NUREG-0517
Supplement No. 5

Safety Evaluation Report
related to the operation of Salem Nuclear Generating Station, Unit No. 2

Docket No. 50-311

Public Service Electric and Gas Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1981

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1.0 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

In October 1974, the U.S. Atomic Energy Commission (AEC) issued its Safety Evaluation Report (SER) regarding the application by the Public Service Electric and Gas Company (PSE&G or licensee) for licenses to operate the Salem Nuclear Generating Station, Units 1 and 2. Since then, the Nuclear Regulatory Commission (NRC) has issued Supplements 1 through 4 which documented the resolution of several outstanding issues in further support of the licensing activities. Further review of the Unit 2 operating license application resulted from a number of studies performed following the accident at the Three Mile Island Unit 2 (TMI-2) reactor plant.

On April 18, 1980, a fuel loading and low power testing license was issued for Salem Unit 2 based, in part, upon requirements established for the TMI-2 accident. Initially, the license permitted fuel loading and zero power testing. The license was subsequently amended: Amendment No. 2, dated August 22, 1980, permitted the licensee to perform the low power test program identified in Section 8.16 of Appendix A to the license at power levels not to exceed 5 percent of rated core thermal power. A similar licensing action was taken on both the Sequoyah Nuclear Plant Unit 1 and the North Anna Power Station Unit 2. Amendment Nos. 1, 3, and 4 to the license involved minor modifications to the Salem Unit 2 Technical Specifications.

The purpose of this supplement is to further update our Safety Evaluation Report by providing (1) our evaluation of additional information submitted by the licensee since the issuance of Supplement No. 4 to the Safety Evaluation Report, (2) our evaluation and status of the non-TMI-2 outstanding issues identified in Section 1.7 of Part I of SER Supplement No. 4, (3) our evaluation of TMI-2 requirements which must be completed prior to the issuance of a full power operating license, (4) our evaluation of dated requirements which the licensee must implement by the dates identified in NUREG-0737, "Clarification of TMI Action Plan Requirements," and (5) our evaluation of additional information for those actions of the Safety Evaluation Report where further discussion or changes are in order.

Our review of TMI-2 requirements is based on a compilation of those requirements that have been specifically approved by the Commission for implementation. The requirements are derived from NRC's Action Plan (NUREG-0660) and are found in NUREG-0737, "Clarification of TMI Action Plan Requirements." The Salem Nuclear Generating Station Unit 2 was measured against the applicable requirements of Title 10 of the Code of Federal Regulations (10 CFR) as augmented by these requirements.

As part of our review of Salem Unit 2 for compliance with the Commission's regulations, we requested the licensee to verify that Salem Unit 2 meets the applicable requirements in 10 CFR Parts 20, 50, and 100 except for those instances where specific exemptions were approved by the staff as delineated in the Salem 2 license. The licensee responded to this request with a letter dated September 3, 1980, which contained a comparison of Salem Unit 2's compliance with the regulations.

Accordingly, PSE&G stated in a letter dated September 9, 1980, that Salem Unit 2 complies with the applicable regulations with the exception of those instances where specific exemptions or alternate means have been justified by the licensee and approved by the staff. Based on our review of the licensee's response and our audit of their application for an operating license with regard to all applicable regulations of the Commission, we have determined that Salem Nuclear Generating Station Unit 2 will operate in conformity with the provisions of the Act, and the rules and regulations of the Commission, and that there is reasonable assurance that the activities that would be authorized by the operating license for this plant can be conducted without endangering the health and safety of the public.

Each of the following sections of this supplement is numbered the same as the corresponding section of the Safety Evaluation Report and Supplements No. 1-4, except Section 22.0 which addresses TMI-2 requirements and Section 23.0 which presents our conclusions.

Each section is supplementary to and not in lieu of the discussion in the Safety Evaluation Report and Supplements No. 1-4 thereto, except where specifically noted. Appendix A is a continuation of the chronology of principal actions related to the processing of the application. Appendix F contains the Emergency Preparedness Evaluation Report.

As a result of our review, certain matters remain outstanding at the time of issuance of this report. Since we have not completed our review and reached our final position in these areas, we consider these matters to be open. We expect to complete our review prior to issuance of a full-power operating license and will report the results of our review in a supplement to the Safety Evaluation Report. The open items are addressed below:

(1) The Federal Emergency Management Agency (FEMA) is reviewing the State and Local emergency plans. The NRC staff must review the FEMA findings and determinations prior to issuance of a full power license.

(2) We require that a successful emergency response exercise be conducted to test the emergency preparedness plans.

(3) We require that the deficiencies identified in our Emergency Preparedness Evaluation Report (Appendix F to this supplement) be corrected.

(4) There are a number of items that must be completed prior to operation above five percent power (e.g., completion of the training portion of the Special Low Power Test Program, completion of the modifications related to the control room design review). These items have been included as conditions to the Salem Unit 2 License.

Since the issuance of a fuel loading and low power testing license on April 18, 1980, The Licensee has completed several milestones. A list of the significant milestones are as follows:

(1) Completion of initial fuel loading: May 27, 1980;

(2) Initial criticality: August 2, 1980;

(3) Initiation of Low Power Test Program: August 24, 1980.

The licensee completed each of the tests in the Low Power Test Program (LPTP) prior to August 30, 1980 at which time Salem 2 was cooled down due to a leak in the control rod drive mechanism. Salem 2 has been in a cold shutdown condition since that time. The training portion of the LPTP will be completed prior to operation above 5% power.

3.0 DESIGN CRITERIA-STRUCTURES, COMPONENTS EQUIPMENT AND SYSTEMS

3.5. Missile Protection Criteria

3.5.1 Turbine Missiles

During November 1979, the NRC became aware of a problem of stress corrosion cracking in the rotor discs of Westinghouse nuclear service low pressure turbines. Meetings were held with Westinghouse and owners of Westinghouse nuclear service turbines to explore the probable extent and severity of the problem. Westinghouse initially recommended early inspection of turbines that had long operating times, and particularly those machines with discs of marginal material properties and a history of steam or secondary water chemistry problems. Subsequently, inspections were performed on about eighteen more operating nuclear service Westinghouse turbines, with indications of cracking, some severe, found in most of them. Investigations are continuing. The licensee has provided information on the material properties of the Unit 2 low pressure turbine discs, as well as calculations of critical crack sizes and predicted crack growth rates in these discs. The method used by Westinghouse to predict crack growth rates for the licensee is based on evaluating all of the cracks found to date in Westinghouse turbines, past history of similar turbine disc cracking, and results of laboratory tests. The prediction method takes into account two main parameters; the yield strength (and stress) of the disc, and the temperature of the disc at the bore area where the cracks of concern are occurring.

We have evaluated the Westinghouse data and calculations submitted by the licensee, and in addition, performed our own calculations for crack growth and critical crack size. On the basis of our evaluation, we conclude that the Salem 2 low pressure turbine rotor discs satisfy the requirements of General Design Criteria 1 and 4 of Appendix A to 10 CFR 50 and that Salem Unit 2 may be safely operated until the second refueling outage, at which time the LP turbine discs will be inspected.

3.7 Seismic Design

3.7.1 Seismic Stress Analysis of Safety Related Piping

In Section 3.7.1 of Supplement No. 4 to the Safety Evaluation Report (April 1980), we stated that before Salem Unit 2 exceeded 5 percent power, we must approve the licensee's evaluation with respect to our Office of Inspection and Enforcement Bulletin 79-07, "Seismic Stress Analysis of Safety Related Piping."

On September 10, 1980, we received a submittal from PSE&G which stated that its piping evaluation was complete and that all required hardware changes had been made. We had previously approved the analytical techniques which the licensee used in this evaluation. We have not totally completed our benchmarking of PSE&G's computer program; however, the work completed to date indicates that no problems are expected. We feel that the remaining benchmarking will merely be confirmatory in nature.

Therefore, based upon our evaluation of PSE&G's work, we approve the licensee's actions concerning IE Bulletin 79-07. Since our continuing review of the PSE&G computer program is only confirmatory, we conclude that this issue is sufficiently resolved for full-power operation.

3.8 Design of Category I Structures

3.8.3 Category I Masonry Walls

Seven safety related masonry walls at the Salem Generating Station Unit 2 have been identified by the licensee as walls not conforming to their design drawings/specification. These walls are located as follows:

1. There is one auxiliary building masonry wall at elevation 100 feet 0 inches on column line 14, separating Unit 1 from Unit 2. This wall is approximately 30 feet long by 20 feet high. There are seven (7) supports for 2 inch control air lines mounted on this wall: two (2) on the Unit 1 side of the wall and five (5) on the Unit 2 side of the wall. These air lines are classified as seismic Category I.

2. There is one masonry wall over the doorway in the corridor adjacent to the wall described in (1) above. These walls do not support safety related equipment but the safety related cable trays penetrating through these walls may be adversely affected by their failure.

3. There are four (4) masonry walls enclosing a battery room in each unit. These walls do not support any equipment but their failure may have an adverse effect on the safety related batteries and equipment adjacent to the walls.

4. There is a masonry wall in the control room of each Unit. These walls do not support safety related equipment but they are in the immediate vicinity of cabinets housing seismic Category I instrumentation and, therefore, their failure may be of consequence to the safety of the plant.

A meeting was held on November 20, 1980, between the NRC staff and representatives of PSE&G to discuss the above listed masonry walls. A site tour was held prior to the meeting to examine the walls under investigation. During the meeting, the licensee stated that there were no design criteria or QA/QC programs established for the initial construction of the masonry walls. The tour confirmed the as-built condition of the walls as follows:

1) Walls surrounding battery room - some horizontal reinforcement bars are missing;

2) Wall in control room area - horizontal reinforcement bars in approximately every other joint are missing; vertical expansion joint is present; walls are in close proximity to safety-related cable trays and safety related cabinets;

3) Auxiliary building corridor wall between Units 1 and 2 - horizontal reinforcement bars are randomly missing; one void was found; safety-related control air piping is supported by wall (7 hangers); wall is in close proximity to safety-related cable trays;

4) Auxiliary building doorway wall - horizontal reinforcement bars are randomly missing; wall is in close proximity to safety-related cable trays.

The licensee and its consultant, Compu-Tech, performed an evaluation of the as-built capacity of the above identified masonry walls utilizing the following evaluation criteria:

1. The design criteria were generally based on the "Building Code Requirements for Concrete Masonry Structures," ACI-531.

2. Salem 2 FSAR load combination equations were used.

3. The values of the allowable stresses of the material, in some cases, were based on the available information from the supplier of the masonry and/or applicable test data.

4. Seismic loads were based on the damping values of two percent for OBE and five percent for the DBE.

5. The analysis was performed using the finite element analysis with an assumption of uncracked masonry. Working stress design method was used in the analysis. The allowable tensile stress carried by masonry was on the order of 25 psi.

6. Stresses resulting from each piece of equipment weighing more than 100 pounds were combined with the inertial loads of the walls using the absolute sum method. If the total weight of attached equipment was less than 100 pounds its effect on the wall was neglected.

The interim NRC masonry wall evaluation criteria were also presented to and discussed with the licensee and its consultant. The major difference between the licensee proposed criteria and the staff interim criteria lies in the allowable stresses to be used in the wall capacity evaluation. For an OBE, the licensee's criteria allow up to 40 psi in tension, whereas, the staff criteria allow only 25 psi for unreinforced masonry and zero tensile stress for reinforced masonry. For an SSE, the staff criteria also call for zero allowable tensile stress for all masonry walls. These differences in criteria require future resolution.

The licensee is in the process of implementing a series of specific wall strengthening actions which resulted from their evaluation based on their criteria. The remedial actions are:

1. Battery room enclosure: No action is planned because an analysis demonstrated that the enclosure meets the licensee's criteria.

2. Control room wall: Installation of two vertical steel columns, one on each side of the expansion joint. These columns will be tied to the masonry walls by means of a system of bolts and plates.

3. Wall separating the two units at Elev. 100 feet 2 inches: Installation of three (3) vertical columns at about seven to nine foot intervals. These columns will be braced against the adjacent reinforced concrete walls by means of struts.

The strengthening program is expected to be completed in January, 1981.

Based on the information obtained through the onsite inspection of the walls, discussion with the licensee representatives with respect to the licensee analysis methods and criteria, evaluation of their proposed wall capacity strengthening program and the staff's expertise on the behavior of masonry walls, the following findings and conclusions are made:

1. The Salem Unit 2 non-conforming masonry walls under the plant shutdown condition or the 5% low power testing condition do not present safety hazards to the public.

2. The licensee's proposed remedial actions appear to be reasonable pending further NRC staff review.

3. The licensee will be required to complete the following actions prior to operation above 5% power:

   a. Submit the information requested during the November 20, 1980, meeting,

   b. Complete the wall capacity strengthening program or remedial actions described above,

   c. Confirm that the proposed remedial actions do not preclude the option of implementing additional modifications which would, if dictated by future staff review, render the mmasonry wall design to meet the zero tensile stress requirements under OBE and SSE conditions,

4. Prior to startup following the first refueling, PSE&G shall resolve the difference between the staff criteria and that of the licensee's to the satisfaction of the staff and implement the required fixes that might result from such a resolution.

Fulfillment of the above listed items provides reasonable assurance that, in the event of earthquake and various postulated accidents occuring within the structures, the masonry walls will withstand the specified design conditions without impairment of structural integrity or the performance of required safety functions. Conformance with the criteria and analysis procedures discussed and the wall capacity strengthening program described above constitutes an acceptable basis for satisfying, in part, the requirements of General Design Criteria 2 and 4.

3.11 Environmental Design of Engineered Safety Features Equipment

In December, 1979 the staff issued guidance for the environmental qualification of safety-related electrical equipment (NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"). By letter dated February 19, 1980, the staff requested that PSE&G review the environmental qualification documentation for each item of safety-related electrical equipment which could be exposed to a harsh environment so as to identify the degree to which the associated environmental qualification program complies with the staff's position as described in this NUREG. Further, where there are deviations, we requested the applicant to provide the basis for concluding that the associated environmental qualification program demonstrates that each item in question is environmentally qualified for its service conditions.

PSE&G provided an environmental qualification submittal on December 1, 1980. The results of our review of this submittal are as follows.

PSE&G identified twenty-eight out of sixty item types, necessary to mitigate the consequences of an accident, as being deficient in meeting the requirements of NUREG-0588. The deficiencies were primarily indicated as lacking documentation. The licensee provided interim and final resolutions for all of these. The resolutions consisted of analyses of actual service requirements, replacement, relocation to a non-harsh environment, design and procedural changes.

The staff is not in total agreement as to the finality of some of these resolutions. However, the corrective course being pursued by the licensee is considered adequate for the interim period and therefore provides sufficient basis for operation of the Salem 2 unit at the 100% power level. Final resolution by the staff will be addressed in the February 1, 1981, Safety Evaluation Report.

On December 9-10, 1980 the Staff performed a preliminary audit of the test data and/or documentation referenced in the licensee's December 1, 1980, submittal. The audit included a re-review of four items previously reviewed in a September 8-9, 1980 audit and review of three additional items identified as environmentally qualified by the licensee.

The staff's December 9-10, 1980, audit of previously reviewed items revealed that radiation qualification documentation was lacking for the slide bearing lubricant on a Westinghouse charging pump motors. The licensee provided confirmatory information from Westinghouse on the adequacy of this lubricant.

The documentation supporting the environmental qualification of the three new items was found to be satisfactory. The licensee identified a gasket failure during the test of a NAMCO limit switch. Although the limit switch continued to function throughout the test, the licensee plans to replace the gasket on these limit switches with qualified gaskets at the first refueling outage.

An additional audit, in January 1981, will complete the staff's evaluation of the licensee's environmental qualification program.

The Commissioner's Memorandum and Order dated May 23, 1980, directs the staff to complete its review of environmental qualification, including the publication of the Safety Evaluation Reports, by February 1, 1981 for all operating reactors Also, this order directs that by no later than June 30, 1982, all electrical equipment in operating reactors subject to this review be in compliance with the NUREG or operating reactor guideline documents as appropriate. The staff intends to complete the environmental qualification review in accordance with these dates.

4.0 REACTOR

4.2 Mechanical Design

4.2.2 Fuel Design

This evaluation concerns the use of Westinghouse PAD 3-3 computer code in plant safety analyses. We find its use in the Salem analysis acceptable for first cycle operating at full power. The evaluations presented below supersede our earlier thermal performance analyses portions of Section 4.2 of the Salem SER.

Thermal Performance Analysis

The new Westinghouse fuel thermal performance code PAD 3-3 is described in WCAP-8720, "Improved Analytical Methods Used in Westinghouse Fuel Rod Design Calculations," October 1976. This code contains a revision of an earlier fission gas release model and revised models for helium solubility, fuel swelling, and fuel densification.

The new Westinghouse code was approved with four restrictions as described in our safety evaluation of February 9, 1979 (letter from J. Stolz, NRC to T. Anderson, Westinghouse). Three of those restrictions deal with nuherical limits and have been complied with. The fourth restriction relates to use of the PAD 3-3 code for the analysis of fission gas release from uranium dioxide (UO_2) for power increasing conditions during normal operation. This restriction applies to the safety analysis of Salem Unit 2. However, Westinghouse has stated that this restriction does not adversely affect the results of the safety analyses performed for Salem. Although we believe that this is essentially correct for the planned operation of Salem Unit 2, Westinghouse has prepared and submitted a detailed evaluation of this fourth restriction in WCAP-8720, Addendum 1.

At this time, we have not completed our review of the Westinghouse evaluation of this restriction. However, our review has progressed to the point where the following conclusions can be made.

1. The Westinghouse evaluation of our restriction on the use of the PAD 3-3 code supports Westinghouse's earlier statement that the restriction does not adversely affect the results of the safety analyses performed for Salem Unit 2.

2. We continue to believe that this result is essentially correct and anticipate some additional information from Westinghouse to confirm this conclusion.

3. Because the restriction pertains to the release of fission gases from the fuel, any change in our conclusions would not have significant impact at low burnup (e.g., first cycle operation), when the fission gas inventory in the fuel is low.

At this time we can therefore state that for the first cycle operation at full power, the restriction for PAD 3-3 is not significant and the analyses as presently docketed for Salem are acceptable. We anticipate a timely completion of our review of the Westinghouse evaluation prior to operation at extended burnup.

With respect to the thermal performance of the reactor fuel, this analysis conforms with the requirements set forth in 10 CFR 50 Appendix K and 10 CFR 50 Appendix A, General Design Criterion 10.

5.0 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.5 Steam Generator Tube Integrity

In Section 5.2.5 of SER Supplement No. 4, we noted that steam generators of the design used in the Salem plants have experienced denting and cracking of the steam generator tubes. We required PSE&G to implement a water chemistry control program, but noted that 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. We also required that inspection ports be installed in each steam generator prior to start-up after the first refueling and that Row 1 tubes in the Salem Unit 2 steam generators be plugged prior to exceeding 5% power. These requirements were incorporated into the Salem Unit 2 low power license.

Since that time the staff has determined that adherence to the following staff positions will provide sufficient assurance that operation of the steam generators will not constitute an undue risk to the health and safety of the public. These positions supercede our earlier evaluations presented in Section 5.2.5 of Supplement 4 to the Salem SER. The Salem Unit 2 low power license was amended (Amendment No. 3, dated October 10, 1980) to reflect these positions.

Inspection Ports

For some forms of steam generator tube degradation which have occurred in units similar to the Salem Unit 2 design, eddy current testing and tube gauging alone are not sufficient to assess and monitor tube and support plate conditions. In order to perform adequate assessment and monitoring of these areas, we require that inspection ports be installed in each steam generator. These ports should be installed just above the upper support plate and in line with the tube lane. At the upper support plate level, at least one inspection port is required which shall be large enough for visual observation of the tube lane.

Under the as low as reasonably achievable (ALARA) concept, the ports should be installed before the start of operations, if possible, in order to minimize personnel exposure. Although installation prior to initial operation is preferable, we have determined that the potential installation exposure following the first cycle of operation is not significant enough to justify the delay of the initial start-up of the plant to permit the installation of inspection ports. However, since secondary side contamination will increase as the operating time increases, we continue to require that these ports be installed prior to start-up after the first refueling.

Row 1 Steam Generator Tubes

Operating experience has shown that the Row 1 tubes in the steam generators of Westinghouse design in use at Salem Unit 2 are particularly susceptible to an early onset of cracking because of their small bend radius. We do not currently require licensees to plug Row 1 tubes prior to start-up or issuance of full power license. Westinghouse has committed (in a letter from R. M. Anderson to R. H. Vollmer, May 12, 1980) to a program to determine the particular susceptibility of Row 1 tubes to cracking. The program involves removing numerous tubes from the Trojan plant and subjecting them to nondestructive and destructive testing to identify the cause of the cracking and to develop a field inspection method capable of detecting potential leaking tubes. The results of this evaluation are expected to be available in the latter part of 1980. We will review the program results and decide at that time on the necessity to plug the Row 1 tubes. If necessary, we will require that these tubes be plugged prior to startup after the first refueling.

Summary

We have concluded that, with the additional measures mentioned above and discussed further below, 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 in the Technical Specifications 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.

Steam generator tube integrity as described above is directly a consideration for General Design Criteria 14, 15, 30, 31, and 32 of Appendix A to 10 CFR 50. We conclude that the pertinent sections of these General Design Criteria have been met with respect to the steam generator internals.

5.3 Inservice Inspection Program

5.3.2 Inservice Testing of Pressure Isolation Valves

There are several safety systems connected to the reactor coolant system pressure boundary that have design pressure below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suction below RCS pressure. In order to protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high pressure RCS and the low pressure systems. The isolation capability of these valves can be demonstrated by periodic leak testing to criteria which provide reasonable assurance that the design pressure of the low pressure systems will not be exceeded and, possibly, lead to an inter-system LOCA. We therefore have required that the licensee perform periodic leak testing of an RCS pressure boundary isolation valve after all disturbances to the valve are complete. The RCS pressure boundary isolation valves to be so tested are to be listed in Table 3.4-1 of the Technical Specifications.

Pressure isolation valves are required to be Category A or AC and to meet the appropriate valve leak rate test requirements of IWV-3420 of Section XI of the ASME Code except as discussed below. The licensee has agreed to categorize their pressure isolation valves for the safety injection, residual heat removal, and boron injection systems, as Category A or AC. We find these categorizations acceptable.

The staff's present position on leak rate criteria is that maintaining a leakage rate at or below 1 GPM will ensure the integrity of the valve and demonstrate the adequacy of the redundant pressure isolation function. The requirement for periodic testing will give an indication of the onset of valve degradation over a finite period of time. Significant increases over this rate from one test to another would be an indication of valve degradation.

Leak rates higher than 1 GPM will be considered if the leak rate increases are less than 1 GPM above the previous test leak rate or if the system design precludes measuring 1 GPM with sufficient accuracy. These items will be reviewed on a case by case basis.

PSE&G has agreed to meet the leak rate criteria for each valve upon completion of additional modifications to their present leak detection system. Modifications will be completed by the end of the first refueling outage. In the interim, the licensee has proposed an alternate testing scheme whereby a limited amount of parallel pressure isolation valve configurations will be assigned a cumulative leak rate of 3.0 GPM or less. We find these commitments acceptable provided that the interim testing be completed prior to the first refueling, that the parallel configurations are limited to a maximum of three valves, and that the leak rate criteria not exceed 3 GPM for the three-valve configuration.

Limiting Conditions for Operation (LCO) have been included in the Technical Specifications which will require corrective action (i.e., shutdown or system isolation) when the leakage limits are not met. Also surveillance requirements, which state the acceptable leak rate testing frequency, have been included in the Technical Specifications.

We conclude that PSE&G's commitments to periodic leak testing of pressure isolation valves between the reactor coolant system and low pressure systems will provide reasonable assurance that the design pressure of the low pressure systems will not be exceeded, and thus reduce the probability of an occurrence of an inter-system LOCA. Based on the provisions described above, we conclude that the pertinent requirements found in GDC 14 and 55 have been met.

6.0 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.3 Containment Isolation System

In Supplement No. 4 to the Safety Evaluation Report (SER) for the Salem plant, Unit 2, in Section 6.2.3, we concluded that the pressure-vacuum relief system, consisting of one 10-inch line, could be used as often as necessary during the normal plant operating modes of startup, power, hot standby, and hot shutdown. However, the staff has recently developed the position (applicable to all licensees) that additional restrictions should be placed upon containment purging and venting during normal plant operation. Use of the pressure-vacuum relief system is considered to be a venting operation. Additional restrictions on purging and venting will decrease the likelihood of the purge or vent lines being open in the event of a LOCA. Such open lines constitute a direct connection between the containment atmosphere and the outside environment, and failure of the redundant purge or vent line isolation valves to close as required during a LOCA, though they may have been properly tested and qualified, would result in offsite doses far in excess of 10 CFR Part 100 guidelines.

Therefore, we require that the licensee limit the use of the pressure-vacuum relief system to a total of no more than 90 hours per year during the normal plant operating modes of startup, power, hot standby, and hot shutdown. The licensee has indicated that plant modifications may be necessary to meet this requirement. PSE&G is continuing an evaluation of this matter and will notify NRC if modifications are found to be necessary. All of the other restrictions described in Section 6.2.3 of Supplement No. 4 shall also remain in effect; in particular, (1) the isolation valves in the 36-inch diameter lines of the purge system shall remain closed at all times during the normal plant operating modes of startup, power, hot standby, and hot shutdown; and (2) the isolation valves in the 10-inch diameter line of the pressure-vacuum relief system shall be aligned such that the maximum open position corresponds to 60 degrees. In the cold shutdown and refueling modes, the purge system and the pressure-vacuum relief system may be used simultaneously and without time limitation. The Technical Specifications and license conditions reflect these requirements. This conforms to the requirements of GDC 54, 55, 56, and 57 with respect to containment purging and venting.

6.2.3.1 Containment Isolation Valves

By letter dated December 10, 1980, the applicant addressed a staff concern regarding the acceptability of the containment isolation provisions for the main feedwater lines. For these lines, General Design Criterion 57 of Appendix A to 10 CFR Part 50, requires that at least one containment isolation valve be provided outside containment, and that it be either automatic, locked closed, or capable of remote manual operation; GDC 57 further states that a simple check valve may not be used as the automatic isolation value.

Each of the four main feedwater lines is equipped with a single stop check valve outside containment. The stop check valves have local manual operators. Since stop check valves permit positive closure, they are not considered to be simple check valves. Consequently, the stop check valves satisfy the requirements of GDC 57; however, in the event of an accident, environmental and radiological conditions should not preclude operator access to these valves. If the valves are not accessible by operators to effect a positive closure, they can only function as simple check valves, which GDC 57 prohibits.

