MAY 0 1 1986

Docket Files

Docket Nos: 50-443
and 50-444

MEMORANDUM FOR: E. Rossi
E. Reis, OELD

FROM: Vincent S. Noonan, Director
PWR Project Directorate #5
Division of PWR Licensing-A

SUBJECT: FINAL DRAFT SSER FOR SEABROOK, UNITS 1 AND 2

Enclosure 1, is a copy of the final draft SSER-4 for Seabrook, Units 1 and 2. This includes the input from the review groups as of April 25, 1986.

Please review the enclosed report and provide your concurrence to V. Nerses, Licensing Project Manager (x 28535) by C.O.B. May 2, 1986.

Please note that Sections 18 (18.1 and 18.2), 3.11 and 13.3 must be published without further changes (for further clarification on this please refer to Enclosure 2)

Vincent S. Noonan, Director
PWR Project Directorate #5
Division of PWR Licensing-A

Enclosures:
Final SSER-4 For Seabrook

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Enclosure 1

NUREG-0896
Supplement No. 4

Safety Evaluation Report
related to the operation of Seabrook Station, Units 1 and 2

Docket Nos. 50-443 and 50-444

Public Service Company of New Hampshire, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

April 1986

NUREG-0896, Supp. No. 4 SER RELATED TO THE OPERATION OF SEABROOK STATION, UNITS 1 AND 2 APRIL 1986

ABSTRACT

This report is Supplement 4 to the Safety Evaluation Report (SER, NUREG-0896, March 1983) for the application filed by the Public Service Company of New Hampshire, et al., for licenses to operate Seabrook Station, Units 1 and 2 (Docket Nos. STN 50-443 and STN 50-444). It has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission and provides recent information on open items identified in the SER. The facility is located in Seabrook, New Hampshire. Subject to favorable resolution of the items discussed in this report, the staff concludes that the facility can be operated by the applicant without endangering the health and safety of the public.

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1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

On March 7, 1983, the Nuclear Regulatory Commission staff (NRC or staff) issued a Safety Evaluation Report (SER), NUREG-0896, on the application of Public Service Company of New Hampshire (PSNH, hereinafter referred to as the applicant) for licenses to operate Seabrook Station, Units 1 and 2. In April 1983, the NRC issued the first supplement to the SER (SSER 1), in June 1983 the second supplement (SSER 2) was issued, and in July 1985 the third supplement (SSER 3) was issued tc at document. This fourth supplement (SSER 4) provides information t .pdate the status of the NRC review.

Each of the sections and appendices of this supplement is designated the same as the related portion of the SER. The contents of this document are supplementary to the initial SER, SSER 1, SSER 2, and SSER 3 and not in lieu of those documents unless otherwise noted. The NRC Project Manager for the Seabrook operating lice (OL) review is Mr. Victor Nerses. He may be reached by telephone at 3 92-8535 or by mail at the following address:

Mr. Victor Nerses, Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

1.7 Outstanding Issues

Section 1.7 of the SER noted that certain outstanding issues in the staff's review had not been resolved by the time the report was issued. This supplement closes five of those items. These items, and the sections of this supplement that present results of the staff's evaluation, are

(4) Preservice and inservice inspection and testing programs (5.2.4, 6.6.1)

(6) Stresses/dynamic qualification of equipment (3.10)

(8) TMI Action Plan items (13.5.1, 15.9.7)

(9) Fracture tougness of RCPB and secondary system materials (5.2.3, 10.3.6)

(19) Control room design review (18)

As of this supplement, the remaining outstanding issues and the related SER sections are

(2) Emergency preparedness (2.3.3, 13.3)

(4) Preservice and inservice inspection and testing programs (2.5.5.3, 3.9 6, 5.4.12)

(6) Environmental qualification of equipment (3.11)

(8) TMI Action Plan items (3.9.3.2, 4.4.5.4, 6.2.8, 9.3.4.2, 13.3, 14, 15.9.5, 15.9.9)

(10) Level measurement error (7.3.2.8)

(11) Instrumentation and control for safe shutdown (7.4.2.1, 7.4.2.4)

(12) Radiation data management system (7.5.2.2)

(14) Solid radwaste management system (11.4)

(16) Shift technical advisor, TMI Action Plan Item I.A.1.1 (13.1.2.2, 13.2.2.1)

(17) Steam generator tube rupture (15.6.3)

(20) Fire protection (9.5.1.9)

1.8 Confirmatory Issues

Section 1.8 of the SER noted that there are some items that have been resolved essentially to the staff's satisfaction but for which certain confirmatory information has not yet been provided by the applicant. This supplement closes 19 of the confirmatory items. These items, and the sections of this supplement that present results of the staff's evaluation, are

(7) Conformance of reactor internals and control rod drive mechanism materials aging and tempering temperatures to staff guidelines (4.5.2)

(9) Staff review of LOFTRAN computer code (5.2.2)

(10) Conformance with RG 1.36 for compatibility of thermal insulation with RCPB and ESF materials (5.2.3.1, 6.1)

(11) Confirmation of maximum yield strength of RCPB materials (5.2.3)

(12) Analysis of the containment purge and vent system (6.2.4, 6.2.8)

(13) Containment subcompartment analysis (6.2.1.2)

(14) Formal documentation of previously provided information related to several instrumentation and control systems (7.3.2, 7.5.2.1, 7.7.2)

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(23) Compliance with RG 1.9 (8.3.1.2)

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(27) Compliance of non-Class 1E circuits to Class 1E requirements (8.3.3.3.1)

(28) DC nonsafety loads (8.3.2.4)

(29) Compliance with RG 1.63 (8.3.3.6.3)

(32) Conformance to GDC 35 for fracture toughness of main steam and feedwater materials (10.3.6)

As of this supplement, the remaining and additional confirmatory items are

(1) Underground transmission line easement (2.1.2)

(5) Staff review of applicant response to IE Bulletin 79-02 (3.9.3.3)

(6) Loose parts monitoring system (4.4.5.3)

(12) Analysis of the containment purge and vent system (6.2.4, 6.2.8)

(14) Formal documentation of previously provided information related to several instrumentation and control systems (7.2.2, 7.4.2.5, 7.6.7)

(16) Main steam atmospheric relief valves (7.4.2.2)

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(31) Diesel generator exhaust inspection and protection (9.5.8)

(33) Sampling capability for vacuum pumps during startup (10.4.2)

(37) Health physics organization (12.5.1)

(38) Experience level for the ISEG (13.4.1)

(40) Inadvertent boron dilution (15.4.6)

(41) Systems outside containment containing radioactive material, TMI Action Plan Item III.D.1.1 (15.9.15)

(42) Emergency feedwater pump turbine anomalies and temporary 3-inch drainline (3.10.1.5)

(43) PVORT equipment-specific issues and generic issues (7.10.2.3)

1.9 License Condition Item

In Section 1.9 of the SER, the staff noted several issues for which a license condition may be desirable to ensure that staff requirements are met during plant operation if those requirements have not been met before the operating license is issued. The license condition may be in the form of a condition in the body of the operating licenses, or a limiting condition for operation in the Technical Specifications appended to the licenses.

This supplement closes five license condition items. These items and the sections of this supplement that present results of the staff's evaluation are

(6) Reactor coolant system vents, TMI Action Plan Item II.B.1 (5.4.12)

(7) Degraded grid voltage protection (8.3.1.1)

(14) Administrative procedures (applicable TMI Action Plan items) (13.5.1)

(18) Plant performance during a steam generator tube rupture (15.6.3)

(19) Voiding in the reactor coolant system, TMI Action Plan Item II.K.2.17 (15.9.5)*

As of this supplement the remaining license condition items are

(1) Turbine system maintenance program (3.5.1.3)

(2) Relief and safety valve test requirements, TMI Action Plan Item II.D.1 (3.9.3.2)

(3) Detection of inadequate core cooling, TMI Action Plan Item II.F.2 (4.4.5.4, 4.4.8)

(4) Inservice inspection program (5.2.4, 6.6.1)

(5) Natural circulation tests (5.4.6.5)

(8) Compliance with NUREG-0612 (control of heavy loads) (9.1.5)

(9) Postaccident sampling, TMI Action Plan Item II.B.3 (9.3.4.2)

(10) Secondary water chemistry monitoring and control (10.3.5)

(11) Solid radwaste management system (11.4)

(12) Shift Technical Advisor, TMI Action Plan Item I.A.1.1 (13.1.2.2, 13.2.2.1)

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*This item was closed out in SSER 3, but it was not recorded as such in SSER 3)

(13) Emergency preparedness (13.3)

(15) Operating and maintenance procedures, applicable TMI Action Plan items (13.5.2)

(16) Implementation and maintenance of the physical security plan (13.6)

(17) Training during low-power testing, TMI Action Plan Item I.G.1 (14)

(20) Control room design review, TMI Action Plan Item I.D.1 (18)

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.2 Classification of Structures, Systems, and Components

3.2.2 System Quality Group Classification

As was noted in the SER, staff acceptance of the quality group classification of systems and components that perform a safety function was contingent upon the applicant revising appropriate pages of FSAR Table 3.2-2. These revisions to Table 3.2-2 were made in Amendments 48, 55, and 56 to the FSAR.

The staff has reviewed the revised pages of Table 3.2-2 in Amendments 48, 55, and 56, and they are acceptable. The staff concludes that the quality group classification of systems and component in FSAR Table 3.2-2 is in conformance with the guidance in Regulatory Guide (RG) 1.26 and provides assurance that component quality is commensurate with the importance of the safety function of these systems and components and constitutes an acceptable basis for satisfying the requirements of General Design Criterion (GDC) 1 and is, therefore, acceptable.

3.8 Design of Seismic Category I Structures

3.8.1 Concrete Containment

In the SER, it was stated that the applicant has committed to perform an ultimate capacity analysis for the containment and that the staff will review the analysis. In the SER, it was not noted that the staff requested the analysis for information only. The applicant met this commitment when the analysis was submitted for information by letter dated June 7, 1983.

3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Structures, and Core Support Structures

3.9.3.1 Loading Combinations, Design Transients and Stress Limits

In Section 3.9.3.1 of the SER, the staff stated that it had not completed its review of design documents for selected pumps, valves, and piping because it was awaiting further information from the applicant. The outstanding information related to: (1) the documentation of pressure boundary checks for an ASME Code Class 2 pump (Staff Question 210.85) and (2) details of the procedure for ensuring Code compliance in the evaluation of piping tees or branch connections in ASME Code Class 1 piping systems (Staff Question 210.89).

In a letter dated March 10, 1983, the applicant provided a response to Question 210.85. The response, Report ME-991 entitled "Pressure Boundary Calculations of Horizontal Pumps," is applicable to the containment spray pumps at the Seabrook Station, Units 1 and 2. The staff concluded that the applicant has adequately documented acceptable procedures for ensuring that appropriate design checks have been implemented to demonstrate that the pressure boundary parts of ASME Code Class 2 pumps meet the applicable rules in NC-3000 of ASME Code Section II.

In a letter dated October 10, 1985, the applicant provided a response to Question 210.89. In that response, the applicant stated that the specific data relative to piping tees and branch connections which were requested by the staff and listed in Attachments 1 and 2 of the response will be included as a part of the required ASME Code Class 1 stress reports. The staff has concluded that inclusion of this requested information in the Class 1 stress reports provides the required traceability to demonstrate acceptable compliance with the ASME Code Class 1 requirements.

The staff design documentation audit which was discussed briefly in the SER consisted of an evaluation of the following specific components:

(1) ASME Code Class 2 containment spray pump

(2) ASME Code Class 2 and 3 butterfly valves used in service water systems

(3) a portion of the safety injection piping system which includes both ASME Code Class 1 and 2 piping

(4) a support for the piping systems in item 3 above

In the process of conducting this audit, the staff and its consultant, Oak Ridge National Laboratory, reviewed the following documents which are applicable to the above list of components:

(1) design reports for ASME Code Class 1 components

(2) the equivalent of design reports for ASME Code Class 2 and 3 components

(3) design specifications

(4) references to the reports in items 1, 2, and 3 above

On the basis of a review of the above design documentation and subsequent meetings and correspondence on this issue, the staff arrived at the following conclusions:

(1) Design specifications required by the ASME Code have been prepared and contain a complete basis for the construction of the components.

(2) The design reports for Class 1 components and the equivalent to design reports for Class 2 and 3 components which are required by the Code have been prepared. The input data used are traceable to and agree with the design specification, and the analyses show compliance with Code requirements.

(3) The design specifications include appropriate provisions to ensure adequate performance of components during their anticipated service, and to demonstrate that appropriate documentation has been received which shows compliance with the specifications.

3.9.3.2 Design and Installation of Pressure-Relief Devices

As required by NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.D.1, all pressurzied-water-reactor (PWR) plant licensees and applicants are required to demonstrate that their pressurizer safety valves (SVs), power-operated relief valves (PORVs), PORV block valves, and all associated discharge piping will function adequately under conditions predicted for design-basis transients and accidents. In response to this requirement, the Electric Power Research Institute (EPRI), on behalf of the PWR Owners Group, has completed a full-scale valve testing program, and the Owners Group has submitted these test results to the NRC. Additionally, each PWR plant applicant for an OL was required to submit a report by the time of fuel load which would demonstrate the operability of these valves and the associated piping. In Section 3.9.3.2 of the SER, the staff stated that the applicant had not provided information on TMI Action Plan Item II.D.1, "Performance Testing of BWR and PWR Relief and Safety Valves."

On October 10, 1985, and March 17, 1986, the applicant responded to this requirement with submittals that contained information from the EPRI valve test program results which applies to Seabrook 1 and 2. The submittal also states that the safety and relief valve discharge piping and supports are constructed to ensure functionability. NUREG-0737 states that a plant-specific post-implementation review of these submittals will be performed.

The staff has not completed a detailed review of the applicant's submittals; however, on the basis of a preliminary review, the staff finds that the general approach of using the EPRI test results to demonstrate operability of the safety valves, PORVs, and PORV block valves is acceptable. The applicant's submittal notes that Seabrook 1 and 2 utilizes safety valves, PORVs, and PORV block valves of the same size and model that performed satisfactorily for test sequences considered representative or that bound conditions to which the valves could be exposed.

In summary, on the basis of a preliminary review, the staff has concluded that the applicant's general approach to responding to this TMI Action Plan item is acceptable and provides adequate assurance that the Seabrook 1 and 2 reactor coolant system overpressure protection systems can adequately perform their intended functions for the period during which the staff completes its detailed review. If the completion of that detailed review reveals that modifications or adjustments to safety valves, PORVs, PORV block valves, or associated piping are needed to ensure that all intended design margins are present, the staff will require that the applicant make appropriate modifications.

3.9.3.3 Component Supports

The staff stated in the SER that the applicant's response to NRC Office of Inspection and Enforcement (IE) Bulletin 79-02 for the Seabrook facility was under review. The staff has undertaken a generic review of all applicants' and licensees' responses with respect to pipe support baseplate flexibility and its effect on anchor bolt loads. The staff has determine that completion of this review is not required to support the full-power license, as it is confirmatory in nature. If the results of the generic review reveal that modifications are necessary to ensure the proper functioning of these supports, the staff will require that the applicant make appropriate modifications. Therefore, the staff considers SER confirmatory issue 5 closed.

3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

3.10.1.1 Introduction

Evaluation of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an audit of selected equipment items to develop a basis for the judgment of the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program.

Guidance for the evaluation is provided by Section 3.10 of the Standard Review Plan (SRP, NUREG-0800) and its ancillary documents: Regulatory Guides (RGs) 1.61, 1.89, 1.92, and 1.100; NUREG-0484; and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is required to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50); Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100. The program is evaluated by a Seismic Qualification Review Team (SQRT) that consists of engineers from NRC and the Idaho National Engineering Laboratory (INEL, EG&G Idaho).

3.10.1.2 Discussion

The SQRT reviewed the equipment dynamic qualification information in the Final Safety Analysis Report (FSAR) Sections 3.9.2 and 3.10 and visited the plant from November 5 through November 8, 1985, to determine the extent to which the equipment installed at Seabrook Unit 1 meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment as well as instrumentation, in both the nuclear steam supply system (NSSS) and the balance of plant (BOP) scopes, was selected for the audit. Table 3.1 identifies the equipment audited. The plant-site visit included field observations of the actual, final equipment configuration and its installation. Observing the field installation of the equipment is necessary to verify and validate equipment modeling employed in the qualification program. These observations were followed by a review of the corresponding design specifications and test and/or analysis documents maintained in the applicant's central files. The applicant also provided details of the maintenance, startup testing, and in-service inspection.

The audit identified both generic and plant-specific concerns. Subsequently, the applicant submitted additional information resolving some of the issues. A summary of the issues and their disposition is presented in the following sections and in Table 3.1.

3.10.1.3 Generic Items

During the field observation of the nuclear instrumentation system cabinet, the SQRT noted that the clearance between this unit and the adjacent solid state protection system train B was not adequate. The team also learned that this problem was associated with many other cabinets. However, the applicant was aware of the problem and indicated that the problem was being analyzed and its resolution was being actively pursued. A final and satisfactory resolution of this problem, on a generic basis, should be confirmed to the NRC before fuel load.

During the documentation review of the reactor makeup water valve (RMWV-30: NSSS-5), it was discovered that the g-loading assumed for the valve qualification has not been reconciled with the as-built condition. In addition, this has not been done for other valves. However, the applicant indicated that a reconciliation program was in progress. The staff is to be informed (before fuel load) when the program is completed.

The life-span of nonmetallic parts for 3-inch air-operated valves has not been evaluated, nor has such an evaluation been performed for many other equipment items. The applicant subsequently submitted documentation providing maintenance and replacement schedules indicating that a program is in place that takes life-span into account. Therefore, this issue is resolved.

3.10.1.4 Equipment-Specific Items

The SQRT review of the Wyle Laboratories report on the diesel generator relay control cabinet (BOP-16) tests revealed a number of anomalies. These are detailed in the report. The additional applicant information noting that the pulling out of the stud will not make it an internal missile, considering its configuration and point of separation, is acceptable to the staff. Further cracking of insulators did not affect operability. Therefore, this issue is resolved.

3.10.1.5 Confirmatory Items

The Wyle Laboratories tests on the emergency feedwater pump turbine (Terry Turbine: BOP-5) revealed many anomalies, some of which appear to require field modifications. The applicant must confirm that all the anomalies have been satisfactorily resolved.

