bulletin Action Item No. 6.

In response to part (a) of Action Item No. 7, TVA stated that the required review of operating procedures and training instructions would be performed before fuel loading. This review will ensure that operators are instructed not to override automatic operations of the engineered safety features, unless their continued operation will result in unsafe plant conditions or until the plant is clearly in a stable, controlled state, and engineered safeguards are no longer required. This is an acceptable response to part (a) of Action Item No. 7.

Item Part (b) of Bulletin Action Item 7 was superseded by HPI termination criteria contained in the staff-approved Westinghouse generic guidelines for emergency procedures regarding small break LOCAs for non-UHI plants. TVA has incorporated these guidelines into the Sequoyah plant procedures and is participating in the Owners Group effort to develop generic guidelines for UHI plants (currently under staff review in WCAP-9639). The status of our review of WCAP-9639 is reported in Section I.C.1 of this report. We find that TVA has responded in an acceptable manner to part (b) of Bulletin Action Item No. 7.

Part (c) of Bulletin Action Item No. 7 has been superseded by IE Bulletin 79-06c as augmented by NUREG-0623. Our review of TVA's response to Bulletin 79-06C is discussed later in this section.

From their response to part (d) of Bulletin Action Item No. 7, TVA has indicated that operators are provided additional information and instructions to not rely upon pressurizer level alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions. This is an acceptable response to the concerns expressed in part (d).

In response to Bulletin Action Item No. 8, TVA performed a review of all safety-related valve positions, positioning requirements, and positive controls to ensure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. This review included related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes. TVA also described their current administrative procedures related to this concern. We find that their response has adequately expressed the concerns in Action Item No. 8.

In response to Action Item No. 9, TVA has reviewed operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to ensure that undesired pumping, venting, or other release of radioactive liquids and gases will not occur inadvertently (e.g., by the resetting of engineered safety features instrumentation). All such systems were identified. As a result of this review, TVA will design and install radiation detectors which will automatically isolate the reactor coolant drain tank and the floor and equipment drain surge when high radiation is detected. Design details will be submitted for staff review. We find that TVA's response to Bulletin Action Item No. 9 is acceptable.

In response to Action Item No. 10, TVA performed the required review and modification of maintenance and test procedures to ensure that they require (1) verification of the operability, by test or inspection, of redundant safetyrelated systems prior to the removal of any safety-related system from service, (2) verification of the operability of all safety-related systems when they are returned to service following maintenance or testing, and (3) explicit notification of involved reactor operations presonnel whenever a safety-related system is removed from and returned to service. Pending confirmation of the completion of this review, we find TVA's response to Bulletin Action Item No. 10 acceptable.

TVA has incorporated the requirements of Bulletin Action Item No. 11 into the Sequoyah plant procedures. Their response to this item is therefore acceptable.

In response to Bulletin Action Item 12, TVA described the methods currently available for dealing with hydrogen in the reactor coolant system. TVA committed to revise plant procedures to include instructions to the operator for dealing with noncondensible gases in the primary system. The Westinghouse Owners Group is currently developing guidelines for such procedures as part of its generic response to Item 2.1.9 of NUREG-0578 regarding inadequate core cooling. This commitment represents an acceptable response to the bulletin concern. TVA also described the methods used to deal with amounts of hydrogen gas in the primary containment following a LOCA. We have reviewed the method of combustible gas control in containment nd found it acceptable. Therefore, TVA has adequately responded to Bulletin .ion Item No. 12.

In response to Action Item 13, TVA identified the technical specification change needed to reflect tripping the pressurizer level bistables. Another revision to the technical specifications was later required to accommodate the change in the safety injection initiation logic identified in the response to Action Item No. 3. We find TVA's response to Item 13 acceptable.

In summary we find that TVA has taken appropriate actions to meet the requirements of IE Bulletins 79-06A, and 79-06A, Revision 1.

IE Bulletin 79-06C was issued to all licensees with Westinghouse-designed operating plants on July 26, 1979. By letter dated, January 31, 1980 provided a response to Items 1.A and 1.B of the short-term requirements of Bulletin 79-06C. Since items 2 through 5 of the short-term requirements are covered by Item 2.1.9 of NUREG-0578, our evaluation of these items may be found in Section I.C of this report. Based on our review of the January 31, 1980 submittal, we find TVA's response to the short-term requirements 1.A and 1.B of IE Bulletin 79-06C acceptable.

II.K.3 Generic Review Matters - Small Break LOCAs and Loss of Feedwater Accidents

As part of the overall safety review, we evaluated the Sequoyah auxiliary feedwater system. We found that the AFW system meets Section 10.4.9 of the Standard Review Plan, including power diversity requirements. TVA in their letter dated January 25, 1980, stated that they have implemented all the "short-term" recommendations made by the Bulletins and Orders Task Force and identified in NUREG-0611. However, consistent with the provisions of the Task Action Plan, we are implementing only the short-term AFW system recommendations as requirements for licensing in the case of Sequoyah.