The applicant must therefore demonstrate to the satisfaction of the staff that the present containment isolation provisions for the main feedwater lines comply with the requirements of GDC 57 under all postulated accident conditions, or propose a design change that will achieve compliance. An approach which we would find acceptable, and which the applicant has stated is feasible, would be to add power operators to the stop check valves to permit automatic isolation on remote manual actuation from the main control room. Automatic isolation capability is preferable since it would also satisfy the requirements for system isolation in the event of a main steam line break accident. This information must be provided within 90 days of the issuance of a full-power license. Design changes, if necessary, shall be implemented during the first refueling outage.

Until such time that the applicant can justify that the present main feedwater line containment isolation provisions satisfy GDC 57, or proposed design changes can be implemented to upgrade the isolation provisions, a departure from the explicit requirements of GDC 57 is acceptable in accordance with the introduction to Appendix A to 10 CFR Part 50. Interim acceptance of the present isolation provisions; i.e., the stop check valves functioning as simple check valves, is based on other system design considerations. For example, there are main feedwater control valves upstream of the check valves. These valves are fast acting (8 second closure times) and automatically close. Consequently, they provide backup isolation capability. Also the secondary system forms a closed system inside containment. Because of the importance of assuming secondary system integrity inside containment in the event of a LOCA, the system is seismically designed, and pipe whip and missile protected. Therefore, rupture of the secondary system is not postulated to occur either concurrent with or as a result of a LOCA. With this assurance of system integrity and backup isolation capability, the stop check valves are acceptable containment isolation valves in the interim.

6.3 Emergency Core Cooling System

6.3.3 Performance Evaluation

6.3.3.1 Emergency Core Cooling System Analyses

The NRC staff has been generically evaluating three materials models that are used in ECCS evaluations. Those models predict cladding rupture temperature, cladding burst strain, and fuel assembly flow blockage. We have (a) discussed our evaluation with vendors and with other industry representatives, (b) published NUREG-0630, "Cladding Swelling and Rupture Models for LOCA Analysis," and (c) required licensees to confirm that their operating reactors would continue to be in conformance with 10 CFR 50.46 if the NUREG-0630 models were substituted for the present materials models in their ECCS evaluations and certain other compensatory model changes were allowed.

Until we have completed our generic review and implemented new acceptance criteria for cladding models, we have required that the ECCS analyses be accompanied by supplemental calculations to be performed with the materials models of NUREG-0630. For these supplemental calculations only, we have accepted other compensatory model changes allowed for the confirmatory operating reactor calculations mentioned above.

Those supplemental calculations have been provided by the licensee. PSE&G also addressed a recently identified non-conservatism of the Westinghouse 1978 ECCS evaluation model. The new concern was discovered by Westinghouse who formally notified the staff in November, 1979.

Specifically, Westinghouse had discovered that the February, 1978 ECCS evaluation model was, in part, based on cladding burst tests which were conducted at relatively fast temperature-ramp rates; whereas the LOCA analyses of actual plant heatup rates (including those of Salem Unit 2) were at relatively slow temperature-ramp rates.

The licensee assessed the impact of this calculational error using the NUREG-0630 models (but not the allowed compensatory model changes) and determined that it would require a reduction in F_Q of 0.04.

However, the licensee identified a larger offsetting margin in F_Q available through the use of thermohydraulic models already approved for some applications. This margin was worth 0.2 in F_Q. Thus no F_Q reduction was required.

Based on our review of the licensee's submittal, we conclude that our concerns related to the swelling and rupture issue have been satisfactorily addressed and that Salem Unit 2 continues to be in conformance with the requirements of 10 CFR 50.46.

6.3.3.7 Sump Debris

In a letter dated July 21, 1980, the staff requested that the licensee address concerns related to the potential for debris in containment which would inhibit ECCS performance at Salem Unit 2. Information provided by the licensee supplements observations made by NRR staff members in visits to the Salem plant. The following discussion provides our conclusions.

Housekeeping

We have evaluated housekeeping requirements within containment to preclude debris from non-LOCA sources, e.g., maintenance and inspection activities.

The Salem Nuclear Plant quality assurance program establishes written guidelines for assuring that good housekeeping practices are followed during maintenance. The Salem Unit 2 Technical Specifications include surveillance requirements which are implemented pursuant to written procedures. The requirements include inspections to verify that no loose debris which could be transported to the sump remains in the containment, periodic inspections of the containment sump suction inlets to ensure that they are not blocked by debris and inspection of the sump components (trash racks, screens, etc.) to verify that structural distress or corrosion is not present.

The Salem Unit 2 Technical Specifications and surveillance inspections requirements adequately address control of loose debris in the containment. We find the housekeeping provisions for Salem Unit 2 to be acceptable.

Small Debris

We have considered materials capable of being transported to the sump which would have a tendency to form particles small enough to pass through the fine screens in the sump.

Virtually all of the piping insulation in the containment and particularly in the lower containment regions is of the metal mirrored type. This material is not expected to float or to form small particles as a result of pipe whip or jet impingement.

The licensee has stated that Colemanite, Johns-Manville Cereblanket, and any other non-metallic thermal insulation which could produce small debris (small enough to pass through sump screens) is used in only small quantities, at locations remote from the sump compartment, and like the paints used in containment, is designed to remain intact and in place under accident conditions.

Larger Debris

We have considered the use of materials which would have the potential to block the containment sump screens if transported to the screens as a result of an accident. The present design of the containment sump will be modeled and tested under conditions of up to fifty percent screen blockage.

Virtually all of the piping insulation in the contaiment and particularly in the lower containment regions is of the metal-mirrored type. Based on the observations made during our site visit and the licensee's assessment, we believe it unlikely that a significant quantity of metal-mirror insulation debris would be transported to the sump. This conclusion is based primarily on the large number of obstructions in the form of piping of varying sizes, pipe hangers, snubbers, pipe support members, structural steel, platforms, cabling, motors, stairways, etc., to the passage of a material like metal-mirror insulation to the sump.

ECCS Status

We have reviewed the adequacy of the information available to the control room operator to monitor the Low Pressure Injection (LPI) system status during recirculation cooling. We conclude that sufficient information (e.g., flow rate, pump motor current, pump discharge pressure, etc.) is available to the operator to detect LPI performance degradation.

The licensee has committed that during the recirculation mode an operator will be delegated the principal responsibility of monitoring the performance of the ECCS systems. Assessment of pump status and ECCS degradation will be made by cognizant technical personnel utilizing appropriate reference material (pump curves, etc.) to be made available in the Technical Support Center. This assessment and other technical information will be readily available to the operators in the control room. Additionally, a post-accident log will be initiated as part of the Emergency Duty Officer's Check Sheet for the purpose of monitoring and trending low pressure injection system performance. The Office of Inspection and Enforcement will verify that Salem Unit 2 operators are specifically instructed in the recognition and mitigation of LPI performance degradation. The Salem Unit 2 LOCA emergency operating procedures also include guidance to alert the operator of the symptoms of inadequate core cooling.

Based on procedures and operator training which address the potential for ECCS performance degradation, we find the above measures acceptable to monitor ECCS performance during the recirculation mode at Salem Unit 2. The Office of Inspection and Enforcement will verify that these actions have been completed prior to operation above five percent power.

Summary

Based on the considerations noted above with respect to housekeeping requirements, the avoidance of materials likely to form small-size debris, the lack of apparent mechanism for blockage of more than the previously tested value of fifty percent of the screen area by larger debris, and the ability to monitor and control LPI system status, we conclude that the present design of Salem Unit 2 provides reasonable assurance that the post-LOCA recirculation of core coolant will not be impaired by debris and is therefore acceptable. We have requested, and the licensee has committed to provide, a detailed survey of insulation materials prior to startup following the first refueling. This information will be used in the staff's ongoing research activities to improve the sump performance analysis techniques.

6.4 Control Room Habitability System

Our evaluation of Control Room Habitability Systems is discussed in Section 22.2, Item III.D.3.4 of this supplement.

6.5 Containment Pressure Boundary Fracture Toughness

We have assessed the ferritic materials in the Salem Unit 2 containment system that constitute the containment pressure boundary to determine if the material fracture toughness is in compliance with the requirements of General Design Criterion 51, "Fracture Prevention of Containment Pressure Boundary."

GDC-51 requires that under operating, maintenance, testing and postulated accident conditions, (1) the ferritic materials of the containment pressure boundary behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized.

The Salem Unit 2 containment is a reinforced concrete structure with a thin steel liner on the inside surface which serves as a leaktight membrane. The ferritic materials of the containment pressure boundary which were considered in our assessment were those applied in the fabrication of the equipment hatch, personnel lock, penetrations and fluid system components, including the isolation valves required to isolate the system. These components are the parts of the containment system which are not backed by concrete and must sustain loads.

The Salem Unit 2 containment pressure boundary is comprised of ASME Code Class 1, 2, and MC components. In late 1979, we reviewed the fracture toughness requirements of the ferritic materials of Class MC, Class 2 and Class 1 components which typically constitute the containment pressure boundary. Based on this review we determined that the fracture toughness requirements contained in ASME Code Editions and Addenda typical of those used in the design of the Salem Unit 2 containment may not ensure compliance with GDC-51 for all areas of the containment pressure boundary. We initiated a program to review fracture toughness requirements for containment pressure boundary materials for the purpose of defining those fracture toughness criteria that most appropriately address the requirements of GDC-51.

Prior to completion of this study, we have elected to apply in our licensing reviews, as an interim requirement, the criteria identified in the Summer 1977 Addenda of Section III of the ASME Code for Class 2 components. Because the criteria which have been applied in construction differ in Code classification and Code editions and addenda, we have chosen the criteria in the Summer 1977 Addenda of Section III of the Code to provide a uniform review, consistent with the safety function of the containment pressure boundary materials.

We have reviewed the Class 1, 2, and MC components in the Salem Unit 2 containment pressure boundary according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components. This review consisted of reviewing the fracture toughness data obtained for the ferritic materials in the containment pressure boundary to demonstrate explicit compliance with the fracture toughness requirements specified for Class 2 components in the Summer 1977 Addenda of Section III of the ASME Code. With one exception we have been able to confirm by test data that the fracture toughness of the ferritic in the component pressure boundary meets the requirements in the 1977 Addenda of the Code.

However, we have been unable to confirm by test data that certain segments of the A106 Grade C piping used in the steam generator feedwater system meet our interim criteria. These pipe segments are oustide containment between the penetration and the stop check isolation valve for steam generator feedwater lines 5, 6, 7, and 8. The applicant is unable to provide fractuee toughness test data for these pipe segments because the earlier editions of the ASME Code to which the piping was purchased did not require fracture toughness testing. The applicant was requested to take additional action to contact the pipe fabricators and obtain fracture toughness data and the thermal histories for the heats and steel in the Salem 2 feedwater piping segments. During visits to the fabrication shops, members of the NRC and licensee staffs determined that fracture toughness tests were not conducted by the fabricators for the heats of steel used in the Salem 2 feedwater pipe segments. However, information describing the thermal history of the pipe during fabrication was provided verbally by the pipe fabricators to the staff.

Based on the information obtained from the pipe fabricators, we have determined that the A106 feedwater piping was final finished in the mill at 1600°F and subsequently heated to 1150°F after welding during assembly. This thermal history corresponds to a normalized and tempered condition for A106 material. In the normalized and tempered condition, the nil ductility temperature (NDT) for A106 piping can be estimated to be above -20°F but no greater than 40°F.

The NDT range has been estimated from the data contained in NUREG Report-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," U.S. NRC, October 1979. Based on this estimated range of NDT for the A106 feedwater piping, we conclude that the A106 feedwater piping meets the fracture toughness requirements specified for Class 2 components in the 1977 Addenda of Section III of the ASME Code. Compliance with the Code rules ensures that the materials in the containment pressure boundary will behave in a nonbrittle manner for those conditions stated in the requirement, that the probability of rapdily propagating fracture is minimized, and that the material meets the requirements of GDC-51.

7.0 INSTRUMENTATION AND CONTROL

7.2 Reactor Trip System

7.2.2 Anticipated Transients Without Scram (ATWS)

Section 7.2.2 of Supplement No. 4 to the Salem Safety Evaluation Report addressed the background of the staff's concerns on ATWS and required interim procedures and operator training to reduce the risk from anticipated transients without scram. Further requirements may result from the Commission's rulemaking on ATWS. Supplement No. 4 stated that we had reviewed PSE&G's proposed procedures for ATWS and approved them for low power operation (less than or equal to five percent of full power). However, to make them applicable for full power operation PSE&G was required to revise them in accordance with the staff comments. The revisions included changes to the procedure for response to a reactor trip to specifically identify the occurrence of an ATWS event and call for an immediate manual trip of the turbine.

PSE&G has provided us with the revised ATWS emergency procedures which incorporate the staff's comments. We have reviewed them and based on our review and observations, we conclude, pending the outcome of the Commission's rulemaking on ATWS, that the emergency procedure changes implemented and operator training conducted on ATWS are acceptable for full power operation of the Salem Nuclear Generating Station, Unit 2 in accordance with General Design Criteria 10, 15, 26, 27, and 29 of 10 CFR 50 Appendix A. This acceptance is based on our understanding of the plant response to postulated anticipated transients without scram events. The Commission will, by rulemaking, determine on a generic basis whether any future modifications are necessary to resolve ATWS concerns and establish the required schedule for implementation of such modifications.

7.9 Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation

On November 30, 1979, the Office of Inspection and Enforcement issued IE Bulletin 79-27 "Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation" to all power reactor facilities with an operating license and to those nearing licensing. This bulletin outlined actions to be taken to address control system malfunctions and significant loss of information to the control room operator as a potential consequence of the loss of Class 1E and non-class 1E buses supplying power to these plant systems. Bulletin 79-27 was issued to Public Service Electric and Gas Company by Confirmatory Orders dated April 4, 1980. Further, IE Information Notice 80-10, issued on March 7, 1980, provided information related to the Crystal River Unit 3 event of February 26, 1980 in which a significant loss of information to the operator resulted from a loss of power to a portion of the plant instrumentation system.

As a result of these concerns for operating plants, PSE&G analyzed the vital instrument buses, essential control panels, and non-essential control panels on a circuit-by-circuit basis to identify failure modes. The results of this analysis were reviewed with consideration for system relationships and alternate equipment availability. Based on this analysis and review, PSE&G concluded that the failure of any one vital instrument bus or control panel would not prevent station operating personnel from taking the plant from power operation to cold shutdown in a safe manner. The results of the analysis and review, in tabular form, will be provided to the operators for use with existing procedures. The Office of Inspection and Enforcement will verify that this action has been completed prior to operation above 5 percent power.

Certain design modifications were identified during the review with the potential for further aiding the operator in bringing the plant to cold shutdown. These modifications primarily involve changing the power source for certain displays from the two essential control panels to the four vital instrument buses. In a letter dated July 31, 1980, PSE&G has agreed to implement these design modifications during the first refueling outage. We find this implementation schedule to be satisfactory.

Based on our review, we find that the licensee has satisfied those portions of GDC-13 of Appendix A to 10 CFR 50 which are amplified by IE Bulletin 79-27 and are applicable to Salem Unit 2.

7.10 Engineered Safety Features (ESF) Reset Controls

On March 13, 1980, the Office of Inspection and Enforcement issued Bulletin 80-06 "Engineered Safety Feature (ESF) Reset Controls," to address the concern that the use of reset pushbuttons alone could permit certain engineered safety feature system components to revert to the normal state following safety system actuation.

As a result of these concerns for operating plants, PSE&G conducted detailed drawing reviews, including schematic level review where appropriate. As discussed in letters dated June 13 and July 19, 1980, the reviews showed that reset actions for two sets of valves must be corrected to prevent the possibility of the valves changing position during override or reset of a safety actuation signal. Required modifications will be implemented prior to full power operation. Reset testing was performed as a part of the preoperational testing of the plant, and additional testing is required by the Bulletin. The Office of Inspection and Enforcement will verify that these actions have been completed prior to exceeding 5 percent power.

Based on our review, we find that the licensee has satisfied IE Bulletin 80-06, which amplifies the requirements of Section 4.16 of IEEE Std. 279 as required by 10 CFR 50.55a(h).

8.0 ELECTRIC POWER

8.3 Onsite Power Systems

8.3.4 Diesel Generator Reliability

NUREG/CR-0660 "Enhancement of Onsite Emergency Diesel Generator Reliability" made specific recommendations on increasing the reliability of nuclear power plant emergency diesel generators. Information requests concerning these recommendations, and also concerning the design of the fuel oil storage and transfer system, were transmitted to the applicant on December 14, 1979. The licensee responded in a letter dated February 14, 1980, stating how PSE&G meets or will meet the recommendations of NUREG/CR-0660 and our additional concerns.

We have reviewed these responses and have determined that conformance to the recommendations is as follows:

	Recommendation	Conformance
1.	Moisture in Air Start System	Yes
2.	Dust and Dirt in D/G Room	Yes
3.	Turbocharger Gear Drive Problem	Not Applicable
4.	Personnel Training	Partial
5.	Automatic Prelube	Yes
6.	Testing, Test Loading and Preventative Maintenance	Partial
7.	Improve Identification of Root Cause of Failures	Yes
8.	D/G Ventilation and Combustion Air Systems	Yes
9.	Fuel Storage and Handling	Yes
10.	High Temperature Insulation for Generator	*
11.	Engine Cooling Water Temperature Control	Yes
12.	Concrete Dust Control	Yes
13.	Vibration of Instruments and Controls	Yes

On the basis of our review we have concluded that there is sufficient assurance of diesel generator reliability to warrant unrestricted plant operation through the first refueling period. However, to assure long term reliability of the diesel generator installations we require that the following procedural modifications be implemented prior to restart after the first refueling.

*Explicit conformance to Recommendation 10 is considered unnecessary by the staff in view of the equivalent reliability provided by the design, margin and qualification testing requirements that are normally applied to emergency standby diesel generators.

1. Personnel Training: Preventative maintenance, minor repairs, and trouble shooting for the emergency diesel generators is performed by the plant's electrical and mechanical maintenance personnel, but no specific training concerning diesel generator maintenance and trouble shooting is being provided for these personnel. The licensee states that the personnel receive an intermediate skills training course and on the job training. We require that a complete formal training program be implemented for all the mechanical and electrical maintenance, quality control, and operating personnel, including supervisors, who will be responsible for the maintenance and availability of the diesel generators. The depth and quality of this training program shall be at least equivalent to that of training programs normally conducted by major diesel engine manufacturers.

2. Test Loading: The licensee stated that the diesel generators are designed to run unloaded for up to one week without degradation of engine performance or reliability. In addition, PSE&G also stated that there are no procedures for loading the engine after no load operation, and that operator action is relied upon to shut the engine down. We require that operating procedures be developed that require loading the diesel engine to a minimum of 25 percent of full load for one hour after eight hours of continuous no load operation or as recommended by the engine manufacturer.

The present diesel generator design meets the requirements of Criteria 17 and 21 of Appendix A of 10 CFR Part 50. Upon completion of the above changes and modifications, the design of the diesel generator and its auxiliary systems will also be in conformance with recommendations of NUREG/CR-0660 for enhancement of diesel generator reliability and the related NRC guidelines and criteria. We therefore conclude that this will provide reasonable assurance of diesel generator reliability through the design life of the plant.

9.0 AUXILIARY AND EMERGENCY SYSTEMS

9.7 Fire Protection System

The staff has reviewed PSE&G's proposed fire protection program and fire hazards analysis against the guidelines of Appendix A to Branch Technical Position APCSB 9.5-1, supplemental staff guidelines dated June 14, 1977, and applicable NFPA standards. The staff concludes that the fire protection program meets GDC 3, and is acceptable for full power operation.

During the fuel loading licensing activities, we informed the Commission that except for five remaining items, all modifications relative to fire protection were completed. The remaining five modifications, which included an alternate shutdown system to accomplish cold shutdown, were to be completed by October 1980. However, by letter dated August 19, 1980, PSE&G informed us that four of the five items would not be implemented until a later date. Subsequently, by letters dated August 22 and September 4, 1980, the licensee further discussed these four items. Based on these submittals the staff's position on these items is as follows:

1. Portable radio communication. The portable radio system should be installed prior to operation above 5% power. FCC approval is required before the system becomes operational. PSE&G is attempting to expedite FCC approval so that the system can be fully operational prior to exceeding 5% power. We, therefore, conclude that PSE&G is making a reasonable attempt to complete this item. PSE&G shall notify NRC if significant delays are encountered in obtaining FCC approval.

2. Installation of ventilation dampers. The installation of all dampers should be completed prior to operation above 5% power.

3. Installation of a Halon system in the relay room. The installation of the Halon system in the relay room should be completed prior to operation above 5% power.

4. Installation of the alternate shutdown equipment to achieve cold shutdown. The alternate shutdown capability to achieve hot shutdown from outside the control room is now operational. The installation of the fire barriers to enhance the separation of switchgear units should be completed prior to operation above 5% power. The design modifications which allow plant shutdown without having access to either the relay room or the control room is scheduled to be operational by March 2, 1981. The only other item left is the wrapping of several trays with a mineral wool blanket to give a 1-hour fire barrier between divisions separated by less than 20 feet. Due to modifications as a result of the TMI-2 accident and other requirements, additional cables will be installed in these trays. Since it would be required to unwrap these trays to install the additional cables, and since an alternate shutdown capability exists to reach hot shutdown, we find it reasonable to wait until March 20, 1981 to wrap the above-indicated cable trays.

On October 27, 1980, the Commission approved for publication in the Federal Register a new §50.48 and Appendix R to 10 CFR Part 50 delineating certain fire protection provisions for nuclear power plants licensed to operate prior to January 1, 1979. Although this fire protection rule does not apply to Salem Nuclear Generating Station No. 2 unit, by letter December 1, 1980, the licensee committed to implement in Unit 2 any modifications required for Salem Unit 1 for the following three issues identified in Appendix R as items to be backfitted.

1. Section III.G, Fire Protection of Safe Shutdown Capability

2. Section III.J, Emergency Lighting

3. Section III.O, Oil Collection System for Reactor Coolant Pump.

The implementation schedule will be in accordance with the requirements of the rule.

Based on these commitments and our evaluation, we conclude that Salem Unit 2 fire protection program will meet all the requirements of Appendix R to 10 CFR Part 50 when the committed modifications have been completed, meets the requirements of GDC 3, and therefore is acceptable.

12.0 RADIATION PROTECTION

In Section 12.0 of Supplement No. 4 to the Salem 2 Safety Evaluation Report, we stated that prior to issuance of a full power license for Salem 2, PSE&G should submit a reorganization plan that would satisfy our concerns associated with the Salem radiation protection organization. By letter dated August 22, 1980, PSE&G submitted a license amendment request that provided for significant changes to the Salem Radiation Protection organization. These changes meet our positions in the "Draft Criteria for Utility Management and Technical Competence" and Regulatory Guide 8.8 as follows:

1. The Radiation Protection Engineer (RPE-equivalent to the Radiation Protection Manager) reports directly to the Station Manager, independent of operational, technical, or administrative groups. The RPE is a required member of the Station Operations Review Committee (SORC). Staff qualifications require that the RPE meet or exceed the recommendations of Regulatory Guide 8.8.

2. The newly formed Radiation Protection Department has an independent radiation protection function at all levels, and is separate from other functions such as chemistry. The Senior Radiation Protection Supervisor has been designated as a backup to the RPE. All Technical Supervisors, Technicians, and Technical Assistants within the department are devoted to the radiation protection function.

3. A formal program to replace contractor radiation protection personnel with permanently assigned station radiation protection technicians has been implemented. Additionally, a qualification and retraining program conducted in accordance with ANSI 18.1 provides formal qualification and training for the radiation protection department personnel.

By letter dated October 1, 1980 PSE&G stated that a majority of the reorganization actions and programs will be complete by July 1, 1981 with full implementation by November 1, 1981. In the interim, a permanent staff is being recruited and all contractor radiation protection technicians are receiving classroom and on-the-job training on systems, radiological fundamentals, and procedures.

These actions and commitments by PSE&G for the Salem Station adequately meet the positions of NUREG-0660/0737, the "Draft Criteria," and Regulatory Guide 8.8 regarding the Radiation Protection Organization, and are therefore satisfactory. An evaluation of the Salem Radiation Protection Department will be performed during a routine inspection.

We conclude that the licensee's current organization which uses contractor radiation protection personnel is capable of assuring plant operations in compliance with the applicable requirements of 10 CFR 20, 50.36a and Appendix I to 10 CFR 50 in the interim until the permanent organization described above is fully operational on November 1, 1981.

13.0 CONDUCT OF OPERATIONS

13.1 Plant Organization, Staff Qualification and Training

13.1.1 Training Programs

In Section 13.1.1 of Supplement No. 4 to the Salem Safety Evaluation Report, we stated that the number of licensed operators for Salem Unit 2 is not sufficient to meet requirements for operation in modes 1, 2, 3 or 4. Our evaluation of the current licensed operator staffing situation for Salem 2 is contained in Section 22.2, item I.A.1.3 of this supplement.

The information contained in NUREG-0517, SER for the Salem Nuclear Generating Station, Unit 2, thru Supplement No. 4 on licensed operator training remains valid. Standard Review Plan 13.2, "Training," was used in the review. Regulatory Guide 1.8, "Selection and Training of Personnel," and 10 CFR 55.20 through 55.23 and 55.25 were used to evaluate the programs.

13.2 Emergency Planning

Our evaluation of emergency preparedness is discussed in Section 22.2, item III.A.1.1 of this supplement.

15.0 ACCIDENT ANALYSIS

15.1 General

15.1.1 Normal Operation and Anticipated Operational Transients

In Section 15.1.1 of Supplement 4 to the Salem Safety Evaluation Report, the staff stated that we required PSE&G to commit to provide prompt responses to additional information requirements regarding the review of Westinghouse transient analysis codes dealing with steam line and feedwater line break accidents.