Subsequent to SQRT review at the site, the applicant completed the review of new documentation based on a 1979 Terry turbine test and 1985 seismic analysis and found it acceptable with the two following explanations.

(1) The Seabrook site has a different governor system precluding the tripping problem.

(2) A support bracket was added to stiffen the piping to eliminate the problem of excessive displacement. The response is satisfactory.

Therefore, the applicant confirmed that the anomalies have been resolved, and this issue is now resolved.

The field observation of the emergency feedwater pump turbine (BOP-5) found that a temporary 3-inch drain line had been installed. Reportedly, the line might become a permanent fix. If the line is to be permanent, the applicant must establish the seismic adequacy of this line and confirm it to the NRC.

3.10.1.6 Summary and Conclusion

On the basis of the observation of the field installation, the review of the qualification documents, and the applicant's responses to SQRT's questions during the audit, the staff finds that the applicant's seismic and dynamic qualification program is well defined and adequately implemented. When the issues identified in Sections 3.10.1.3, 3.10.1.5, and in Table 3.1 are closed, the applicant will have met the applicable portions of GDC 1, 2, 4, 14, and 30; Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100.

3.10.2 Operability Qualification of Pumps and Valves

3.10.2.1 Introduction

The NRC staff performs a two-step review of each applicant's pump and valve operability assurance program to determine whether the program can ensure that all pumps and valves important to safety will operate when required for the life of the plant under normal and accident conditions. The first step is a review of FSAR Section 3.9.3.2. However, the information in the FSAR is general in nature and lacks sufficient detail to allow the staff to determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. Thus, the staff also conducts an onsite audit, the second step of the review process.

A Pump and Valve Operability Review Team (PVORT), consisting of engineers from the NRC and INEL, conducts the audit, which reviews a representative sample of installed pump and valve assemblies and their supporting qualification documents at the plant site. On the basis of the results of both the audit and the FSAR review, the PVORT determines whether the applicant's overall program conforms to the licensing criteria in SRP Section 3.10. The applicant must conform to SRP Section 3.10 to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 and Appendix B to 10 CFR 50.

3.10.2.2 Discussion

The PVORT reviewed the pump and valve operability assurance information in FSAR Section 3.9.3.2 and conducted an onsite audit to determine the extent to which the pumps and valves important to safety meet the criteria listed above. The results of the FSAR evaluation appeared in the SER (dated March 10, 1983). These were supplemented by specific comments presented at a pre-audit meeting held August 7, 1985. Several of these issues were adequately resolved by the applicant in a letter dated September 24, 1985. The remaining issues were addressed and resolved during the onsite audit.

Table 3.2 summarizes the status of the 10 items identified in the SER. The staff has determined (1) that the applicant's position on these items has been adequately clarified and (2) that the applicant has committed to actions that will adequately address the concerns.

The onsite audit, which was conducted November 5 through November 8, 1985, consisted of field observations of equipment configuration and installation for a representative sample of plant equipment. The PVORT selected for evaluation three NSSS and six BOP pump and valve assemblies. Table 3.3 summarizes the status of each assembly that was audited. The field observations were followed by a review of the design and purchase specifications, test/analysis documents, and other documents related to equipment operability that are maintained in the applicant's central files. In addition to reviewing information concerning the selected assemblies, the PVORT reviewed information on the plant's overall equipment qualification program. Included within this broad evaluation were those programs and procedures necessary to ensure that equipment qualification issues and concerns will continue to be addressed for the life of the plant. One such program--concerning the deep draft pump issue (refer to IE Bulletin 79-15)--was reviewed in depth.

The PVORT resolved all but five of the specific operability concerns that were identified. These five concerns follow.

(1) Auxiliary feedwater pump turbine operability with moisture in the steam was not addressed.

(2) The auxiliary feedwater pump turbine end seal was cracked and the cause had not been determined.

(3) Operability of the auxiliary feedwater pump turbine trip and throttle valve was not ensured after an overspeed trip.

(4) Timing requirements were not addressed for control check valve FW-V-331.

(5) Cooling tower pump SW-P-110A O-ring maintenance procedures were not addressed in accordance with the manufacturer's requirements.

In addition, the applicant was informed of five generic issues that must be addressed before fuel load. These five issues follow.

(1) Not all of the preservice tests required before fuel load have been completed.

(2) Approximately 10 to 15% of all pumps and valves important to safety were not yet qualified and installed.

(3) The plant maintenance procedures were not complete enough for the staff to determine that safety-related equipment will be maintained in its qualified state for the life of the plant.

(4) BOP valves less than 2 inches in size were not included in the Seabrook pump and valve operability assurance program.

(5) The FSAR active valve lists were not current.

These concerns and issues are confirmatory and form the basis for the discussion presented in Section 3.10.2.3 below.

After the site audit, the applicant submitted letters dated December 31, 1985, and April 8, 1986, which resolved four of the specific issues and all five of the generic issues. The remaining specific issue to be resolved is operability of the auxiliary feedwater pump turbine trip and throttle valve following an overspeed trip (item 3 of the specific issues). The manner in which each confirmatory issue was addressed is briefly discussed in Section 3.10.2.3 and is indicated in Table 3.3.

The PVORT has found that the applicant is dealing with the equipment qualification issue in a positive manner. All of the SER items were adequately resolved through additional clarifications and appropriate commitments provided by the applicant. During the audit, the applicant addressed all questions posed by the PVORT and committed to resolve all audit issues before fuel load. Furthermore, the applicant discussed significant aspects of the overall equipment qualification program--such as amplified response spectra reconciliation, equipment modification and reconciliation of original qualification reports, nozzle load verification, and review of non-safety-related equipment located in close proximity to safety-related equipment. Consequently, the PVORT believes that the continuous implementation of the applicant's overall program should provide adequate assurance that the pumps and valves important to safety will operate as required for the life of the plant.

3.10.2.3 Confirmatory Issues

Based on the PVORT's evaluation of the Seabrook pump and valve operability assurance program, the staff has identified to the applicant the following five equipment-specific issues and five generic confirmatory issues that must be resolved before fuel load:

Equipment-Specific Confirmatory Issues

(1) The applicant shall confirm that the auxiliary feedwater pump (FW-P-37A) turbine operability is addressed in regard to the potential of having moisture in the driving steam.

    Applicant Response During hot functional testing, problems were identified involving water slug formation in the steam supply lines to the turbine-driven emergency feedwater (EFW) pump. The applicant explained that design changes are being implemented, which will protect the piping and supports as well as minimize associated problems with the EFW pump turbine. The changes include the addition of drains, resloping lines, adding time-sequenced valves, heat tracing, modification of the turbine governor, and the use of a lower viscosity hydraulic fluid in the turbine governor. The commitment to complete the modifications before fuel load, as well as the onsite review of the qualification documents provide confidence that the EFW pump turbine will function as required. This issue is resolved.

(2) Before the audit, the turbine end of the auxiliary feedwater pump (FW-P-37A) was found to have a cracked seal. The cause of the seal failure had not been determined nor had steps been taken to prevent a recurrence. The applicant shall confirm that this failure is investigated and resolved.

Applicant Response After a 48-hour endurance run during hot functional testing, minor leakage was identified at the seal. A dimensional check discovered that the rotor was mismachined in the area of the seal. This machining error prevented the seal from being properly secured to the rotor. The applicant stated that the rotor has been remachined by Ingersoll and is now reinstalled. Retesting before fuel load will verify seal integrity. This issue is resolved.

(3) Operation of the auxiliary feedwater pump (FW-P-37A) turbine trip and throttle valve was not investigated when a maximum differential pressure existed across the valve (such as a turbine overspeed trip condition). The applicant shall confirm that the trip and throttle valve can be operated easily during an emergency condition.

Applicant Response To date, the applicant has not provided a response which addresses this issue. This issue remains open.

(4) Check valve FW-V-331 was changed from a swing check to a control check valve that has specific opening and closing times. The operating times for this control check valve were not addressed in the startup, testing, or operating procedures. The applicant shall confirm that the operating times have been investigated and the timing requirements identified and met.

Applicant Response The applicant provided several reasons why the inservice test (IST) program will not include closing time requirements for the valve. (1) For the purpose of controlling waterhammer effects, a valve closure time slower than design is acceptable. (2) The valve closure time is not very likely to speed up during its qualified life. (3) The valve closure time requirements were established based upon faulted plant conditions. (4) Any test performed at less than faulted plant conditions will not be meaningful, because the closure times will always be slower than the critical limit. This explanation combined with the onsite review of the qualification documents provides confidence that this component will function as required. This issue is resolved.

(5) The maintenance procedures for the cooling tower pump (1-SW-P-110A) were still in draft form at the time of the audit. The procedures did not address the two O-rings located at the lateral supports for the pump column. The applicant shall confirm that the final maintenance procedures specify the special handling and replacement of the O-rings.

Applicant Response The applicant has submitted copies of the repetitive task sheets (RTSs) for the service water pump. The implementation of these tasks combined with the onsite discussion of the overall maintenance program adequately resolves this issue.

Generic Confirmatory Issues

(1) At the time of the audit, the maintenance procedures were available for review in draft form only. The applicant shall confirm that the final maintenance procedures will be consistent with the component manufacturer's recommendations. The applicant shall describe how limited-life components

are identified, and how the equipment will be maintained in an operable and qualified state for the life of the plant. The applicant shall provide several examples (at least one pump and one valve) of the final maintenance procedures for review.

Applicant Response The applicant has submitted copies of the repetitive task sheets (RTSs) that illustrate the manner by which various maintenance tasks will be performed. Each RTS includes necessary information such as task description, equipment identification, acceptance criteria, references to pertinent vendor procedures, and safety precautions. This material combined with the onsite discussion of the maintenance program adequately resolves this issue.

(2) The applicant shall provide written confirmation in the FSAR that all active BOP valves are covered by the Seabrook pump and valve operability assurance program. In particular, the applicant shall confirm that BOP valves smaller than 2 inches have been included.

Applicant Response The appropriate sections of the Seabrook FSAR have been revised by Amendment 56, resolving this generic issue.

(3) At the conclusion of the PVORT audit, it was apparent that a complete list of active valves had not been provided in the FSAR. The applicant shall confirm that all active valves are correctly identified in the FSAR.

Applicant Response The safety-related BOP and NSSS valves have been identified in FSAR Table 3.9 (B)-25 and 3.9 (N)-11 by Amendment 56. This issue is resolved.

(4) At the time of the audit, most construction tests had already been completed. However, the hot functional tests were still in progress. The applicant shall confirm that all pre-service tests that are required before fuel load have been completed.

Applicant Response In a letter dated April 8, 1986, the applicant committed to complete the preservice testing before commercial operation. This issue is resolved.

(5) At the time of the audit, approximately 10 to 15% of all pumps and valves important to safety had not been qualified. The applicant shall confirm that all pumps and valves important to safety are properly qualified and installed. In addition, the applicant shall provide written confirmation that the original loads used in tests or analyses to qualify pumps and valves important to safety are not exceeded by any new loads, such as those imposed by a loss-of-coolant accident (hydrodynamic loads) or as-built conditions.

Applicant Response In a letter dated April 8, 1986, the applicant committed to complete the qualification of all safety-related active pumps and valves before fuel load. This issue is resolved.

3.10.2.4 Summary

On the basis of the results of (1) the component walkdown and the review of the qualification document packages, (2) the additional explanations and information provided by the applicant throughout the audit, and (3) the resolution of the SER unresolved items, the staff concludes that an appropriate pump and valve operability assurance program has been defined and implemented. The continuous implementation of this overall program should provide adequate assurance that all pumps and valves important to safety will perform their safety-related functions as required for the life of the plant. With the exception of the specific open issue identified in Section 3.10.2.3, the staff concludes that the applicant has qualified those pumps and valves important to safety to meet the applicable portions of GDC 1, 2, 4, 14, and 30 (Appendix A to 10 CFR 50), as well as Appendix B to 10 CFR 50.

3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment*

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in General Design Criteria (GDC) 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323; and various NRC Regulatory Guides (RGs) and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews.

The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term OL applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical

*Section 3.11 was not edited. An NRC memorandum (April 25, 1986) from T. M. Novak (Division of PWR Licensing-A) to E. S. Christenburg (Hearing Division, OELD) states: "Since the technical staff and I (by this memo) have concurred with the SSER-4 inputs, these inputs will be published without further change."

equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to operating license (OL) applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR 50, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for Seabrook Station Unit 1 may be qualified according to the criteria specified in Category I of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated August 12, 1983, September 7, 1984, October 31, 1985, and April 3, 1986, to supplement the information in FSAR Section 3.11.

The staff has reviewed the adequacy of the Seabrook environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and is in the process of reviewing the program for safety-related mechanical equipment. The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49. The results of the staff review of the program for safety-related mechanical equipment will be included in a subsequent SSER.

3.11.3 Staff Evaluation

The staff evaluation included an onsite examination of some equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in Section 3.11 of the NRC Standard Review Plan (NUREG-0800), Revision 2, in NUREG-0588 Category I, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on February 25, 26, and 27, 1986. The audit consisted of a review of 12 files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4 of this report.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule.

(1) safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(2) nonsafety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain post-accident monitoring equipment (R.G. 1.97, Category 1 and 2 post-accident monitoring equipment).

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs) that have components located in a harsh environment are listed in Table 3.11-1 of this report.

Table 3.11.1 Seabrook Station Unit 1 Safety Related Systems Included in the Environmental Qualification Program

System
Auxiliary Steam
Containment Air Handling
Containment Air Purge
Control Building Air Handling
Containment Building Spray
Component Cooling Water-Primary
Combustible Gas Control
Containment On-Line Purge
Rod Control and Position
Chemical and Volume Control
Diesel Generator Air Handling
Drains-Floor
Diesel Generator
Containment Enclosure Air Handling
Electrical Distribution
Electrical Distribution - Emergency
Emergency Feedwater Pump House Air Handling
Emergency Feedwater Pump House Air Handling
Fuel Storage Building Air Handling
Feedwater
Heat Tracing
In-Core Instruments
Miscellaneous Equipment

Main Steam
Main Steam Drain
Nitrogen Gas
Nuclear Instrumentation
Primary Auxiliary Building Air Handling
Reactor Coolant
Residual Heat Removal
Radiation Monitoring
Reactor Makeup Water
Steam Generator Blowdown
Spent Fuel Pool Cooling
Safety Injection
Sampling System
Service Water
Service Water Pumphouse Air Handling
Vibration Monitoring System
Vents
Waste Processing - Liquid Drains

This list of systems was reviewed and found acceptable by the staff.

To address conformance with 10 CFR 50.49(b)(2) concerning nonsafety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant included all such equipment in the equipment qualification program. In addition the staff reviewed and found acceptable, the applicant's conformance with the requirements of R.G. 1.75 to show electrical and physical separation between safety-related and nonsafety-related electrical equipment. The applicant also performed a review in response to the concerns addressed by the staff in IE Information Notice 79-22, "Qualification of Control Systems," dated September 14, 1979. The staff review found the applicant's response to the concerns addressed in IE Information Notice 79-22 acceptable. Based on the above, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant has identified a number of exceptions. The staff will determine the acceptability of these exceptions as part of its review for conformance with RG 1.97. This review may result in the addition of equipment to the environmental qualification program.

3.11.3.2 Qualification Methods

3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed criteria for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in the NUREG are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The staff has reviewed the methods used by the applicant to demonstrate qualification to assure that they are in compliance with NUREG-0588, Category I.

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Section III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualifications:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.

- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.

- Design control measures shall be established for verifying the adequacy of design.

- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, the staff will require that qualification documentation for three items of safety-related mechanical equipment be submitted by the applicant. The staff review will verify that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be used for determining the environmental conditions associated with LOCAs or high-energy line breaks (HELBs), inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the environmental conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside Containment

The applicant provided the LOCA/main steamline break (MSLB) profiles used for equipment qualification program submittals. The peak values resulting from these profiles are as follows:

	Maximum Temperature °F	Maximum Pressure psig	Humidity, %
LOCA/MSLB	370.0	34.5	100

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is, there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside Primary Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs outside containment. The criteria used to define the location of HELBs are described in FSAR Section 3.6. The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the peak temperatures identified by the applicant are acceptable, with the exception of the issue of superheated steam discussed below.

The staff reviewed the methodology submitted by Westinghouse for computing mass and energy releases for postulated high energy line break accidents. This methodology, when applied to plant-specific analyses, may predict a higher thermal environment (i.e., superheated steam) than that previously prescribed for environmental qualification of safety-related equipment. However, the applicant provided information stating that Seabrook can achieve a safe shutdown under any postulated superheated temperature profile due to an MSLB. This is achieved principally by the separation criteria conceptually designed into these building areas. The staff is currently in the process of reviewing the information provided by the applicant. If this review results in higher values of pressure and temperature, the applicant will be required to review the Seabrook environmental qualification program for the potential impact on all equipment and to requalify equipment as necessary, to comply with the requirements of 10 CFR 50.49. Consequently, this is and will remain an open item until the review currently in progress is completed, and the results are approved by the staff.

3.11.3.3 Submergence

The submergence potential has been determined by the applicant to be below (-)20 ft-8 in. inside the containment and at various elevations in buildings outside the containment building. The applicant has taken appropriate corrective actions to either justify submerged operation, relocate, or qualify the affected equipment.

3.11.3.3.4 Chemical Spray

A chemical spray inside containment may be used to mitigate the effects of an accident. The applicant has included this parameter in the evaluation of equipment located inside containment.

3.11.3.3.5 Aging

The aging program requirements for Seabrook electrical equipment are defined in Category I of NUREG-0588. All degrading influences must be considered and included in the aging program. Justification for excluding pre-aging of equipment in type testing must be established based on equipment design and application, or on state-of-the-art aging techniques. A qualified life is to be established for each equipment item.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. The applicant committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American National Standard ANS-3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate.

The applicant has described a program that incorporates the above guidelines and has stated that the maintenance/surveillance program is in effect at Seabrook.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values for the radiation levels postulated to exist following a LOCA. The application and methodology employed to determine these values were presented to the applicant in NUREG-0588 and NUREG-0737. The staff review determined that the values to which equipment was qualified enveloped the requirements identified by the applicant.

The maximum value specified by the applicant for use in equipment qualification inside containment, and in areas outside containment exposed to post-LOCA recirculating fluid environments, is 2.0×10^8 rads (gamma plus beta). This value is acceptable for use in the qualification of equipment.