We have not yet reevaluated the AFW system and we have not yet reviewed a system reliability analysis that is being performed by the applicant as recommended by the Bulletins and Orders Task Force. However, based on such analyses performed on similar Westinghouse-designed plants, we expect that the modifications required to improve the reliability of the system will be relatively minor, if any are indeed required. On this basis, the staff requires that the "short term" generic AFW system recommendations from NUREG-0611 be implemented before full power. TVA has committed to implement the requirements.

Our review of small break LOCAs for the Sequoyah plant is discussed in Section I.C.1 of this report.

The remainder of the recommendations identified in NUREG-0611 will be implemented with an appropriate implementation schedule upon approval by the Director of the Office of Nuclear Reactor Regulation.

III. EMERGENCY PREPARATIONS AND RADIATION PROTECTION

III.A.2 Improve Licensee Facilities for Responding to Emergencies

III.A.1.2.a Onsite Technical Support Center (2.2.2.b - NUREG-0578)

POSITION

Each operating nuclear power plant shall maintain an onsite technical support center (TSC) separate from and in close proximity to the control room that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the technical support center. Records that pertain to the as-built conditions and layout of structures, systems and components shall be readily available to personnel in the TSC.

CLARIFICATION

1. By January 1, 1980, the licensee shall meet the items that follow.

   a. Establish a TSC and provide a complete description,

   b. Provide plans and procedures for engineering/management support and staffing of the TSC,

   c. Install dedicated communications between the TSC and the control room, near site emergency operations center, and the NRC,

   d. Provide monitoring (either portable or permanent) for both direct radiation and airborne radioactive contaminants. The monitors should provide warning if the radiation levels in the support center are reaching potentially dangerous levels. The licensee should designate action levels to define when protective measures should be taken (such as using breathing apparatus and potassium iodide tablets, or evacuation to the control room),

   e. Assimilate or ensure access to technical data, including the licensee's best effort to have direct display of plant parameters, necessary for assessment in the TSC,

   f. Develop procedures for performing this accident assessment function from the control room should the TSC become uninhabitable, and

   g. Submit to the NRC a longer range plan for upgrading the TSC to meet all requirements.

Each licensee is encouraged to provide additional upgrading of the TSC as soon as practical, but no later than January 1, 1981.

It is recommended that the TSC be located onsite in close proximity to the control room.

The TSC should be large enough to house 25 persons.

The center should be activated in accordance with the "Alert" level as defined in the NRC document "Draft Emergency Action Level Guidelines," NUREG-0610 dated September 1979.

The instrumentation to be located in the TSC should be qualitatively comparable to that in the control room.

The power supply to the TSC instrumentation should be reliable and of a quality compatible with the TSC instrumentation requirements.

Each licensee should establish the technical data requirements for the TSC. As a minimum, data should be available to permit the assessment of:

Plant safety systems parameters
In-plant radiological parameters
Offsite radiological parameters

Each licensee should review current technology as regards transmission of those parameters identified for TSC display.

The center should be well built in accordance with sound engineering practice. However, in the event that access to the center is prevented, each licensee should prepare a backup plan for responding to an emergency from the control room.

The licensee should provide protection for the technical support center personnel from radiological hazards.

DISCUSSION AND CONCLUSIONS

TVA has designated the relay room next to the control room as the site technical support center. The habitability system for this area is the same one provided for the main control room. The TSC is sufficiently large to accommodate 25 people.

Information which has been provided indicates that communication links between the TSC and the control room, the emergency operations center in Chattanooga, and the NRC have been installed.

TVA has now committed to providing a closed circuit television system to display parameters in the TSC. A portable camera, normally stored in the TSC, will be utilized by a camera man in constant communication with the TSC to scram the control room as requested to provide specific parametric information.

The TSC will be activated in accordance with the Sequoyah Emergency Plan. TVA has identified the personnel who will report to and make up the technical support center staff if the emergency plan is activated during the day. If the emergency plan is activated outside of regular work hours, TSC staffing will be at the discretion of the Site Emergency Director.

Personnel staffing the TSC will have an extensive set of reference materials available to them.

The Radiological Emergency Plan has been amended to establish the TSC. As defined in the REP, the role of the TSC is to serve as an assembly/work area for designated support individuals knowledgable of and responsible for engineering and management support of reactor operations in the event of an accident. The REP further describes the habitability, communications and availability of technical information in the TSC.