The plant response analyses for postulated steam line and feedwater line breaks were evaluated with the use of the MARVEL computer program (WCAP-7909). MARVEL is a systems code designed to model transients which do not result in primary side two-phase separation. The primary system nodes are treated homogeneously. The MARVEL computer program is presently under review by the NRC staff. Due to some simplified assumptions used in the development of the code, the staff requires confirmation from Westinghouse of the steam line break and feedwater line break analytical methodology with a more detailed model, as provided in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases;" WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture'" and WCAP-9236, "NOTRUMP - A Nodal Transient Steam Generator and General Network Code." By letter dated August 13, 1980, the licensee has agreed to participate in a confirmatory review of their steam and feedwater line break analyses, as part of the ongoing generic review of the Westinghouse topical reports. This review is intended to confirm that the analyses conducted for Salem Unit 2 were appropriate and conservative. PSE&G agreed to provide plant specific inputs to NRC for an independent audit should the staff conduct one.

The analytical method used for postulated transients and accidents are normally reviewed on a generic basis. Our review at this time indicates that there is reasonable assurance that the conclusions based on the SAR analyses will not be appreciably altered by the completion of the analytical method review. If the final approval of the methods indicates revisions to the analyses are required, the licensee will be required to implement the results of such changes.

Therefore, pending completion of the confirmatory Salem Unit 2 analyses described above, we have concluded that the plant design acceptably conforms to the requirements of 50.46 and GDC 10 for steam line and feedwater line break accidents.

17.0 QUALITY ASSURANCE

17.1 General

Our review of the quality assurance program description for the operations phase for the Salem Nuclear Generating Station has verified that the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Appendix D of the FSAR through Amendment 43. This determination of acceptability included a review of the list of safety-related structures, systems, and components (Q-list) to which the quality assurance program applies. The results of a revised procedure for conducting the Q-list review that involves other NRR technical review branches and significantly enhances the staff's confidence in the acceptability of the Q-list have been discussed with the licensee. Differences between the Q-list submitted by PSE&G and NRR requirements have been resolved by licensee documentation dated September 9, 1980. Therefore, this matter is resolved for full power licensing.

22.0 TMI-2 REQUIREMENTS

22.1 Introduction

In a letter dated June 26, 1980, we advised all applicants for construction permits and operating licenses of the Commission's guidance regarding the requirements to be met for current operating license applications. The requirements are derived from NRC's Action Plan (NUREG-0660) and are found in NUREG-0694, "TMI-Related Requirements for New Operating Licenses."

The requirements discussed in NUREG-0694 were listed in four categories: those required for fuel loading and low power testing; those required for full-power operation; those requiring internal NRC action; and those required to be implemented by a certain date.

Subsequently, by letter dated October 31, 1980, a compilation of those TMI-related items that have been specifically approved by the Commission for implementation was issued to all licensees and applicants. This letter transmitted NUREG-0737, "Clarification of TMI Action Plan Requirements," which included information about schedules, applicability, method of implementation review, submittal dates, and clarification of technical positions.

Since requirements for fuel loading and low power testing were addressed in Part II of Supplement No. 4 to the Salem Nuclear Generating Station Unit 2 Safety Evaluation Report, this supplement only addresses the full power requirements and dated requirements of NUREG-0694 as clarified and supplemented by NUREG-0737.

Each applicable full power requirement and appropriate dated requirements are discussed below and follows the numbering sequence used in NUREG-0694 and NUREG-0737. The staff's review of the issues described in this section are based on the explicit requirements contained in NUREG-0694 as updated in NUREG-0737.

22.2 Full Power Requirements

I. Operational Safety

I.A.1 Operating Personnel and Staffing

I.A.1.3 Shift Manning

Position

At any time a licensed nuclear unit is being operated in Modes 1-4 for a PWR (Power Operation, Startup, Hot Standby, or Hot Shutdown respectively) or in Modes 1-3 for a BWR (Power Operation, Startup, or Hot Shutdown respectively), the minimum shift crew shall include two licensed senior reactor operators (SRO), one of whom shall be designated as the shift supervisor, two licensed reactor operators (RO) and two unlicensed auxiliary operators (AO). For a multi-unit station, depending upon the station configuration, shift staffing may be adjusted to allow credit for licensed senior reactor operators (SRO) and licensed reactor operators (RO) to serve as relief operators on more than one unit; however, these individuals must be properly licensed on each such unit. At all other times, for a unit loaded with fuel, the minimum shift crew shall include one shift supervisor who shall be a licensed senior reactor operator (SRO), one licensed reactor operator (RO) and one unlicensed auxiliary operator.

Adjunct requirements to the shift staffing criteria stated above are as follows:

a. A shift supervisor with a senior reactor operator's license, who is also a member of the station supervisory staff, shall be onsite at all times when at least one unit is loaded with fuel.

   A shift supervisor with a senior reactor operator's license on both units and who is a member of the station supervisory staff shall be onsite at all times when both of the units are loaded with fuel.

b. A licensed senior reactor operator (SRO) shall, at all times, be in the control room from which a reactor is being operated. The shift supervisor may from time-to-time act as relief operator for the licensed senior reactor operator assigned to the control room.

c. For any station with more than one reactor containing fuel, the number of licensed senior reactor operators onsite shall, at all times, be at least one more than the number of control rooms from which the reactors are being operated.

d. In addition to the licensed senior reactor operators specified in a., b., and c above, for each reactor containing fuel, a licensed reactor operator (RO) shall be in the control room at all times.

e. In addition to the operators specified in a., b., c., and d. above, for each control room from which a reactor is being operated, an additional licensed reactor operator (RO) shall be onsite at all times and available to serve as relief operator for that control room. As noted above, this individual may serve as relief operator for each unit being operated from that control room, provided he holds a current license for each unit.

f. Auxiliary (nonlicensed) operators shall be properly qualified to support the unit to which assigned.

g. In addition to the staffing requirements stated above, shift crew assignments during periods of core alternations shall include a licensed senior reactor operator (SRO) to directly supervise the core alternations. This licensed senior reactor operator may have fuel handling duties but shall not have other concurrent operational duties.

Licensees of operating plants and applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation.

The administrative procedures shall also set forth a policy, the objective of which is to operate the plant with the required staff and develop working schedules such that use of overtime is avoided, to the extent practicable, for the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, health physicists, auxiliary operators, I&C technicians and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions.

The staff recognizes that there are diverse opinions on the amount of overtime that would be considered permissible and that there is a lack of hard data on the effects of overtime beyond the generally recognized normal 8-hour working day, the effects of shift rotation, and other factors. NRC has initiated studies in this area. Until a firmer basis is developed on working hours, the administrative procedures shall include as an interim measure the following guidance, which generally follows that of IE Circular No. 80-02.

In the event that overtime must be used (excluding extended periods of shutdown for refueling, major maintenance or major plant modifications), the following overtime restrictions shall be followed:

(1) An individual should not be permitted to work more than 12 hours straight (not including shift turnover time).

(2) There should be a break of at least 12 hours (which can include shift turnover time) between all work periods.

(3) An individual should not work more than 72 hours (excluding shift turnover time) in any 7-day period.

(4) An individual should not be required to work more than 14 consecutive days without having 2 consecutive days off.

However, recognizing that circumstances may arise requiring deviation from the above restrictions, such deviation may be authorized by the plant manager or his deputy, or higher levels of management in accordance with published procedures and with appropriate documentation of the cause.

If a reactor operator or senior reactor operator has been working more than 12 hours during periods of extended shutdown (e.g., at duties away from the control board), such individuals shall not be assigned shift duty in the control room without at least a 12-hour break preceding such an assignment.

NRC encourages the development of a staffing policy that would permit the licensed reactor operators and senior reactor operators to be periodically assigned to other duties away from the control board during their normal tours of duty.

If a reactor operator is required to work in excess of 8 continuous hours, he shall be periodically relieved of primary duties at the control board, such that periods of duty at the board do not exceed about 4 hours at a time.

The guidelines on overtime do not apply to the shift technical advisor provided he or she is provided sleeping accommodations and a 10-minute availability is assured.

Operating license applicants shall complete these administrative procedures before fuel loading. Development and implementation of the administrative procedures at operating plants will be reviewed by the Office of Inspection and Enforcement beginning 90 days after July 31, 1980.

Discussion

At the time the fuel load license was issued for Salem Unit 2, it was recognized that the licensee had an overall shortage of licensed personnel necessary to allow for a full five shift staffing of the Salem Station with both units in operation. At the time, the licensee had only eight senior reactor operators (SRO) and four reactor operators (RO) licensed for both units. However, additional licensing examinations were scheduled for May and June 1980 and the projection was that, if everyone passed, there would be 10 SROs licensed on both units, 6 ROs licensed on both units, 22 SROs licensed on Unit 1 only, and 19 ROs licensed on Unit 1 only.

A fuel load license was issued on April 18, 1980 that authorized PSE&G to operate on 12-hour shifts through the fuel load and low power test phases, pending availability of the additional licensed operators.

As a result of the TMI Lessons Learned recommendations, the licensing examinations had increased in scope to cover thermodynamics and heat transfer, and the passing grades had been increased to 70 percent in each category and 80 percent overall. The result was that fewer Salem Unit 2 operator candidates passed the examinations than the licensee had anticipated.

PSE&G informed the staff in late July 1980 that it still did not have a sufficient number of licensed operators for a full five shift operation. This was confirmed by letter dated August 1, 1980. This matter was discussed on several occassions by telephone with PSE&G management representatives, and at the Salem site on August 15, 1980. On August 20, PSE&G sent a letter to the staff containing a detailed breakdown of its current operator status and its projections for obtaining additional licensed personnel from now until March of 1983. Figure 22.2-1 depicts these projections.

In addition to the operators shown on the graph, the licensee intends to train engineers to be shift supervisors with SRO qualifications. Ultimately, (about March of 1983), these individuals are to replace the Shift Technical Advisors at the plant. In the short term, however, they could be used for shift work as SROs, if necessary. The earliest date that these Shift Supervisor/Engineers might become available with SRO qualifications is May 1981, when eight individuals are projected to become licensed as SROs. This date, however, is contingent upon a waiver being granted to permit licensing of these individuals as SROs without the minimum of one year of experience as RO, as required by current NRC licensing criteria. Without this waiver, the earliest availability date for these individuals is about May of 1982.

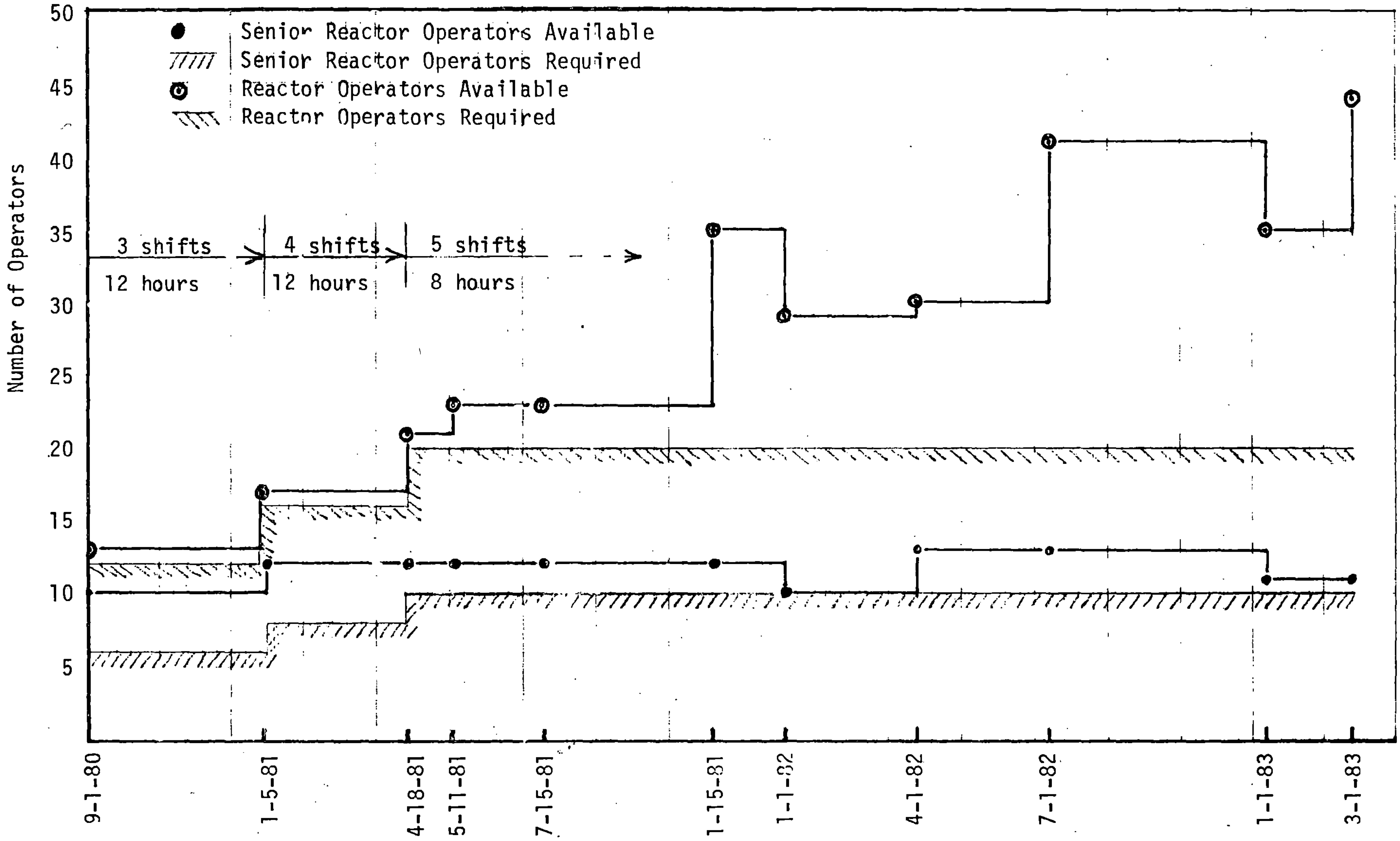
The staff recognizes that the new shift manning requirements and the restrictions on use of overtime were only formally imposed on July 31, 1980. We also recognize that licensed operators cannot be qualified quickly.

In the case of Salem, PSE&G policy is to develop potential candidates for licensed operators by hiring new personnel as Utility Operators (UO). After one year of experience as a UO and six months experience as an Apprentice Equipment Operator, an individual may be promoted to Equipment Operator (EO). Two years of experience as an EO is required before an individual is eligible to enter training to become a licensed Reactor Operator (RO). Fourteen months of training is required before the individual is eligible to take the examination for a reactor operator license. The result is that, even if an employee progresses at the fastest possible rate, a minimum time of four years and eight months is required before an individual can become licensed. The staff agrees with this training-experience philosophy, because it results in licensed operators who have a solid knowledge of the plant before they obtain their licenses. The result, however, is that PSE&G is now forced to try to make do for the time being with an inadequate number of licensed operators.

In the August 20, 1980 letter, PSE&G proposed that it be allowed to continue 12-hour shift operation and that it be allowed to operate with only three reactor operators on each shift instead of four.

Figure 22.2-1
Projected Operator Availability

Salem Station



The Unit 1 and Unit 2 control rooms are nearly identical. They are physically separated by an approximately 6-foot wide corridor which runs between the control rooms. Two half-glass partitions form the walls between the control rooms and the corridor. While the rooms are physically separated, a person in either control room can observe some of the activities in the other control room. Doors from each control room into the common corridor allow easy access from one control room to the other. The total distance between the two control consoles is less than the separation between consoles in some dual-unit plants that use a common control room. At the time the fuel load license was issued, the staff considered that one senior reactor operator could supervise and support the activities in the control rooms of both Units 1 and 2. We thus agreed that for the purpose of SRO assignment, we would treat the two control rooms as a joint room which would require that only one SRO be assigned. However, for the purpose of RO assignment, we decided that the control rooms should be considered as separate rooms, thus requiring the assignment of two ROs to each control room.

PSE&G proposed that, on an interim basis, it be allowed to consider the two control rooms as a joint control room, thus requiring the assignment of only three ROs instead of four ROs to meet the staff criteria. In support of this proposal, the licensee argues that:

a. Each control room would have an assigned licensed reactor operator with a relief operator available. The operation of a unit from the control room is a one person function. Assistance is needed primarily during a LOCA when the reactor cooling pumps must be tripped when the reactor pressure decreases to 1500 psi. The other assistance for the operator is to give him personal relief from his duties, to aid in performing his routine work and to work with him during unit startup, shutdown and testing operations. In summary, the need for the relief operator occurs only a few times a day.

b. One of the routine duties which distract the licensed reactor operator is the equipment tagging function. At Salem, a special computerized tagging system (TRIS), which is 80% complete, will minimize this work for the operator and free him to give more attention to the unit's operation. This in turn will reduce the need for assistance from the relief operator.

c. To assure quick response by the relief reactor operator, a dedicated intercom system will be installed between the two control rooms.

d. During startup, shutdown, major load changes and test operations, the relief operator will be stationed in the control room.

e. The time required to go from one control room to the other in leisurely fashion does not exceed ten seconds.

f. During a safety injection, the operator is locked out from operating safeguard systems for one minute. Therefore, the response time of ten seconds for the relief operator is one-sixth of that before he can be of any assistance.

g. There is a dedicated licensed senior reactor operator in the control room area whose response time also does not exceed ten seconds.

h. While the shift technical advisor is not always in the control room area, his response time is less than three minutes.

i. During two months of the period the waiver would be in effect, Salem Unit 1 will be shutdown for a planned maintenance outage. The need for a dedicated relief operator during this time is insignificant.

The staff has considered this proposal and the supporting safety rationale presented by the licensee. While the PSE&G arguments have some validity, we conclude that there should be two reactor operators assigned to each control room to assure that there will be adequate "hands" immediately available in the event they are needed.

PSE&G proposes to continue 12-hour shift operation until sufficient additional licensed personnel become available through the training program. With two licensed SROs and four ROs required per shift, the Salem Station would have to operate using three 12-hour shifts from the time of Unit 2 full power licensing until January 5, 1981. The station already has been on three shift operation since the fuel load license was issued in April, 1980. Shift assignments would be made such that licensed operators would work 12-hour shifts for four days, followed by two days off. There would be no requalification training of licensed operators during this period. Beginning on January 5, 1981, four additional reactor operators are projected to become available, and from then until April 13, 1981, the licensee proposes to use four 12-hour shifts for the licensed operators. This would allow requalification training of the licensed operators to commence on January 5, 1981. On April 13, 1981, availability of four additional reactor operators would allow the licensee to switch to five eight-hour shifts for the licensed operators. This is the normal staffing pattern which meets the staff's requirements without scheduled overtime. This pattern would be continued from April 13, 1981, on into the future while the licensee continues to build up the plant staff.

Use of three ROs instead of four ROs in the control rooms would enable the licensee to initiate four 12-hour shifts at the time of licensing of Unit 2, and a change to five eight-hour shifts could be made on January 5, 1981, when the four additional ROs are projected to be available. This would allow requalification training to commence immediately upon full power license issuance for Unit 2, and would require a shorter period of 12-hour shifts than would be the case if four ROs are required. While this is significant, we do not feel that the improved schedule advantages outweigh the safety advantage of having two ROs in each control room. While one operator probably can handle normal functions in one of the Salem control rooms, there are additional functions that need to be accomplished in an emergency, such as restoring the power to certain ECCS valves during the recirculation mode. A problem existing on one unit that required the assistance of the relief operator would preclude the services of that operator being immediately available in the event of an accident on the second unit.

We have examined and are continuing to examine the matter of 12-hour shifts, particularly over an extended period of time. The results to date are inconclusive. Intuitively, it seems logical that at the end of a 12-hour shift, an operator would be more fatigued and less apt to respond rapidly and correctly to a problem than would be the case at the end of an eight-hour shift. Based on the results of a short contract study, we have reviewed some data which indicate that there may indeed be some degradation in worker response over a 12-hour shift as compared to an eight-hour shift. However, most of the data were obtained from laboratory studies and from occupational situations that are not very comparable to the reactor operator function. It is not apparent from the data seen thus far whether the degradation is significant. There are also reports of beneficial effects of regularly scheduled 12-hour shifts, compared to call-in overtime when required, particularly on operator attitudes toward shift work, which should be a plus in terms of overall plant operation. The petro-chemical industry reportedly has used and is using 12-hour shifts successfully. PSE&G reports that its operators are quite content with the present 12-hour shift schedule; they have been unable to find any adverse effects of 12-hour shifts in terms of the number and types of Licensee Event Reports submitted in comparison with equivalent operating periods under an eight-hour shift schedule. The staff will continue to study this matter as it relates to all plants, but for now we can find no hard data which suggest that 12-hour shifts are unacceptable from the standpoint of plant safety.

We also have made a close study of the plans submitted by PSE&G regarding its current licensed operator status and their plans for the future. We find that the licensee will continue to have a minimal staff of reactor operators until November, 1981, at which time they expect an input of 14 additional ROs from the RO training program that started in September 1980. We find that the licensee will have an adequate number of SRO licensed individuals during the early part of the period, but that there will be little margin in the total number. This situation will continue until perhaps mid-1982, depending upon when the first group of Shift Supervisor/Engineers are eligible to become licensed as SROs. After the first group of Shift Supervisor/Engineers obtain their SRO licenses, the licensee should have ample SRO licensed individuals to support continuing five-shift operation without reliance on scheduled overtime.

Conclusions

We have reviewed the information submitted by PSE&G in the August 20, 1980 letter and have compared the information with the applicable portions of 10 CFR 50.34(b)(7); 10 CFR 50.54(i), (j), (k), (l), and (m); 10 CFR 55; and the Interim Criteria dated July 31, 1980.

For the long term, the licensee proposes to operate in accordance with the regulations and the Interim Criteria; our evaluation shows that its program complies with the requirements and is acceptable. For the next few months, however, the licensee has too few ROs licensed on Unit 2 to comply with the Interim Criteria, and has proposed that it be allowed to work 12-hour shifts, without operator requalification training until January 5, 1981, and then continue with the 12-hour shifts, but with operator requalification, until

April 13, 1981. At that time, operation on five eight-hour shifts would commence, which would be in compliance with the Interim Criteria.

We have discovered no hard data which would indicate that working 12-hour shifts over an extended period, as proposed by the licensee, would result in an unacceptable degradation of safety. Accordingly, we conclude that operation of the Salem Station on 12-hour shift schedules, with numbers of licensed operators as required by our Interim Criteria, in the manner described by the licensee in the August 20, 1980 letter, is acceptable.

We consider that the licensee's alternative proposal to use only three ROs per shift instead of the four ROs required by the Interim Criteria would reduce the number of licensed individuals available to respond immediately to an emergency and is therefore unacceptable.

For the long term, we conclude that the licensee has made adequate plans for the total numbers of licensed operators and senior operators to be available for shift manning. For the short term, however, there does exist a shortage of licensed operators.

In view of the shortage of trained and licensed operators and with an allowance for uncertainty in the targeted completion dates proposed by PSE&G, we require that:

(a) Regular requalification training of operators commence by March 1, 1981, and

(b) Regularly scheduled eight-hour shifts (without reliance on routine use of overtime) commence by June 1, 1981.

I.B.1 <u>Management for Operations</u>

I.B.1.2 <u>Safety Engineering Group</u>

<u>Position</u>

An independent safety engineering group shall be established to increase the available technical expertise located onsite and to provide for continuing systematic, and independent assessment of nuclear plant activities. This group, which shall consist of not less than five dedicated, full-time engineers, shall be physically located onsite, but shall report offsite to a high level corporate official who is not in the management chain for power production. The function of this group shall be to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, Licensee Event Reports, and other appropriate sources which may indicate areas for improving plant safety. Where useful improvements can be achieved, it is expected that this group will develop detailed recommendations for revised procedures, equipment modifications, or other means of achieving the goal of improved plant safety. A principal function of the independent safety engineering group shall be to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as much as practical. The independent group shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

Discussion and Conclusion

PSE&G provided an independent safety engineering group during the special low power test program in accordance with the staff position. We require that PSE&G maintain the safety engineering group on a continuing basis for full power operations. In a letter dated August 19, 1980, PSE&G agreed to retain its independent safety engineering group (known as the Safety Review Group) onsite during full power operation. The Safety Review Group will continue to report to the General Manager-Licensing and Environment. This requirement will be incorporated in the Technical Specifications. We conclude that Item I.B.1.2 is acceptably resolved for full-power operation.

I.C.1 Short-Term Accident Analysis and Procedure Revision
Position

Analyze the design basis transients and accidents including single active failures and considering additional equipment failures and operator errors to identify appropriate and inappropriate operator actions. Based on these analyses, revise, as necessary, emergency procedures and training.

This requirement was intended to be completed in early 1980; however, some difficulty in completing this requirement has been experienced. Clarification of the scope and revision of the schedule was developed and was issued October 31, 1980. The following implementation schedule was established for responding to the additional clarification.

Reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures should be completed and submitted to the NRC for review by January 1, 1981. The NRC staff will review the analyses and guidelines and determine their acceptability by July 1, 1981, and will issue guidance to licensees on preparing emergency procedures from the guidelines. Following NRC approval of the guidelines, licensees and applicants for operating licenses issued prior to January 1, 1982, should revise and implement their emergency procedures at the first refueling outage after January 1, 1982. Applicants for operating licenses issued after January 1, 1982 should implement the procedure prior to operation. This schedule supersedes the implementation schedule included in NUREG-0578, Recommendation 2.1.9 for item I.C.1(a)2, Reanalysis of Transients and Accidents. For those licensees and/or owners groups that will have difficulty in attaining the January 1, 1981 due date for submittal of guidelines, a comprehensive program plan, proposed schedule, and a detailed justification for all delays and problems shall be submitted in lieu of the guidelines.

Discussion and Conclusions

In Amendment No. 2 to License DPR-75, we stated that prior to operation above 5% power, PSE&G must revise the emergency operating procedures related to the small break loss-of-coolant accident and inadequate core cooling. We also stated that we would observe a simulation of selected emergency procedures conducted by Salem personnel and observe a walk-through of at least one emergency procedure in the control room. The objective was to verify that the emergency procedures adequately addressed successful mitigation of accidents and transients, as required in Section I.C.8 of NUREG-0660 and NUREG-0694.

On August 21 and 22, 1980, a team of NRC and contractor personnel observed Salem operators participating in the simulation of several transients and accidents on the Zion simulator. The transients and accidents included loss-of-coolant accidents (LOCA) in a range of break sizes, steam generator tube rupture, loss of main feedwater, and recovery from inadequate core cooling. Some transients and accidents were run more than once and equipment failures such as loss of offsite power and failure of one emergency diesel generator, failure of scram breakers to open (ATWS), and failure of individual components in the emergency core cooling systems and auxiliary feedwater systems were included in the simulated events. During the simulation of the events and following each event, we discussed the operators' actions and the procedures with the operators.