3.11.3.4 Outstanding Equipment

The Seabrook qualification program has a total of 111 item groups, qualification is completed on 97. The remaining 14 is scheduled for completion by April 30, 1986. The applicant originally committed to qualify all equipment for a post-accident operability time of 1 year. Subsequently, the applicant discovered that there are 10 item types (i.e., 10 items type out of the 114 item groups) that cannot be qualified for a post-accident operating time of 1 year. The staff typically requires qualification for a period of 100 days post accident, and in some instances the regulations allow for post accident qualification periods substantially less than 100 days. The following is a list of the ten item types and their post-accident qualification periods as provided by the applicant.

EQ File Number	Description	Post-Accident Operating Time	Number of Items
174-00-01	Foxboro Transmitters	100 days	13 items
252-38-01	ASCO Temperature Switches	30 days	4 items
600-01-01	Raychem HKV Motor Connector Kits	100 days	13 items
173-05-03	Maisoneilan E/P Converter	100 days	4 items

248-36-01	Borg-Warner Feedwater Isolation Valves	4 hours	4 items
600-06-01	NAMCO EC 210 Series Conduit Seals	318 days	16 items
113-03-01	Okonite 600V Power Cable	30 days	Only the cable that is subject to submergence is limited to 30 days qualification. This applies to all cable listed here.
113-17-01	Anaconda 600V Control Cable	30 days	
113-18-01	Anaconda 300V Instrumentation Cable	30 days	
113-20-01	ITT Surprenant Instrumentation Cable	30 days	

The staff reviewed the qualification information provided by the applicant for the ten item types listed above and found that the staff requirement for 100 days has been met on four of the ten item types and the remaining six meets the post-accident time margin requirements specified in Regulatory Position C.4 of Regulatory Guide 1.89. Therefore the staff finds this acceptable.

3.11.4 Environmental Qualification Audit

On February 25, 26, and 27, 1986, the staff, with assistance from EG&G Idaho, Inc., conducted an audit of the applicant's qualification files and equipment installed at the plant. Twelve files were audited to determine if the documents in the qualification files supported the qualification status determined by the applicant.

The files selected for audit were

(1) Okonite Cable (File No. 113-03-01)
(2) Transamerica Level Transmitter (File No. 174-15-01)
(3) Brandrex Cable (File No. 113-06-01)
(4) Reliance Motor (File No. 236-11-06)
(5) Limitorque Motor Operator (File No. 248-37-01)
(6) ASCO Solenoid Valve (File No. NSSS-220-02)
(7) ITT-Suprenoit Cable (File No. 113-19-01)
(8) Conax Conduit Seal Assembly (File No. 118-03-01)
(9) Rotork Motor Operator (File No. 173-05-02)
(10) Barton Transmitter (File No. 252-16-02)
(11) Endevco Accelerometer and Charge Converter (File No. 252-30-01)
(12) Weidmiller Terminal Block (File No. 600-02-01)

Several deficiencies were noted and discussed with the applicant at the time of the audit and transmitted to the applicant by letter dated April 10, 1986. The applicant proposed acceptable corrective measures in the form of additional information and file revision to eliminate the deficiencies cited.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location, and installation are consistent with qualification documents. The applicant proposed acceptable corrective measures for the deficiencies that were found and committed to resolve all deficiencies by fuel load.

3.11.5 Conclusions

The staff has reviewed the Seabrook program for the environmental qualification of electrical equipment important to safety and is in the process of reviewing the safety-related mechanical equipment. The purpose of the review was to determine the adequacy and scope of the qualification program and to verify that the methods used to demonstrate qualification is in compliance with applicable regulations and standards.

As identified in this report, the following items must be resolved.

1. All electrical equipment within the scope of 10 FR 50.49 must be environmentally qualified prior to fuel load.

2. All safety-related mechanical equipment must be environmentally qualified before exceeding 5% of full power.

3. The pressure and temperature conditions involving superheat must be resolved before exceeding 5% of full power.

Based on the results of our review and subject to acceptable resolution of items 1, 2 and 3 above, the staff concludes that the applicant has demonstrated conformance with the requirements for environmental qualification as outlined in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections II, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria as specified in NUREG-0588.

Table 3.1 Summary of SQRT audit

Item No.	Description	Applicant ID no.	Safety function	Review findings	Resolution	Status
NSSS-2	3-inch air-operated globe valve	LCV-459	Safety function moved to another valve; SQRT reviewed qualification for pressure containment.			Qualified
NSSS-3	Safety injection system accumulator tank	SI-TK-9A	Provides storage for emergency core cooling water.	Base anchor bolts smaller than those used to qualify the tank.	Independent analysis by UE&C showed smaller bolts have adequate strength.	Qualified
NSSS-4	Electric hydrogen recombiner power supplies		Provide power supply for electric hydrogen recombiner for containment hydrogen removal after a LOCA.			Qualified
NSSS-5	Reactor water makeup valve	RMW-V-30	Provides containment isolation.	1. Assumed g-load not reconciled with as-built condition (generic).		To be confirmed
				2. Lifespan of nonmetallic parts not evaluated; clearance inadequate (generic).	2. Done.	
NSSS-6	8-inch motor-operated gate valve	RHR-8716A, B	Provides shutoff for the residual heat removal system.			Qualified
NSSS-7	Reactor trip switchgear	CP-CP-111	Provides reactor trip safety function.			Qualified
NSSS-8	Reactor vessel level information system 8086 cabinets	MM-CP-486A	Provide reactor vessel liquid level information after a seismic event.	Cabinets not installed.	SQRT reviewed installation drawings and considered them adequate.	Qualified pending proper installation
NSSS-11	Nuclear instrumentation system cabinet	RP	Provides alarm function; as secondary control function, indicates reactor status during startup, power operation; overpower trip protection.	Clearance from adjacent cabinets inadequate (generic)	To be handled on a generic basis.	Qualified
NSSS-12	Safeguards test cabinet	MM-CP-14, 15	Supplies power to the control panel.			Qualified

Table 3.1 (Continued)

Item number	Description	Applicant ID no.	Safety function	Review findings	Resolution	Status
NSSS-13	Instrument bus power switch: static inverter	EDE-I-1A	Supplies power to the instrument bus distribution panel that provides power to instrumentation monitoring and indicating plant parameters.	Auditable link between the test report model and the field model missing.	Subsequently provided.	Qualified
BOP-1	36-inch butterfly valve	CAP-V-1, 4	Isolates the containment.	Model number not on the valve; therefore, it could not be compared to that shown on the long form.		Qualified
BOP-3	Control switch	CP-CS-6601-1	Trips the reactor manually from the main control board.			Qualified
BOP-4	Computing device	EDE-AY-9700, 9710	Converts signal for monitoring diesel generator output current for postaccident monitoring.	Site-specific RRS exceeds Westinghouse's generic RRS.	Requalification completed; device found acceptable.	Qualified
BOP-5	Emergency feedwater pump and turbine	FW-TD-2, FW-P-37A	Provide emergency feedwater to the steam generator.	1. A substantial number of anomalies to be resolved. 2. temporary 3-inch line must be seismically qualified.	1. Done. 2. Pending.	To be confirmed
BOP-6	4-inch motor-operated globe valve	MS-V-204, 205 206, 270	Provides isolation function in a 4-inch bypass line around the main steam isolation valves.			Qualified
BOP-7	Neutron flux signal processor	NI-NM-6690, etc.	Indicates the neutron flux and shutdown margin to the operator.	Model number did not match that on the long form.		Qualified
BOP-11	Vibration monitoring control panel	VB-CP-299, VB-YM-6832	Indicates the position of the pressure relief valves to the operator; the recorder has no safety function.	Model number not shown on the panel; could be found only by referring to the drawing. (The number on the drawing was the one shown on the long form.)		Qualified

Table 3.1 (Continued)

Item number	Description	Applicant ID no.	Safety function	Review findings	Resolution	Status
BOP-14	18-inch feedwater isolation valve	FW-V-30	Provides containment isolation for the feed-water piping.	Valve operator test specimen had some test anomalies related to O-ring seal design.	Seals were redesigned to eliminate leakage problems.	Qualified
BOP-15	6-inch motor-operated gate valve	CBS-V-38	Provides shutoff for the containment spray system.			Qualified
BOP-16	Diesel generator relay control panel	DG-CP-36, 37	Provides a control function for the diesel generator.	Adequate justification not provided for two test anomalies.	Applicant provided adequate justification for these anomalies.	Qualified
BOP-17	Pressure switch	DGA-PS-OPL-1	Regulates lube oil flow to the diesel engine.	Qualification briefly reviewed to see that a complete qualification package was available.	Complete.	Qualified

Table 3.2 Status of pump and valve operability assurance items

SER items[1]	Finding/ resolution	Status
Based on the summaries in FSAR Tables 3.9(B)-14 and 18 (Amendment 53), it is not clear if the applicant has completely qualified the emergency feedwater and fuel oil transfer pumps. The applicant should provide the appropriate information in each table to demonstrate that these pumps are qualified in a manner consistent with FSAR Section 3.9(B).3.2a (Amendment 53).	Satisfactory	Closed[2]
It is not clear from FSAR Table 3.9(B)-2 and Section 3.9(B).3.1 (Amendment 48) that LOCA loads have been specified in the design load combinations for BOP Class 1 components and supports. The applicant should confirm that LOCA loads have been applied to the appropriate BOP equipment in a manner similar to that given in FSAR Section 3.9(N).1.6 for NSSS equipment.	Satisfactory	Closed[3]
FSAR Section 3.9(B).3.2b (Amendment 48) describes operability assurance for active BOP valves 2 inches and larger. The applicant should include all sizes of active BOP valves in the operability assurance program.	Satisfactory	Closed[3]
The applicant should provide specific information for the BOP pumps and valves similar to the information provided in FSAR Tables 3.9(N)-10 and -11 for NSSS pumps and valves.	Satisfactory	Closed[2]
FSAR Table 3.9(B)-2 (Amendment 47) summarizes the load combinations for Class 1, 2, and 3 BOP components and supports. The applicant should identify the stress criteria used to qualify Class 1 BOP valves.	Satisfactory	Closed[2]
FSAR Tables 3.9(B)-3 and 3.9(N)-7 provide the stress criteria for Class 2 and 3 non-active BOP and NSSS pumps, respectively. The applicant should identify these non-active pumps.	Satisfactory	Closed[2]
The applicant should clearly show the extent to which RG 1.148, ANSI/ASME N551.1 draft standards, and ANSI B16.41 are met.	Satisfactory	Closed[3]

See footnotes at end of table.

Table 3.2 (Continued)

SER items[1]	Finding/ resolution	Status
The applicant should clarify the methods used for qualification. Specific information should be presented in the FSAR, and be available for review at the site. The applicant should demonstrate: • The extent to which operational testing is performed at design-basis conditions (full flow, pressure, temperature, etc.). • The technical basis for qualifying equipment by similarity analysis and prototype testing. • Qualification of the equipment as an assembly rather than individual components.	Satisfactory	Closed[3]
The applicant should clearly show how implementation of the initial test program, maintenance and surveillance, in-service inspection, and quality assurance programs will maintain equipment operability throughout the 40-year plant life. Specific criteria should be presented in the FSAR, and be available for review at the site.	Satisfactory	Closed[3]
The following actions by the applicant would enhance the staff's understanding of the plant: • The terms "DSL" and "LOCA DISPL" in FSAR Table 3.9(B)-6 (Amendment 48) should be defined. • The seismic accelerations discussed in FSAR Section 3.9(B)3.2a should be specified and how they were used to qualify "rigid" and "flexible" BOP pumps, should be described. • FSAR Sections 3.9(B)3.2b and 3.9(N)3.2a(2) describe BOP and NSSS programs for testing valves of various designs and sizes during simulated faulted conditions. The criteria used to select the valves for testing and specify the range of sizes that are covered should be discussed.	Satisfactory	Closed[2]

See footnotes at end of table.

Table 3.2 (Continued)

SER items[1]	Finding/ resolution	Status
· Confirm that the evaluation of NSSS check valves will include "stress analysis of critical parts which may affect operability, including faulted condition loads," as is the case for BOP check valves.		

[1]Items were identified in the SER and supplemented by specific comments presented at a pre-audit meeting on August 7, 1985.

[2]This item was adequately resolved on the basis of information submitted by the applicant in a letter from R. Sweeney, Bethesda Office Manager Seabrook Station, to V. Nerses, NRC Seabrook Project Manager, dated September 24, 1985, entitled "Advance Copies of Annotated FSAR Pages and System Turnover Status."

[3]This item was adequately resolved on the basis of information reviewed by the staff during the site audit on November 5-8, 1985. The applicant committed to close out this item in a manner and time that are acceptable to the staff.

Table 3.3 Summary of PVORT audit

Plant ID no.	Description	Safety function	Findings	Resolutions	Status	Remarks
FW-P-37A (BOP)	Turbine-driven auxiliary feedwater pump	Provides feedwater to the steam generator if normal feedwater is not available.	a,b,c	d	e	The applicant must address turbine operation when there is moisture in the steam and turbine trip and throttle valve operation after a trip. The turbine end pump seal was found to be cracked. The reason for the failure must be investigated and resolved. Findings "a" and "c" were resolved by applicant's April 8, 1986, letter.
FW-V-331 (BOP)	Main feedwater to steam generator B isolation check valve	Isolates the feedwater header if feedwater is lost.	f	d	Closed	Operating time of this valve is important to safety. Timing requirements were not addressed. This issue was resolved by applicant's April 8, 1986, letter.
CC-V-975 (BOP)	Primary component cooling water to radiation monitor isolation valve	Isolates the radiation monitor when full primary containment cooling water flow is required by safety-grade equipment.			Closed	Specific concerns were resolved during the audit.
FW-V-48 (BOP)	Steam generator C feedwater containment isolation valve	Closes on containment isolation signal.			Closed	Specific concerns were resolved during the audit.
CC-V-122 (BOP)	Primary component cooling water return isolation from from non-safety-grade components	Closes on isolation signal.			Closed	Specific concerns were resolved during the audit.
SW-P-110A (BOP)	Cooling tower pump A	Provides cooling water flow when the cooling tower is used as the ultimate heat sink.	g	d	Closed	Two O-rings are used to control lateral support of pump column. The O-rings should be maintained for the life of the plant. This issue was resolved by applicant's April 8, 1986, letter.
CS-P-2B (NSSS)	Centrifugal charging pump B	Provides borated and makeup water as well as high-head safety injection.			Closed	Specific concerns were resolved during the audit.
RC-V-456A (NSSS)	Pressurizer power-operated relief valve	Opens to prevent a reactor trip due to overpressure of pressurizer.			Closed	Specific concerns were resolved during the audit.
RH-V-14 (NSSS)	Cold-leg injection residual heat removal return line isolation valve	Closes for containment isolation and hot-leg recirculation.			Closed	Specific concerns were resolved during the audit.
--	All pumps and valves important to safety	Operate as required during the life of the plant under normal and accident conditions.	h,i,j,k,l	d	Closed	All generic issues were solved by the applicant's April 8, 1986, letter.

See footnotes that follow table.

Table 3.3 (Continued)

a. Turbine operation when moisture is mixed with the steam was not investigated; turbine operation with moisture in the steam must be addressed (specific).

b. The turbine trip and throttle valve was not installed in a way that ensured easy operation. Easy operation of the trip and throttle valve with a maximum differential pressure across the valve (for example, a turbine overspeed condition) was not demonstrated. Easy operation of the trip and throttle valve must be investigated (specific).

c. The turbine end pump seal was found to be cracked. The cause of the cracked pump seal needs to be investigated and resolved (specific).

d. At the conclusion of the site audit, the staff summarized the remaining open issues. The applicant was informed of the appropriate actions necessary to resolve the specific and generic confirmatory issues before fuel load (specific).

e. The qualification status will be "Closed" when the specific and generic issues are resolved (specific).

f. This valve was changed from a swing check valve to a control check valve that has specific opening and closing times. The operating times were not addressed in the startup, testing, or operating procedures. The applicant shall confirm that the operating times have been investigated and the timing requirements identified and met (specific).

g. The maintenance program did not include procedures for replacing the O-rings per manufacturer's recommendations. The maintenance program should include procedures for maintaining the qualification status of the O-rings for the life of the plant (specific).

h. Maintenance procedures were in a draft form and generally not available for review. The applicant shall confirm that all final maintenance procedures are consistent with manufacturer's requirements. The applicant shall describe how limited-life components are identified. The applicant shall provide examples of maintenance procedures for review (generic).

i. BOP valves smaller than 2 inches were not included in the FSAR active valve list. The applicant shall confirm that the FSAR BOP list addresses valves less than 2 inches (generic).

j. The active valve lists in the FSAR were not complete. The applicant shall confirm that all active pumps and valves are included in the FSAR active component lists (generic).

k. All preservice tests have not been completed. The applicant shall confirm that all preservice tests that are required before fuel load have been completed (generic).

l. The applicant has not completed the qualification of all pumps and valves important to safety. The applicant shall confirm that all pumps and valves important to safety are qualified before fuel load (generic).

4 REACTOR

4.5 Reactor Materials

4.5.1 Control Rod Drive Structural Materials

The staff concludes that the control rod drive (CRD) mechanism structural materials are acceptable and meet the requirements of General Design Criteria (GDC) 1, 14, 26 as well as 10 CFR 50.55a.

The staff reached this conclusion because the applicant demonstrated that the properties of materials selected for the CRD mechanism components exposed to the reactor coolant satisfy Appendix I of Section III of the ASME Code, and Parts A, B, and C of Section II of the Code, and conform with the staff position that the yield strength of cold-worked austenitic stainless steel should not exceed 90,000 psi. The applicant met the guidelines of Regulatory Guide (RG) 1.85 by using materials of construction that are approved for use by ASME Code cases.

The controls imposed upon the austenitic stainless steel of the CRD mechanisms conform to most of the recommendations of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal." The applicant's alternative approaches discussed in SER Section 5.2.3 have been found acceptable.

The controls imposed upon austenitic stainless steels to reduce sensitization satisfy, to the extent practical, the recommendations of RG 1.44, "Control of the Use of Sensitized Stainless Steel." The applicant's alternative approaches are discussed in SER Section 5.2.3 and have been determined to be acceptable.

The applicant has confirmed that the tempering temperatures and aging temperatures of heat-treatable materials in the CRD mechanism are specified to eliminate the susceptibility to stress corrosion cracking in reactor coolant. The fabrication and heat-treatment practices performed provide reasonable assurance that stress corrosion cracking will not occur during the design life of the components. The compatibility of all materials used in the control rod system in contact with the reactor coolant satisfies the criteria of Articles NB-2160 and NB-3120 of Section III of the ASME Code.