However, the Radiological Emergency Plan (REP) also makes it clear that the TSC will play a very small functional role in the event of an emergency. The Site Emergency Director and his deputies will operate from the main control room. The Communications Room has been designated as the first alternate control center. We have discussed with TVA the elimination of approximately six people from the list of those required by the REP to report to the Control Room. This will reduce the congestion in the control room and these six people can report to the TSC which is immediately adjacent to the control room and therefore will be available for assignment from that point.

Portable radiation monitors will be provided for the TSC until permanent monitors are available.

TVA has committed to provide prior to fuel load, a status report of their long range plan for upgrading the TSC to meet all requirements.

Based on providing the television system for parameter display in the TSC and a reduction in the number of people reporting directly to the control room, we find the TSC acceptable for fuel load and, as discussed below, operations up to January 1, 1981.

The staff has concluded, however, that the full intent of the TSC concept can be met only when the Site Emergency Director performs his role independent of the Control Room and preferably in the TSC. We will require that this transition

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TII.A.3.3 Communications

Position

Two direct dedicated telephone lines must be operative between the plant and the NRC.

Discussion

The applicant has satisfied this requirement.

III.B.1 NRC Approval of Overall Emergency Preparedness

Refer to Section III.A.3-12 for discussion.

III.D Worker Protection - Health Physics Program Improvements

As a result of analyses by the NRC staff, by the Presidential Commission on Three Mile Island, by the NRC Special Inquiry Group and others, it has been determined that it is necessary to improve nuclear power plant worker radiation protection to allow workers to take effective action to control the course and consequences of an accident, as well to keep exposures as low as reasonably achievable (ALARA) during normal operation and accidents, by improving radiation protection plans, health physics, inplant radiation monitoring, control room habitability, and radiation worker exposure data base.

We require all licensees to prepare and implement radiation protection plans (RPP) which will incorporate commitments to criteria in existing Regulatory Guides, including Regulatory Guide 8.8, and Standard Review Plan Chapter 12, as well as criteria to be developed from analysis of the IE appraisal of health physics programs at all operating sites. The RPP will be integrated into the emergency plan to assure worker protection without unduly restricting accident mitigation and recovery. Licensees are to improve systems for monitoring inplant radiation and airborne radioactivitiy with instruments appropriate for a broad range of routine and emergency conditions and to provide calibration methods for such instruments. We also will expand the requirements for nuclear facility radiation worker records to permit later epidemiologic studies of worker health.

For Sequoyah Units 1 and 2, we will require the implementation of a radiation protection plan by September 1981, improvements in radiation monitoring by June 1982, and implementation of improved radiation record collection by March 1983.

III.D.2.4.a Area Radiation Monitors (Partial) (2.1.8.c - NUREG-0578)

POSITION

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant plant personnel may be present during an accident.

CLARIFICATION

Use of Portable versus Stationary Monitoring Equipment

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments for the following reasons:

a. The physical size of the auxiliary/fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

b. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

c. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

d. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

Iodine Filters and Measurement Techniques

A. The following are short-term recommendations and shall be implemented by the licensee by January 1, 1980. The licensee shall have the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single channel analyzer (SCA). The SCA window should be calibrated to the 365 keV of ^{131}I. A representative air sample shall be taken and then counted for ^{131}I using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

B. By January 1, 1981, the licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. This area should be ventilated with clean air containing no airborne radionuclides which may contribute to inaccuracies in analyzing the sample. Here, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble bases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples and effluent charcoal samples under accident conditions.

DISCUSSION AND CONCLUSION

The applicant states that Sequoyah has portable low volume air samples equipped with particulate filters and charcoal adsorbers. Collected samples are analyzed by gross radioactivity analysis and by gamma radiation spectrum analysis.

10 CFR Part 20 provides criteria for control of exposures of individuals to radiation in restricted areas, including airborne iodine. Since iodine concentrates in the thyroid gland, airborne concentrations must be known in order to evaluate the potential dose to the thyroid. If the airborne iodine concentration is

IV. RECOMMENDATIONS OF NRC SPECIAL INQUIRY GROUP

Item 1 Control Room Design Review

The NRC staff, together with our consultants from the Essex Corporation, have reviewed the control room design for the Sequoyah plant to assess the degree to which that design reflects human factors considerations. As expected, we identified a number of deficiencies. These include inadequacies in the design of the annunciator system, insufficient highlighting of important instrumentation displays, and control room layout problems. The significance of these deficiencies is being evaluated to determine what, if any, modifications are required prior to licensing.

Item 2 Power Ascension Test Schedule

The applicant has submitted a schedule of startup and power ascension tests for the facility which includes an additional nine special tests incorporating low power natural circulation. It is IE's intention that the Senior Resident Inspector will witness the initial performance of each of the special tests and has much of the normal startup and power ascension tests as practicable. This effort will be augmented, as necessary, by other Region II inspection.