On August 26, 1980, the team observed a walk-through of the Emergency Operating Instruction for a LOCA in the Salem Unit 1 control room and discussed the procedure with the operators. The Salem Unit 1 control room is not significantly different from the Unit 2 control room with respect to the emergency procedures discussed in this section.

The procedures provided for our review have been revised to reflect the Westinghouse analysis of small-break LOCAs and inadequate core cooling in accordance with a Salem 2 license requirement and Task Action Plan (NUREG-0660) Item I.C.1.

Some procedural deficiencies were identified to PSE&G personnel during the simulator exercises and the control room walk-through. The necessary changes were made to drafts of the procedures. We require that these changes be made to the approved procedures and that the Salem operators be briefed on the changes and their bases prior to their assuming operating responsibilities on Unit 2 above 5% of rated power. We also require that the remainder of the emergency operating instructions be revised in accordance with our comments on the reviewed procedures and that the operators be briefed on the revisions within 30 effective full power days of operation. The Office of Inspection and Enforcement will verify that these requirements are satisfied.

Based on our review of the emergency procedures and our observation of the procedures being implemented on the simulator and in the plant walk-through, we have concluded that when the required changes have been made to the procedures we reviewed, the Salem operating emergency procedure will be acceptable for operation at power levels up to 100 percent.

The licensee responded to the additional clarification of this position (NUREG-0737) in a letter dated December 9, 1980. The licensee stated that the Westinghouse Owners Group will submit a detailed description of their program to comply with the requirements of Item I.C.1 by January 1, 1981. The program will identify Owners Group submittals to be made. The additional effort required to attain full compliance with Item I.C.1, with proposed schedules for completion, will be identified as discussed in a Westinghouse Owners Group meeting with the NRC on November 12, 1980.

We find this commitment acceptable and find that the licensee meets the requirements for full power operation. However, further detailed review will be necessary as outlined above.

I.C.7 NSSS Vendor Review of Procedures

Position

Obtain NSSS vendor review of power-ascension test and emergency procedures to further verify their adequacy.

This requirement must be met before issuance of a full-power license.

Discussion and Conclusions

The NSSS vendor, Westinghouse Electric Corporation, has reviewed the Salem Unit 2 power-ascension test procedures and emergency procedures. The changes recommended by Westinghouse have been incorporated into the procedures. This has been documented in a letter to the NRC dated September 5, 1980. This satisfies Item I.C.7 of NUREG-0694.

I.C.8 Pilot Monitoring of Selected Emergency Procedures for NTOL Applicants

Position

Correct emergency procedures as necessary based on the NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of ac power, steam-line break or steam-generator tube rupture).

This action will be completed prior to issuance of a full power license.

Discussion and Conclusions

During our review of these procedures, we met with PSE&G on June 27, 1980 and August 7, 1980 to discuss the Salem plant characteristics and the control room emergency procedures for loss-of-coolant accidents, steam generator tube rupture, loss of main feedwater, recovery from inadequate core cooling and verification of natural circulation. These discussions resulted in several minor revisions to the procedures and on August 21 and 22, 1980, these revised procedures were employed to mitigate the simulated consequences of accident and transient conditions on the Zion simulator.

While executing the LOCA procedures during the simulator exercises, we observed that there could be a narrow range of small break sizes for which the procedures would require repeated termination and reinitiation of safety injection. This procedure could cause the operator to postpone the cooldown and depressurization of the reactor coolant system. This was discussed with PSE&G on August 26, 1980. Subsequently PSE&G discussed this matter with the reactor vendor and modified the safety injection reinitiation criteria for this situation to provide timely cooldown of the reactor system. The Office of Inspection and Enforcement will verify that the revised procedures are established at the Salem Nuclear Generating Station prior to operation above five percent power.

We have reviewed the guidelines for small-break LOCA and inadequate core cooling for Westinghouse plants and conclude that PSE&G has revised its Salem procedures to follow these guidelines. A more complete discussion of this item is in Section 22.2, I.C.1. This satisfied Item I.C.8 of NUREG-0694.

I.D.1 Control Room Design Review

Position

Perform a preliminary assessment of the control room to identify significant human factors deficiencies and instrumentation problems and establish a schedule approved by the NRC for correcting deficiencies.

Discussion and Conclusions

Section IV, Item I (Control Room Design Review) of the Salem Nuclear Generating Station Unit 2 SER Supplement No. 4, identified five deficiencies to be corrected prior to escalating beyond five percent power. The staff has verified through the NRC Resident Inspector that three of the deficiencies (lamp test, labeling and vertical meter failure) have been corrected in accordance with Supplement No. 4. The corrective actions on the other two (annunciator audible alarms and emergency procedures) are in progress and scheduled to be completed shortly. The completion of the two remaining deficiencies in accordance with Supplement No. 4 will be verified by the NRC Resident Inspector prior to going above five percent power.

I.G.1 Training During Low-Power Testing

Position

The TMI Task Action Plan states that applicants for operating licenses will perform a set of low power tests to increase the capability of shift crews and ensure training in plant evolutions and off-normal events. Near-term operating license facilities will be required to develop and implement intensified exercises during the low power testing programs. This may involve the repetition of startup tests on different shifts for training purposes.

Discussion and Conclusion

Supplement No. 4 stated that a series of low power tests similar to those to be performed at Sequoyah Unit 1 have been proposed by PSE&G for Salem Unit 2 and that the staff is in the process of evaluating the proposed program.

The staff completed its evaluation of the tests on August 15, 1980, and concluded that the tests satisfied the criteria stated in Supplement No. 4. On August 22, 1980, Amendment No. 2 to the Salem Unit 2 License was issued which approved a change to the Technical Specifications necessary to perform the tests.

PSE&G began the testing on August 23, 1980, and continued through August 29, 1980, at which time the unit was shutdown corrective maintenance of a leaking control rod drive mechanism.

Test No. 1, Natural Circulation Test

The Natural Circulation Test was performed with 3 percent reactor thermal power (3% RTP). All four RCPs were shutdown and natural circulation was established and verified. Response was as expected with no anomalies. The average loop delta-T stabilized at 40°F and the hottest core exit thermocouple was less than 585°F.

Test No. 2, Natural Circulation with Simulated Loss of Offsite AC Power

The reactor was brought to 1 percent RTP with all RCPs operating. The RCPs and the vital bus infeed breakers were tripped open. The diesel generators successfully started and picked up the vital loads. Natural circulation was maintained in all RCS loops.

Test No. 3, Natural Circulation with Loss of Pressurizer Heaters

Test No. 3 demonstrated the ability to maintain natural circulation and saturation margin with loss of pressurizer heaters. While in the natural circulation mode, the heaters were turned off and the reactor coolant system (RCS) was allowed to depressurize. The depressurization rate was determined to be 105 psi per hour. Charging and steam dump were varied to allow operator training of control of saturation margin.

Test No. 4, Effect of Steam Generator Secondary Side Isolation on Natural Circulation

Natural circulation was established at 1% RTP with T_{avg} at 150°F. The feedwater and steam lines for one steam generator were isolated and the RCS allowed to stabilize. A second steam generator was then similarly isolated. The transients were slow and easily followed by the operators. Plant parameters responded as expected, with a maximum RCS loop delta-T of 55°F. No indication of reverse flow was noted.

Test No. 5, Natural Circulation at Reduced Pressure

This test was similar to Test No. 3 with the exception that auxiliary pressurizer spray was used to accelerate depressurization. The performance of the saturation meter was observed and the meter accuracy verified.

Test No. 6, Cooldown Capability of the Charging and Letdown System

This test demonstrated the ability of the chemical and volume control system (CVCS) to remove heat from the reactor coolant system with the reactor shutdown, one reactor coolant pump (RCP) in operation to simulate decay heat, and all steam generators isolated. With maximum CVCS charging and letdown flow the cooldown rate was 7.3°F per hour. With minimum charging and letdown flow the rate was 4.5°F per hour.

Test No. 7, Simulated Loss of All Onsite and Offsite AC Power

After completion of the above tests, several reruns were performed for additional operator training. The final test, Simulated Loss of All Onsite and Offsite AC Power, was then performed. The reactor was shutdown with four RCPs operating to simulate decay heat input to the RCS. A simulated station blackout was initiated. Batteries provided instrument and lighting power and the steam-driven auxiliary feedwater pump was used to maintain the plant in hot standby condition.

Following completion of the last test the plant was brought to cold shutdown. Although each test had been performed at least once, not all shift operators have participated in one test and observed two others as required by Criterion No. 2 (see Supplement No. 4). In PSE&G's letter to NRC of September 5, 1980, PSE&G committed to completing the remainder of the required training "when a full power license is imminent."

Test No. 8, Establishment of Natural Circulation from Stagment Conditions

Test No. 9A, Forced Circulation Cooldown

Test No. 9B, Boron Mixing and Cooldown

Two tests of the nine identified in Supplement No. 4, Natural Circulation from Stagnant Conditions and Forced Circulation Cooldown, and Boron Mixing and Cooldown were not performed. In accordance with an NRR letter of July 11, 1980, PSE&G will conduct the boron mixing test at a later date when sufficient decay heat is available to perform the test with the reactor shutdown, and the Natural Circulation Test from Stagnant Conditions will be performed by each operator on a simulator updated with data developed from the test performed at Sequoyah.

Based on acceptable test performance to date, the staff concludes that issuance of a full power license is acceptable with the condition that the low power test training program be completed prior to exceeding 5% of rated power and the boron mixing test be completed as indicated above.

II. Siting and Design

II.B.2 Plant Shielding

Position

Provide (1) a radiation and shielding design review that identifies the location of vital areas and equipment in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by radiation during operations following an accident resulting in a degraded core, and (2) a description of the types of corrective actions needed to assure adequate access to vital areas and protection of safety equipment.

This requirement shall be met before issuance of a full-power license. (See NUREG-0578, Section 2.1.6b, and letters of September 27 and November 9, 1979.) (See Section 22.3, II.B.2 for dated requirements position, discussed herein.)

Discussion and Conclusions

By letters dated 10/12/79, 1/4/80, 6/2/80, 7/1/80, and 12/9/80, PSE&G has submitted commitments and documentation of actions to be taken at Salem 2 to implement short term lesson learned items in NUREG-0578.

The Salem radiation and shielding design review utilized post-accident release criteria which were somewhat more conservative (e.g., 10% of core solids) than the criteria provided in NUREG-0578, Regulatory Guides 1.4 and 1.7, Technical Information Document (TID) 14844, and General Design Criterion (GDC) 19 of Appendix A to 10 CFR 50. Source terms are based on one-day decay. For those areas which may require access one hour after an accident, the dose rates used to determine if GDC 19 criteria are met are a factor of 10 higher than one day decay results. The source term code used for the review was the ORIGEN code, and the Rockwell Reactor Shield Design Manual was used for shielding and dose rate calculations.

Areas evaluated for effects on access are located in the auxiliary building and penetration areas and included the following systems and areas: residual heat removal (RHR) system, safety injection system, chemical volume control system (CVCS), demineralizer area, reactor coolant filter, charging pump compartments, seal water filter area, chemistry lab, primary sample lab, fuel handling building, spent fuel pool heat exchanger area, liquid radwaste system, control room, technical support center, diesel generator compartments, diesel oil supply tank compartments, electrical relay and switchgear rooms, gaseous and liquid radwaste valve stations, and component cooling. Adequate access to vital areas under post-accident conditions has been provided through access restrictions and design changes involving the installation of additional shielding.

PSE&G cited areas which they will examine to see if additional shielding is necessary. These areas include: RHR compartment, RHR suction piping, charging pump valves, primary sample system tubing, gaseous radwaste system, piping chases containing highly radioactive fluids, and fuel handling building containment personnel hatch.

The effects of decay on access to these areas have also been calculated. All vital areas which require continuous or frequent occupancy in order to control, monitor, and evaluate the accident were identified. These areas include the control room technical support center, diesel generator compartments, diesel oil supply tank compartments, and electrical relay and switchgear rooms. Other areas for which limited access is available under postulated conditions are the liquid radwaste valve station, component cooling pump, and auxiliary feedwater pump and valve areas. PSE&G has committed to install permanent shielding for reducing dose rates from the primary sample lines and in the sample analysis area by 1/1/82 as required by NUREG-0737 (see Section 22.3, II.B.2 of this supplement). Onsite verification of these shielding modifications will be made during routine inspections.

While permanently installed shielding is planned where practical, temporary shielding such as lead bricks, lead blankets, and lead sheets will also be available at the station for local shielding.

The radiation and shielding design review conducted by the applicant identifies vital areas and additional shielding needs and design changes in accordance with our position in NUREG-0578, and is, therefore, acceptable.

II.B.3 Post-Accident Sampling

Position

Provide (1) a design and operational review of the capability to promptly obtain and perform radioisotopic and chemical analyses of reactor coolant and containment atmosphere samples under degraded core accident conditions without excessive exposure, (2) a description of the types of corrective actions needed to provide this capability, and (3) procedures for obtaining and analyzing these samples with the existing equipment.

This requirement shall be met before issuance of a full power license. See NUREG-0578, Section 2.1.8a, and letters of September 27 and November 9, 1979. (See Section 22.3, II.B.3 for dated requirements position, discussed herein.)

Discussion and Conclusion

The licensee has provided the staff with copies of his interim procedures for postaccident sampling and analysis of reactor coolant and of contaminated atmosphere. These procedures establish preparations, actions, techniques, and instructions for the safe procurement, handling, and analysis of potentially highly radioactive samples, such as would be encountered following a reactor accident involving core damage. The staff has reviewed these procedures and has found them to be acceptable until installation of an improved sampling system is complete.

The licensee has also provided the staff with a proposed design for an improved sampling system. The staff issued further clarification on this position in NUREG-0737. The licensee committed in a letter dated December 9, 1980 to have final design details available by January 1, 1982. In accordance with the implementation schedule given in NUREG-0737, the staff review of this system will be performed after installation of the sampling system is completed.

II.B.4 Training for Mitigating Core Damage

Position

Complete the training of all operating personnel in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. The training program shall include the following topics:

Incore Instrumentation

1. Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.

2. Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

Excore Nuclear Instrumentation (NIS)

1. Use of NIS for determination of void information; void location basis for NIS response as a function of core temperatures and density changes.

Vital Instrumentation

1. Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual vs. indicated level),

2. Alternative methods for measuring flows, pressures, levels and temperatures.

    a. Determination of pressurizer level if all level transmitters fail.

    b. Determination of letdown flow with a clogged filter (low flow).

    c. Determination of other Reactor Coolant System parameters if the primary method of measurement has failed.

Primary Chemistry

1. Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak tight systems.

2. Expected isotopic breakdown for core damage; for clad damage.

3. Corrosion effects of extended immersion in primary water; time to failure.

Radiation Monitoring

1. Response of Process and Area Monitors to severe damages; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (over-ranged detector); expected accuracy of detectors at different locations; use of detectors to determine extent of core damage.

2. Methods of determining dose rate inside containment from measurements taken outside containment.

Gas Generation

1. Methods of H_2 generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of non-condensibles.

2. H_2 flammability and explosive limit; sources of O_2 in containment or Reactor Coolant System.

Discussion and Conclusions

Public Service Electric and Gas Company has committed to this program as indicated in Supplement No. 4 to NUREG-0517 (TMI-2 Issues Related to Fuel Load and Low Power Test Program.)

By letter dated April 1, 1980, Public Service submitted a summary of the training material for Mitigating Core Damage. A review of this material has indicated that all topics will be addressed and that training will be completed prior to full power operation. By letter dated September 10, 1980, PSE&G reconfirmed their commitment to comply with this position.

NUREG-0737, "Clarification of TMI Action Plan Requirements", revised the implementation schedule of this position for operating reactors. By letter dated December 9, 1980, PSE&G committed to meet the operating reactor schedule. However, since PSE&G submitted a summary of their training material prior to receipt of a fuel-load license for Salem 2, the staff requires that PSE&G continue to complete the requirements of this position on the schedule defined for operating license applicants.

Therefore, based on the foregoing, we have concluded the Salem Unit 2 should comply with NUREG-0737, Item II.B.4, prior to operation above five percent power. The Office of Inspection and Enforcement will verify completion of training prior to operation above five percent power.

II.B.7 Analysis of Hydrogen Control

Position

Reach a decision on the immediate requirements, if any, for hydrogen control in small containments, and apply, as appropriate, to new OLs pending completion of the degraded core rulemaking in II.B.8 of the Action Plan.

Discussion and Conclusions

The staff position on plants such as Salem, which have dry containments, is that inerting is not required as an interim action and that continued operation and licensing of dry containment plants is justified using the current design basis, pending the rulemaking proceeding (See Section 22.2, II.B.8).

II.B.8 Rulemaking Proceeding on Degraded-Core Accidents

Position

Issue an advance notice of rulemaking or requirements for design and other features for accidents involving severely damaged cores.

These actions shall be completed before issuance of a full-power license.

Discussion and Conclusions

The accident at Three Mile Island, Unit 2 resulted in a severely damaged core accompanied by the generation and release to containment of hydrogen in excess of those limits allowed in current regulations. This accident highlighted the difficulties associated with mitigating the consequences of an accident more severe than the current design basis accidents. As a consequence, the TMI Action Plan (NUREG-0660), item II.B.8, calls for a rulemaking proceeding on consideration of degraded or melted cores in safety reviews to solicit comments.

The first steps in the resolution of item II.B.8 will be the issuance of an advance notice of proposed rulemaking and the issuance of an Interim Rule. The advance notice was transmitted to the Commission in SECY 80-357, Degraded Cooling Rulemaking. The Commission approved the advance notice on September 4, 1980. The proposed Interim Rule was transmitted to the Commission on August 25, 1980 in SECY 80-399, "Proposed Interim Amendment to 10 CFR 50 Relating to Hydrogen Control and Certain Degraded Core Considerations," and was subsequently approved on September 4, 1980. The Interim Rule, in summary, addresses the following areas: .

1. Requires inerting of all BWR Mark I and Mark II containments.

2. Requires all other plants to evaluate the effects of large amounts of hydrogen generation and to propose and assess mitigation techniques for control of hydrogen.

3. Codifies various Lessons Learned items to reduce the likelihood of degraded core accidents.

In addition to the effects related to the rulemaking, the staff has requested that a research program be initiated to investigate the effects of degraded/melted core accidents for generic LWR plant designs, and to investigate various safety systems to reduce the effects of such accidents. Additionally, the staff has contracted with the Lawrence Livermore National Laboratory for assistance on evaluating the effectiveness of distributed ignition sources within containment on an expedited basis. The staff will, however, evaluate a spectrum of mitigation techniques to control hydrogen and reduce the impact of severely degraded core accidents as part of the safety research program discussed above.

We estimate the end date of the rulemaking proceeding to be about 1983. However, the projected end date for all the interim NRC actions identified above is January 15, 1982.

II.D.3 Relief and Safety Valve Position

Position

Install positive indication in the control room of relief and safety valve position derived from a reliable valve position detection device or a reliable indication of flow in the valve discharge pipe.

This requirement shall be met before fuel loading. See NUREG-0578, Section 2.1.3a (Ref. 4), and letters of September 27 (Ref. 23) and November 9, 1979 (Ref. 24).

Discussion and Conclusion

In Part II, Section II.D.5 of Supplement No. 4 to the Salem Safety Evaluation Report, we stated that the power-operated relief valve (PORV) limit switches used to obtain positive indication of PORV position were seismically and environmentally qualified. This conclusion was based upon a letter from PSE&G dated March 28, 1980 in which this statement was made. Subsequent to the issuance of Supplement No. 4, PSE&G verbally notified the Office of Inspection and Enforcement on August 22, 1980 that the installed PORV limit switches were not qualified. PSE&G, upon discovery of this error, immediately issued a design change request to install seismically and environmentally qualified PORV limit switches. The Office of Inspection and Enforcement has verified that qualified switches are now installed. The licensee concluded in a letter dated August 28, 1980 that the error in the March 28, 1980 letter was due to an internal communication problem. Procedures were modified to prevent reoccurrences of this problem.

We find that Salem 2 is in conformance with the requirements of this position.

II.E.1.1 Auxiliary Feedwater System (AFWS) Reliability Evaluation

Position

1. Provide a simplified auxiliary feedwater system reliability analysis that uses event-tree and fault-tree logic techniques to determine the potential for AFWS failure following a main feedwater transient, with particular emphasis on potential failures resulting from human errors, common causes, single point vulnerability, and test and maintenance outage.

2. Provide an evaluation of the AFWS using the acceptance criteria of Standard Review Plan Section 10.4.9.

3. Describe the design basis accident and transients and corresponding acceptance criteria for the AFWS.

4. Based on the analyses performed, modify the AFWS, as necessary.

These requirements shall be met before issuance of a full power license.

Discussion and Conclusions

I. Introduction and Background

In a letter dated September 21, 1979, our requirements regarding the Salem Auxiliary Feedwater System (AFWS) were forwarded to PSE&G. The licensee provided responses in letters dated November 1, 1979, May 5, June 11, June 27, and July 1, 1980.

The following plant specific recommendations did not apply to this plant: GS-1, GS-5, GS-8, GL-1, and GL-3. Therefore, a discussion of these recommendations are not included in this supplement. The basis for these recommendations can be found in Appendix III of NUREG-0611, and the system description which determined the basis for not applying these recommendations can be found in Appendix X of NUREG-0611.

The following paragraphs present the results of our evaluation of the information provided by PSE&G to meet our requirements.

II. Implementation of Our Recommendations

A. Short Term Recommendations

1. Recommendation GS-2 - The licensee should lock open single valves or multiple valves in series in the AFW system pump suction piping and lock open other single valves or multiple valves in series that could interrupt all AFW flow. Monthly inspections should be performed to verify that these valves are locked and in the open position. These inspections should be incorporated into the surveillance requirements of the plant Technical Specifications. (See the discussion below on Recommendation GL-2 for the longer-term resolution of this concern.)

The licensee, in its letter of November 1, 1979, listed the manual valves in this category, and stated that Surveillance Procedure SP(O) 4.7.1.2(a) is being revised to denote that these valves will be locked open. This procedure will be performed once a month. Technical Specification Surveillance Requirement 4.7.1.2 has been clarified to assure that locked valves are checked monthly for proper position. We have reviewed the licensee's response and conclude that recommendation GS-2 is adequately met, and, therefore, acceptable. The adequacy of these surveillance procedures will be verified by the Office of Inspection and Enforcement prior to operation above 5% power.

2. Recommendation GS-3 - The licensee has stated that it throttles AFW system flow to avoid water hammer. The following recommendations are, therefore, applicable to Salem. PSE&G should reexamine the practice of throttling AFW steam flow to avoid water hammer. The licensee should verify that the AFW system will supply on demand sufficient initial flow to the necessary steam generators to assure adequate decay heat removal following loss of main feedwater flow and a reactor trip from 100% power. In cases where this reevaluation results in an increase in initial AFW system flow, the licensee should provide sufficient information to demonstrate that the required initial AFW system flow will not result in plant damage due to water hammer.

Subsequent to the transmittal of the above recommendation, NRC, by letter of November 20, 1979, issued Amendment No. 22 to Facility Operating License No. DPR-70 for Salem Unit 1. This amendment lifted a previous restriction of 1.2 in./minute on secondary water level rise in the event of low steam generator level but set forth criteria for operating procedures which include a limitation of auxiliary feedwater flow of 200 gallons per minute per steam generator when coincidentally all water flow to the feedring has been interrupted for more than five minutes and the water level in the steam generator is below the top of the feedring.

The licensee, in its letter of October 30, 1979, on the subject of feedwater hammer, committed to perform a test on Salem Unit 2 to demonstrate that unacceptable feedwater hammer will not result from anticipated feedwater transients to the steam generator. Assuming satisfactory test performance, the licensee could increase the maximum allowed feedwater flow rate to a steam generator with an uncovered feedring to the maximum flow rate obtained in the test without experiencing water hammer.

Our review of the licensee's submittal of June 11, 1980, providing the basis for AFWS flow requirements indicates that the minimum AFW flow requirement (440 gpm) is compatible with the existing flow limitation. We conclude that recommendation GS-3 is adequately met, and therefore, acceptable, providing the licensee successfully performs the proposed water hammer test, based on an NRC approved procedure. If the test is unsuccessful, we will require modifications and will provide a safety evaluation regarding the tests and modifications.

3. Recommendation GS-4 - Emergency procedures for transferring to alternate sources of AFW supply should be available to the plant operators. These procedures should include criteria to inform the operator when, and in what order, the transfer to alternate water sources should take place. The following cases should be covered by the procedures:

   - Primary water supply is not initially available. The procedures for this case should include any operator actions required to protect the AFW system pumps against self-damage before water flow is initiated; and,

   - Primary water supply is being depleted. The procedure for this case should provide for transfer to the alternate water sources prior to draining of the primary water supply.

   In response to this recommendation, PSE&G indicated in a letter dated November 1, 1979 that its operating procedures provide detailed steps to transfer the auxiliary feedwater pump suction to an alternate source. In our letter of April 4, 1980, we requested that the necessary procedures be provided to use all alternate water sources, e.g., Demineralized Water Storage Tank, Fire Water Storage Tank, Service Water System, in a preferred sequence. The licensee agreed to meet this request in its letter of May 5, 1980. In this letter it was also noted that one alternate flow path from the Demineralized Water Storage Tank includes a seismic category I, normally dry pipe routed through the vital switchgear room. In its letter of July 1, 1980, the licensee stated that "modifications will be made to the normally-open drain valve on this isolated section of pipe such that it will be piped directly to a floor drain to preclude any potential for flooding the switchgear room." We conclude that this modification is acceptable but require that the licensee should also initiate a surveillance procedure to further preclude any potential for flooding the switchgear room when this pipe is filled. We conclude that recommendation GS-5 is adequately met, and, therefore, acceptable. The adequacy of the surveillance procedures will be verified by the Office of Inspection and Enforcement prior to operation above 5% power.

4. Recommendation GS-6 - The licensee should confirm flow path availability of an AFW system flow train that has been out of service to perform periodic testing or maintenance as follows:

   - Procedures should be implemented to require an operator to determine that the AFW system valves are properly aligned and a second operator to independently verify that the valves are properly aligned.

   - The licensee should propose Technical Specifications to assure that prior to plant startup following an extended cold shutdown, a flow test would be performed to verify the normal flow path from the primary AFW system water source to the steam generators. The flow test should be conducted with AFW system valves in their normal alignment.