Cleaning and cleanliness control are in accordance with ANSI Standard N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," and follow to the extent practicable the recommendations of RG 1.37, "Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants." The applicant's alternative approaches have been reviewed and approved by the staff as discussed in SER Section 5.2.3.

4.5.2 Reactor Internals Materials

The staff concludes that the materials used for the construction of the reactor internals and core support structures are acceptable and meet the requirements of GDC 1 and 10 CFR 50.55a. The conclusion is based upon the following considerations:

The applicant has met the requirements of GDC 1 and 10 CFR 50.55a with respect to ensuring that the design, fabrication, and testing of the materials used in the reactor internals and core support structures are of high quality and adequate for structural integrity. The controls imposed upon components constructed of austenitic stainless steel satisfy most of the recommendations of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal," and RG 1.44, "Control of the Use of Sensitized Stainless Steel." Where the recommendations of these regulatory guides were not followed, the alternative approaches taken by the applicant have been reviewed by the staff and found acceptable, as is discussed in SER Section 5.2.3.

The materials used for construction of components of the reactor internal and core support structure have been identified by specification and found to be in conformance with the requirements of NG-2000 of Section III and Parts A, B, and C of Section II of the ASME Code. In addition, the applicant has met the guidelines of RG 1.85, "Code Case Acceptability ASME Section III Materials," by using materials in construction that are approved for use by ASME Code cases.

As proven by extensive testing and satisfactory performance, the specified materials are compatible with the anticipated environment and corrosion is expected to be negligible.

The controls imposed on the reactor coolant chemistry provide reasonable assurance that the reactor internal and core support structure will be adequately protected during operation from conditions which could lead to stress corrosion of the materials and loss of component structural integrity.

The material selection, fabrication practices, examination and testing procedures, and control practices performed in accordance to these recommendations provide reasonable assurance that the materials used for the reactor internal and core support structure will be in a metallurgical condition to minimize inservice deterioration. Conformance with requirements of the ASME Code and the recommendations of the regulatory guides constitutes an acceptable basis for meeting, in part, requirements of GDC 1 and 10 CFR 50.55a.

5 REACTOR COOLANT SYSTEM

5.2 Integrity of the Reactor Coolant Pressure Boundary

5.2.2 Overpressure Protection

5.2.2.1 Overpressure Protection During Power Operation

The SER stated: "The applicant's analysis on the adequacy of safety valve capacity was performed using the LOFTRAN code. This code is under review by the staff. If the final approval of LOFTRAN indicates that any revisions to the analysis are required, the effect of these changes on Seabrook will be evaluated."

Subsequently, the staff has accepted the Westinghouse topical report WCAP-7907, "LOFTRAN Code Description" (dated June 27, 1983). Thus, this item is closed.

5.2.3 Reactor Coolant Pressure Boundary Materials

The staff concludes that the plant design is acceptable and meets the requirements of General Design Criteria (GDC) 1, 4, 14, 30, and 31 of Appendix A to 10 CFR 50, the requirements of Appendices B and G to 10 CFR 50, and the requirements of 10 CFR 50.55a. This conclusion is based on the staff's review of the FSAR.

The materials used for construction of components of the reactor coolant pressure boundary (RCPB) have been identified by specification and found to be in conformance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Compliance with the provisions of the Code for material specifications satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

The materials of construction of the RCPB exposed to the reactor coolant have been identified and all of the materials are compatible with the primary coolant water, which is chemically controlled in accordance with appropriate Technical Specifications. This compatibility has been proven by extensive testing indicating conformance with most of the recommendations of Regulatory Guide (RG) 1.44, "Control of Sensitized Stainless Steel." The exceptions are discussed in the following paragraphs:

(1) The applicant has exercised an exception to testing for nonsensitization of materials as permitted by Position C.3 of RG 1.44. This exception allows material of product forms with simple shapes not subject to distortion during heat treatment not to be tested for sensitization provided the solution heat treatment is followed by water quenching. The product forms do not have inaccessible cavities or chambers that would preclude rapid cooling when water is quenched; and therefore, not testing for sensitization in these cases is acceptable to the staff.

(2) The applicant has taken exception to Position C.4.(a) of RG 1.44 which establishes 200°F as the upper temperature limit for materials other than L grade that can be exposed to reactor coolant with a dissolved oxygen concentration greater than 0.10 ppm. The exception is taken during startup operation when oxygen scavenging by hydrazine is initiated at reactor coolant temperatures between 180°F and 225°F. Because the startup operation is of relatively short duration, the staff does not believe that any significant corrosion or stress corrosion cracking of these materials in contact with reactor coolant containing a higher concentration of dissolved oxygen would occur in such a short period of time. In addition, the reactor coolant is chemically controlled in accordance with appropriate Technical Specifications. The compatibility of the RCPB materials with these chemical and oxygen control methods has been proven by extensive testing with satisfactory performance.

(3) The applicant has taken exception to Positions C.4.(b) and C.5.(a) of RG 1.44 which indicate that cast metal and weld metal should have a ferrite content of 5% or more to be exempt from testing for susceptibility to intergranular stress corrosion cracking (IGSCC). This exception is based upon the staff's evaluation and acceptance of the nuclear steam supply system designer's Topical Reports, WCAP-8324-A of June 1975 (Westinghouse), and WCAP-8693 of January 1976 (Westinghouse). The compatibility of the RCPB materials and the applicant's fabrication requirements with the reactor coolant environment has been proven by extensive testing with satisfactory performance. The two topical reports also served as the basis for not testing for sensitization to IGSCC in the heat-affected zones of weld procedure qualification test plates made subsequently. The production control procedures on weld heat inputs, and ferrite content controls have reduced the degree of sensitization of materials (including the heat-affected zone) to IGSCC and the chemistry controls.

General corrosion of all material, except unclad carbon and low-alloy steel, will be negligible. For these materials, conservative corrosion allowances have been provided for all exposed surfaces in accordance with the requirements of the ASME Code, Section III. The above evidence of compatibility with the coolant and compliance with the Code provisions satisfies the requirements of GDC 4 relative to compatibility of components with environmental conditions.

The materials of construction for the RCPB are compatible with the thermal insulation used in these areas. The thermal insulation used on the RCPB is either the reflective stainless steel type or is made of nonmetallic compounded materials that are in conformance with the recommendations of RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steels." Conformance with the above recommendations satisfies the requirements of GDC 14 and GDC 31 relative to prevention of failure of the RCPB.

The ferritic steel tubular products and the tubular products fabricated from austenitic stainless steel have been found to be acceptable by nondestructive examinations in accordance with the provisions of the ASME Code, Section III. Compliance with these Code requirements satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

SER Section 5.2.3 indicated that the applicant had not provided required fracture toughness data and had not demonstrated compliance with 10 CFR 50, Appendix G, for the materials of the RCPB. The staff, with the assistance of Idaho National Engineering Laboratory (INEL), reviewed the fracture toughness of Seabrook RCPB materials and their compliance with 10 CFR 50, Appendix G. This review, documented in SER Section 5.3.1.1, indicated that the applicant meets all the requirements of Appendix G. Hence, the review of RCPB material fracture toughness and compliance with 10 CFR 50, Appendix G is complete.

The fracture toughness tests required by the ASME Code, augmented by Appendix G to 10 CFR 50, provide reasonable assurance that adequate safety margins against nonductile behavior or rapidly propagating fracture can be established for all pressure-retaining components of the RCPB. The use of Appendix G of the ASME Code, Section III, and the results of fracture toughness tests performed in accordance with the Code and NRC regulations in establishing safe operating procedures, provide adequate safety margins during operating, testing, maintenance, and postulated accident conditions. Compliance with these Code provisions and NRC regulations satisfies the requirements of GDC 31 and 10 CFR 50.55a regarding prevention of fracture of the RCPB.

The applicant has taken the following alternative approaches to the recommendations of RG 1.50, "Control of Preheat Temperature for Welding Low Alloy Steels": (1) Welding procedures are qualified within the preheat temperature range rather than at the minimum preheat temperature and (2) preheat temperatures are maintained for an extended period of time rather than until the start of post-weld heat treatment. The staff concludes that these alternative approaches are adequate to prevent hydrogen cracking (the concern of RG 1.50) and will not cause other hazards. Accordingly, the staff accepts these alternative approaches. The controls used provide reasonable assurance that components made from low-alloy steels will not crack during fabrication. If cracking does occur, the required Code inspections should detect such flaws. These controls satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

The controls imposed on electroslag welding of ferritic steels are in accordance with the recommendations of RG 1.34, "Control of Electroslag Weld Properties," and provide assurance that welds fabricated by the process will have high integrity and will have a sufficient degree of toughness to furnish adequate safety margins during operating, testing, maintenance, and postulated accident conditions. Conformance with the recommendations of RG 1.34 also satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

The controls imposed on welding ferritic and austenitic steels under conditions of limited accessibility satisfy, to the extent practical, the recommendations of RG 1.71, "Welder Qualification for Areas of Limited Accessibility." As an alternative approach to Position C.1, the applicant's contractors supervise the welders closely, and welding situations in production recur often enough to ensure that the most skilled welders are used in areas of limited access. The staff concludes that, because such welds are inspected, qualification of the welders making acceptable welds occurs automatically under the Code. These controls satisfy the quality standards requirements of GDC 1, GDC 50, and 10 CFR 50.55a. The controls imposed on weld cladding of low-alloy steel components by austenitic stainless steel are in accordance with the recommendation of RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components."

The controls to avoid stress corrosion cracking in RCPB components constructed of austenitic stainless steels satisfy, to the extent practical the recommendations of RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid System and Associated Components of Water-Cooled Nuclear Plants." The staff acknowledges that to prohibit chemical compounds with sulfur, chlorides, fluorides, etc. of all items that come in contact with austenitic stainless steels is not practical. The applicant's approach for controlling the chemical contents of those items that come in contact with austenitic stainless steel components and maintaining them at reasonably low levels is acceptable to the staff. The thermo-mechanical processing of austenitic stainless steel components in the RCPB is controlled to limit the yield strength of the components to a maximum of 90,000 psi.

The controls followed during material selection, fabrication, examination, protection, sensitization, and contamination provide reasonable assurance that the RCPB components of austenitic stainless steels are in a metallurgical condition that minimizes susceptibility to stress corrosion cracking during service. These controls satisfy the requirements of GDC 4 relative to compatibility of components with environmental conditions and the requirements of GDC 14 relative to prevention of leakage and failure of the RCPB.

The controls imposed during welding of austenitic stainless steels in the RCPB satisfy, to the extent practical, the recommendations of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal," and RG 1.71, "Welder Qualification for Areas of Limited Accessibility." The staff reviewed the alternative approaches taken by the applicant and found them acceptable. The applicant's alternative approach of using chemical analysis in lieu of magnetic measurement devices to analyze the weld metal deposit to determine ferrite content has been discussed in the Westinghouse report WCAP-8324 and was previously approved by the staff in a letter dated December 23, 1974, from D. B. Vassallo, NRC, to R. Salvatori, Westinghouse. The applicant's alternative approaches to RG 1.71 were discussed previously in this section of the SER.

The controls provide reasonable assurance that (1) welded components of austenitic stainless steel did not develop microfissures during welding and (2) they have high structural integrity. These controls satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a, and satisfy the requirements of GDC 14 relative to prevention of leakage and failure of the RCPB.

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

5.2.4.3 Evaluation of Compliance with 10 CFR 50.55a(g)

This evaluation supplements conclusions in SER Section 5.2.4.3. SER Supplement 3 noted that the staff considered the review of the preservice inspection (PSI) program to be an open issue. Its resolution was subject to the applicant's (1) providing additional plant-specific information about the effectiveness of the ultrasonic examination of the cast austenitic stainless steel welds in the primary piping systems, (2) providing clarification on the visual acuity requirements for personnel performing visual examinations, and (3) submitting all relief requests with supporting technical justifications.

The staff has completed its review of the FSAR through Amendment 56 (November 1985), the Seabrook Unit 1 Balance-of-Plant (BOP) PSI Program (Revision 1, January 6, 1984), the Seabrook Unit 1 Reactor Pressure Vessel PSI Program Plan

(Revision 3, March 15, 1984), the Seabrook Unit 1 Supplemental Examination Program Plan (SEPP) (Revision 0, November 25, 1985), and a letter from the applicant dated December 20, 1985, responding to the outstanding issues.

The staff recognized that the ultrasonic examination of the cast stainless steel fittings and components in the primary piping system might be difficult. However, a review of the available documentation indicated that appropriate calibration standards were not included in the PSI program. In SSER 3, the staff stated that the applicant should attempt and document a preservice inspection on all welds with the best available instrumentation, with straight beam and angle beam techniques, in accordance with the requirements of Section XI of the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code).

Attachment A to the applicant's December 20, 1985, submittal states that the welds will be examined ultrasonically and the examination results will be documented as part of the BOP PSI program. In support of the ultrasonic examination, cast stainless steel material has been acquired and fabricated into calibration standards. The applicant is developing an ultrasonic procedure to examine the cast stainless steel welds; it will be made available for staff review. The staff has met with the applicant on April 15, 1986 and on this date had a specific demonstration provided at the plant site to determine the effectiveness of the applicant's ultrasonic examinations using the qualified procedures on actual plant welds. The results of this meeting will be reported in a future SER supplement.

The applicant has committed to revise Visual Examination Procedure 80A647A to state that personnel performing visual examinations shall be certified in accordance with the latest revision of Nuclear Energy Services (NES) Document No. 80A9069 and that at least one member of a visual-examination team shall be certified to at least Level II. The staff considers this issue resolved.

The specific areas where the ASME Code requirements cannot be met will be identified after the examinations are performed. The applicant has committed to identify all plant-specific areas where the Code requirements cannot be met and provide a supporting technical justification for requesting relief. The staff will complete the review and will report its conclusions in a supplement to the SER after the applicant

(1) demonstrates the effectiveness of the ultrasonic testing procedures and instrumentation to examine the cast stainless steel weldments

(2) submits all relief requests with a supporting technical justification

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection begins.

This section was prepared with the assistance of Department of Energy (DOE) personnel at Idaho National Engineering Laboratory (INEL).

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials (Materials and Fabrication)

The staff concludes that the reactor vessel materials are acceptable and satisfy the requirements of GDC 1, 4, 14, 30, 31, and 32 of Appendix A to 10 CFR 50; the material testing and monitoring requirements of Appendices B, G, and H to 10 CFR 50; and the requirements of 10 CFR 50.55a. This conclusion is based on the following:

The materials used for construction of the reactor vessel and its appurtenances have been identified by specification and found to be in conformance with ASME Code, Section III. Special requirements of the applicant with regard to control of residual elements in ferritic materials have been identified and are considered acceptable. Compliance with the above Code provisions for material specifications satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

Ordinary processes were used for the manufacture, fabrication, welding, and nondestructive examinations of the reactor vessel and its appurtenances. Nondestructive examinations in addition to Code requirements were also performed. Because the applicant has certified that the requirements of ASME Code, Section III have been complied with, the processes and examinations used are considered acceptable. Compliance with these Code provisions satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

When components of ferritic steels are welded, Code controls are supplemented by conformance with the recommendations of regulatory guides as follows:

(1) The controls imposed on welding preheat temperatures are in conformance to the extent practical with the recommendations of RG 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel." The staff reviewed and found acceptable the alternative approaches taken by the applicant (see Section 5.2.3 of this supplement). These controls (a) provide reasonable assurance that components made from low-alloy steels did not crack during fabrication and (b) minimize the potential for subsequent cracking. These controls also satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

(2) The controls imposed on electroslag welding of ferritic steels are in conformance with the recommendations of RG 1.34, "Control of Electroslag Weld Properties." These controls on the process ensure that the welds fabricated will have high integrity and will have a sufficient degree of toughness to furnish adequate safety margins. These controls satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

(3) The controls imposed during weld cladding of ferritic steel components are in conformance with the recommendations of RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components." These controls provide assurance that underclad cracking did not occur during weld cladding of the reactor vessel and satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

When components of austenitic stainless steels are welded, Code controls are supplemented by conformance with the recommendations of regulatory guides as follows:

(1) The controls imposed on delta ferrite in austenitic stainless steel welds satisfy most of the recommendations of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal." The staff reviewed and finds acceptable the alternate approaches taken by the applicant (see Section 5.2.3 of this supplement).

(2) The controls imposed on electroslag welding of austenitic stainless steels are in conformance with the recommendations of RG 1.34 (see item 2 above). These controls satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a.

The controls (during all stages of welding) to avoid contamination and sensitization that could cause stress corrosion cracking in austenitic stainless steels conform with the recommendations of regulatory guides as follows:

(1) The controls to avoid contamination and excessive sensitization of austenitic stainless steel satisfy, to the extent practical, the recommendations of RG 1.44. The staff reviewed and finds acceptable the alternative approaches taken by the applicant (see Section 5.2.3 of this supplement). The controls used provide reasonable assurance that welded components were not contaminated or excessively sensitized before and during the welding process. These controls satisfy the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a, and the GDC 4 requirement relative to material compatibility.

(2) The controls regarding onsite cleaning and cleanliness controls of austenitic stainless steel are in conformance with the recommendations of RG 1.37 or the alternate approaches taken by the applicant have been reviewed and approved by the staff (see Section 5.2.3 of this supplement). These controls provide reasonable assurance that austenitic stainless steel components were properly cleaned on site, and Appendix B to 10 CFR 50, regarding controls for onsite cleaning of materials and components, is satisfied.

Integrity of the reactor vessel studs and fasteners is ensured by conformance with most of the recommendations of RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." The applicant's alternative approach of not specifying a maximum ultimate tensile strength and relying on the bolting material's low-alloy steel chemistry, heat treatment, and toughness requirements to control ultimate tensile strength is acceptable to the staff. Compliance with these recommendations and with the applicant's alternative approaches satisfies the quality standards requirements of GDC 1, GDC 30, and 10 CFR 50.55a; the prevention of fracture of the RCPB requirement of GDC 31; and the requirements of Appendix G to 10 CFR 50, as detailed in the provisions of the ASME Code, Sections II and III.

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.1 Steam Generator Materials

The staff concludes that the steam generator materials specified are acceptable and meet the requirements of GDC 1, 14, 15, and 31, and Appendix B to 10 CFR 50. This conclusion is based on the following:

(1) The applicant has met the requirements of GDC 1 with respect to codes and standards by ensuring that the materials selected for use in Class 1 and Class 2 components will be fabricated and inspected in conformance with codes, standards, and specifications acceptable to the staff. Welding qualification, fabrication, and inspection during manufacture and assembly of the steam generator will be done in conformance with the requirements of Sections III and IX of the ASME Code.

(2) The requirements of GDC 14 and 15 have been met to ensure that the reactor coolant boundary and associated auxiliary systems have been designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage and rapidly propagating failure, and of gross rupture, during normal operation and anticipated operational occurrences.

    The primary side of the steam generator is designed and fabricated to comply with ASME Code, Class 1, criteria as required by the staff. The secondary side pressure boundary parts of the steam generator will be designed, manufactured, and tested to ASME Code, Class 1, criteria although the staff-required classification is ASME Code, Class 2.

    The crevice between the tube sheet and the inserted tube will be minimal because the tube will be expanded to the full depth of insertion of the tube in the tube sheet. The tube expansion and subsequent positive contact pressure between the tube and the tube sheet will preclude a buildup of impurities in the crevice region and will reduce the probability of crevice boiling.

    The tube support plates will be manufactured from ferritic stainless steel material, which has been shown in laboratory tests to be corrosion resistant to the operating environment. The tube support plates will be designed and manufactured with broached holes rather than drilled holes. The broached-hole design promotes high velocity flow among the tube, sweeping impurities away from the support plate locations.

(3) The requirements of GDC 31 have been met with respect to the fracture toughness of ferritic materials since the pressure boundary materials of ASME Code, Class 1, components of the steam generator will comply with the fracture toughness requirements and tests of Subarticle NB-2300 of Section III of the Code. The materials of the ASME Code, Class 2, components of the steam generator will comply with the fracture toughness requirements of Subarticle NC-2300 of Section III of the Code.

(4) The requirements of Appendix B to 10 CFR 50 have been met since the onsite cleaning and cleanliness controls during fabrication conform to the recommendations of RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plant." The controls placed on the secondary coolant chemistry are reviewed in SER Section 10.3.5.

Reasonable assurance of the satisfactory performance of the steam generator tubing and other generator materials is provided by (a) the design provisions and the manufacturing requirements of the ASME Code, (b) rigorous secondary water monitoring and control, and (c) the limiting of condenser in-leakage. The controls described above, combined with conformance with applicable codes, standards, staff positions, and regulatory guides, constitute an acceptable basis for meeting in part the requirements of GDC 1, 14, 15, and 31, and Appendix B to 10 CFR 50.

5.4.2.2 Steam Generator Tube Inservice Inspection

In response to a staff request for additional information relative to the criteria to be used to determine at what point a degraded steam generator tube should be plugged (Question 210.69), the applicant submitted a letter dated March 26, 1986. In this response, the applicant reported that Seabrook is using the criteria in the ASME Code, Section XI, Paragraph IWB-3521, which states that the allowable outside diameter indication of cracks, wastage or intergranular corrosion shall not exceed 40% of the tube wall thickness. This is consistent with Section 4.4.5.4 of the current Seabrook Technical Specification which requires that a tube shall be removed from service when the imperfection depth reaches 40% of the nominal tube wall thickness, where the 40% value is determined in accordance with the recommendations of Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." RG 1.121 recommends that tubes with partly through-wall cracks, wastage, or combinations of these should have a factor of safety against failure by bursting under normal operating conditions of not less than 3 at any tube location.

On the basis of the above information, the staff has concluded that the criteria for plugging degraded steam generator tubes at the Seabrook Station are acceptable.

5.4.12 Reactor Coolant System Vents (II.B.1)

In the SER, the staff indicated that before the vent system is considered fully operational, the applicant must

(1) Complete operating procedures based on staff-approved operating guidelines.

(2) Adopt operability requirements for the vent system in the plant Technical Specifications.

(3) Include the vent system in approved inservice testing and inspection programs.

Item 1 is a confirmatory item that will be resolved during a site inspection and will not be written up in a future supplement unless an unanticipated problem is found.

Items 2 and 3 are plant Technical Specification items that will be reviewed when the proof and review copy of the Technical Specifications has been issued and will not be reported in a future supplement unless an unanticipated problem is found.

6 ENGINEERED SAFETY FEATURES

6.1 <u>Engineered Safety Features Materials</u>

The staff concludes that the engineered safety features (ESF) materials specified are acceptable and meet the requirements of General Design Criteria (GDC) 1. 4, 14, 31, 35, and 41 of Appendix A to 10 CFR 50; Appendix B to 10 CFR 50, and 10 CFR 50.55a. This conclusion is based on the following:

(1) GDC 1, 14, and 31 and 10 CFR 50.55a have been met with respect to ensuring an extremely low probability of leakage, of rapidly propagating failure, and of gross rupture. This is evident because the materials selected for the engineered safety features satisfy Appendix I of Section III of the ASME Boiler and Pressure Vessel Code, and Parts A, B, and C of Section II of the Code, and the staff position that the yield strength of cold-worked stainless steels shall be less than 90,000 psi.

Fracture toughness was not indicated as having been performed on ferritic materials in the ESF systems. However, on the basis of the results of impact testing by other applicants of the same specification steels, and other correlations of the metallurgical characterizations of these materials with the fracture toughness data in NUREG-0577, the staff concludes that the fracture toughness properties of the ferritic materials in the ESF systems provide adequate margin from rapidly propagating failure and gross rupture.

The controls on the use and fabrication of the austenitic stainless steel of the systems satisfy most of the requirements of Regulatory Guide, (RG) 1.31, "Control of Ferrite Content of Stainless Steel Weld Metal," and RG 1.44, "Control of the Use of Sensitized Stainless Steel." The alternate approaches taken by the applicant have been reviewed and are acceptable to the staff (see SER Section 5.2.3). Fabrication and heat treatment practices performed accordingly provide assurance that the probability of stress corrosion cracking will be reduced during the postulated accident time interval. Conformance with the codes and regulatory guides and with the staff positions mentioned above constitutes an acceptable basis for meeting the requirements of GDC 1, 4, 14, 35, and 41; Appendix B to 10 CFR 50; and 10 CFR 50.55a, in which the systems are to be designed, fabricated, and erected so that they can perform their function as required.

(2) GDC 1, 14, and 31 have been met with respect to ensuring that the reactor coolant boundary and associated auxiliary systems have an extremely low probability of leakage, of rapidly propagating failures, and of gross rupture. The controls placed on concentrations of leachable impurities in nonmetallic thermal insulation used on components of the engineered safety features are in accordance with the requirements of RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steels." Compliance with the requirements of RG 1.36 forms a basis for meeting the requirements of GDC 1, 14, and 31.

(3) The requirements of GDC 4, 35, and 41 and Appendix B to 10 CFR 50, have been met with respect to compatibility of ESF components with environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. The controls on the pH and chemistry of the reactor containment sprays and the emergency core cooling water following a loss-of-coolant or design-basis accident are adequate to reduce the probability of stress corrosion cracking of the austentitic stainless steel components and welds of the (ESF) systems in containment throughout the duration of the postulated accident to completion of cleanup.

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.2 Containment Subcompartment Analysis

The applicant states in the FSAR that the mass and energy release data for all high-energy-line breaks considered for subcompartment analyses were generated by Westinghouse. However, the applicant has apparently incorrectly referenced the blowdown model used. The applicant should provide an appropriate reference in order for the staff to assess the acceptability of the blowdown data. The staff is continuing its evaluation of the applicant's subcompartment analysis and will report on the resolution of this matter in a future supplement to the SER.

6.2.4 Containment Isolation System

The staff has evaluated the contribution to the offsite radiological consequences of purge system operation at the onset of a loss-of-coolant accident (LOCA) and before isolation valve closure occurs in response to the containment isolation signal. Using the guidance of Branch Technical Position (BTP) CSB 6-4 of Standard Review Plan (SRP) Section 6.2.4, the staff estimated the resultant purge contribution to the doses at the exclusion area and low population zone boundaries to be less than 1 rem to the thyroid, which is negligible compared to the LOCA doses reported in Section 15 of the SER. Therefore, the staff concludes that the potential radiological consequences attributable to purge system operation at the onset of a postulated LOCA are not a factor in approving use of the purge system during normal plant operation.

Item II.E.4.2 of NUREG-0737 states that fluid lines of nonessential systems that penetrate containment should be automatically isolated in response to the containment isolation signal. In Amendment 56 to the FSAR, the applicant defined an essential system (or line) as one that is necessary for mitigating the consequences of an accident, and identified the essential systems and lines in Table 6.2-83 of the FSAR. They include the residual heat removal system, containment spray system, high-head safety injection system, and containment pressure-sensing lines. All other fluid lines penetrating containment are identified in Table 6.2-83 as being nonessential. The staff notes, however, that the following nonessential system lines are not automatically isolated:

- chemical and volume control (Penetration Nos. 28, 29, 30, 31)

- primary component cooling water thermal barrier (Penetration Nos. 48A, 48B, 49A, 49B)

- reactor coolant system (Penetration Nos. 77A, 77B, 78A, 78B)

The applicant should provide appropriate justification for not automatically isolating system lines penetrating containment that have been declared non-essential. The staff will report on the results of its review in a future supplement to the SER.

6.2.6 Containment Leakage Testing Program

By letter dated February 12, 1986, the applicant proposed three changes to the containment leakage rate design parameters.

(1) Decrease the primary containment integrated leakage rate (L_a) from 0.2 to 0.15% by weight of containment air per day.

(2) Decrease the combined leakage rate limit for Appendix J, Type B and C, penetrations from 0.75 L_a to 0.60 L_a.

(3) Increase the combined bypass leakage rate fraction from 0.15 L_a to 0.60 L_a for all penetrations identified as secondary containment bypass leakage paths.

The staff's evaluation of these proposed changes is described below:

(1) The proposed change in L_a is a decrease and is, therefore, conservative and acceptable.

(2) Appendix J to 10 CFR 50 specifically requires that the combined leakage rate from all Type B and C (local) leakage rate tests be less than 0.60 L_a. Thus, decreasing this acceptance criterion at Seabrook from 0.75 L_a to 0.60 L_a is necessary and acceptable.

(3) The applicant proposes to increase the limit on the fraction of primary containment leakage which could bypass the secondary containment (the containment enclosure) and thus not be treated by the containment enclosure emergency cleanup system before release to the environment. This proposed increase is from 0.15 L_a to 0.60 L_a. On the basis of its review (presented in Section 15.6.5.1 of this supplement) of the radiological consequence associated with the change, the staff finds this change acceptable.

6.6 Inservice Inspection of Class 2 and 3 Components

6.6.3 Evaluation of Compliance with 10 CFR 50.55a(g)

This evaluation supplements conclusions in SER Section 6.6.3. SER Supplement 3 stated that the preservice inspection (PSI) program was an open issue subject to the applicant's (1) providing additional information about the PSI examination of welds in the residual heat removal (RHR), emergency core cooling (ECC), and containment heat removal (CHR) systems; (2) providing clarification on the visual acuity requirements for personnel performing visual examinations; and (3) submitting all relief requests with supporting technical justifications.

The staff has completed its review of the FSAR through Amendment 56 (November 1985), the Seabrook Unit 1 Balance of Plant (BOP) PSI Program (Revision 1, January 6, 1984); the Seabrook Unit 1 Supplemental Examination Program Plan (SEPP) (Revision 0, November 25, 1985), and a letter from the applicant dated December 20, 1985, responding to the outstanding issues.

Attachment A to the applicant's December 20, 1985, submittal addresses volumetric examination of a representative sample of welds in the RHR, ECC, and CHR systems. In lieu of revising the BOP PSI Program, the applicant has developed a Supplemental Examination Program Plan (dated November 25, 1985). In this plan, Code Case N-408 was used as guidance for selecting welds to be ultrasonically examined in those portions of reactor makeup water (RMW), safety injection (SI), containment building spray (CBS), and chemical and volume control (CVC) systems that had been exempted from examinations based on the exclusion criteria in Paragraph IWC-1220 of Section XI of the ASME Code.

The applicant has stated that for the systems identified above, approximately 15% of the welds in each system have been selected for the SEPP preservice inspection, which constitutes twice the number of weld inspections required by Code Case N-408. The staff has reviewed the SEPP and determined that the selection of welds for PSI satisfies the inspection requirements of GDC 36, 39, 42, and 45, and that use of Code Case N-408 is acceptable, based on the conditions specified in RG 1.147.

The applicant has committed to revise Visual Examination Procedure 80A647A to state that personnel performing visual examinations shall be certified in accordance with the latest revision of NES Document No. 80A9069 and that at least one member of a visual-examination team shall be certified to at least Level II. The staff considers this issue resolved.

The specific areas where the Code requirements cannot be met will be identified after the examinations are performed. The applicant has committed to identify all plant-specific areas where the Code requirements cannot be met and provide a supporting technical justification for requesting relief. The staff will report this evaluation in a supplement to the SER after the information is submitted by the applicant.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

This review was conducted with the assistance of DOE personnel at Idaho National Engineering Laboratory (INEL).

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Trip System

7.2.4 Generic Implications of Anticipated Transient Without Scram (ATWS) Events at Salem Nuclear Power Plant (Generic Letter 83-28)

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant (SNPP 1) failed to open upon an automatic reactor trip signal from the reactor protection system. This incident occurred during plant startup, and the reactor was tripped manually by the operator about 30 seconds after the initiation of the automatic trip signal. The failure of the circuit breakers has been determined to be related to the sticking of the undervoltage trip attachment. Before this incident, on February 22, 1983, during startup of SNPP 1, an automatic trip signal occurred as the result of steam generator low-low level. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip. Following these incidents, on February 28, 1983, the NRC Executive Director for Operations (EDO) directed the staff to investigate and report on the generic implications of these ocurrences. The results of the staff's inquiry into these incidents are reported in NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant." As a result of this investigation, the Commission requested (by Generic Letter 83-28, dated July 8, 1983) all licensees of operating reactors, applicants for an operating license, and holders of construction permits to respond to certain generic concerns. These concerns are categorized into four areas: (1) post-trip review, (2) equipment classification and vendor interface, (3) post-maintenance testing, and (4) reactor trip system reliability improvements.

The subsections below address items (1) post-trip review, (3) post-maintenance testing, and (4) reactor trip system reliability improvements.

(1) Post-Trip Review

Data and Information Capability

The following review guidelines were developed after initial evaluation of the responses of various utilities to Item 1.2 of Generic Letter 83-28; that incorporate the best features of these submittals. Thus, these review guidelines represent a "good practices" approach to post-trip review. The staff has reviewed the applicant's response to Item 1.2 against these guidelines.

A. The equipment that provides the digital sequence of events (SOE) record and the analog time-history records of an unscheduled shutdown should provide a reliable source of the necessary information to be used in the post-trip review. Each plant variable that is needed to determine the cause and progression of the events following a plant trip should be monitored by at least one recorder (such as an SOE recorder or a plant process computer) for digital parameters, and by strip charts, a plant process computer, or analog recorder for analog (time history) variables. Performance characteristics guidelines for SOE and time-history recorders are as follows:

- Each SOE recorder should be capable of detecting and recording the SOE with a sufficient time discrimination capability to ensure that (1) the time responses associated with each monitored safety-related system can be ascertained and (2) a determination can be made as to whether the time response is within acceptable limits based on the accident analyses in FSAR Chapter 15. The recommended guideline for the SOE time discrimination is approximately 100 milliseconds. If current SOE recorders do not have this time discrimination capability, the applicant should show that the current time discrimination capability is sufficient for an adequate reconstruction of the course of the reactor trip and post-trip events. As a minimum this should include the ability to adequately reconstruct the transient and accident scenarios presented in Chapter 15 of the FSAR.

- Each analog time-history data recorder should have a sample interval small enough so that the incident can be accurately reconstructed following a reactor trip. As a minimum, the applicant should be able to reconstruct the course of the transient and accident sequences evaluated in the accident analysis of Chapter 15 of the FSAR. The recommended guideline for the sample interval is 10 seconds. If the time-history equipment does not meet this guideline, the applicant should show that the time-history capability is sufficient to accurately reconstruct the transient and accident sequences presented in Chapter 15 of the FSAR. To support the post-trip analysis of the cause of the trip and the proper functioning of involved safety-related equipment, each analog time-history data recorder should be capable of updating and retaining information from approximately 5 minutes before the trip until at least 10 minutes after the trip.

- All equipment used to record SOE and time-history information should be powered from a reliable, noninterruptible power source. The power source need not be Class 1E.

B. The SOE and time-history recording equipment should monitor, respectively, enough digital and analog parameters to ensure that the course of the reactor trip and post-trip events can be reconstructed. The parameters monitored should provide enough information to determine the root cause of the unscheduled shutdown, the progression of the reactor trip, and the response of the plant parameters and protection and safety systems to the unscheduled shutdowns. Specifically, all input parameters associated with reactor trips, safety injections, and other safety-related systems, as well as output parameters sufficient to record the proper functioning of these systems, should be recorded for use in the post-trip review.

The parameters deemed necessary, as a minimum, to perform a post-trip review that would determine if the plant remained within its safety limit design envelope are given in Table 7.1. They were selected on the basis of staff engineering judgment after a complete evaluation of utility submittals. If the applicant's SOE recorders and time-history recorders do not monitor all of the parameters suggested in Table 7.1, the applicant should show that the existing set of monitored parameters is sufficient to establish that the plant remained within the design envelope for the accident conditions analyzed in Chapter 15 of the FSAR.

C. The information gathered by the SOE and time-history recorders should be stored in a way that allows data retrieval and analysis. The data may be retained in either hard copy (computer printout, strip chart record, etc.) or in an accessible memory (magnetic disc or tape). This information should be presented in a readable and meaningful format, taking into consideration good human factors practices, such as those given in NUREG-U700, "Guidlines for Control Room Design Reviews."

D. Retention of data from all unscheduled shutdowns provides a valuable reference source for determining the acceptability of the plant vital parameter and equipment response to subsequent unscheduled shutdowns. Information gathered during the post-trip review is to be retained for the life of the plant for post-trip review comparisons of subsequent events.

Evaluation and Conclusion

By letters dated November 4, 1983 (DeVincentis) and March 6, 1986 (DeVincentis), the applicant provided information regarding the Seabrook post-trip review program data and information capabilities. The staff has evaluated the applicant's submittals against the review guidelines described above.