In our position letter of April 4, 1980, we modified our requirements to the licensee as follows: "1) revise station operating procedures to require a second operator to independently verify that the AFWS valves are properly aligned after the plant operator performed his original AFWS flow path verifications per plant surveillance procedures required after the system has been out of service, and 2) verify that the Salem Station will use the AFWS for plant startup with all AFWS valves in their normal alignment and supplying water from the primary water source (the Auxiliary Feed Storage Tank) to the steam generators." The licensee, in its letter of May 5, 1980, agreed to meet our requirements. Technical Specification 4.7.1.2 includes a provision to verify the AFWS flowpath during plant startup following a cold shutdown. We conclude that recommendation GS-6 is adequately met, and therefore, acceptable. The adequacy of the operating and surveillance procedures will be verified by the Office of Inspection and Enforcement prior to operation above 5% power.

5. Recommendation GS-7 - The licensee should verify that the automatic start AFW system signals and associated circuitry are safety-grade. If this cannot be verified, the AFW system automatic initiation system should be modified in the short-term to meet the functional requirements listed below. For the longer term, the automatic initiation signals and circuits should be upgraded to meet safety-grade requirements as indicated in Recommendation GL-5.

   a. The design should provide for the automatic initiation of the auxiliary feedwater system flow.

   b. The automatic initiation signals and circuits should be designed so that a single failure will not result in the loss of auxiliary feedwater system function.

   c. Testability of the initiation signals and circuits shall be a feature of the design.

   d. The initiation signals and circuits should be powered from the emergency buses.

   e. Manual capability to initiate the auxiliary feedwater system from the control room should be retained and should be implemented so that a single failure in the manual circuits will not result in the loss of system function.

   f. The alternating current motor-driven pumps and valves in the auxiliary feedwater system should be included in the automatic actuation (simultaneous and/or sequential) of the loads to the emergency buses.

   g. The automatic initiation signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFW system from the control room.

In Supplement #4, Part II, to the Salem SER (NUREG-0517), it was concluded that the Salem Unit 2 AFW initiation circuitry design meets NUREG-0578 short-term (control grade) requirements listed above (a-g). (See the discussion below on Recommendation GL-5 for long term implementation.) Based on that previous evaluation, we conclude that Salem Unit 2 meets the requirements of this recommendation.

B. Additional Short Term Recommendations

1. Recommendation - The licensee should provide redundant level indications and low level alarms in the control room for the AFW system primary water supply to allow the operator to anticipate the need to make up water or transfer to an alternate water supply and prevent a low pump suction pressure condition from occurring. The low level alarm setpoint should allow at least 20 minutes for operator action, assuming that the largest capacity AFW pump is operating.

In response to this recommendation, the licensee stated that the existing Auxiliary Feedwater Storage Tank includes both a low and a low-low level alarm for Control Room annunciation and indication. The low level alarm allows approximately 30 minutes for operator action and the low-low level alarm allows 10 minutes.

In our position letter of April 4, 1980 to the licensee, we stated that this design was acceptable for the short term. For the long term, we required the licensee to provide the following: 1) redundant auxiliary feedwater storage tank level indications and redundant level alarms inside the control room; 2) the above level indications and alarms should be redundant all the way from the detectors at the auxiliary feedwater storage tank to the readouts and alarms inside the control room. Power supplies for the level indication and alarms should also be redundant. Since the auxiliary feedwater storage tank is a seismic Category I water source, the entire water level indication and alarm system should in the long term be designed to safety grade requirements including the use of Class 1E circuitry and power supplies, and 3) reset the low-low level alarm to allow at least 20 minutes for operator action, assuming that the largest capacity AFW pump is operating.

The licensee in its letter of May 5, 1980, agreed to meet these requirements. On the basis of our review, therefore, we conclude that Salem meets the provisions of this recommendation.

2. Recommendation - (This recommendation has been revised from the original recommendation in NUREG-0611.) The licensee should perform a 48-hour endurance test on all AFW system pumps, if such a test or continuous period of operation has not been accomplished to date. Following the 48-hour pump run, the pumps should be shut down and cooled down and then restarted and run for one hour. Test acceptance criteria should include demonstrating that the pumps remain within design limits with respect to bearing/ bearing oil temperatures and vibration and that pump room ambient conditions (temperature, humidity) do not exceed environmental qualification limits for safety-related equipment in the room.

The licensee in its letter of May 5, 1980, stated that the tests have been completed on the Salem Unit 1 AFW pumps and that a report will be issued. In our meeting with the licensee on May 18, 1980, it was agreed that this report will be reviewed by Office of Inspection and Enforcement personnel. For Salem Unit 2, a similar test will be performed prior to reaching full power. If the test results are not acceptable to NRC, we will then require modifications, and will issue a safety evaluation regarding the tests and modifications. Based on these commitments, we conclude that the response to this recommendation is acceptable.

3. Recommendation - The licensee should implement the following requirements as specified by Item 2.1.7.b on page A-32 of NUREG-0578:

"Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements for the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9."

PSE&G, in a letter dated August 8, 1980, stated that indication of auxiliary feedwater flow to each steam generator meets safety-grade requirements. The "safety-grade" requirements for this recommendation are still under review. This is a dated requirement which must be completed by July 1, 1981.

4. Recommendation - Licensees with plants which require local manual realignment of valves to conduct periodic tests on one AFW system train and which have only one remaining AFW train available for operation, should propose Technical Specifications to provide that a dedicated individual who is in communication with the control room be stationed at the manual valves. Upon instruction from the control room, this operator would realign the valves in the AFW system train from the test mode to its operational alignment.

By letter dated November 1, 1979, PSE&G indicated that the capability to deliver at least 100% of the required AFW flow is maintained, since there are three AFW pumps per unit. The surveillance procedures only allow testing of one pump at a time, so two trains would still be available. As a result of the licensee's testing lineup, we conclude that this recommendation is not applicable to Salem.

C. Long-Term NUREG-0694 Recommendations

1. Recommendation GL-2 - Licensees with plants in which all (primary and alternate) water supplies to the AFW systems pass through valves in a single flow path should install redundant parallel flow paths (piping and valves).

Licensees with plants in which the primary AFW system water supply passes through valves in a single flow path, but the alternate AFW system water supplies connect to the AFW system pump suction piping downstream of the above valve(s), should install redundant valves parallel to the above valve(s) or provide automatic opening of the valve(s) from the alternate water supply upon low pump suction pressure.

The licensee should propose Technical Specifications to incorporate appropriate periodic inspections to verify the valve positions.

The AFWS pump suction design includes a common suction pipe which routes the normal auxiliary feedwater pump supply from the auxiliary feedwater storage tank (AFWST) to three individual pump suction lines. A manual gate valve is located in the common suction pipe (1AF1 for Unit 1 and 2AF1 for Unit 2). This valve is installed in the inverted position. Inadvertent closure of this valve would isolate the normal pump suction flow path. The licensee proposed a positive means of preventing valve closure in a letter dated September 23, 1980. This involved radiographing the valve to ensure an open flow path, drilling and pinning the yoke bushing and stem in the open position, and removal of the handwheel. The exposed section of the valve stem will be retained so that the valve disc position can be easily verified. We concur with the proposed modification. The Office of Inspection and Enforcement will verify the radiographed valve position and the valve modifications prior to operation above 5% power. We conclude that recommendation GL-2 is adequately met, and therefore, acceptable.

2. <u>Recommendation GL-4</u> - Licensees having plants with unprotected normal AFW system water supplies should evaluate the design of their AFW systems to determine if automatic protection of the pumps is necessary following a seismic event or a tornado. The time available before pump damage, the alarms and indications available to the control room operator, and the time necessary for assessing the problem and taking action should be considered in determining whether operator action can be relied on to prevent pump damage. Consideration should be given to providing pump protection by means such as automatic switchover of the pump suctions to the alternate safety-grade source of water, automatic pump trips on low suction pressure, or upgrading the normal source of water to meet seismic Category I and tornado protection requirements. (Note: this recommendation was not included in our September 21, 1979 requirements letter.)

   The primary water supply for the AFWS is maintained in the 220,000 gallon auxiliary feedwater storage tank (AFWST). The water inventory is sufficient for about 8 hours of decay heat removal. The AFWST is seismic Category I but not tornado missile resistant. Alternative water supply sources include the demineralized water storage tanks, and the fire protection and domestic water storage tanks, none of which are safety grade. In the event the AFWST is incapacitated by a tornado missile strike, the seismic category I and tornado missile resistant service water system can be lined up to supply auxiliary feedwater by installation of a spool piece.

In Section 3.5.2 of Supplement No. 4 to the Salem Safety Evaluation Report, it was concluded that a reasonable time estimate from the loss of the AFWST to completion of the spool piece connection is 53 minutes. This time interval is acceptable based on an estimate of 70 minutes without cooling before the core begins to be uncovered. It is concluded "that the applicants have the capability of lining up the service water system to the auxiliary feedwater pumps in a time interval which assures that the core is adequately cooled in the event of loss of all normal water backup system."

Subsequent to publication of Supplement No. 4, three additional concerns were identified in this area. The first concern involves the installation of the spool piece during or right after a tornado, when many actions might have to be taken at the same time. At the June 18 meeting on Salem Unit 2, the licensee made a commitment to modify plant procedures to require spool piece installation in the event of a tornado warning. We, therefore, consider that the licensee has adequately met this concern. The Office of Inspection and Enforcement will verify the adequacy of these procedures prior to operation above 5% power.

The second concern involves the determination of whether operator action can be relied on to prevent pump damage in the event of the design tornado, due to the possibility that the AFWST supply to the AFW pumps becomes unavailable because of either the tornado wind forces or strikes by tornado missiles. Recent information has indicated that the time available for operator action to prevent pump damage following a loss of pump suction supply may be shorter than previously assumed. We require that the licensee resolve this question to the staff's satisfaction prior to operation above 5% power.

The third concern involves the possible harmful effects of utilizing the service water, which under normal conditions has a salt concentration approximately half that of seawater. Since, subsequent to a postulated incident, the AFWS would have to be utilized for decay heat removal and cooldown until the residual heat removal system (RHRS) can be cut in, there is some concern that sufficient salt could solidify to decrease steam generator heat transfer to unacceptable levels and also cause flow blockage. Another concern is the possibility of unacceptable corrosion during this time period.

The licensee has submitted an analysis on this subject in letters dated July 1 and September 3, 1980.

The licensee's submittal assumed seawater salt concentration, which conservatively bounds the Delaware River salt concentrations for all conditions. PSE&G, in FSAR Amendment 43, had indicated that auxiliary feedwater was required for 48 hours after reactor trip in order to reach the RHR system pressure/temperature cut-in point.

At the end of 48 hours, the sodium chloride concentration was calculated to be 31.5%, which is well within the solubility limit for both room temperature and operating temperature. Some precipitation of calcium sulfate may occur but this would not significantly affect the steam generator heat transfer characteristics.

Based on the licensee's submittal, we conclude that the steam generators could operate for 48 hours with salt water feed without significant degradation of the steam generator shell side heat transfer, and that flow path clogging by salt deposition would not be expected. Therefore, we conclude that the licensee's design is acceptable for full power operation. With regard to corrosion effects, we conclude that salt corrosion effects would not prevent the heat removal function of the steam generators for the postulated scenarios, however, we recognize that corrosion effects from 48 hours of operation with a saline solution most likely would deteriorate the secondary side of the steam generators for subsequent operation. We would, therefore, require the licensee to demonstrate the acceptability of the steam generators prior to subsequent operation.

We conclude that Recommendation GL-4 is adequately met, and therefore, acceptable.

3. Recommendation GL-5 - The licensee should upgrade the AFW system automatic initiation signals and circuits to meet safety-grade requirements.

   In a letter dated August 8, 1980, PSE&G stated that automatic initiation of the auxiliary feedwater system meets safety-grade requirements. This recommendation is still under review. This is a dated requirement which must be completed by July 1, 1981.

4. Conclusions

   On the basis of the above considerations, we have concluded that the Salem Unit 2 auxiliary feedwater system meets the Section II.E.1.1 full power requirements of NUREG-0694 and NUREG-0737 and, therefore, is acceptable.

II.E.3.1 Emergency Power for Pressurizer Heaters

Position

Install the capability to supply from emergency power buses a sufficient number of pressurizer heaters and associated controls to establish and maintain natural circulation in hot standby conditions.

The requirement shall be met before issuance of a full-power license. (See NUREG-0578, Section 2.1.1, and letters of September 27 and November 9, 1979.)

Discussion and Conclusions

On September 13, 1979, the NRC requested Public Service Electric and Gas Company to provide additional information in the area of Lessons Learned and Emergency Preparedness as a result of the TMI-2 accident. By letters dated October 12, 1979 and January 4, 1980, PSE&G submitted its design regarding Section 2.1.1, Emergency Power Supply for Pressurizer Heaters for Salem Unit 2.

Following a loss of offsite power, stored and decay heat from the reactor would normally be removed by natural circulation using the steam generators as the heat sink. Natural circulation cooling of the primary system requires the use of the pressurizer to maintain a suitable over-pressure on the reactor coolant system.

The Salem design is such that it has the capability to manually connect approximately 400 kw of pressurizer heaters from one backup group to the emergency power source. This connection is accomplished by an installed, manually-operated interlocked transfer scheme between the pressurizer heaters and the "A" diesel generator. An additional backup group of heaters, approximately 400 kw, is being provided with the capability to be connected in a similar manner to the "C" diesel generator to provide redundancy.

An analysis performed by Westinghouse indicates that 150 kw of pressurizer heaters is needed to assure maintenance of natural circulation. These backup heater groups will be manually set up such that only 150 kw can be supplied from each emergency bus. Each redundant heater group has access to only one Class 1E division power supply. Motive and control power interfaces with the emergency buses will be through safety grade circuit breakers.

The pressurizer heaters will not be automatically tripped from the emergency buses upon a safety injection actuation signal. The equipment required for a LOCA with the inclusion of the 150 kw pressurizer heaters would be slightly above the 2000 hour rating of the diesel generator but well below the 30 minute rating. The diesel generator ratings are posted on the control console with the diesel generator watt meters marked with the 30 minute rating and 2000 hour rating. Operating procedures are in force to instruct the operator to maintain the loads within the appropriate diesel generator ratings.

We have reviewed the Salem Unit 2 design with respect to emergency power supply for pressurizer heaters. Based on our review, we conclude that the existing design for emergency power for pressurizer heaters meets the Section II.E.3.1 full-power requirements of NUREG-0694 and NUREG-0737, and therefore is acceptable.

II.E.4.2 Containment Isolation Dependability

Position

Provide (1) containment isolation on diverse signals, such as containment pressure or ECCS actuation, (2) automatic isolation of nonessential systems (including the bases for specifying the nonessential systems), (3) no automatic reopening of containment isolation valves when the isolation signal is reset.

These requirements shall be met before issuance of a full-power license. See NUREG-0578, Section 2.1.4 (Ref. 4), and letters of September 27 (Ref. 23) and November 9, 1979 (Ref. 24). (See Section 22.3, II.E.4.2 for dated requirements position, discussed herein.)

Discussion

The Salem Nuclear Generating Station Unit 2 utilizes a phased containment isolation system. This system is actuated by engineered safety feature Phase A and Phase B containment isolation signals. The Phase A containment isolation signal system complies with the diversity requirements of Standard Review Plan 6.2.4. It is initiated by a safety injection signal which can be actuated by any one of the following parameters: (1) high steam line flow with either low steam line pressure or low-low T average, (2) high containment pressure, (3) high steam line differential pressure, (4) low pressurizer pressure, and (5) manual actuation. The Phase B containment isolation signal is actuated by a containment high-high pressure signal or manually. All of the containment isolation signals are summarized in Table 22.2-1.

PSE&G has categorized all systems penetrating containment as being either essential or non-essential. The essential systems are as follows:

Residual Heat Removal - part of Safety Injection
Safety Injection
Containment Fan Coolers - Service Water
Steam Supply to Auxiliary Feedwater Pump Turbine
Main Steam Atmosphere Relief
Auxiliary Feedwater
Charging Portion for Safety Injection

All non-essential systems having automatic containment isolation valves, and which are not required for an orderly reactor shutdown or to maintain containment atmospheric conditions, are closed by a Phase A containment isolation signal. The reactor coolant pump motor cooling water supply and return, reactor coolant pump thermal barrier cooling water discharge and the reactor coolant pump seal water return lines are isolated by the Phase B containment isolation signal.

In the licensee's current classification of essential vs. non-essential systems, PSE&G has classified the reactor coolant pump services as non-essential and has automatically isolated these systems by the containment Phase B isolation signal. Certain systems, while not engineered safety feature (ESF) systems required by design for accident mitigation, may nonetheless be considered important to post-accident plant safety and valuable in accident mitigation. Such systems may be deemed essential insofar as not requiring diversity in the parameters sensed for the initiation of containment isolation. The reactor coolant pump services fall into this category, and so we find the isolation provisions for these lines to be acceptable.

The Westinghouse Owners Group has prepared a report entitled "Classification of Lines Penetrating Containment and a Review of Containment Isolation Logic and Philosophy." The report has been reviewed by PSE&G for applicability to Salem Unit 2. The licensee has determined that Salem conforms with the established essential/non-essential categories and recommended isolation provisions, and that no further changes are required in the Salem design other than those noted below.

The licensee has reviewed the containment isolation valve control system design and identified two specific containment penetrations for which one or both of the containment isolation valves might open upon resetting the containment isolation signal. These were the containment isolation valves in the reactor coolant drain tank pump discharge line and the pressurizer relief tank gas analyzer line. PSE&G has modified the design of these control systems for these isolation valves to preclude the possibility of inadvertent opening of these valves in the event of resetting the containment isolation signal. We conclude that this action has acceptably satisfied the requirements pertaining to the design of the containment isolation valves control systems and the isolation signal reset function.

Therefore, we conclude that the licensee has met the requirements of II.E.4.2 and that the design is acceptable for full power licensing.

II.K.3 Final Recommendations of B&O Task Force (Item C.3.3)

Position

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in an annual report.

This requirement shall be met before issuance of a full-power license.

Discussion and Conclusions

The licensee responded to this Action Plan requirement in a letter dated June 27, 1980. PSE&G stated that prompt reporting will be made on all PORV and safety valve failures, and that documentation of all challenges will be included each year in the December monthly report. Technical Specification changes for the reporting of any PORV malfunction within 30 days have been included for the Salem Unit 2 plant.

On this basis, we consider the Section II.K.3, Item C.3.3, full power requirements have been met.

TABLE 22.1-1

Containment Isolation Signals and Input Parameters

Containment Isolation - Phase A

a. Manual Actuation
b. High Containment Pressure
c. Low Pressurizer Pressure
d. High Differential Pressure Between Steam Lines
e. High Steam Line Flow Coincident with Either Low Steam Line Pressure or Low-Low T_{avg}

Containment Isolation - Phase B

a. Manual Actuation
b. High-High Containment Pressure

Containment Ventilation Isolation

a. Manual Actuation
b. High Containment Pressure
c. Low Pressurizer Pressure
d. High Differential Pressure Between Steam Lines
e. High Steam Line Flow Coincident with Either Low Steam Line Pressure or Low-Low T_{avg}
f. High Containment Radiation - Particulate
g. High Containment Radiation - Iodine
h. High Containment Radiation - Gaseous

Main Steam Line Isolation

a. Manual Actuation
b. High-High Containment Pressure
c. High Steam Line Flow Coincident with Either Low Steam Line Pressure or Low-Low T_{avg}

Feedwater Isolation

a. Manual Actuation
b. High Containment Pressure
c. Low Pressurizer Pressure
d. High Differential Pressure Between Steam Lines
e. High Steam Line Flow Coincident with Either Low Steam Line Pressure or Low-Low T_{avg}
f. High-High Steam Generator Water Level
g. Reactor Trip Coincident with Low T_{avg}.

III. Emergency Preparations and Radiation Protection

III.A.1.1 Upgrade Emergency Preparedness

Position

Provide an emergency response plan in compliance with NUREG-0654, Rev.1 (November 1980) "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." NRC will give substantial weight to FEMA findings on offsite plans in judging the adequacy against NUREG-0654. Perform an emergency exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations.

This requirement shall be met before issuance of a full-power license.

Discussion and Conclusions

We have reviewed the applicant's revised emergency plan against the current regulatory requirements contained in 10 CFR Part 50 and the guidance criteria in NUREG-0654 dated November 1980. Upon satisfactory completion of the items identified below, the staff will issue a favorable finding with respect to emergency preparedness matters for full power operation of Unit 2 at the Salem Nuclear Generating Station.

1. Correct the deficiencies identified in our Emergency Preparedness Evaluation Report which is included as Appendix F to this report (NUREG-0694, item III.A.1.1)

2. Perform an emergency response exercise that tests the integrated capability and a major portion of the basic elements existing within the emergency preparedness plans and organizations (NUREG-0694, item III.A.1.1)

3. Submit radiological response plans of State and local governments within the plume exposure pathway Emergency Planning Zone as well as the plans of State governments within the ingestion pathway Emergency Planning Zone (10 CFR 50.33g)

4. NRC review of the Federal Emergency Management Agency findings and determinations as to whether State and local emergency plans are adequate and capable of being implemented (10 CFR 50.47a)

III.D.1.1 Primary Coolant Sources Outside Containment

Position

Reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels, measure actual leak rate and establish a program to maintain leakage at as-low-as-practical levels and monitor leak rates.

This requirement shall be met before issuance of a full-power license.

Discussion and Conclusions

Public Service Electric & Gas (PSE&G) provided a summary description of their leakage reduction program in their letter dated July 8, 1980. The description includes justifications for the exclusion of those systems not covered by the program. The inability to use any of the systems not covered would not preclude the use of any mode for cooling the core nor prevent the use of any safety system. For those systems where leakage is measured during shutdown, leak rate measurements will be made and reported prior to startup. For those systems where leakage is measured during plant operation, leak rate measurements will be made and reported within 60 effective full-power days of plant operation.

The staff has reviewed the proposed leak reduction program and concludes that the provisions of III.D.1.1 have been satisfied.

III.D.2.4 Offsite Dose Measurements

Position

The NRC will place approximately 50 thermoluminescent dosimeters (TLDs) around the site in coordination with the applicant's and state's environmental monitoring program. This action shall be completed prior to issuance of a full power license.

Discussion and Conclusions

The Office of Inspection and Enforcement has stated that 33 TLDs have been placed around the plant site. A program has been established as part of the New Jersey and Delaware state environmental programs to collect and process the TLDs quarterly and send the results to NRC.

Based on the above, we conclude that the Section III.D.2.4 full power requirements of NUREG-0694 have been met.

III.D.3.4 Control Room Habitability

Position

Identify and evaluate potential hazards in the vicinity of the site as described in SRP Sections 2.2.1, 2.2.2, and 2.2.3, confirm that operators in the control room are adequately protected from these hazards and the release of radioactive gases as described in SRP Section 6.4, and, if necessary, provide the schedule for modifications to achieve compliance with SRP Section 6.4.

This requirement shall be met by issuance of a full-power license.

Discussion and Conclusion

Since both Units 1 and 2 of the Salem Station occupy a common control room building, the original staff review of the control room habitability systems encompassed the control rooms for both units. The staff's Safety Evaluation Report dated October 11, 1974, at Section 15.3 concluded that these systems met the requirements of 10 CFR Part 50, Appendix A, General Design Criterion 19. The review at that time also encompassed potential hazards in the vicinity of the site and it was noted in Section 2.2 that additional analysis of potentially hazardous cargo being transported on the Delaware River was required. Supplement No. 3 to the Salem Safety Evaluation Report dated December 29, 1978 reported in Section 6.4, that no airborne hazard existed for which any additional control room habitability system features would be required. The staff has concluded therefore, that the criteria of SRP Section 6.4 have been met.

By letter dated August 13, 1980, the staff was notified by the applicant that it had independently reviewed the control room habitability systems guidance provided in SRP Sections 2.2.1, 2.2.2, 2.2.3 and 6.4 and Regulatory Guides 1.78 and 1.95, and concluded that the design of the Salem Unit 2 control room is such as to assure that operators in the control room will be adequately protected against exposure to unacceptable levels of radiation during and after a design basis accident and unacceptable levels of hazardous chemicals released on or in the vicinity of the site. The licensee concluded that no design modifications are necessary.

This conclusion is consistent with the staff's previous findings as stated above. We conclude that the applicant has satisfied the requirements of Section III.D.3.4 of NUREG-0694 and NUREG-0737.

IV. Practices and Procedures

IV.F.1 Power-Ascension Test

Position

IE will monitor the power-ascension test program to confirm that safety is not compromised because of the expanded startup test program and economic costs of the delay in commerical operation.

This action shall be taken during the startup and power-ascension program.

Discussion

IE will monitor the power-ascension test program.

22.3 Dated Requirements

With respect to TMI-2 dated requirements, we state in NUREG-0737 that "the requirements herein (which include the requirements from NUREG-0694) are applicable to applicants for operating licenses and such applicants are expected to meet the same schedule of implementation as indicated for operating reactors. Operating license reviews being finalized over the next few months will be handled on a case-by-case basis. Any item for which the implementation date is prior to the expected date of issuance of an operating license will be considered to be a prerequisite to obtaining that license."

In letters dated August 3, August 19, and August 22, 1980, PSE&G submitted a mid-year status of design and installation of Category B (dated requirement items identified in NUREG-0694) modifications and the proposed schedule for implementation of modifications at Salem Unit 2. PSE&G subsequently modified the proposed schedule to reflect the implementation schedules indicated in NUREG-0737. The following section presents an evaluation of each of the dated requirements included in NUREG-0737.

NUREG-0737 stated that the requirements contained in that document do not constitute the total set of TMI-related actions in the TMI-2 Action Plan, NUREG-0660. Upon further staff development of criteria and planning, additional requirements will be issued. It is expected that as revisions to the Action Plan Requirements are finalized, they will be applicable to Salem Unit 2.

I. Operational Safety

I.A.1 Operating Personnel and Staffing

I.A.1.1 Shift Technical Advisor

Position

In a letter dated October 30, 1979 from the NRC to all licensees of operating plants and applicants for operating licenses, the staff clarified the requirements for the shift technical advisor (STA). Specifically, the STA shall have (1) a bachelor's degree or equivalent in a scientific or engineering discipline, (2) specific training in the response and analysis of the plant for transients and accidents, (3) training in the plant design and layout, and (4) six months of on-site experience. NUREG-0737 further stated that all licensees shall submit a description of their long-term STA program, including qualification, selection criteria, training plans, and plans, if any, for the eventual phaseout of the STA program.