A. The applicant described the performance characteristics of the equipment used to record the SOE and time-history data needed for post-trip review. On the basis of its review of the applicant's submittals, the staff finds that the SOE recorder and time-history characteristics conform to the guidelines described above and are acceptable.

B. The applicant has established and identified the parameters to be monitored and recorded for post-trip review. On the basis of its review, the staff finds (1) that the parameters selected by the applicant include all of those identified in Table 7.1 and (2) that they conform to the guidelines described in B above. They, are therefore, acceptable.

C. The applicant described the means for storage and retrieval of the information gathered by the SOE and time-history recorders, and for the presentation of this information for post-trip review and analysis. On the basis of its review, the staff finds that this information will be presented in a readable and meaningful format, and that the storage, retrieval, and presentation conform to the guidelines of C above. Thus, the means for storage and retrieval of information and for its presentation for post-trip review and analysis are acceptable.

D. The applicant's submittal of March 6, 1986, indicates that the data and information used during post-trip reviews will be retained in an accessible manner for the life of the plant. On the basis of this information, the staff finds that the applicant's program for data retention conforms to the guidelines of D above, and is acceptable.

Thus, on the basis of its review of the applicant's submittals, the staff concludes that the applicant's post-trip review data and information capabilities are acceptable.

(3) Post-Maintenance Testing

The following paragraphs evaluate the applicant's responses to Items 3.1.3 and 3.2.3 of Generic Letter 83-28. The requirements for these two items are identical, except that Item 3.1.3 applies these requirements to the reactor trip system components and Item 3.2.3 applies them to all other safety-related components. Because of the similarity of the items, the responses to both items were evaluated together.

Requirements

Licensees and applicants shall identify, if applicable, any post-maintenance test requirements in existing Technical Specifications that can be demonstrated to degrade rather than enhance safety. Appropriate changes to these test requirements, with supporting justification, shall be submitted for staff approval.

Evaluation and Conclusions

In a submittal dated November 4, 1983 (De Vincentis), the applicant stated that there were no post-maintenance testing requirements in Technical Specifications for either the reactor trip system or other safety-related components that degraded safety. In a submittal dated August 22, 1985 (Thomas), the applicant further reported that the currently proposed Technical Specifications do not include any post-maintenance test requirements. The applicant also committed to continue to review test and maintenance programs to identify an rectify any testing that might degrade safety.

Thus, on the basis of the applicant's August 22, 1985, statement, the staff finds the applicant's responses acceptable for Items 3.1.3 and 3.2.3 of Generic Letter 83-28.

(4) Reactor Trip System Reliability Improvements

Generic Letter (GL) 83-28 was issued by NRC on July 8, 1983, indicating actions to be taken by applicants based on the generic implication of the anticipated transient without scram (ATWS) events at SNPP 1. Item 4.3 of the generic letter requires that modifications be made to improve the reliability of the reactor trip system by implementation of an automatic actuation of the shunt attachment on the reactor trip breakers. By letter dated November 4, 1983, the applicant committed to implement the automatic shunt trip modifications similar to the generic Westinghouse design, and by letters dated September 9, 1985, and March 18, 1986, PSNH provided responses to the plant-specific questions identified by the staff in its August 10, 1983, Safety Evaluation Report of the generic Westinghouse design. The staff has reviewed the applicant's proposed design for the automatic actuation of reactor trip breaker shunt trip attachments and finds it acceptable.

The applicant has stated that the modifications for Seabrook Unit 1 have been completed, but has not submitted proposed Technical Specifications. The applicant should complete the modifications for Seabrook Unit 2 and submit proposed Technical Specifications in accordance with GL 85-09 for staff review.

Evaluation and Conclusions

The following required plant-specific information items were identified on the basis of the staff's review of the Westinghouse Owners Group (WOG) proposed generic design for this modification:

(1) Provide the electrical schematic/elementary diagrams for the reactor trip and bypass breakers showing the undervoltage and shunt coil actuation circuits as well as the breaker control (e.g., closing) circuits, and circuits providing breaker status information/alarms to the control room.

The design of the electrical circuits for the shunt trip modification has been reviewed and found to be consistent with the WOG generic proposed design which was previously reviewed and approved by the staff. However, the applicant's design includes test jacks to facilitate the capability to perform response time tests during plant operation. This addition to the WOG generic design consists of test jacks wired through resistors directly across the shunt trip actuation relay coil. Thus, test connections for an undervoltage trip signal are available to perform the response time test. The resistors in series with the test connections to the relay coil provide protection against potential accidental short circuits or groundings during response time testing to ensure that such events would not result in an inadvertent breaker trip or overload on the protection system power source for the undervoltage trip attachment. On the basis of its review of this plant-specific aspect of the design, the staff concludes that this aspect does not introduce a safety-significant consideration, will facilitate on-line response time testing, and is, therefore, acceptable.

(2) Identify the power sources for the shunt trip coils. Verify that they are Class 1E and that all components providing power to the shunt trip circuitry are Class 1E and that any faults within non-Class 1E circuitry will not degrade the shunt trip function. Describe the annunciation/indication provided in the control room upon loss of power to the shunt trip circuits. Also, describe the overvoltage protection and/or alarms provided to prevent or alert the operator(s) to an overvoltage condition that could affect both the undervoltage (UV) coil and the parallel shunt trip actuation relay.

The applicant states that control power for the reactor trip and bypass breaker shunt trip coils is supplied from the Class 1E 125-V dc station batteries and dc distribution system. There is no non-Class 1E circuitry whose failure could degrade the Class 1E shunt trip circuitry.

Indication that power is available to the shunt trip coil circuits is provided by the circuit breaker red (closed) and green (open) position indication lights. Normally, one light would be on, depending on breaker position. If both lights are out, this would indicate a problem with power availability. In addition, various auxiliary relays are picked up when the reactor trip breakers are closed for normal power operation. Loss of control power would cause the relays to drop out. The resulting incorrect indication and alarm would lead to detection of the loss of control power. Loss of control power caused by loss of the dc system (loss of power to the 125-V dc distribution panel) would be alarmed by the dc system undervoltage alarms.

The UV coil and the parallel shunt trip actuation relay receive power from the solid state protection system (SSPS). The power supply within the SSPS has overvoltage protection set at 115% of nominal voltage (48-V dc). The UV coil and the parallel shunt trip actuation relay have been designed to perform their function up to a voltage as high as 115% of nominal voltage.

On the basis of its review, the staff concludes that appropriate consideration has been given to the aspects of the design described above and the design is, therefore, acceptable.

(3) Verify that the relays added for the automatic shunt trip function are within the capacity of their associated power supplies and that the relay contacts are adequately sized to accomplish the shunt trip function. If the added relays are other than the Potter & Brumfield MDR series relays (P/N 2383A38 or P/N 955655) recommended by Westinghouse, provide a description of the relays and their design specifications.

The design includes the Potter & Brumfield MDR series P/N 955655 relays as specified in the WOG generic design for the automatic shunt trip function. The relay contacts are adequately sized to accomplish the shunt trip function. The staff finds this aspect of the design to be acceptable.

(4) State whether the test procedure/sequence used to independently verify operability of the undervoltage and shunt trip devices in response to an automatic reactor trip signal is identical to the test procedure proposed by WOG. Identify any differences between the WOG test procedure and the test procedure to be used and provide the rationale/justification for these differences.

The applicant notes that the steps used to independently confirm the operability of the undervoltage trip and shunt trip devices in response to an automatic reactor trip signal will be the same as the test procedure proposed by WOG. This procedure will be implemented following the installation of the automatic shunt trip modification. The staff finds this acceptable.

(5) Verify that the circuitry used to implement the automatic shunt trip function is Class 1E (safety related), and that the procurement, installation, operation, testing, and maintenance of this circuitry will be in accordance with the quality assurance criteria set forth in Appendix B to 10 CFR 50.

The applicant confirmed that the circuitry used to implement the automatic shunt trip function is Class 1E (safety related) and the procurement, installation, operation, testing, and maintenance of this circuitry will be in accordance with the quality assurance criteria set forth in Appendix B to 10 CFR 50. The staff finds this acceptable.

(6) Verify that the shunt trip attachments and associated circuitry are/will be seismically qualified (i.e., be demonstrated to be operable during and after a seismic event) in accordance with the provisions of Regulatory Guide (RG) 1.100, Revision 1, which endorses IEEE Standard 344, and that all non-safety-related circuitry/components in physical proximity to or associated with the automatic shunt trip function will not degrade this function during or after a seismic event.

The applicant states that the shunt trip attachment and associated circuitry have been seismically qualified by Westinghouse in accordance with the provisions of RG 1.100, Revision 1, which endorses IEEE Standard 344. Since the automatic shunt trip circuitry/components are mounted in the reactor trip switchgear which has been seismically qualified, there are no non-safety-related circuitry/components which can fail and degrade the automatic shunt trip functions during or after a seismic event.

(7) Verify that the components used to accomplish the automatic shunt trip function are designed for the environment in which they are located.

The applicant has verified that the plant-specific environmental conditions are enveloped by the Westinghouse qualifications except that the lower end of the Seabrook normal switchgear room temperature is 55°F as compared with 60°F qualified by Westinghouse, and the atmospheric pressure is slightly positive. The applicant states these differences will not affect the operation of the switchgear. The staff finds this acceptable.

(8) Describe the physical separation provided between the circuits used to manually initiate the shunt trip attachments of the redundant reactor trip breakers. If physical separation is not maintained between these circuits, demonstrate that faults within these circuits cannot degrade both redundant trains.

The applicant states that the control switches (reactor trip and safety injection) to manually initiate the shunt trip attachment to provide reactor trip are located on the main control board. The redundant train wiring is separated on the control switches by barriers and is routed in separate conduits/wireways within the main control board to terminal blocks for termination of field cable. The redundant train cabling from the main control board to the reactor trip switchgear is routed in separate raceways. Within the reactor trip switchgear, the wiring is routed in separate wireways in accordance with the standard Westinghouse design. The automatic shunt trip panels are located within the switchgear enclosure for their respective train. The above separation is in accordance with the physical separation criteria as given in the FSAR. The staff finds the above separations acceptable.

(9) Verify that the operability of the control room manual reactor trip switch contacts and wiring will be adequately tested before startup after each refueling outage. Verify that the test procedure used will not involve installing jumpers, lifting leads, or pulling fuses and identify any deviations from the WOG procedure. Permanently installed test connections (i.e., to allow connection of a voltmeter) are acceptable.

The applicant notes that the operability of the control room manual reactor trip switch contacts and wiring will be tested before startup after each refueling outage. The procedure, "Post Refueling Pre-Startup RX Trip Breaker Surveillance," tests the control room manual reactor trip switch contacts and wiring, and does not involve installing jumpers, lifting leads, or removing fuses. The staff finds this acceptable.

(10) Verify that each bypass breaker will be tested to demonstrate its operability before placing it into service for reactor trip breaker testing.

The applicant states that plant-specific procedures have been developed that use the local close and trip pushbutton switches when testing each bypass breaker before placing them into service for reactor trip breaker testing. The staff finds that this is acceptable.

(11) Verify that the test procedure used to determine reactor trip breaker operability will also demonstrate proper operation of the associated control room indication/annunciation.

The applicant states that plant procedures that were developed to determine reactor trip breaker operability also demonstrate proper operation of the associated control room indication/annunciation. The staff finds this acceptable.

(12) Verify that the response time of the automatic shunt trip feature will be tested periodically and shown to be less than or equal to the response time assumed in the FSAR analyses or specified in the Technical Specifications.

The applicant states that the automatic shunt trip feature for each trip and bypass breaker will be tested during each refueling. The response time will be verified equal to or less than 0.167 seconds, as referenced in the Generic Westinghouse Design for Automatic Shunt Trip Actuation (WOG letter OG-101 from J. J. Sheppard to D. G. Eisenhut, dated June 14, 1983). The staff finds this acceptable.

(13) Propose Technical Specification changes to require periodic testing of the undervoltage and shunt trip functions and the manual reactor trip switch contacts and wiring.

The applicant states that Technical Specifications for the reactor trip breakers and the manual reactor switch contacts and wiring will be addressed during the review and final revision of Seabrook's Technical Specifications. This matter will, therefore, be subject to further staff review following the submittal of proposed Technical Specification changes.

On the basis of the review of the applicant's response to the plant-specific questions identified in the staff's evaluation of the Owner's Group generic design modifications, the staff finds that the shunt trip modifications are acceptable. The applicant should submit proposed Technical Specifications in accordance with GL 85-09 to reflect the implementation of the shunt trip modifications.

It should be noted that this evaluation satisfies the preimplementation review requirements for Item 4.3 of Generic Letter 83-28. Therefore, the modification for the automatic actuation of the shunt attachments of the reactor trip breakers should be implemented before the full-power license for Seabrook Units 1 and 2 is issued.

7.3 Engineered Safety Features Systems

7.3.2 Specific Findings

7.3.2.2 Volume Control Tank Level Control and Protection Interaction

The SER for Seabrook states that the applicant is required to provide formal documentation to support this issue. The staff has concluded that the applicant's letters dated October 14, 1982, and January 25, 1983, provide sufficient formal confirmatory documentation which ensures that the operators will be properly alerted to the failure of the volume control tank level control system and will take the appropriate action necessary to ensure an adequate supply of water to the charging pumps. This issue is, therefore, considered resolved.

7.3.2.3 Test of Engineered Safeguards P-4 Interlock

The SER for Seabrook states that the required equipment modifications providing suitable test features for the P-4 interlocks must be completed before fuel load. By letter dated February 14, 1986, the applicant provided information referencing drawings to show the required modifications necessary to obtain the permanent test features for the P-4 interlocks. On the basis of review of the final design drawings, the staff considers this issue resolved.

7.3.2.5 Operation and Testing of Main Steam and Feedwater Isolation Valves

The Seabrook SER states that the applicant should provide formal documentation to reflect the main steam isolation valve logic design reviewed and accepted by the staff. By letters dated January 25, 1983, and February 14, 1986, the applicant provided the required confirmatory information. This issue is, therefore, considered resolved.

7.3.2.6 Solid-State Protection System Relay Contacts

As discussed in the SER for Seabrook, the applicant performed an independent test to verify the contact current-carrying capabilities of the SSPS relays. As required, the applicant has provided formal documentation by letter dated February 14, 1986, which identifies the required acceptance criteria and verifies that they have been met. The staff finds this information acceptable and has concluded that a single contact can handle the magnitude of 512 amps that would be applied upon safeguards actuation.

The applicant committed to modify the Seabrook design so that single contacts will be used in the safeguards actuation circuits instead of the original parallel design. Subsequently, the applicant has stated that it intends to retain the parallel contact design since either contact can perform the protection function by itself. The staff finds this acceptable.

On the basis of the above discussion, the staff considers this issue resolved.

7.3.2.7 Steam Generator Level Control and Protection

The SER for Seabrook states that the applicant should provide formal documentation which indicates that four level channels with two-out-of-four logic will be used to actuate feedwater isolation on high steam generator level. By letter dated February 14, 1986, the applicant provided references to various FSAR changes that adequately reflect the required logic design. Based on review of the latest FSAR information, the staff considers this issue resolved.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.1 Bypassed and Inoperable Status Indication

As required by the SER for Seabrook, the applicant provided formal documentation by letters dated February 14, 1986, to reflect the bypassed and inoperable status indication system design. On the basis of this additional information, the staff concludes the issue resolved.

7.6 Interlock Systems Important to Safety

7.6.7 Specific Findings

7.6.7.2 RCS Pressure Control During Low-Temperature Operation

The SER for Seabrook states that the applicant committed to modify the Seabrook design to include redundant auctioneering cards for the low-temperature interlock associated with reactor coolant system (RCS) pressure control. The applicant has revised (Amendment 49) the FSAR to adequately reflect the redundant auctioneering circuits. On the basis of its review of the FSAR, the staff considers this issue resolved.

7.6.7.3 Spurious Valve Actuation Protection

As required by the Seabrook SER, the applicant has provided information (letter dated February 14, 1986) which verifies that valve SI-V93 is to be included as part of the RG 1.47 implementation. The information also verifies that where the single-failure criterion is satisfied by the removal of motive electric power to prevent spurious valve action, the subject valves will continue to have operable, redundant position indication in the main control room (i.e., the redundant position indication circuits will use different power supplies so that they will remain operable when the motive power is removed from the valve operator). On the basis of the above discussion, the staff considers this issue resolved.

7.6.7.5 Position Indication for the Residual Heat Removal Inlet Isolation Valves

As required by the SER for Seabrook, the applicant has provided documentation (letter dated February 14, 1986) to verify that true valve position indication will always be indicated in the control room subsequent to the removal of motive power from the valve operator to prevent spurious operation. On the basis of its review of the latest information, the staff considers this issue resolved.

7.6.7.7 Residual Heat Removal System

As required by the SER for Seabrook, the applicant provided formal documentation (February 14, 1986, letter) to verify the staff-approved alarm design and to show through analysis the time allowed for the performance of operator action for reinstatement of residual heat removal (RHR) should there be a loss of instrument/control power while operating in the RHR mode. The information states that if the RHR suction isolation valves close because of a power failure in the logic circuit, the valves can be reopened from the remote shutdown station through the operation of spring-return-to-normal control switches. The applicant states that upon receipt of an alarm, this action can be performed expeditiously (less than 10 minutes) at the remote shutdown station. The applicant has performed a worst-case analysis, reactor coolant system vented, which shows that 12 minutes is available before bulk coolant would reach saturation temperature. The applicant has provided information which shows that if bulk boiling does occur it would take more than 50 minutes to uncover the core. This time could be extended by adding coolant to the reactor coolant system via the operable charging pump. On the basis of a review of the latest information, the staff considers this issue resolved.

7.6.7.8 Tower Actuation Signal

The Seabrook SER required that the applicant provide formal documentation to reflect the staff-approved tower actuation (TA) logic circuit design. By letter dated February 14, 1986, the applicant referenced FSAR sections and drawings which provide formal information describing the TA logic. On the basis of the February 14, 1986, submittal of formal documentation, the staff considers this issue resolved.

7.7 Control Systems

7.7.2 Specific Findings

7.7.2.2 Control System Failures

The SER for Seabrook states that the staff has concluded, with reasonable assurance, that the consequences of multiple control system failures are bounded by the FSAR analyses. Also, as required by this Section 7.7.2.2, the applicant has submitted formal documentation to support the staff's conclusion. The information describes the events that will result from the failure of a common sensor and identifies the specific FSAR analysis that bounds each event. On the basis of this additional information, the staff considers this issue resolved.

7.7.2.3 IE Information Notice 79-22

As reflected in the SER for Seabrook, the staff concluded, on the basis of the applicant's study, that the consequences of high-energy-line break (HELB) effects on control systems are bounded by the FSAR analyses. As required by the subject section, the applicant has provided formal documentation in a January 25, 1983, letter to support the staff's conclusion. Therefore, this issue is considered resolved.

Table 7.1 Parameters needed for post-trip review

SOE	Time-history recorder	Parameter/signal
x[1]		Reactor trip
x[1]		Safety injection
x		Containment isolation
x[1]		Turbine trip
x		Control rod position
x[1]	x	Neutron flux, power
x	x	Containment pressure
–[2]	–[2]	Containment radiation
	x	Containment sump level
x[1]	x	Primary system pressure
x[1]	x	Primary system temperature
x[1]		Pressurizer level
x[1]		Reactor coolant pump status
x[1]	x	Primary system flow
–[3]	–[3]	Safety injection: flow, pump/valve status
x		Position of main steam isolation valve
x	x	Steam generator pressure
x[1]	x	Steam generator level
x[1]	x	Feedwater flow
x[1]	x	Steam flow
–[3]	–[3]	Auxiliary feedwater system: flow, pump/valve status
x		ac and dc system status (bus voltage)
x		Diesel generator status (start/stop, on/off)
x		Position of power-operated relief valve

[1]Trip parameters.

[2]Parameter may be monitored by either an SOE or a time-history recorder.

[3]Acceptable recorder options are (1) system flow recorded on an SOE recorder, (2) system flow recorded on a time-history recorder, or (3) equipment status recorded on an SOE recorder.

8 ELECTRICAL POWER SYSTEMS

8.1 General

In the Seabrook SER, staff stated that it would conduct a review of electrical drawings and would visit the site to view the installation and arrangement of electrical equipment and cables for the purpose of verifying proper implementation of the design as described in the FSAR. In addition, the staff identified certain items in the SER for design verification during the site visit. A site visit was conducted by the staff on September 24 through 26, 1985, during which certain concerns were identified. Staff discussion and resolution of these concerns are addressed below. Items for design verification and confirmatory issues identified in the SER are discussed in the appropriate sections that follow.

Diesel Generator Control Drawings

During the site visit, the staff's review of the diesel generator (DG) control drawings revealed that if the DG control switch is in the local position, the DG will be unavailable for automatic start on a safety injection (SI) signal. This condition was not alarmed in the control room as part of the conditions that can render the the DG incapable of responding to an automatic emergency start signal. The staff required that this condition be included in the list of conditions that can render DG incapable of responding to an automatic emergency start signal to satisfy Branch Technical Position (BTP) PSB-2.

By letter dated November 27, 1985, the applicant committed to include this condition in the list of conditions that can render the DG incapable of responding to an automatic emergency start signal. This satisfies BTP PSB-2 and is acceptable. Implementation of this design will be verified by NRC Region I staff.

Control Circuitry of Recirculation Isolation Valve

The staff's review of the control circuitry of recirculation isolation valve SI-V-93 revealed that redundant indication that meets the single-failure criterion was not provided for this valve (redundant indication had been provided, but from the same valve limit switch). The staff required that another indication from a diverse device (e.g., stem-mounted switch) be provided to satisfy BTP PSB-18.

By letter dated November 27, 1985, the applicant committed to install another indication from a stem-mounted switch. This satisfies BTP PSB-18 and is acceptable. Implementation of this design will be verified by NRC Region I personnel.

Circuitry for Penetration Protection

The staff's review of the circuits for penetration protection revealed that the breaker control power supply for primary and backup protection for structure cooling fans does not meet the single-failure criterion, i.e., power is not supplied from different batteries. The staff required that the breaker control power for primary and backup protection for these fans be from different batteries to satisfy the recommendations of RG 1.63, Position 1.

By letter dated November 27, 1985, the applicant indicated that the breakers for the above cooling fans do not require control power to trip in order to isolate a fault. These breakers utilize a direct-acting electro-mechanical overcurrent trip device which depends on its circuit for tripping power. Hence, no external control power is required for tripping. On this basis, the staff considers this concern resolved.

8.2 Offsite Electric Power System

8.2.2 Compliance with GDC 17

8.2.2.3 Routing of Offsite Power Circuits

In the Seabrook design, the three offsite power circuits are routed, from the terminating structure to a common switching station, in close proximity at or below ground level and adjacent to the plant's access road. These circuits are routed in a metal-enclosed SF6 gas-insulated bus. The plant's main access road runs adjacent to and has a number of bridges across the transmission line routing. One of the bridges is an access road to a public recreation area. The staff was concerned that a vehicular accident could damage all three offsite circuits simultaneously. In response to staff concern, the applicant indicated that guardrails protect the transmission lines from vehicle damage, and the location of the access road on plant property, controlled access, and strict plant-regulated speed limits afford additional protection. The staff stated in the Seabrook SER that the design of offsite power circuits is acceptable pending confirmation of guardrails design adequacy and/or assurance of the low likelihood of vehicular-type accidents.

By letter dated November 27, 1985, the applicant submitted the guardrail design for staff review. The staff reviewed and evaluated the adequacy of the design of guardrails for protecting the offsite power circuits from vehicular accidents. On the bais of its evaluation, the staff concludes that the applicant has minimized the likelihood of simultaneous damage to the three offsite circuits. Therefore, the design meets GDC 17 and is acceptable.

8.2.3 Compliance with GDC 18

8.2.3.1 Capability To Test Transfer of Power Among the Offsite Circuits

The capability to test the transfer of power from the immediate access offsite circuit to the other circuit was not addressed in the FSAR. The staff stated in the SER that pending incorporation of the applicant's response in FSAR Section 8.2, the staff concludes that the design meets GDC 18 and is acceptable. Subsequently, the applicant amended FSAR Section 8.2 to include this information. This satisfies the staff's concern and the staff considers this item resolved.

8.3 Onsite Power Systems

8.3.1 Onsite AC Power System Compliance with GDC 17

8.3.1.1 Low and/or Degraded Grid Voltage Condition

8.3.1.1.1 Compliance with Position B1 of BTP PSB-1

The second level of undervoltage protection for the Seabrook design does not meet the guidelines of Position 1 of BTP PSB-1. The design relies strictly on operator action when there is no accident signal for disconnection, rather than on automatic disconnection after a time delay for the operator to restore adequate voltage. In addition, immediate rather than delayed automatic disconnection was to be initiated if there were a coincident accident signal.

In regard to the first exception, the applicant indicated that adequate safety systems (not exposed to or not rendered inoperable by degraded grid voltage) are available for safe shutdown. The staff stated in the SER that this approach is acceptable for the resolution of this item; however, the adequacy of systems and equipment used for safe shutdown and exposed to degraded grid voltage will be pursued with the applicant.

Subsequently, by letter dated November 27, 1985, the applicant submitted a list of systems and equipment not exposed to or not rendered inoperable by degraded voltage. The staff has reviewed this information and concludes that sufficient systems and equipment required for safe shutdown will be available in the event of a degraded grid voltage. Most of these systems are either not operating during normal plant operation or do not rely on electric power for operation. For safety equipment which is running normally, redundant equipment exists in standby, unaffected by a degraded grid condition. In some cases, equipment relies on dc power for operation and all instrumentation is connected to 120-V ac uninterruptible power supply (inverters backed up by batteries) which is unaffected by degraded grid voltage conditions. On this basis, the staff considers the item resolved.

In regard to the remaining exception to the BTP PSB-1 position (immediate rather than delayed automatic disconnection when there is an accident signal), the applicant indicated that the Seabrook design has the required delayed automatic disconnection. The staff has confirmed the implementation of this design feature in the Seabrook design and considers this item resolved.

8.3.1.1.3 Compliance with Position B3 of BTP PSB-1

(1) The staff stated in the SER that: Table 2 of the voltage analysis (applicant's letter dated July 2, 1982) indicates that starting the non-safety motor CAH-FN-1C will cause a voltage drop on the associated non-Class 1E bus, below 80%. The staff concluded that pending confirmation that this voltage drop is localized and will not cause a similar drop on Class 1E buses, this item is acceptable.

    By letter of November 27, 1985, the applicant submitted a revised voltage analysis. After reviewing Table 2 of the voltage analysis, the staff concludes that starting the non-Class 1E motor CAH-FN-1C has no adverse effects on the Class 1E buses, i.e., the voltage on the Class 1E buses remains above 80%. This satisfies the concern and the staff considers this confirmatory item resolved.

(2) The staff stated in the SER that Table 3 of the voltage analysis (applicant's letter dated July 2, 1982) considers starting of all accident loads simultaneously. The table considers other Class 1E loads that are running when the accident loads are started, but does not address non-Class 1E loads that are running or that may start during the same time interval that the Class 1E loads are starting. The staff concluded that pending confirmation that starting and running of non-Class 1E loads has been considered in the study, this item is acceptable.

By letter dated February 24, 1986, the applicant submitted a revised Table 3 of the voltage regulation study, which included the effect of starting non-Class 1E loads coincident with accident loads on the Class 1E bus voltages. The staff has reviewed this table and concludes that all voltages at the motor terminals are above the 80% voltage required for starting Class 1E motors with the exception of voltages at the terminals of fans EAH-FN-4A (79%) and 4B (77%). However, these fans are capable of starting with terminal voltages of as low as 75% because these motors are only 72% loaded (based on applicant's discussions with the fan vendor). On this basis, the staff finds this item acceptable.

(3) The staff stated in the SER that Table 4 of the voltage analysis (applicant's letter dated July 2, 1982) indicates a 2.9% overvoltage at the safety buses during the condition of minimum anticipated loads with the utility grid at maximum anticipated voltage. Pending confirmation that there will be no overvoltage at the motor terminals, the staff finds this item acceptable.

By letter dated November 21, 1985, the applicant submitted a revised voltage study. This study indicates the maximum overvoltage condition to be 0.8% rather than 2.9% as in the original submittal. The applicant has stated that a nominal motor feeder voltage drop of 1% should ensure that no overvoltage condition exists at the motor terminals. This meets Position 3 of BTP PSB-1 and the staff finds it to be acceptable.

(4) The voltages at the 120/240-V distribution panel buses will vary between 109.9 V and 128.9 V. For short periods, during voltage dips due to motor starting, the bus voltage may drop to 95.8 V. A transient undervoltage condition of 95.8 V and a steady state of 129 V would have no adverse effect on the instruments for the level indication. The staff stated in the SER that, pending confirmation that the level indicators are designed to operate between 110 and 129 V, the staff finds this item acceptable.

By letter dated November 27, 1985, the applicant indicated that this particular level indicator is no longer supplied power via the non-regulated Class 1E 120-V ac power distribution panels. A review was performed by the applicant to identify any other typical Class 1E instruments which are supplied power from the non-regulated Class 1E 120-V ac system. As a result, another model level indicator was identified with a nominal operating voltage range of 115 ± 8% (105.8 to 124.2 V). The applicant has submitted confirmation from the manufacturer that a supply voltage of 105 to 130 V ac is acceptable for this instrument. On the basis of this confirmation, the staff considers the item resolved.

8.3.1.1.4 Compliance with Position B4 of BTP PSB-1

This position requires that the analytical techniques and assumptions used in the voltage analysis performed to optimize the Class 1E bus voltages for Position 3 of BTP PSB-1, must be verified by actual measurements.

By letter dated January 23, 1986, the applicant submitted the results of a test which was conducted to verify the analytical results of the Seabrook Station voltage regulation study. The staff has reviewed the results of this test and concludes that Seabrook onsite power system meets BTP PSB-1 and is acceptable.

8.3.1.2 Compliance with the Guidelines of RG 1.9 (Revision 2)

8.3.1.2.1 Frequency Recovery (BTP PSB-1, Position C5)

An earlier revision of FSAR Section 8.1.5.3 indicated an exception to Position C5 of RG 1.9 (Rev. 2). This position recommends that during loading sequence, frequency should be restored to 60 ± 1.2 Hz within 60% of the load sequence interval. RG 1.9, however, permits a greater percentage of the load sequence interval for recovery if it can be justified by analysis.

By letter dated March 12, 1982, the applicant indicated that the Seabrook design meets Position C5 and that FSAR Section 8.1.5.3 would be modified accordingly. The staff stated in the Seabrook SER that this item is acceptable pending confirmation that the FSAR has been modified accordingly. Subsequently, the applicant modified FSAR Section 8.1.5.3 to remove the exception. The staff has reviewed the revision and concludes that the Seabrook design conforms to BTP PSB-1, Position C5, and considers this item resolved.

8.3.1.2.3 Diesel Generator Qualification Tests

The staff requires that new and previously untried diesel generator designs to be used in nuclear plants undergo a prototype reliability qualification testing program in accordance with IEEE Standard 387. Specifically, a 300 start-and-load test program is required with no more than three failures. The staff stated in the SER that this item is acceptable, pending review and confirmation of the program test report.

By letter dated November 27, 1985, the applicant submitted for staff review the results of the diesel generator qualification testing program. On the basis of this information, it is concluded that the diesel generators at Seabrook plant have successfully passed a prototype reliability verification program of 300 valid start-and-load tests with no more than three failures. Therefore, the staff considers this item resolved.

8.3.1.2.4 Diesel Generator Automatic Controls

Section 5.6.2.2(1) of IEEE Standard 387-1977 (endorsed by RG 1.9, Revision 2) requires that a start-diesel signal shall override all other operating modes and return control of the diesel generator unit to the automatic control system. On the basis of the FSAR, it appeared that control of the diesel generator was not returned to the automatic control system as required by the standard.

By letter dated July 2, 1982, the applicant provided a proposed change to the FSAR. Given this proposed change, the staff concluded in the Seabrook SER that the diesel generator control will be returned to the automatic control system and is acceptable, pending verification of the design as part of staff site visit.

Subsequently, a site visit and a review of drawings was conducted September 24 through 26, 1985. During the site visit, the staff examined schematic drawings showing the design for returning control of the diesel generator unit to the automatic control system on receipt of a safety injection signal. On the basis of this verification, the staff considers the item resolved.

8.3.1.2.5 Diesel Generator Voltage Capability

The Class 1E motors for the Seabrook design are capable of starting and accelerating their rated load with 80% voltage at the motor terminals. The output voltage of the diesel generator can, however, drop to 75% as permitted by Position 4 of RG 1.9 (Rev. 2). The applicant indicated that Seabrook diesel generators are designed to limit the output voltage to a minimum of 80% and that this capability has been demonstrated by factory load tests.

The staff stated in the Seabrook SER that the capability of the diesel generator to maintain voltage levels above 80% will be verified as part of the staff's review of diesel generator qualification test results.

By letter of November 27, 1985, the applicant submitted the results of the diesel generator qualification testing program. On the basis of the staff's review of this information, it is concluded that the Seabrook diesel generators are capable of maintaining voltage levels above 80% during sequencing of loads on the safety buses. Therefore, the staff considers this item resolved.

8.3.1.2.6 Capability of the Diesel Generator to Accept the Design Load

The cooling tower pump load (800 hp) that is normally connected at time interval 37 seconds may be connected at the 52-second time interval or any time after 52 seconds. The staff was concerned that the diesel generator may not be able to handle such a heavy load at or after the 52-second interval. The applicant indicated that the diesel generator has been tested to demonstrate its ability to successfully start a load larger than the 800-hp cooling tower pump at the 52-second loading sequence interval.

The staff stated in the SER that pending review and confirmation of the subject test this item is considered acceptable.

By letter dated November 27, 1985, the applicant submitted the results of the diesel generator qualification testing program. On the basis of the results of this program, the staff concludes that the Seabrook diesel generator is capable of starting a 1000-hp motor after being loaded to 4560 kW. This is more conservative than starting an 800-hp motor at the 52-second time interval (3885 kW), and the staff finds this to be acceptable. However, periodic testing using the 800-hp load at 52 seconds will be included in the Technical Specifications.

8.3.1.2.7 Diesel Generator Protective Trips

The staff stated in the SER that the Seabrook diesel generator protective trips meet the guidelines of Position 7 of RG 1.9 (Rev. 2) and are acceptable pending design confirmation by the staff during its site visit and drawing review.

Subsequently, a site visit and an audit drawing review was conducted September 24 through 26, 1985. During the site visit, the staff examined diesel generator control schematic drawings showing bypassing of protective trips (all except overspeed, generator differential, and lube oil pressure with a two-out-of-three coincidence logic) during accident condition. On the basis of the above verification of the design, the staff considers this item resolved.

8.3.1.2.8 Capability of Diesel Generator To Accept Design Load After Operation at Light or No Load

Originally, the applicant indicated that electric preheaters are necessary for no-load operation of the diesel generator without the accumulation of products of combustion in the exhaust system when the turbocharger inlet air temperature is below 50°F. The applicant stated that the preheaters will be (1) automatically energized when there is a safety injection accident signal, offsite power is available, and there are low ambient conditions; (2) automatically deenergized or tripped when offsite power is or becomes unavailable; (3) powered from the diesel's associated Class 1E bus; and (4) seismically supported. In addition, the circuitry associated with the preheaters will meet Class 1E design requirements. The staff stated in the Seabrook SER that, pending confirmation of the design implementation, the staff considers this item to be resolved.

By letter dated November 27, 1985, the applicant indicated that on the basis of its discussion with the diesel manufacturer, the applicant has determined that preheaters in the diesel air intake plenum are no longer required. On the basis of the acceptability of not having the preheaters in the diesel air intake plenum when the turbocharger inlet air temperature is below 50°F as evaluated in Section 9.5.4.1 of this supplement, the staff concludes that the implementation of the preheater design discussed above is no longer required and this item is resolved.

The staff also stated in the SER that as part of the review of the diesel generator qualification and preoperational test results, it will verify the capability of the diesel generator to accept design load after operation at light load or no load.

By letter dated November 27, 1985, the applicant submitted the results of the diesel generator qualification testing program. On the basis of the results of this testing program, the staff concluded that the Seabrook diesel generators are capable of accepting design load after operation at no load for 6 hours. This satisfies the staff's concern and is acceptable. The acceptability of the test results from the preoperational testing program will be performed by NRC Region I staff. Periodic testing to demonstrate this capability will be required by the Technical Specifications.