This requirement shall be met by January 1, 1981.

Discussion and Conclusions

By letter dated September 10, 1980, PSE&G forwarded resumes of four individuals for whose services PSE&G has contracted from Westinghouse and General Physics Corporation. PSE&G proposes to use these individuals as replacements for three PSE&G engineers who are now serving as Shift Technical Advisors at Salem. This would enable the licensee to enter these three PSE&G employees in a training program aimed at producing additional licensed operators for Salem.

Three of the four contract individuals are graduate engineers. The fourth has a BS degree in mathematics and is a product of the Navy nuclear program with three years of responsible experience in the Navy program. All of the four individuals have had PWR experience, and all have received special training in themodynamics, Salem systems, and emergency procedures. None of the four have six months experience on site, and the licensee has asked for a waiver of this requirement.

The fully trained STAs (required by January 1, 1981) will have completed their training and be available for assignment on shift by the end of December, 1980. Salem Unit 1 is scheduled to be down for maintenance and refueling between September and December, 1980. It appears that the services of the contract STAs might be needed for a period of no more than a few weeks.

In view of the circumstances described above, and in recognition of the need to obtain additional licensed operators as soon as possible, we conclude that a waiver of the six-month on-site experience requirement for the contracted STAs is acceptable until such time as the fully trained STAs are available for assignment on shift.

I.A.2.1 Immediate Upgrading of Operator and Senior Operator Training and Qualification

Position

Applicants for SRO license shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at the specific plant) and no more than 2 years shall be academic or related technical training.

Certifications that operator license applicants have learned to operate the controls shall be signed by the highest level of corporate management for plant operation.

Revise training program to include training heat transfer, fluid flow, thermodynamics, and plant transients.

An applicant for an SRO license will be required to have experience equivalent to one year's experience as a licensed operator.

Discussion and Conclusion

Applications received for a senior operator license on Salem Unit No. 2 have indicated that the required experience levels have been met.

Certifications that operator license applicants have learned to operate the controls will be signed by F. W. Schneider, Vice President - Production.

The Licensed Operator Training Programs have been revised to include training in heat transfer, fluid flow, thermodynamics, and plant transients.

Individuals who have received a Senior license on Salem Unit No. 2 meet all experience requirements.

Applications which have been recently submitted are signed by the Vice President - Production. Training programs have been revised as required. The staff (OLB) will review revised training programs in accordance with Item A.2.C of H. Denton's letter of March 28, 1980.

We conclude that PSE&G has satisfied the requirements of NUREG-0737, Item I.A.2.1.

I.A.2.3 Administration of Training Programs for Licensed Operators

Position

Training instructors who teach systems, integrated response, transient and simulator courses shall successfully complete an SRO examination and instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedures and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

Discussion and Conclusion

All Salem instructors that teach systems, integrated responses, and transient courses presently hold valid SRO licenses. Instructors participate in the applicable portions of the requalifications program.

Based on the foregoing, we have concluded that Salem Unit 2 has complied with NUREG-0737, Item I.A.2.3.

I.A.3.1 Revise Scope and Criteria for Licensing Exams

Position

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations. Contents of the licensed operator requalification program shall be modified to include instruction in heat transfer fluid flow, thermodynamics, and mitigation of accidents involving a degraded core.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license.

Requalification programs shall be modified to require specific reactivity control manipulations. Normal control manipulations, such as plant or reactor startups, must be performed. Control manipulations during abnormal or emergency operation shall be walked through and evaluated by a member of the training staff. An appropriate simulator may be used to satisfy the requirements for control manipulations.

Discussion and Conclusion

Applicants for operator licenses will grant permission to the NRC to inform plant management regarding the results of examination.

Content of the licensed operator requalification program has been modified to include instruction in heat transfer, fluid flow, thermodynamics, and mitigation of accidents involving a degraded core.

The criteria for requiring a licensed individual to participate in accelerated requalification have been modified to reflect the new passing grade for issuance of licenses.

The requalification program has been modified to require specific reactivity control manipulations as per Enclosure 4 to H. Denton's letter of March 28, 1980. One week of simulator training is scheduled for each licensed operator per year. Control manipulations during abnormal or emergency operations are evaluated by the simulator training staff and provided to PSE&G. As many reactivity manipulations as practical will be performed at Salem; those manipulations not performed at Salem will be performed on a simulator.

Based on the information submitted by PSE&G, we conclude that Salem Unit 2 has satisfied all requirements of NUREG-0737, Item I.A.3.1.

I.C.1 Short-Term Accident Analysis and Procedure Revision

Position

Analyze the design basis transients and accidents including single active failures and considering additional equipment failures and operator errors to identify appropriate and inappropriate operator actions. Based on these analyses, revise, as necessary, emergency procedures and training.

This requirement was intended to be completed in early 1980; however, some difficulty in completing this requirement has been experienced. Clarifications of the scope and revision of the schedule were issued on October 31, 1980. The following implementation schedule was established for responding to the additional clarification.

Reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures should be completed and submitted to the NRC for review by January 1, 1981. The NRC staff will review the analyses and guielines and determine their acceptability by July 1, 1980, and will issue guidance to licensees on preparing emergency procedures from the guidelines. Following NRC approval of the guidelines, licensees and applicants for operating licenses issued prior to January 1, 1982, should revise and implement their emergency procedures at the first refueling outage after January 1, 1982. Applicants for operating licenses issued after January 1, 1982 should implement the procedures prior to operation. This schedule supersedes the implementation schedule included in NUREG-0578, Recommendation 2.1.9 for item I.C.1(a)3, Reanalysis of Transients and Accidents. For those licensees and/or owners groups that will have difficulty in attaining the January 1, 1981 due date for submittal of guidelines, a comprehensive program plan, proposed schedule, and a detailed justification for all delays and problems shall be submitted in lieu of the guidelines.

Discussion and Conclusions

Our evaluation of this matter is addressed in Section 22.2, Item I.C.1, of this supplement.

I.C.6 Verifying Correct Performance of Operating Activities

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the oeople performing the activity (see NUREG-0585, Recommendation 5), or both. An acceptable program for verfication of operating activities is described in NUREG-0737.

This position should be implemented by January 1, 1981.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that they will implement this position on January 1, 1981, as required by NUREG-0737.

The staff finds this commitment acceptable.

II. Siting and Design

II.B.1 Reactor Coolant System Vents

Position

Provide a description of the design of reactor coolant system and reactor vessel head high point vents that are remotely operable from the control room and supporting analyses. This requirement shall be met by July 1, 1981. See letters of September 27 and November 9, 1979.

Install reactor coolant system and reactor vessel head high-point vents that are remotely operable from the control room. This requirement shall be met by July 1, 1982.

Discussion and Conclusion

By letters dated January 4, 1980, and September 5, 1980, PSE&G provided a conceptual design for the TMI-Task Action Plan requirement II.B.1 to install reactor coolant system vents. The licensee has designed the vent system to be remotely controlled and monitored and has committed that the design will be safety grade, seismically qualified, and single-failure proof. Finally, PSE&G has confirmed that a break in the vent line will be within the envelope of present accident analyses and that these analyses are for the vent line break.

Our preliminary review of this information has concluded that this conceptual design adequately addresses the requirements of our November 9, 1979 letter on vents. However, a detailed evaluation of the design has not been completed. Some areas that will require further detail are vent system qualification to operate under accident conditions, system testability, piping design, procedural guidelines and analyses.

By letter dated December 9, 1980, the licensee committed to submit additional information on the design of the vent system by July 1, 1981. This commitment is in accordance with the implementation schedule established in NUREG-0737 and we find it acceptable.

The licensee has committed to install reactor coolant vents in accordance with the required implementation schedule subject to availability of a unit outage of sufficient duration. However, we require that the vent installation be completed no later than the required date of July 1, 1982 established in NUREG-0737.

II.B.2 Plant Shielding

Position

Complete modification to assure adequate access to vital areas and protection of safety equipment following an accident resulting in a degraded core.

This requirement shall be met by January 1, 1982, for vital area access and by June 30, 1982 for qualification of safety-related electrical equipment.

Discussion and Conclusions

Our evaluation of the radiation and plant shielding report which is required prior to full-power operation is presented in Section 22.2, Item II.B.2 of this report.

Planned modifications for additional shielding installation for the primary sampling area have been committed to be complete by January 1, 1982. The licensee has committed to fully qualify all safety-related electrical equipment by June 30, 1982.

We find these commitments acceptable.

II.B.3 Post Accident Sampling

Position

Complete corrective actions needed to provide the capability to promptly obtain and perform radioisotopic and chemical analysis of reactor coolant and containment atmosphere samples under degraded-core conditions without excessive exposure.

This requirement shall be met by January 1, 1982.

Discussion and Conclusions

In a letter dated July 8, 1980, Public Service Electric & Gas Company (PSE&G) provided the staff with the preliminary design of a post accident sampling system which conforms to the design criteria established by the NRC staff.

PSE&G's installation schedule for Salem Unit 2 anticipates completion by January 1, 1982. Until the improved system can be installed, the licensee will continue to use the interim procedure discussed in Section 22.2, II.B.3, for sampling and analysis.

The staff has reviewed PSG&E's submittals on this item. PSE&G has committed to procure and install equipment and to implement the relevant procedures for operation of the equipment necessary to comply with the staff's criteria, as set forth in NUREG-0578, in the letter of November 9, 1979, in NUREG-0694, and in NUREG-0737. The staff finds the described equipment and procedures to be in compliance with these criteria. PSE&G projects January 1, 1982 as the date for installation of equipment items necessary for safe operation of the improved post accident sampling system subject to availability of a unit outage of sufficient duration.

We require, however, that the modifications be completed no later than te required date of January 1, 1982 established in NUREG-0737.

II.D.1 Relief and Safety Valve Test Requirements

Position

Complete tests to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents. Complete tests to qualify for PWR block valves.

This requirement shall be met by July 1, 1981. Plant-specific submittals for qualification of safety relief valves and block valves should be submitted in accordance with the schedules established in NUREG-0737.

Discussion and Conclusions

The applicant has stated that it will participate in the EPRI/NSAC program to conduct performance testing of PWR relief and safety valves and associated piping and supports. The applicant has referenced the proposed EPRI program ("Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems," dated December 13, 1979) for the performance testing of these valves.

A description of the test program was provided to the NRC by EPRI in December 1979. We will review this program and schedule to ensure that the NUREG-0578 requirements are met. Preliminary discussions with EPRI also indicate that meeting the clarified requirements of NUREG-0578 is feasible.

In a letter dated September 5, 1980, PSE&G has committed to meet the requirements of this item to the extent practicable at this time. We believe that this commitment provides adequate assurance that the requirement for performance testing of relief and safety valves will be satisfied. Our basis for accepting this commitment is, first, that the preliminary discussions with EPRI indicate that their proposed test program will meet the requirements of NUREG-0578, and second, that we will review the test programs and schedule to confirm acceptability of the program and applicability to the applicant's facility.

The licensee's response to the performance testing requirement for PWR relief and safety valves is acceptable. The staff will perform a detailed review of the program proposed by EPRI and of the applicability of the program to all PWRs, including the applicant's facility.

PSE&G has committed to meet the plant-specific requirements of this position by the due dates established in NUREG-0737 provided that the EPRI test program is completed on schedule. We believe that this commitment provides adequate assurance that this requirement will be satisfied. However, we require that the licensee notify the staff of any potential slips in the implementation schedules established in NUREG-0737.

II.E.1.2 Auxilary Feedwater Initiation and Indication

(a) Initiation

Position

Upgrade as necessary, automatic initiation of the auxiliary feedwater system to safety-grade quality.

This requirement shall be met by July 1, 1981.

Final design information shall be submitted by January 1, 1981.

Discussion and Conclusions

PSE&G stated in a letter dated August 3, 1980 that the automatic initiation of the auxiliary feedwater system meets safety-grade requirements. The submittals which describe the licensee's compliance with the safety-grade requirement are still under review. The licensee stated that further design details will be submitted by January 1, 1981. We find this commitment acceptable.

(b) Indication

Position

Upgrade, as necessary, the indication of auxiliary feedwater flow to each steam generator to safety grade quality.

This requirement shall be met by July 1, 1981.

Final design information shall be submitted by January 1, 1981.

Discussion and Conclusions

In a letter dated August 3, 1980, PSE&G stated that the indication of auxiliary feedwater flow to each steam generator meets safety-grade requirements. The submittals which describe the licensee's compliance with the safety-grade requirement are still under review. The licensee stated in a letter dated December 9, 1980, that further design details will be submitted by January 1, 1981. We find this commitment acceptable.

II.E.4.1 Containment Dedicated Penetration

Position

Install a containment isolation system for external recombiners or purge systems for post-accident combustible gas control, if used, that is dedicated to that service only and meets the single-failure criterion.

This requirement shall be met before January 1, 1981.

Discussion and Conclusions

Our discussion and conclusion regarding the need for dedicated penetrations for hydrogen control at Salem Unit 2 were given in Section II.E.4.1 of Supplement No. 4 to the Salem Unit 2 Safety Evaluation Report. We concluded that this requirement is not applicable to Salem Unit 2. However, the licensee has reviewed and revised the Salem Unit 2 procedures for hydrogen recombiner use following an accident that results in a degraded core and a release of radioactivity to the containment, and has determined that they are adequate. Also, there are no shielding requirements or personnel exposures involved in operating the existing recombiners since they are located inside the containment and are remote manually controlled from the main control room.

Therefore, we conclude that Salem Unit 2 complies with the provisions of Item II.E.4.1 of the TMI Action Plan.

II.E.4.2 Containment Isolation Dependability

Position

a. The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

b. Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4, item II.3.f during operational conditions 1, 2, 3, and 4. Furhtermore, these valves must be verified to be closed at least every 31 days.

c. Containment purge and vent isolation valves must close on a high radiation signal.

Each licensee will provide, and justify, the minimum containment pressure that will be used to initiate containment isolation as stated in position a. by January 1, 1981. By July 1, 1981, all operating plants must be in comliance with position a. All operating plants must be in compliance with postion b. by January 1, 1981. All operating plants must be in compliance with position c. by July 1, 1981. (See Section 22.2, II.E.4.2 for the full power requriements part of this position.)

Discussion and Conclusions

The licensee stated in a letter dated December 9, 1980, that they are currently in compliance with positions b. and c. of this item. A detailed discussion of PSE&G's compliance with position b. is contained in Section 6.2.3 of this supplement. A postimplementation review of the licensee's compliance with position c. of this item will be performed at a later date.

By letter dated December 9, 1980, the licensee stated that they will implement the requirements associated with the staff's position on containment setpoint pressure on the schedule required by NUREG-0737.

The staff finds this commitment acceptable.

II.F.1 Additional Accident Monitoring Instrumentation

Position

Install continuous indication in the control room of the following parameters:

a. Containment pressure from minus 5 psig to three times the design pressure of concrete containments and four times the design pressure of steel containments;

b. Containment water level in PWRs from (1) the bottom to the top of the containment sump, and (2) the bottom of the containment to a level equivalent to 600,000 gallons of water;

c. Containment atmosphere hydrogen concentration from 0 to 10 volume percent;

d. Containment radiation up to 10^8 Rad/hr;

e. Noble gas effluent from each potential release point from normal concentrations to 10^5 mCi/cc (Xe-133).

f. Provide capability to continuously sample and perform onsite analysis of the radionuclide and particulate effluent samples.

This instrumentation shall meet the design and qualification criteria specified in NUREG-0737.

This requirement shall be met by January 1, 1982.

Discussion and Conclusion

a. Containment Pressure Indication

In a letter dated August 22, 1980, PSE&G stated that the installation of an extended range containment pressure measuring system has been delayed because of the unavailability of qualified equipment and suitable containment penetrations.

Transmitters designed to the new standards (IEEE 323-1974) have been ordered and are scheduled for delivery by January 1, 1981. Standard transmitters are also being obtained for temporary substitution, if delivery is further delayed.

The licensee further stated that qualified bellows assemblies (or diaphragms) for use inside the containment are a long-delivery item. In the interim, standard assemblies have been purchased and will be installed.

In the August 22, 1980 letter, PSE&G committed to modify the existing penetrations for the new system.

PSE&G's position is that plant operation may proceed without causing any undue safety hazard to the public until the new system is installed on the basis that the four existing transmitters have a range of -5 to +55 psi which extends well above the maximum calculated pressure (45.2 psig) for a postulated LOCA inside the containment and the containment design pressure (47 psig).

PSE&G has verbally stated that the extended-range containment pressure measuring system will meet the design provisions of Regulatory Guide 1.97, except that the presently available bellows assemblies on the diaphragms are not suitably qualified. We will resolve this matter in further discussions with the licensee.

The licensee has agreed to confirm in writing the verbal information given above.

In a letter dated December 9, 1980, PSE&G projected installation of the qualified transmitters by January 1, 1982, subject to availability of a unit outage of sufficient duration. We require, however, that the containment pressure measuring equipment by installed on January 1, 1982 as required by NUREG-0737.

We conclude that, pending receipt of the confirmatory documentation mentioned above, the licensee's provisions for measuring containment pressure are acceptable, except for the bellows assemblies qualification issue which we will review further.

b. <u>Containment Water Level Indication</u>

For the containment liquid level, only two systems were considered by PSE&G; differential pressure transmitters and an analog tank level type indicating system. There are numerous other methods of level measurement; however, the difficulty of seismically and environmentally qualifying them precluded their consideration.

The differential pressure system would require core boring of the containment sump bottom for installation of a process sensing line. This application would require extensive design field modification. Therefore, the other system was selected by Salem Unit 2 because of its ease of installation in addition to being environmentally and seismically qualified.

A purchase order was placed on April 3, 1980 with an originally promised delivery date of August 25, 1980. The present delivery date is February, 1981. Delivery has slipped due to the magnitude of orders received by the vendor, his relocation in July to a new facility, and the closure of the plant for vacation. In a letter dated August 3, 1980, PSE&G estimated that one month will be required to install the system, including a 1-week unit outage for final hookup. In a letter dated December 9, 1980, PSE&G projected installation of the system by January 1, 1982 subject to availability of a unit outage of sufficient duration.

In a letter dated August 22, 1980, PSE&G stated that until the new system is installed, plant operation may proceed without causing any undue safety hazard to the public because:

1. The existing tank level type digital indicating system covers the required indicating range by identifying the key sump levels for accident operation.

2. The setpoints for indication and alarm of "RHR Pump NPSH Permissive" and "Maximum Flood Level" have been revised to the latest requirements.

3. Sump level is only a backup indication to the RWST level.

PSE&G has verbally informed the staff that Salem Unit 2 has a redundant containment water level instrument which serves as both the narrow range and wide range instruments. It uses the bottom of the containment sump as its zero point and measures to a height of 17 feet. It meets the provisions of Regulatory Guide 1.89 and the provisions of the proposed revision to Regulatory Guide 1.97, except that the level information is not recorded. The staff concludes that this interim system is acceptable pending installation of the final system. The licensee has agreed to confirm in writing the information given verbally.

The licensee asserts that recording the containment water level information is not necessary. Recording the containment water level is currently a requirement of NUREG-0737 and, therefore, the staff requires that this position be met on the NUREG-0737 implementation date of July 1, 1981.

We conclude that, pending receipt of the confirmatory documentation mentioned above, Salem Unit 2 may operate at full power with its present containment water level indicators until the new system is installed. We require that the system be installed on July 1, 1981, as required by NUREG-0737.

c. Containment Hydrogen Indication

The licensee presently has redundant hydrogen analyzers and has recalibrated them to provide an indication of hydrogen concentration within the containment from 0 to 10 volume percent. The analyzers were originally calibrated for a 0 to 4 volume percent hydrogen concentration. It is not clear, however, that the analyzers will operate acceptably over the expanded hydrogen concentration range. PSE&G, in conjunction with the manufacturer of the analyzers (Bacharack), will provide written documentation of the analyzer performance capability over the 0 to 10 volume percent range of hydrogen concentration. The licensee has also verbally informed the staff that the hydrogen analyzers satisfy the design criteria of Regulatory Guide 1.97, Rev. 2, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident." The licensee has agreed to confirm this in writing. However, there have been many changes made to the proposed revision to Regulatory Guide 1.97. Therefore, design and qualification criteria were explicitly stated in NUREG-0737.

In a letter dated December 9, 1980, the licensee committed to meet the requirements of NUREG-0737 by January 1, 1982, subject to availability of a unit outage of sufficient duration. We require, however, that the system be installed on January 1, 1982, as required by NUREG-0737.

We, therefore, find that PSE&G has met the requirements of this position.

d. Containment Radiation

In a letter dated July 1, 1980, PSE&G committed to provide Salem Unit 2 with high range in-containment monitors with a maximum detection range of 10^7 R/hr. The monitors will be single range with readout and continuous recording in the Control Room. Ion chambers with 60 Kev photon sensitivity and separate vital bus power will be installed. The monitors will meet the seismic qualification requirements of Regulatory Guide 1.100 and environmental qualification requirements of Regulatory Guide 1.89.

During refueling outages, the monitors will be calibrated in accordance with the manufacturer's instructions.

In the interim, PSE&G proposes to use the currently installed high range (10^7 R/hr) containment radiation monitor. Environmental testing has shown this unit will work during a temperature and pressure transient, but may fail due to condensation upon return to normal conditions. PSE&G maintains that the present high range radiation monitors should provide useful information. Additionally, core damage can be assessed from various temperature and pressure parameters, containment air grab samples can be analyzed, and external containment radiation levels can be correlated to in-containment activity. These capabilities provide Salem Unit 2 with an interim in-containment high radiation level assessment capability. This position is acceptable for the interim period.

In a letter dated December 9, 1980, the licensee committed to meet the requirements specified in NUREG-0737 on January 1, 1982, subject to availability of a unit outage of sufficient duration. We require, however, that the moniters be installed on January 1, 1982, as required by NUREG-0737.

We, therefore, find that PSE&G meets the requirements of this position.

e. Noble Gas Effluent Monitors

PSE&G has a system for monitoring noble gas effluents in concentrations up to 100 μCi/cc and has ordered instruments from Victoreen to extend the range to 100,000 μCi/cc. The system description provided in the PSE&G letter dated July 8, 1980, was found acceptable by the staff. In a letter dated December 9, 1980, PSE&G committed to meet the requirements specified in NUREG-0737 on January 1, 1982. PSE&G has an acceptable interim system for determining noble gas releases until the final sytem becomes operational.

We, therefore, find that PSE&G meets the requirements of this position.

f. Analysis of Radioiodine and Particulate Effluent Samples

In their letter dated August 3, 1980, PSE&G reports having the capability to continuously sample gaseous effluents and analyze these samples for radioiodines and particulates. The system description provided in the PSE&G letter dated April 11, 1980, was reviewed and found acceptable by the staff.

NUREG-0737 significantly changed some of the requirements of this position.. However, by letter dated December 9, 1980, PSE&G committed to implement the new requirements by January 1, 1982. We, therefore, find that PSE&G meets the requirements of the position.

II.F.2 Instruments for Inadequate Core Cooling

Position

Install, if required, additional instruments or controls needed to supplement installed equipment in order to provide unambiguous, easy-to-interpret indication of inadequate core cooling.

This requirement shall be met by January 1, 1982. By January 1, 1981, the licensee shall provide a report detailing the planned instrumentation system for monitering of inadequate core cooling.

Discussion and Conclusions

Existing ICC Instrumentation and Procedures

In the Salem Unit 2 SER Supplement No. 4, the staff concluded that the subcooling meter installed by PSE&G, using the plant computer, was acceptable for full power operation. Detailed design requirements had not been specified at the time of issuance of that Supplement. Subsequently, final design requirements were issued in NUREG-0737. Although the staff continues to find the existing instrumention acceptable for full power operation, it is the staff position that prior to January 1, 1981, a report detailing the Salem Unit 2 instrumentation to monitor adequacy of core cooling should be submitted. This report should include all information requested in NUREG-0737 and applies to the subcooling meter, the incore thermocouples, the computer used to process instrument signals, and the proposed level measuring system (discussed under the "Additional Instrumentation" heading found below).

The staff has also reviewed the Salem Unit 2 plant procedures to respond to a condition of inadequate core cooling and has found them acceptable for full power operation.

Additional Instrumentation

In the Salem Unit 2 SER Supplement No. 4, the staff concluded that PSE&G had accomplished the necessary actions and commitments with respect to new instrumentation such that this item placed no restrictions on full power operation for Salem Unit 2. This conclusion was based in part on a commitment by the licensee to complete installation of a reactor vessel water level measurement system for detection of inadequate core cooling conditions prior to January 1, 1981.

PSE&G, in letters dated August 3 and August 22, 1980, now indicates that installation cannot be completed on schedule due to delays in development and delivery. They estimate that the earliest possible delivery will be in April, 1981, and have proposed that installation be accomplished during the refueling shutdown currently scheduled for April, 1982.

The staff has been monitoring the progress of other applicants and licensees in meeting schedule requirements of II.F.2 and has had meetings with suppliers of various level measurement systems to review the design and development progress and the equipment procurement situation. Based on our continuing review of this situation, we concluded in NUREG-0737 that the implementation schedule should be changed to January 1, 1982, for all operating reactors and applicants. The staff also required in NUREG-0737 that a description of the proposed level measurement system be provided by January 1, 1981.

Summary

We conclude that PSE&G's existing instrumentation and procedures are acceptable for full-power operation in the interim. By letter dated December 31, 1980, the licensee stated a final design description of the reactor vessel level instrumentation system will be submitted to the staff in early February 1981. We find that the submittal for staff review of documentation of both existing and proposed ICC instrumentation by early February 1981 rather than as specified in NUREG-0737 to be acceptable. We also require that the final system (level measurement system and upgrade of existing system, if necessary) be installed no later than January 1, 1982, and that in-service testing, calibration, and implementation proceed on a schedule acceptable to the staff.

II.K.2.13 Thermal Mechanical Report--Effect of High-Pressure Injection on Vessel Integrity

Position

A detailed analysis shall be performed of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater.

PWR licensees shall submit the results of their evaluations by January 1, 1982.

Discussions and Conclusions

By letter dated December 9, 1980, the licensee stated that a report will be submitted by Westinghouse Owners Group in accordance with the implementation schedule established in NUREG-0737. This report will address thermal-mechanical conditions in the reactor during recovery from small breaks with extended loss of feedwater, and will consist of analyses for generic plant groupings. Following completion of the above, additional plant specific analyses, if required, will be provided. Schedules for plant specific analyses will be determined based on the results of the generic analysis.

The staff finds this commitment acceptable.

II.K.2.17 Potential for Voiding in the Reactor Coolant System During Transients

Position

Analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients. The analysis for all but B&W licensees should be submitted by January 1, 1982.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that a report will be submitted by Westinghouse Owners Group in accordance with the implementation schedule established in NUREG-0737. This report will address potential for void formation in the RCS during natural circulation cooldown conditions, as described in Westinghouse letter, NS-TMA-2298 (T.M. Anderson to P. Check).

The staff finds this commitment acceptable.

II.K.2.19 Sequential Auxiliary Feedwater Flow Analysis

Position

Provide a benchmark analysis of sequential auxiliary feedwater (AFW) flow to the steam generators following a loss of main feedwater.

The analysis for all but B&W licensees sould be submitted by January 1, 1982.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that the transient analysis code (LOFTRAN) and the present small break analysis code (WFLASH) have both undergone benchmarking against plant information or experimental test facilities. The codes have also been compared with each other under appropriate conditions. Westinghouse Owners Group will submit a report addressing the benchmarking of these codes on a schdule consistent with the requirements of this item.

The staff finds this commitment acceptable.

II.K.3.2 Report on Power-Operated Relief Valve Isolation System

Postion

(1) The licensee should submit a report for staff review documenting the various actions taken to decrease the probability of a small-break loss-of-coolant accident (LOCA) caused by a stuck-open power-operated relief valve (PORV) and show how those actions constitute sufficient improvements in reactor safety.

(2) Safety-valve failure rates based on past history of the operating plants designed by the specific nuclear steam supply system (NSSS) vendor should be included in the report submitted in response to (1) above.

This report should be submitted on January 1, 1981.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that the Westinghouse Owners Group is developing a report to address Item II.K.3.2. This report will include historical valve failure rate data and documentation of actions taken to decrease the probability of a stuck-open PORV. The licensee further stated that due to the lengthy process of data gathering, breakdown and evaluation, this report is currently scheduled for submittal by 3/1/81. This report will be used by the licensee to support a decision with regard to the necessity of incorporating an automatic PORV isolation system as specified in Item II.K.3.1.

NUREG-0737 states that "the staff will consider requests for relief from various aspects of these criteria." The staff has determined that the licensee's justification for a delayed submittal is adequate. Therefore, the staff finds PSG&G commitment to be an acceptable resolution of this item.

II.K.3.5 Automatic Trip of Reactor Coolant Pumps During Loss-of-Coolant Accident

Postion

Tripping of the reactor coolant pumps in case of a loss-of-coolant accident (LOCA) is not an ideal solution. Licensees should consider other solutions to the small-break LOCA problem (for example, an increase in safety injection flow rate). In the meantime, until a better solution is found, the reactor coolant pumps should be tripped automatically in case of a small-breack LOCA. The signals designated to initiate the pump trip are discussed in NUREG-0623.

This action item was revised in the May 1980 version of NUREG-0660 to provide for continued study of criteria for early reactor coolant pump trip. Implementation, if any is required, will be delayed accordingly. As part of the continued study, all holders of approved emergency core cooling (ECC) models have been required to analyze the forthcoming LOFT test (L3-6). The capability of the industry models to correctly predict the experimental behavior of this test will have a strong input on the staff's determination of when and how the reactor coolant pumps should be tripped.

Proposed design modifications (if necessary) are due by July 1, 1981. Modification (if necessary) is due by March 1, 1982.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that they will implement the requirements of this position on the dates specified if the staff determines that modifications are necessary.

The staff finds this commitment acceptable.

II.K.3.17 Report on Outages of Emergency Core-Cooling Systems

Position

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation). The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicants for operating license should submit their plan for data collection by January 1, 1981.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that they will implement this NUREG-0737 position on January 1, 1981.

The staff finds this commitment acceptable.

II.K.3.25 Effect of Loss of Alternating-Current Power on Pump Seals

Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

BWR licensees and Westinghouse and Combustion Engineering licensees shall provide results of evaluation and proposed modifications by July 1, 1981 and January 1, 1982, respectively.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that they will implement this NUREG-0737 position on the schedules specified.

The staff finds this commitment acceptable.

II.K.3.30 Revised Small-Break Loss-of-Coolant-Accident Methods

Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented and submitted for NRC approval.

Detailed outline of the scope and schedule for meeting this requirement should be submitted by each licensee and applicant by November 15, 1980.

The additional information requested should be submitted by January 1, 1980. The plant-specific analyses using the revised models should be submitted by January 1, 1983, or one year after any model revisions are approved.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that this item will be completed in accordance with the implementation schedule as outlined in the Westinghouse letter, NS-TMA-2318 (T.M. Anderson to D.G. Eisenhut) dated September 26, 1980.

This letter commits to the implementation schedule specified in NUREG-0737 and, therefore, the staff finds the licensee's commitment to be acceptable.

II.K.3.31 Plant-Specific Calculations to Show Compliance with 10 CFR Part 50.46

Position

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in item II.K.3.30 to show compliance with 10 CFR Part 50.46 should be submitted for NRC approval by all licensees.

Calculations shall be submitted by January 1, 1983, or 1 year after staff approval of LOCA analysis models, whichever is later, only if model changes have been made.

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that this item will be completed in accordance with the required implementation schedule.

The staff finds this commitment acceptable.

III. Emergency Preparations and Radiation Protection

III.A.1.2 Upgrade Emergency Support Facilities

Position

Provide radiation monitoring and ventilation systems, including particulate and charcoal filters, and otherwise increase the radiation protection to the onsite technical support center to assure that personnel in the center will not receive doses in excess of 5 rem to the whole body or 30 rem to the thyroid for the duration of the accident. Provide direct display of plant safety system parameters and call up display of radiological parameters.

For the near-site Emergency Operations Facility, provide shielding against direct radiation, ventilation isolation capability, dedicated communications with the onsite technical support center and direct display of radiological and meteorological parameters.

This requirement shall be met by January 1, 1981, although the safety parameter information requirements will be staged over a longer period of time.

Discussion and Conclusions

The above requirements will be revised, upon Commission approval, by those set forth in NUREG-0696, "Functional Criteria for Emergency Response Facilities". The revised requirements have been published in a draft report for interim use and comment. The NUREG document specifies the functional criteria necessary for the design and implementation of the Technical Support Center and the Emergency Operations Facility.

The Emergency Preparedness Evaluation Report which is discussed in Section 22.2, III.A.1.1, describes the Technical Support Center and the near-site Emergency Operations Facility that have been established on an interim basis. As a result of our review and the applicant's commitments in their letter of August 3, 1980 to meet the requirements set forth in NUREG-0696, we conclude that these interim facilities are acceptable for full power operation pending their upgrading to meet the NUREG-0696 requirements.

III.A.2 Long-Term Emergency Preparedness

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants." (See Section 22.2, III.A.1.1. and III.A.1.2 for a discussion of the full-power requirements part of this position.)

Discussion and Conclusions

By letter dated December 9, 1980, the licensee stated that the requirements of this position will be completed in accordance with the implementation schedule established in NUREG-0737.

The staff finds this commitment acceptable.

III.D.3.3 Inplant Radiation Monitoring

Position

Provide the equipment, training, and procedures to accurately measure the radioiodine concentration in areas within the plant where plant personnel may be present during an accident.

This requirement shall be met before January 1, 1981.

Discussion and Conclusion

By letters dated October 12, 1979, January 4, 1980, July 1, 1980, and December 9, 1980, PSE&G has submitted commitments and documentation of actions to be taken at Salem Unit 2 to implement short-term lessons learned items in NUREG-0578.

The Salem plant has portable low volume air samplers equipped with single channel analyzer capability for measuring I-131. Collected samples are analyzed by gamma radiation spectrum analysis using portable gamma scintillation counting systems. In addition, collected samples may be further analyzed in the plant counting facilities using Ge(Li) detectors.

PSE&G has stated that the low background counting requirement of January 1, 1981 will be met by utilizing a portable Ge(Li) spectrometer, normally located in the service building, and three portable SAM-2 analyzers which can be located in low background areas.

The equipment and procedures described by the licensees meet our position in NUREG-0578, NUREG-0694, and NUREG-0737 for full power operation.

23.0 CONCLUSIONS

Based on our evaluation of the application as set forth in our Safety Evaluation Report issued in October, 1974 and Supplement Nos. 1-4 and our evaluation as set forth in this supplement, we conclude that the operating license can be issued to allow power operations at full rated power (3411 megawatts thermal) subject to license conditions which will require further Commission approval and license amendments before the stated condition can be removed. In addition, actions related to emergency preparedness matters (Section 22.2, III.A.1.1) must be completed prior to issuance of a full power license. These actions include completion of outstanding items in the State, local and site emergency plans and conduct of a satisfactory emergency response exercise.

We conclude that the construction of the facility has been completed in accordance with the requirements of Section 50.57(a)(1) of 10 CFR Part 50, and that construction of the facility has been monitored in accordance with the inspection program of the Commission's staff.

Subsequent to the issuance of the operating license for full rated power for Salem Nuclear Generating Station Unit 2, the facility may then be operated only in accordance with the Commission's regulations and the conditions of the operating license under the continuing surveillance of the Commission's staff.

We conclude that the activities authorized by the license can be conducted without endangering the health and safety of the public, and we reaffirm our conclusions as stated in our Safety Evaluation Report and its supplements.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL SAFETY REVIEW

April 1, 1980	Letter from PSE&G regarding training programs for mitigating core damage.
April 2, 1980	Letter from PSE&G regarding IE Bulletin 79-18.
April 9, 1980	Letter to PSE&G concerning LER 79-71.
April 3, 1980	Letter from PSE&G which forwards computer program verification using PIPDYN II stress analysis for NRC benchwork problems 1, 2, 323A and 803.
April 8, 1980	Letter from PSE&G revising 5/20/77 response to item noted in IE Inspection Report 77-13.
April 9, 1980	Letter to PSE&G discussing LER 79-71.
April 9, 1980	Letter from PSE&G describing plans to staff licensed operator positions on both units following OL issuance for unit.
April 10, 1980	Memo to A. Schwencer from W.J. Ross regarding summary of meeting with PSE&G to discuss implementation of lessons learned items 2.1.7.a and 2.1.7.b at Salem 1.
Monthly Report	Letter 4/10/80 from PSE&G forwarding Monthly Operating Report for March 1980.
April 10, 1980	Letter from PSE&G concerning item of noncompliance noted in IE Inspection Report 80-5.
April 11, 1980	Letter from PSE&G regarding IE Bulletin 80-3.
April 11, 1980	Letter from PSE&G forwarding LER 80-17/1T on 3/28/80, discussing review of environmental qualification documentation.
April 11, 1980	Memo to A. Schwencer from W.J. Ross re. summary of 3/19/80 meeting with PSE&G related to implementation of Appendix I for Salem Unit 2.
April 11, 1980	Letter from PSE&G forwarding revised pages to 10/2/80 response to TMI lessons learned task force short term requirements. Also forwards revised pages previously submitted for Unit 2 by 3/28/80 letter.

April 14, 1980	Letter from PSE&G regarding IE Bulletin 79-1B.
April 14, 1980	Letter from PSE&G forwarding facility security plan and payment of civil penalties resulting from 3/20/80 notice of violation.
April 15, 1980	Letter from Valore, McAllister, Aron, Westmoreland & Vesper Law firm forwarding response to PSE&G's comments concerning request of Lower Alloways Creek Township for suspension of moratorium of issuance of OL.
April 15, 1980	Letter from PSE&G responding to NRC 3/14/80 biological assessment of impact of continued operation or construction of facilities.
April 15, 1980	Letter to PSE&G confirming telephone conversation on 4/11/80.
April 15, 1980	Letter from PSE&G forwarding ecological study of DE River Artificial Island, 1968-76.
April 17, 1980	Letter from PSE&G regarding IE Bulletin 80-4.
April 21, 1980	Letter from PSE&G forwarding NPDES discharge monitoring reports for Jan thru Mar 1980.
April 21, 1980	Letter from PSE&G responding to 1/7/80 letter regarding QA requirements for diesel fuel oil.
April 24, 1980	Letter to PSE&G concerning Inspection Report 79-33.
April 25, 1980	Letter to PSE&G regarding clarification of NRC requirements for emergency response facilities at each site.
April 28, 1980	Letter to PSE&G regarding IE Inspection Report 80-2.
April 29, 1980	Letter to Mayor S.E. Donelson concerning letter written in response to your petition dtd 3/25/80 requesting that L&M take certain actions w/respect to the storage of spent fuel at Salem 1 and 2.
May 1, 1980	Letter from PSE&G forwarding cycle 2 startup test report.
May 1, 1980	Letter from PSE&G forwarding 1979 annual financial reports for PED, DP&LC, AE&PSE&GC.
May 1, 1980	Letter from Whitfield A. Russel & Associates forwarding transcripts of prepared direct testimony and cross examination of JL Parks on behalf of Delmarva P&L Co. in Md public service commission hearing on facility.
May 2, 1980	Letter from PSE&G forwarding revised submittal 3 of security contingency plan.
May 2, 1980	Letter to Mr. H.A. Minch, Acting Executive Secretary, State of Maryland Public Service Commission, re. performance of the Salem Nuclear Generating Station.

May 5, 1980	Letter PSE&G responding to open items identified in NRC 4/14/80 letter regarding auxiliary feedwater system.
May 9, 1980	Letter from PSE&G forwarding monthly operating report for April 1980.
May 9, 1980	Letter from PSE&G forwarding corrections to Monthly Operating Report for April 1980.
May 12, 1980	Letter to Hon. H.A. Williams, Jr. from A.C. Coleman, Jr.
May 13, 1980	Letter from PSE&G forwarding summary of owner's 1980 projected cash flow statements and 1979 annual financial reports.
May 14, 1980	Letter to PSE&G regarding IE Inspection Report 80-5.
May 16, 1980	Letter from PSE&G forwarding request for amendment to license DPR-70 and DPR-75.
May 22, 1980	Letter from PSE&G advising of intention to activate Quinton, NJ facility on 6/16/80 as emergency operating facility.
May 23, 1980	Letter from PSE&G forwarding Revision 5 of security plan.
June 3, 1980	Letter from PSE&G forwarding NPDES discharge monitoring reports for Apr 1980, operating report of industrial waste treatment plant, and wastewater treatment report.
June 3, 1980	Letter from PSE&G responding to violations noted in IE Inspection Reports 80-4 and 80-1.
June 4, 1980	Letter from M&M Nuc Consultants forwarding endorsement 31,4 and 1 to MAELU policy MF-90, XB-72 respectively.
June 4, 1980	Letter from PSE&G regarding IE Bulletin 79-1B.
June 9, 1980	Letter from PSE&G committing to implement NUREG-0660 Additional TMI-2 Related Requirements.
June 9, 1980	Letter from PSE&G regarding IE Bulletin 80-12.
June 10, 1980	Letter from PSE&G forwarding auxiliary feedwater pump test results.
June 10, 1980	Letter from PSE&G forwarding Monthly Operating Report for May, 1980.
June 11, 1980	Letter from PSE&G forwarding response to NRC 9/21/79 request for information regarding auxiliary feedwater flow requirements.
June 11, 1980	Letter to PSE&G transmitting Model TSs concerning decay heat removal capability.

June 12, 1980	Letter from PSE&G forwarding executed Amendment 8 to Indemnity Agreement B-74.
June 12, 1980	Letter from PSE&G submitting supplemental Report revising 9/19/80 response to Inspection Report 79-18.
June 13, 1980	Letter from PSE&G forwarding 1979 Annual Environmental Operating Report (nonradiological).
June 13, 1980	Letter from PSE&G regarding IE Bulletin 80-10.
June 13, 1980	Letter from PSE&G regarding IE Bulletin 80-6.
June 13, 1980	Letter from PSE&G stating that Second Interim Report, per facility 316(b) plan of study, will be distributed to technical advisory group by 6/25/80.
June 13, 1980	Letter from PSE&G informing NRC of decision to delay activation of Quinton training facility as nearsite emergency operations facility until open issues have been addressed satisfactorily.
June 17, 1980	Letter from PSE&G regarding item of noncompliance noted in Inspection Report 80-10.
June 25, 1980	Letter from M&M Nuclear Consultants forwarding Endorsement 39 to ANI Policy NF-230.
June 25, 1980	Letter from PSE&G forwarding Second Interim Report, 316(b) Studies, Jan 1979-Mar 1980.
June 27, 1980	Letter from PSE&G responding to full power license requirements identified at June 19, 1980 meeting.
June 27, 1980	Letter from PSE&G regarding loss of non-class IE instrumentation and control power.
June 27, 1980	Letter from PSE&G submitting plan to satisfy Item 7.4(4) of the Technical Specifications
June 30, 1980	Letter from PSE&G forwarding Submittal 4 to 6/27/80 security contingency plan.
June 30, 1980	Letter from PSE&G regarding IE Bulletin 80-8.
July 1, 1980	Letter from PSE&G forwarding additional information concerning auxiliary feedwater system.
July 1, 1980	Letter from PSE&G providing additional information related to full power license requirements identified at June 19, 1980 meeting.
July 1, 1980	Letter from PSE&G regarding IE Bulletin 79-27.
July 2, 1980	Letter from PSE&G regarding IE Bulletin 80-11.

July 2, 1980	Letter from PSE&G concerning lessons learned requirements dated June 20, 1980.
July 2, 1980	Letter to PSE&G transmitting Model TSs and proposed wording of conditions.
July 2, 1980	Letter from PSE&G responding to IE Inspection Report 80-6 on 3/30/80 thru 4/30/80.
July 3, 1980	Letter from PSE&G requesting approval to proceed with interim use of training facility in Quinton, NJ as nearsite emergency operations facility.
July 3, 1980	Letter to PSE&GC regarding Inspection Report 79-18.
July 8, 1980	Letter from PSE&G forwarding final addendum to report on reactor containment integrated leak rate test.
July 8, 1980	Letter to PSE&G re. potential welding deficiencies in tanks fabricated by Graver Tank and Manufacturing Company.
July 8, 1980	Letter from PSE&G forwarding revised pages to 1/2/80 lessons learned implementation submittal.
July 10, 1980	Letter from PSE&G forwarding Monthly Operating Report for January 1980.
July 10, 1980	Letter from PSE&G concerning RP 79-50/1P on 7/10/79; Westinghouse informed that reactor trip and auxiliary feedwater initiation could be delayed in event of main feedline rupture inside containment.
July 16, 1980	Letter from PSE&G requesting authorization to change individual cell minimum voltages on 125 and 28 volt batteries to 2.13 volts with respect to license DPR-75.
July 16, 1980	Letter from PSE&G regarding status of licensed operating personnel.
July 17, 1980	Letter from PSE&G concerning containment sump model test program.
July 17, 1980	Letter from PSE&G proposing conceptual design for automatic switchover of the ECCS from injection phase to recirculation phase of operation.
July 18, 1980	Letter from PSE&G regarding IE Bulletin 80-06.
August 13, 1980	Letter from PSE&G concerning mainsteam and feedline breaks, NSSS vendor review of procedures, relief, and safety valve position indication, and control room habitability.
August 14, 1980	Letter from PSE&G forwarding emergency instructions.
August 19, 1980	Letter from PSE&G concerning Safety Review Group.

August 19, 1980	Letter from PSE&G forwarding summary of mitigating core damage training.
August 19, 1980	Letter from PSE&G forwarding completion schedule for open items identified at August 15, 1980 meeting.
August 20, 1980	Letter from PSE&G submitting licensed operator staffing plan.
August 21, 1980	Letter from PSE&G submitting revision to licensed operator staffing plan.
August 22, 1980	Letter from PSE&G concerning NUREG-0694 dated requirements.
August 22, 1980	Letter from PSE&G transmitting a request for amendment to Facility Operating License DPR-75.
August 22, 1980	Letter from PSE&G transmitting a request for amendment to Facility Operating Licenses DPR-70 and DPR-75.
August 25, 1980	Letter from PSE&G regarding environmental qualification of Class 1E instrumentation and electrical equipment.
August 25, 1980	Letter from PSE&G concerning in-plant radiation monitoring.
August 25, 1980	Letter from PSE&G regarding containment sump performance.
August 25, 1980	Letter from PSE&G submitting an updated Q-List.
August 26, 1980	Letter from PSE&G concerning brittle fracture toughness and hot pipe.
September 2, 1980	Letter from PSE&G forwarding information on cracking in low pressure turbine discs.
September 3, 1980	Letter from PSE&G regarding use of salt water in steam generators.
September 3, 1980	Letter from PSE&G concerning compliance with NRC regulations.
September 4, 1980	Letter from PSE&G concerning the emergency plan.
September 4, 1980	Letter from PSE&G concerning fire protection.
September 5, 1980	Letter to PSE&G providing preliminary clarification of TMI Action Plan requirements.
September 5, 1980	Letter from PSE&G concerning the low power test program.
September 5, 1980	Letter from PSE&G regarding IE Bulletin 80-11.

September 5, 1980	Letter from PSE&G regarding the high point vent.
September 5, 1980	Letter from PSE&G regarding relief and safety valve test requirements.
September 5, 1980	Letter from PSE&G regarding NSSS vendor review of procedures.
September 5, 1980	Letter from PSE&G concerning IE Bulletin 80-20.
September 8, 1980	Letter from PSE&G transmitting list of safety-related structures, systems, and components to which the operational Quality Assurance Program applies.
September 8, 1980	Letter from PSE&G submitting summary of Natural Circulation Tests.
September 9, 1980	Letter from PSE&G transmitting information concerning primary coolant sources outside containment and noble gas, radioiodine and particulate effluent monitoring.
September 9, 1980	Letter from PSE&G concerning compliance with NRC regulations.
September 9, 1980	Letter from PSE&G requesting response to July 2 letter concerning technical specifications be delayed.
September 9, 1980	Letter from PSE&G transmitting LER 80-26/03L.
September 10, 1980	Letter from PSE&G transmitting Monthly Operating Report for August 1980.
September 10, 1980	Letter from PSE&G regarding degraded core training.
September 10, 1980	Letter from PSE&G requesting waiver of requirement for interim shift technical advisors for the period November 1 - December 6, 1980.
September 11, 1980	Letter from PSE&G regarding equipment qualification.
September 11, 1980	Letter from PSE&G regarding its conformance with General Design Criterion 51, Fracture Toughness.
September 11, 1980	Letter from PSE&G transmitting LER 80-27/03L.
September 11, 1980	Letter from PSE&G transmitting response to IE Bulletin 79-07.
September 13, 1980	Letter to PSE&G transmitting request for additional information.
September 17, 1980	Letter from PSE&G transmitting information regarding containment sump post-LOCA performance.
September 18, 1980	Letter from PSE&G transmitting information on equipment qualification.

September 18, 1980	Letter from PSE&G transmitting LER 80-28/03L.
September 19, 1980	Letter from PSE&G concerning combined inspection 50-272/80-16 and 50-311/80-12.
September 19, 1980	Letter to PSE&G transmitting errata for September 5, 1980 TMI Action Plan clarification.
September 22, 1980	Letter from PSE&G in response to August 15, 1980 letter concerning technical specifications for Westinghouse PWR licensees.
September 23, 1980	Letter from PSE&G regarding IE Bulletin 80-18.
September 23, 1980	Letter from PSE&G concerning auxiliary feedwater system.
September 24, 1980	Letter from PSE&G concerning degraded grid voltage analysis.
September 24, 1980	Letter to PSE&G waiving requirement (on interim basis) for interim shift technical advisors.
September 29, 1980	Letter from PSE&G regarding leak rate testing of reactor coolant system pressure isolation valves.
September 29, 1980	Letter from PSE&G transmitting LER 80-29/03L.
September 30, 1980	Letter from PSE&G concerning IE Bulletin 80-18.
October 1, 1980	Letter to PSE&G concerning environmental qualification of safety-related equipment.
October 1, 1980	Letter from PSE&G forwarding additional information on environmental qualification of safety-related equipment.
October 3, 1980	Letter from PSE&G transmitting Emergency Plan Procedures.
October 6, 1980	Letter from PSE&G transmitting LER 80-30/03L.
October 6, 1980	Letter to PSE&G advising that list of safety-related structures, systems, and components to which quality assurance program applies is acceptably complete.
October 6, 1980	Letter from PSE&G providing supplemental information on degraded core training.
October 6, 1980	Letter to PSE&G concerning implementation of guidance from Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."
October 7, 1980	Meeting with Lower Alloways Creek Fire Department.

October 10, 1980	Issuance of Amendment No. 3 to License No. DPR-75, which deletes requirement for plugging certain tubes in the steam generator prior to exceeding 5 percent power, approves an organizational change and revises certain technical specifications.
October 10, 1980	Letter from PSE&G transmitting September 1980 Monthly Operating Report.
October 10, 1980	Letter from PSE&G concerning combined inspection 50-272/80-20 and 50-311/80-16.
October 14, 1980	Letter from PSE&G providing supplemental response to IE Bulletin 80-20.
October 15, 1980	Letter from PSE&G in response to June 11 letter concerning technical specifications for Westinghouse.
October 17, 1980	Letter from PSE&G concerning combined inspection 50-272/80-19 and 50-311/80-14.
October 20, 1980	Letter from PSE&G regarding IE Bulletin 80-06.
October 21, 1980	Letter from PSE&G transmitting revision to Emergency Plan.
October 29, 1980	Letter from PSE&G advising of change in reporting responsibility for shift technical advisors.
October 29, 1980	Letter from PSE&G transmitting Inservice Inspection Program.
October 30, 1980	Issuance of Order for Modification of License concerning environmental qualification of safety-related electrical equipment.
October 30, 1980	Meeting with PSE&G to discuss questions concerning environmental qualification equipment.
October 31, 1980	Letter to PSE&G concerning senior operator license requirements.
October 31, 1980	Letter to PSE&G transmitting "Clarification of TMI Action Plan Requirements," NUREG-0737.
October 31, 1980	Letter from PSE&G regarding Environmental Qualification of Class IE Equipment, in response to IE Bulletin 79-01B.
October 31, 1980	Letter from PSE&G regarding IE Bulletin 79-06A, Rev. 1.
November 4, 1980	Letter from PSE&G concerning IE Bulletin 80-11.

November 6, 1980	Letter from PSE&G concerning upgrading of emergency support facilities.
November 10, 1980	Letter from PSE&G transmitting Monthly Operating Report for October 1980.
November 13, 1980	Letter to PSE&G concerning final regulations on emergency planning.
November 17, 1980	Letter from PSE&G concerning license training programs.
November 20, 1980	Meeting with PSE&G to discuss NRC design criteria for reinforcement of masonry walls.
November 20, 1980	Letter from PSE&G requesting license amendment concerning reorganization of operation and support staffs.
November 21, 1980	Meeting with PSE&G to discuss outstanding licensing issues.
November 26, 1980	Letter to PSE&G providing clarification of Orders on environmental qualification of safety-related electrical equipment.
November 26, 1980	Letter from PSE&G transmitting revised report on Environmental Qualification of Class IE instrumentation and electrical equipment.
December 1, 1980	Letter from PSE&G concerning containment boundary fracture toughness.
December 1, 1980	Letter from PSE&G regarding impact of Lower Alloways Creek Fire Company on fire protection program.
December 1, 1980	Letter from PSE&G concerning fire protection rule.
December 3, 1980	Meeting with PSE&G to discuss alternate means of complying with General Design Criterion 51.
December 4, 1980	Letter to PSE&G regarding revised regulations on fire protection features.
December 4, 1980	Issuance of Amendment 4 to License No. DPR-75, approving certain organizational changes.
December 9, 1980	Letter to PSE&G transmitting Revision 1 of NUREG-0654/ FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants."
December 9, 1980	Letter from PSE&G concerning confirmation of implementation dates identified in NUREG-0737.

December 11, 1980	Letter from PSE&G transmitting Monthly Operating Report for November 1980.
December 12, 1980	Letter from PSE&G concerning IE Bulletin 80-23.
December 19, 1980	Letter from PSE&G concerning containment boundary fracture toughness.
December 22, 1980	Letter to PSE&G forwarding "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, related staff position, and request for related information.
December 31, 1980	Letter from PSE&G submitting response to information requested in NUREG-0737.
January 6, 1981	Letter from PSE&G concerning the status of licensed operating personnel.
January 12, 1981	Letter from PSE&G forwarding verification of list of correspondence that is part of application for operating license.
January 12, 1981	Letter from PSE&G transmitting Monthly Operating Report for December 1980.
January 13, 1981	Letter from PSE&G concerning documentation of ECCS outages.
January 16, 1981	Letter from PSE&G regarding volume of overhead annunciator volume.
January 19, 1981	Letter to PSE&G providing information regarding the program for environmental qualification of electrical equipment

APPENDIX F

EMERGENCY PREPAREDNESS EVALUATION REPORT

INTRODUCTION

The Public Service Electric and Gas Company (hereinafter referred to as the Licensee, the Company, PSE&G) filed with the Nuclear Regulatory Commission a revision to the Salem Nuclear Generating Station Emergency Plan dated September 5 1980, as amended (hereinafter referred to as the Plan). The Commission's staff conducted a review of this Plan. The staff's review also included a site visit to the facility and a public meeting during the week of October 8, 1979.

The staff issued the criteria of the sixteen operator Planning Objectives in Part II of the "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," (For Interim Use and Comment) NUREG-0654, January 1980.

As a result of public comments, staff comments and development of the final rule on emergency planning, NUREG-0654 was revised and issued in November 1980. The Plan was reviewed against the revised criteria.

This Emergency Preparedness Evaluation Report lists each objective in order followed by a summary of applicable portions of the Emergency Plan as they apply principally to the Operator Planning Objectives. The final section of this report provides our review results and conclusions.

At a later date an appendix will be added to this report describing the findings and determinations of the Federal Emergency Management Agency on the State and local emergency response plans.

EVALUATION

A. Assignment of Responsibility (Organization Control)
Planning Objective

To assure that primary responsibilities for emergency response in nuclear facility operator, State and local organizations within the Emergency Planning Zones have been assigned, that the emergency responsibilities of the various supporting organizations have been specifically established, and that each principal response organization is staffed to respond and to augment its initial response on a continuous basis.

Emergency Plan

The Senior Shift Supervisor for the Salem Nuclear Generating Station is initially designated as the Emergency Duty Officer. When an abnormal condition arises, it is his responsibility to determine if the abnormality meets any of the emergency classifications specified in the plan and to implement the Plan, if necessary. There is 24 hours a day communication capability between the Station and Federal, State, and local response organizations to ensure rapid transmittal of accurate notification information and emergency assessment data.

Responsibility for the overall direction of the on-site emergency response organization is vested in the Emergency Duty Officer (EDO). Qualified members of the station staff who report directly to the EDO have been assigned specific responsibilities for the major elements of emergency response.

We will require that updated and final written agreements with the appropriate agencies and organizations be provided as part of the Emergency Plan prior to issuance of a full power license. These agencies and organizations include the New Jersey State Department of Environmental Protection, New Jersey State Police, Delaware Department of Public Safety, Salem County, Cumberland County, New Castle County, Kent County, Lower Alloways Creek Township, U.S. Department of Energy, U.S. Coast Guard, Radiation Management Corporation, Salem County Memorial Hospital, Lower Alloways Creek Rescue Squad, and a local fire department.

B. Onsite Emergency Organization
Planning Objective

To assure that on-shift facility operator responsibilities for emergency response are unambiguously defined, that adequate staffing to provide initial facility accident response in key functional areas is maintained at all times, and timely augmentation of response capabilities is available, and that the interfaces among various onsite response activities and offsite support and response activities are specified.

Emergency Plan

The Senior Shift Supervisor on duty is designated as the Emergency Duty Officer (EDO) until relieved by an EDO qualified member of station management. The authorities and responsibilities of the Emergency Duty Officer have been clearly specified, including those that cannot be delegated. The Emergency Duty Officer can immediately and unilaterally declare an emergency and make the necessary notifications and recommendations to the authorities responsible for implementing offsite emergency measures.

Station staff emergency assignments have been made and the relationship between the emergency organization and normal staff complement are shown in the Plan. Positions and/or titles and qualifications of shift and plant staff personnel both on and offsite who are assigned major emergency functional duties are listed. The shift staffing for two unit operations satisfies the functional objectives identified in Table B-1 of NUREG-0654 for nuclear power plant emergencies. Company personnel available to augment the minimum shift staff include 5 persons within 30 minutes, 25 persons within 60 minutes, and a total of 26 persons within 90 minutes.

Corporate management personnel who will augment the plant staff and their duties and responsibilities have been established; a long-term emergency organization framework is in place, headed by the Senior Vice President Energy Supply and Engineering. Interfaces between and among the company corporate staff, station staff, governmental and private sector organizations and technical and/or engineering contractor groups have been specified along with services to be provided.

C. Emergency Response Support and Resources
Planning Objective

To assure that arrangements for requesting and effectively using assistance resources have been made, that arrangements for State and local staffing of the operator's Emergency Operations Facility have been made, and that organizations capable of augmenting the planned response have been identified.

Emergency Plan

Arrangements for requesting and utilizing outside resources have been made including authority to request implementation of the Federal Radiological Monitoring and Assessment Plan by either the Emergency Duty Officer or Recovery Manager. Also assistance is available from the reactor vendor and the member companies of the Pennsylvania/New Jersey/Maryland power pool. In addition, emergency services and manpower are available from the PSE&G Research Corporation Energy Laboratory in Maplewood, New Jersey within about four hours. The Emergency Operations Facility will be activated for the more serious emergency classifications having or potentially having environmental consequences (Alert, Site Area Emergency, General Emergency). The facility will accommodate representatives from Federal, State and local government agencies, as well as representatives from contractor and other support groups. It will be the central data collection point for providing information needed by primary response agencies for implementation of protective actions.

D. Emergency Classification System
Planning Objectives

To assure that a standard emergency classification and action level scheme is in use by the nuclear facility operator, including facility system and effluent parameters; and to assure that State and local response organizations will rely on information provided by facility for determinations of initial offsite response measures.

Emergency Plan

The licensee has established four standard emergency classes - Notification of Unusual Event, Alert, Site Area Emergency, and General Emergency. The initiating conditions used for recognizing and declaring the emergency class are based on specific measurable parameters or observable conditions defined as Emergency Action Levels (EAL). Although the licensee has incorporated the various initiating conditions as set forth in NUREG-0654 for each class of emergency, some of the corresponding EALs are not yet acceptable to the staff. We will require a complete and acceptable set of EALs prior to issuance of a full power license. Furthermore, since the Delaware and New Jersey State and local plans are still under development and/or revision, we are awaiting the FEMA finding in order to determine the consistency of the State and local emergency classification scheme with that of the licensee.

E. Notification Methods and Procedures
Planning Objective

To assure that procedures have been established for notification, by the facility, of State and local response organizations and for notification of emergency personnel by all response organizations; to assure that the content of initial and followup messages to response organizations and the public have been established; and to assure that means to provide early warning and clear instruction to the populace within the plume exposure pathway Emergency Planning Zone have been established.

Emergency Plan

Procedures have been established for notification of State and local response organizations in case of emergency. The Emergency Duty Officer has been given the authority and responsibility to initiate prompt notifications to these agencies. Notification to the local authorities is normally provided by the appropriate State agency; however, in the case of a General Emergency, the licensee will directly notify the four local counties by means of a hot line. Although all of the necessary equipment has not yet been installed, we will require that this system be fully operational prior to issuance of a full power license.

The type of information to be reported to the offsite agencies in the event of an emergency has been predetermined in accordance with the recommendations in NUREG-0654 and is included as part of the plan. The plan also includes written messages intended for release to the public ranging from "no action necessary" to "sheltering or evacuation."

The licensee has committed to a prompt notification system which meets the design objective set forth in NUREG-0654. We will require a detailed system description and its method of actuation prior to the issuance of a full power license. The system will be installed and operational by July 1, 1981.

F. Emergency Communications
Planning Objective

To assure that provisions exist for prompt communications among principal response organizations, to emergency personnel and to the public.

Emergency Plan

The station communications system is designed to provide secure, redundant and diverse communications to all essential onsite and offsite locations during normal operations and under accident conditions. Within-station systems are comprised of a station public address system, two-way radio systems, and a conventional telephone system. Offsite systems are comprised of both commercial and leased telephone lines, and two-way radio systems. Two separate commercial telephone lines are dedicated to NRC communications.

These telephones plus other systems are located in plant areas manned 24 hours a day. The Emergency Duty Officer (EDO) will, in emergency situations, communicate directly with the State Police Headquarters of New Jersey and Delaware and the NRC duty officer. In the case of a General Emergency, the EDO will also notify the four local county authorities and the U.S. Coast Guard. These offices are manned 24 hours a day. Communications between the Control Room and the Technical Support Center, Operations Support Center, and Emergency Operations Facility are available. Tests of the systems are conducted monthly.

G. Public Information
Planning Objective

To assure that accurate and timely information is provided to the public on how they will be notified and what their initial actions should be; to assure that the principal points of contact with the news media for dissemination of information (including physical location or locations) are established in advance; and to establish procedures for coordinated dissemination of information to the public.

Emergency Plan

The public information program will consist of general information on nuclear energy, radiation, and emergency planning. This information will be provided to the public in the form of pamphlets, advertisements, or bill inserts such that all of the topic areas will be covered annually. In addition, the licensee will provide specific protective response information covering response options, evacuation methods, routes, relocation centers, and methods of notification. This specific information will be placed in the appropriate local publications at least annually.

In an emergency, the Emergency Operations Facility (EOF) will serve as the principal point of interaction between the station, governmental authorities, and corporate management for exchange of information. The Public Information Manager will coordinate the dissemination of information with the PSE&G Corporate Headquarters. All information released to the news media will be approved by the Recovery Manager in charge of the EOF activities.

The licensee will conduct an annual information program in seminar format for representatives of the news media as well as for the general public.

H. Emergency Facilities and Equipment
Planning Objective

To assure that adequate emergency facilities and equipment to support the emergency response are provided.

Emergency Plan

Emergency facilities needed to support an emergency response have been provided including a Technical Support Center, Emergency Operations Facility and Operations Support Center. Each will be activated for an Alert or higher emergency classification. The Technical Support Center has been established on the third floor of the Clean Facilities Building ("B" Building). The Technical Support Center will be used as the assembly point for Utility, Vendor Support, NRC, or other personnel who would be directly involved in assessment of plant accident response and mitigation. The Emergency Operations Facility is currently located at the licensee's training center in Quinton, New Jersey and will be utilized to evaluate and coordinate emergency and re-entry/recovery operations on a continuing basis by the licensee, Federal, and State officials. It will also be the center for receipt and analysis of field monitoring information submitted by field teams.

The Operations Support Center (assembly area) is located in the aisleway between the station's control rooms and will be the assembly point for unassigned personnel. Emergency equipment and supplies normally stored in the control room will be readily available if needed.

Stored emergency equipment is inventoried quarterly and after each use. Sufficient equipment resources are provided to replace those that may be removed for servicing and calibration. The plan provides a listing of the emergency equipment stored at various strategic locations around the facility.

Onsite monitoring systems and instrumentation used to initiate emergency measures and/or provide continuing assessment are identified. These include meteorological and seismic instrumentation, radiological monitors, process monitors, fire detection systems, and portable dose rate and radiation detection instruments.

The meteorology equipment at the site meets the criteria of Regulatory Guide 1.23, "Onsite Meteorological Programs," dated February 17, 1972. The licensee has provided a description of and completion schedule for an upgraded meteorological program in accordance with Appendix 2 of NUREG-0654.

The licensee has made provisions for offsite monitoring including an extensive TLD network in accordance with the staff's position as well as portable radiation monitoring instruments for use by the offsite field assessment teams. Also, offsite meteorological data can be obtained from the nearby NOAA Weather Station at the Wilmington airport.

I. Accident Assessment

Planning Objectives

To assure the adequacy of methods, systems and equipment for assessing and monitoring actual or potential offsite consequences or a radiological emergency condition.

Emergency Plan

The licensee has identified the instruments that will be used to identify and assess an accident at the Salem Nuclear Generating Station. The methodology is described that would be used to project actual or potential offsite consequences resulting from an accident utilizing the information available to the operator in control room.. A high range containment monitor capable of detecting 10^7 R/hr is available for assessing the gross activity within containment. This information together with the predetermined activity resulting from various radionuclide releases from the coolant and the fuel will aid the licensee in assessing the status and extent of core degradation in the event of a serious accident. Also, the licensee has provided a capability of sensing a release rate of 10^4 curies/second through the plant vent for use in predicting offsite doses in the event of an actual release following a serious accident.

The licensee has also established a methodology to be used for estimating offsite doses in the unlikely event that the plant instruments are off-scale or out-of-service. The details for such projected dose calculations are provided in the emergency plan implementation procedures.

In addition to projecting offsite consequences from measured in-plant parameters, the licensee has also established a field monitoring capability. Field monitoring teams will be employed whenever the radiation protection emergency organizations is activated. Deployment times will range from 30 minutes for the onsite survey team to 60 minutes for the offsite field monitoring teams.

Additional information is required in the Salem emergency plan regarding the means for relating measured field contamination levels to dose rates for key isotopes and gross radioactivity measurements.

J. <u>Protective Response Planning Objectives</u>

To assure that a range of protective actions is available for the plume exposure pathway for emergency workers and the public, guidelines for the choice of protective actions during an emergency, consistent with federal guidance, are developed and in use, and that protective actions for the ingestion exposure pathway appropriate to the locale have been developed.

<u>Emergency Plan</u>

The licensee has established an onsite protective response for employees, contractor personnel, and members of the general public who may be within the exclusion area at the time of an emergency. This response consists of warning and notification, relocation and accountability, and protective actions. Onsite warning and notification will be by means of various alarm system, station public address system, or by members of the security force depending on the location of the individuals within the exclusion area. In the case of a Site or General Emergency, personnel within the protected area will be relocated and an initial accountability completed within thirty minutes. The evacuation routes for non-essential onsite personnel are specified as part of the evacuation study conducted for the plume exposure Emergency Planning Zone. Additional onsite protective measures include the use of individual respiratory protection, protective clothing, and radioprotective drugs.

The plan provides for recommending offsite protective measures depending on the projected dose to the environs. The particular recommendation may be sheltering or evacuation depending on the magnitude of the projected dose, the meteorological conditions, the nature of the release, and the predetermined evacuation time estimated for the sector(s) affected.

K. <u>Radiological Exposure Control Planning Objectives</u>

To assure that means for controlling radiological exposures, in an emergency, are established for emergency workers and the affect population.

<u>Emergency Plan</u>

The licensee has established a radiation protection program for controlling radiological exposures in the event of an emergency. Emergency exposure guidelines have been provided for the various categories of radiation workers. These guidelines are consistent with the EPA Emergency Worker and Life Saving Activity Protective Action Guides. The plan clearly specifies the persons authorized to permit emergency exposures in excess of 10 CFR Part 20 limits.

The capability has been established for 24-hour-per-day dose determination for emergency personnel. Dose records will be maintained to ensure that the exposure history is current.

Onsite contamination control measures for personnel, equipment, and access control are provided. The criteria for decontamination of personnel and equipment are specified in the plan, together with the criteria for permitting return of areas and items to normal use.

Provisions have been established for decontaminating relocated onsite personnel including provisions for extra clothing and decontaminants suitable for the type of contamination expected. Reserve supplies of clothing and decontaminations are stored onsite.

L. Medical and Public Health Support
Planning Objectives

To assure that arrangements are made for medical services for contaminated individuals.

Emergency Plan

PSE&G has made arrangements with the Salem Memorial Hospital to provide medical assistance to site personnel injured from accidents involving either a radiation and/or non-radiation source. The hospital has designated space identified as the Radiation Emergency Area for the care and treatment of contaminated patients. In addition, the licensee has entered into an agreement with the Radiation Management Corporation for various emergency medical assistance services. These services include the utilization of the extensive Radiation Medicine Facilities at the Hospital of the University of Pennsylvania which are equipped for the definitive evaluation and treatment of radiation injuries.

The Station has a first aid facility located in the Administrative Building for providing medical assistance to all site personnel. The facility can provide first aid treatment for minor injuries and emergency aid for more serious injuries. Agreements have been made with two physicians for onsite medical assistance.

A written agreement has been made with Lower Alloways Creek Rescue Squad for transporting injured personnel when necessary.

M. Recovery and Reentry Planning and Postaccident Operations
Planning Objective

To assure that general plans for recovery and reentry are developed.

Emergency Plan

The PSE&G Recovery Management Plan (RMP) is intended to support the Salem Generating Station in the execution of its Emergency Plan. The RMP organization will consist of experienced company management headed by the Senior Vice President-Energy Supply and Engineering, and supervisory personnel who have the authority to assure the best available use of company resources to assist in rapid recovery. The RMP organization will provide:

1. Technical and operational support planning for recovery operation
2. Radiological field monitoring and data assessment
3. Medical assistance through activation of the Emergency Medical Assistance Plan
4. Logistics support for emergency personnel
5. Management level interface with governmental authorities
6. Release of information to news media coordinated with governmental authorities

Any decision on the Company's part to relax protective measures will be made by the Emergency Duty Officer using guidance from the Recovery Manager, the Emergency Coordinators for New Jersey and Delaware, and the senior NRC representatives at the scene. Whenever a recovery operation is to be initiated or any change is to be made in the organizational structure, the Emergency Duty Officer or Recovery Manager will notify the States of New Jersey and Delaware.

N. Exercises and Drills

Planning Objective

To assure that periodic exercises are conducted to evaluate major portions of emergency response capabilities, that the results of exercises form the basis for corrective action for identified deficiencies and that periodic drills are conducted to develop and maintain key skills.

Emergency Plan

Annual exercises will be held involving the response organizations from the States of New Jersey and Delaware, and the licensee. At least once every three years the annual exercise will be conducted on a back-shift between the hours of 6 p.m. and 6 a.m. The scenario used for the various exercises will contain at least the essential elements as set forth in NUREG-0654. Arrangements will be made for qualified observers and a critique will be held after the exercise. Station management will review and resolve any identified deficiencies, and their result will be reviewed by the Station Operations Review Committee within 90 days of the exercise to ensure that appropriate actions have been taken.

In addition to the exercises, various drills will be conducted covering communications, fires, medical emergencies, health physics and radiological monitoring. Depending on the particular drill, the frequency varies from monthly to annually in accordance with that set forth in NUREG-0654. Minimum requirements have been established for each of the drills. Deficiencies resulting from evaluation of the drills will be handled by station management and the Station Operations Review Committee as discussed above.

O. Radiological Emergency Response Training

Planning Objective

To assure that radiological emergency response training is provided to those who may be called upon to assist in an emergency.

Emergency Plan

The licensee provides training in the Emergency Plan and procedures to all permanent plant personnel. This includes assignment of duties and responsibilities, location and use of assembly areas, and familiarization with alarms and communications systems. In addition, those personnel having specific response roles as part of the onsite emergency organization are given specialized training in accordance with their expected duties. These areas include emergency response coordination and direction, accident assessment, radiological monitoring, repair and damage control, rescue, and first aid.

Training is also provided for those offsite organizations whose services may be required in an emergency such as medical support personnel and the local fire companies.

Additional information is required on the training program for personnel who will implement the radiological emergency response plans. Prior to issuance of a full power license, we will require a detailed description of the specialized initial training and periodic retraining programs (including the scope, nature, and frequency) for each of the nine categories of personnel having emergency response roles as listed in NUREG-0654.

P. Responsibility for the Planning Effort: Development, Periodic Review and Distribution of Emergency Plans

Planning Objective

To assure that responsibilities for plan development, review and distribution of emergency plans are established and that planners are properly trained.

Emergency Plan

The General Manager - Electric Production, has the overall authority and responsibility for radiological emergency response planning at the corporate level. The Manager - Nuclear Operations, has the responsibility for plan development and updating, and the Assistant Manager - Salem Generating Station has the responsibility for developing and updating the implementing emergency procedures. Provisions exist for an annual review and revision, if necessary, of the emergency plan and its implementing procedures. Any changes to these documents will be provided to the organizations and individuals having a responsibility for implementing the emergency plan.

The overall emergency preparedness program will be audited by an outside company at least every two years. The audit will include the emergency plan and procedures, training, readiness training and emergency equipment.

CONCLUSION

Based on our review, we conclude that the Salem emergency plan, upon satisfactory correction of the deficiencies listed below, will meet the planning objectives applicable to the licensee as stated in Revision 1 of NUREG-0654 "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants."

In order to rectify the existing deficiencies prior to issuance of a full power license, the plan shall:

1. Describe the means to be provided for informing the transient population within the plume exposure EPZ as to how they may be notified and what their initial action should be in the event of a serious emergency (Sections II.G.1 and II.J.10c of NUREG-0654).

2. Describe the means for relating measured field contamination levels to dose rates for key isotopes (Section II.I.10 of NUREG-0654).

3. Identify the transient population within the Emergency Planning Zones (Section II.J.10b of NUREG-0654).

4. Describe the specialized initial training and periodic retraining programs (including the scope, nature, and frequency) for each of the nine categories of personnel listed in Section II.0.4 of NUREG-0654.

5. Fulfill the following commitments prior to the issuance of a full power operating license:

    a) Finalize and provide letters of agreement with all primary emergency response organizations listed on pages F-2 and F-3 of this supplement.

    b) Provide Emergency Action Levels for all initiating conditions identified in NUREG-0610.

    c) Establish capability for promptly contacting the four county authorities directly in the event of a General Emergency.

    d) Provide a description of the early warning system and its method of actuation.

    e) Complete the emergency planning portion of the public information program.

In addition, as a result of the publication of the final version of NUREG-0654, dated November, 1980, additional items have arisen that need to be addressed in the Salem Emergency Plan. In order to eliminate these items as deficiencies, the Plan shall:

1. Provide for the augmentation of the minimum on-shift staffing in accordance with the time frame shown in Table B-1 of NUREG-0654.

2. Discuss the Federal response capability through the Federal Radiological Monitoring and Assessment Plans (formerly RAP and IRAP) including the information identified in Section II.C.1.b and c of NUREG-0654.

3. Describe the provisions for a coordinated communication link with the fixed and mobile medical support facilities in accordance with Section II F.2 of NUREG-0654.

4. Describe the coordinated arrangements made with State and local agencies for dealing with rumors in times of emergencies (Section II.G.4.c of NUREG-0654).

5. Describe the meteorological program which meets the first three milestones identified in Appendix 2 to NUREG-0654, and a commitment to the schedule established for meeting the remaining five milestones.

6. Provide a revised analysis of the evacuation time estimates within the plume exposure pathway EPZ in accordance with the requirements set forth in Appendix 4 to NUREG-0654.

7. Provide for a quarterly communications drill with the Federal emergency response organizations and the States within the ingestion pathway EPZ in accordance with Section II.N.2a of NUREG-0654.

8. Provide for an annual independent review of the emergency plan, its implementing procedures and practices, training, readiness testing, equipment, and interfaces with State and local governments as specified in Section II.P.9 of NUREG-0654.

9. Provide for updating telephone numbers in emergency procedures at least quarterly in accordance with Section II.P.10 of NUREG-0654.

Upon correction of the identified deficiencies and after receiving the findings and determinations made by the Federal Emergency Management Agency on the State and local emergency response plans, a supplement to this report will provide the staff's overall conclusions on the status of emergency preparedness for the Salem Nuclear Generating Station and related Emergency Planning Zones.

NRC FORM 335 (7-77) U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET**	1. REPORT NUMBER *(Assigned by DDC)* NUREG-0517 Supplement No. 5
4. TITLE AND SUBTITLE *(Add Volume No., if appropriate)* Safety Evaluation Report related to the operation of Salem Nuclear Generating Station, Unit 2. Public Service Electric and Gas Company, et al, Docket No. 50-311	2. *(Leave blank)*
	3. RECIPIENT'S ACCESSION NO.
7. AUTHOR(S)	5. DATE REPORT COMPLETED MONTH January YEAR 1981
9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)* U. S. Nuclear Regulatory Commission Washington, D.C. 20555	DATE REPORT ISSUED MONTH January YEAR 1981
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15. SUPPLEMENTARY NOTES Relates to Docket No. 50-311	14. *(Leave blank)*

16. ABSTRACT *(200 words or less)*

The Nuclear Regulatory Commission has issued Supplement No. 5 to the Safety Evaluation Report in the matter of the application by Public Service Electric and Gas Company, et al for an operating license for the Salem Nuclear Generating Station, Unit 2. Supplements 1 through 4 documented the resolution of several outstanding issues in the Safety Evaluation Report. Supplement No. 5 further updates the Safety Evaluation Report by providing an evaluation of additional information submitted by PSE&G and an evaluation of other requirements which must be completed by PSE&G, in connection with the utility's request for an operating license to operate the facility at 100% power.

17. KEY WORDS AND DOCUMENT ANALYSIS	17a. DESCRIPTORS
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