8.3.1.4 Non-safety Loads Powered from the Class 1E AC Distribution System

The non-Class 1E 1500-hp startup feed pump is normally connected to non-safety-related bus 4 with an alternate (manually initiated) feed from safety-related bus E5 only under contingency conditions. The capability of the Class 1E system to handle this 1500-hp load, when it is already carrying the maximum train A loads, concerned the staff. In response to this concern, the applicant stated that the diesel generator is capable of starting and powering the startup feed pump when carrying the maximum train A load listed in FSAR Table 8.3-1. In addition, the applicant stated that operating procedures will include provisions to require that the operator verify diesel generator loading to ensure that adequate margin is available for running the startup feed pump.

The staff stated in the Seabrook SER that the applicant is required to demonstrate this capability as part of the diesel generator load qualification testing program and preoperation and periodic tests. Pending confirmation of load qualification test results, the staff considered this item resolved. Periodic testing to demonstrate this capability will be required in the Technical Specifications.

By letter dated November 27, 1985, the applicant submitted the results of the diesel generator qualification testing program for staff review. On the basis of its review of this information, the staff concludes that the diesel generators at Seabrook have the capability to handle the 1500-hp load without exceeding the guidelines of Position 4 of RG 1.9 (Rev. 2) with regard to voltage and frequency. Therefore, the staff considers this item resolved. Confirmation that the diesel generator can start and run the startup feed pump while carrying the maximum train A load will remain pending until the preoperational tests are conducted and test results are made available. Verification of the adequacy of these test results will be performed by NRC's Region I staff. Periodic testing to demonstrate this capability will be required in the Technical Specifications.

8.3.1.8 Automatic Transfer of Loads and Electrical Interconnections Between Redundant Divisions

Originally, the power sources to non-Class 1E inverters (UPS-ED-I-2B, UPS-ED-I-4) were automatically transferred between 4160-V bus E5 (safety train A) and 4160-V bus E6 (safety train B). The staff informed the applicant that this automatic transfer did not meet position 4C of RG 1.6. In addition, this automatic transfer or interconnection between redundant divisions did not meet the independence requirement of GDC 17. Subsequently, by letter dated January 7, 1983, the applicant indicated that the power supplies to UPS-ED-I-2B and UPS-ED-I-4 would be modified to eliminate the subject interconnection and there are no other electrical interconnections or automatic load transfers. The staff stated in the Seabrook SER that pending confirmation of the modified designs, it concludes that the design meets RG 1.6 and is acceptable.

By letter dated November 27, 1985, the applicant submitted the modified design. On the basis of its review of the modified design, the staff concludes that the power sources to inverters UPS-ED-I-2B and 4 are all derived from train A and there is no connection to train B. Therefore, the modified design meets Position 4C of RG 1.6 and the staff considers this item resolved.

The staff also stated in the SER that physical independence between redundant ac and dc divisions and between redundant associated divisions is being investigated by the applicant and upon completion of this investigation, the results would be submitted for staff review. Subsequently, by letters dated December 1, 1983; June 20, 1984; and November 27, 1985, the applicant submitted the results of a study performed to identify and justify all electrical interconnections between redundant ac and dc divisions and between redundant associated divisions. The staff's evaluation follows.

(1) <u>13.8-kV Switchgear Feeder Breaker Compartments for Reactor Coolant Pumps</u>

The 13.8-kV switchgear compartments (designated as train A associated) contain train B associated cables. The train B associated cables that enter these compartments are the power feeders for the 13.8-kV reactor coola t pump (RCP) motors and the cables for the power connections to the potential transformers (PTs) (see item 2, below) which is utilized for the solid-state protection system circuits. A postulated failure in one of the switchgear compartments could affect the contained separation group A circuits and specific separation group B cables (feeder to PCP motors and feeder to the PTs). The cables used for the connections to the PTs are routed in embedded conduits and do not intermix with any other separation group circuits.

The cables providing power to RCP motors are armored cables and are routed either in embedded conduits or in dedicated cable trays containing only those cables. These trays are located at the top of a stack of other train B trays. The nominal distance between the trays in a stack within a separation group is 16 inches. On this basis, the staff concludes that there is only a very remote chance that these armored cables which are routed in dedicated cable trays could challenge other associated separation group B circuits because (a) cable trays contain only RCP motor cables, (b) there is a separation of 16 inches between the other trays in a stack, (c) trays are located at the top of the stack minimizing fire propagation to the bottom trays, and (d) the connections of associated separation group B circuits to the associated separation group A circuits are through 13.8-kV feed breakers. Therefore, the staff finds this interface to be acceptable.

(2) <u>Compartments for 13.8-kV Reactor Coolant Pump Potential Transformers</u>

These compartments contain the 13.8-kV 120-V potential transformers (PTs) and associated relaying utilized to provide underfrequency and undervoltage information to the solid-state protection system (SSPS) for the reactor coolant pumps. These four compartments are associated with four instrument channels (I, II, III, and IV).

The cables connecting the PTs to their power source, the 13.8-kV buses, are train B associated. Therefore, there is an interface between train B associated cables and channels of different separation groups. The 13.8-kV train B associated cables enter the bottom of these compartments and they terminate on a bus. This section of the compartment is isolated by metal barriers from the rest of the PT compartment. The bus is routed to another section which contains the 13.8-kV, 120-V PT and Class 1E fuses. This section is also isolated from the instrument and relaying section by metal barriers. On the basis of the barriers and the Class 1E fuses which provide isolation between the redundant associated divisions, the staff finds this interface acceptable.

(3) 4160-V Switchgear Compartments for Preferred Power Supplies

There is an interface between non-Class 1E preferred power supply (train A associated) and Class 1E train B switchgear. However, this connection from the preferred power supply (UAT or RAT)* which is train A associated to train B 4160-V switchgear bus E6, is done utilizing metal-enclosed, non-segregated, three-phase, bus duct. These bus duct runs are independent and do not associate with any other raceway system along their entire length, so that a failure on these bus ducts will not affect any other raceway system. On this basis, the staff concludes that this interface is acceptable.

(4) Vital Instrumentation Distribution Panels

The separation group C distribution panel EDE-PP-1C contains separation group A (train A and train A associated) cables and separation group C (channel III) cables. Similarly, the separation group D distribution panel EDE-PP-1D contains separation group B (train B and train B associated) and separation group D (channel IV) cables. However, metal barriers are provided within panel EDE-PP-1C to separate channel III from train A and train A associated circuits. Similarly, within panel EDE-PP-1D, metal barriers are provided to separate channel IV circuits from train B and train B associate circuits. On this basis, the staff finds these interfaces to be acceptable.

Uninterruptible Power Supply

The separation group A inverter EDE-1-1C contains separation group A (train A and train A associated) cables and a separation group C (channel III) cable. This cable is a dc power feed to the inverter from battery 1C which is designated as channel III. Similarly, the separation group B inverter EDE-1-1D contains separation group B (train B and train B associated) cables and a separation group D (channel IV) cable. This cable is a dc power feed to the inverter from battery 1D designated as channel IV. This interface between the above separation groups exists for all two train and four battery system designs. As a result, there is an interface, by design, between train A and channel I, train A and channel III, train B and channel II and train B and channel IV. On this basis, the staff finds these interfaces to be acceptable.

(5) Process Protection Cabinets

Problems were identified internal to these cabinets where non-vital instrument signals from different separation groups (train A associated and train B associated) were routed together without proper isolation devices. This problem has been rectified by routing these circuits through qualified isolation devices. On this basis, the staff concludes that this modification satisfies the physical separation criteria of RG 1.75 (Rev. 2) and is acceptable.

* Unit auxiliary transformer or reserve auxiliary transformer.

(6) SSPS Train B Output 1 Cabinet

The separation group B SSPS (solid-state protection system) train B output 1 cabinet MM-CP-13 contains separation group A (train A associated) and separation group B (train B and train B associated) cables. The separation group A cable that is associated with the feedwater pump trip circuits is not properly separated from the other separation groups. This has been rectified (via a qualified isolation device) by changing the cable to separation group B and rerouting it to the isolation cabinet MM-CP-470 where the signal is converted to separation group A via a qualified isolation device. On this basis, the staff concludes that this modification satisfies the physical separation criteria of RG 1.75 (Rev. 2) and is acceptable.

(7) Auxiliary Relay Rack 2

The separation group A auxiliary relay 2 contains separation group A (train A associated) and separation group B (train B associated) cables. The separation group B cables that are associated with the group B pressurizer heaters, the boric acid pump CS-P-3B, the power-operated relief valve (PORV) RC-PCV-456B, and the PORV block valve RC-V-124 are not properly separated from the other separation group. This has been rectified (via a qualified isolation device) by changing the cables to separation group A and rerouting them to the isolation cabinet MM-CP-470 where the signal is converted to separation group B via a qualified isolation device. On this basis, the staff concludes that this modification satisfies the physical separation criteria of RG 1.75 (Rev. 2) and is acceptable.

(8) Turbine Generator Electrohydraulic Control Cabinet Bay 4

The separation group A electrohydraulic control (EHC) cabinet contains separation group A (train A associated) cables and a separation group B (train B associated) cable. The separation group B cable is associated with the turbine trip circuit and is not properly separated from the other separation group. This will be rectified (via a qualified isolation device) by changing the cable to separation group A and rerouting it to the isolation cabinet MM-CP-470 where the signal has been converted to separation group B via a qualified isolation device. On this basis, the staff concludes that this modification satisfies the physical separation criteria of RG 1.75 (Rev. 2) and is acceptable.

(9) Switching Station Relay Cabinets

The separation group A switching station relay cabinets located in the Unit 1 relay room contain separation group A (train A associated) and certain separation group B (train B associated) cables. The switching station relay cabinets provide protective relaying for the preferred power supplies. The lockout relays associated with these systems provide contact inputs (tripping and block close) in the control schemes for 4160-V preferred power supply breakers to buses E5 (train A) and E6 (train B). The cables from the 4160-V switchgears to these relay cabinets are designated "train A associated" and "train B associated." The physical separation between these cables on their routing from switchgears to the relay cabinets fully satisfies separation criteria. However, at the relay cabinets the interpanel wiring between various lockout relays within the relay cabinets is run in common wiring harnesses. These wiring harnesses will have predominantly A associated wiring along with very limited B associated wiring (only from bus E6). The applicant performed an analysis to demonstrate that failure modes such as open circuits, short circuits, ground shorts, and hot shorts on these circuits have no impact on the 4160-V breaker control schemes and on other safety-related circuits which share raceways with these circuits. The staff has reviewed the results of this analysis and concludes that the lack of separation between A associated and B associated wiring in the switching station relay cabinets will not prevent safety-related functions, will not affect other safety-related circuits, and is acceptable.

(10/11) Input Signal to Computer Intelligent Remote Terminal Unit

An intelligent remote terminal unit (IRTU) processes field input data and transmits these data to the main computer for use by the video alarm system. Most of the analog input signals provided by the field devices are processed through qualified isolation devices in the Westinghouse electronics cabinets before interfacing with the IRTU termination cabinets. However, other analog inputs which are provided through transducers, digital inputs, and input signals from resistance temperature devices (RTDs) and thermocouples are not processed through qualified isolation devices. For these field input devices, the applicant has provided an analysis to demonstrate that there are no detrimental interactions between redundant separation groups as a result of failures within the IRTU equipment. In this analysis, the applicant included failure modes such as short circuit, open circuit, short to ground, and application of maximum voltage within IRTU cabinets. However, credit was taken for fuses, circuit breakers, and current/voltage-limiting devices to demonstrate that the above failure modes will not cause any detrimental impact on the field input devices. The staff informed the applicant that this was unacceptable.

The inadvertent application of 120-V ac within the IRTU cabinets to the field input devices was discussed a number of times with the applicant. As a result of these discussions, it was determined that 120-V ac could be inadvertently applied to some limited portions of the field input devices. Therefore, the staff required the applicant to perform an actual test to demonstrate that the maximum voltage and currents that are available in these cabinets have no adverse effect on field input devices (transducers, digital input devices, RTDs, and thermocouples) so that the Class 1E train with which the field devices are associated will continue to perform the required safety function before, during, and after the application of maximum credible voltages and currents. The applicant has committed to perform these tests (before full-power operation) and the staff will report the resolution of these items, after the test results are reviewed and evaluated, in a future supplement to the SER.

(12) Turbine Building Instrument Rack

The applicant has stated that there are no electrical interconnections between redundant divisions in this area and physical separation criteria are satisfied. Therefore, this item has been deleted from the SER.

(13) Reactor Trip Switchgear Cabinet 1

The separation group B reactor trip switchgear cabinet contains a separation group A (train A associated) cable and separation group B (train B and train B associated) cables. The separation group A cable that is associated with the turbine trip circuit is not properly separated from the other separation group. This has been rectified by changing the cable to separation group B (through a qualified isolation device) and rerouting it to the isolation cabinet MM-CP470, where the signal is converted to separation group A via a qualified isolation device. On this basis, the staff concludes that this modification satisfies the physical separation criteria of RG 1.75 (Rev. 2) and is acceptable.

(14) Reactor Coolant Pump Motors

The separation group A RCP motor contains separation group A (train A associated) cables and separation group B (train B associated) cables. The separation group B cables are the 13.8-kV power feeder to the RCP motor. The separation group A cables consist of the 480-V power feeds to the oil lift pump and the motor space heaters and those circuits associated with the oil pressure/level switches and motor RTDs.

A postulated failure in these cables could impact the separation group A and the above-mentioned specific separation group B cables, but it will not challenge other separation group B cables, as these cables are routed in dedicated raceways and do not interact with any other separation group B cables. On this basis, the staff concludes that there is only a very remote chance that these associated separation group B cables which are routed in dedicated raceways and are protected by two Class 1E devices in series, could challenge other separation group B circuits. Therefore, the staff finds this interface to be acceptable.

(15) Pressurizer Heaters

Seventy-eight electrically independent pressurizer heaters are spaced around the bottom of the pressurizer with a separation of about 4 inches between individual heaters. Fifteen of these heaters are powered from separation group B power supply and the remaining 63 are powered from separation group A power supplies. These pressure heater cables from the containment electrical penetrations are routed approximately 95% of their length in dedicated raceways. Throughout the length, these raceways are separated in accordance with the recommendation of RG 1.75 (Rev. 2). No other cables share these raceways.

In close proximity to the pressurizer (5 to 10 feet), the separation group A cables and separation group B cables leave their dedicated raceways in order to terminate at the heater terminals under the pressurizer. Because of the close location of the heater terminals, clearance between these cables is limited to only 3 to 4 inches. The pressurizer heater cables in the vicinity of the pressurizer are provided with silicon rubber insulation with glass braid jacket. This ensures safe operation at high temperatures. In addition, the pressurizer heater cables are protected by two Class 1E breakers in series. On this basis, and in view of the fact that this congestion is unavoidable in the Westinghouse standard design of the pressurizer, the staff finds the 4-inch separation at the pressurizer heaters to be acceptable.

(16) Reactor Incore Instrumentation Seal Table

The separation group A seal table contains separation group A (train A and train A associated) cables and separation group B (train B and train B associated) cables. The seal table contains 58 thimbles for the fixed/movable incore instrumentation. Each thimble also contains five fixed self-powered neutron detectors, one thermocouple (for core exit temperature), and a guide tube for the movable detector. The fixed detectors are equally divided between separation group A (train A thermocouple and train A associated neutron detectors) and separation group B (train B thermocouple and train B associated neutron detectors).

Because of the congestion at the seal table, cables of redundant separation groups may be separated by only 1 inch. The voltage and current level in these circuits is of very low value (incore neutron detectors--5 x 10^{-9} to 600 x 10^{-9} amp; thermocouples--0-51 mV), and there are no power supplies in the circuit to produce damaging fault currents. These circuits, once they leave the congested area, are run in separate solid cover trays or conduits. Because of the low voltage and current level in these circuits and in view of the fact that this congestion is unavoidable in the Westinghouse standard design of the guide tubes, the staff finds the above separation to be acceptable.

8.3.2 Onsite DC System Compliance with GDC 17

8.3.2.2 Battery Supports

The staff stated in the SER that an incompatibility between the battery rack and battery may cause the battery case to crack. The cracking may be caused in part by improper support at the battery stress points (the plate support bridge). It was concluded that, pending staff confirmation that seismic testing encompasses this stress-related aging of the battery, the staff considers this item to be acceptably resolved.

By letter dated November 27, 1985, the applicant submitted additional information on the battery rack construction design. The applicant stated that the cells sit on three steel stringers located under the cell center line and are 15 inches from the center. This distributes the cell weight evenly to minimize stress on the cell (no excessive overhang of the battery cells), which was the primary reason battery cells cracked. In addition, test results show that the seismic test of the batteries was successfully performed utilizing the above rack design. This satisfies the staff's concern and this item is considered to be acceptably resolved.

8.3.2.4 Non-Safety Loads Powered from the DC Distribution System and Vital Inverters

A 500-amp non-Class 1E computer inverter is connected to Class 1E battery B-1C. Normally this inverter is fed from an ac source, and when ac power is lost the battery supplies the inverter load. The Class 1E battery B-1C is capable of providing power to this inverter for 15 minutes while supplying its safety-related loads. The inverter load is automatically disconnected by a circuit breaker internal to the inverter from the Class 1E dc system after the 15-minute period. The design, which was used to disconnect the 500-amp load, did not meet Class 1E protection system requirements. The staff informed the applicant that the design must meet Class 1E requirements. Subsequently, the applicant committed to provide a separate trip circuit which meets all requirements of Class 1E circuits. The staff stated in the SER that, pending confirmation of implementation of the separate trip circuit, the design is acceptable.

Subsequently, a site trip and audit drawing review was conducted by the staff September 24 through 26, 1985. During the site visit, the staff verified the implementation of a separate, testable, Class 1E trip circuit which disconnects the non-Class 1E inverter from the Class 1E dc system after 15 minutes of discharge from the battery. On this basis, the staff finds this item acceptably resolved. However, the surveillance requirements for the trip circuit will be included in the plant Technical Specifications.

8.3.3 Common Electrical Features and Requirements

8.3.3.3 Physical Independence: Compliance with GDC 17

8.3.3.3.1 Independence Between Class 1E and Non-Class 1E Circuits

At Seabrook there are two safety related load trains (A and B), four safety-related instrumentation channels, and the balance-of-plant (BOP) non-safety-related circuits. All BOP non-safety-related circuits have been designated as associated circuits. The associated circuits are subject to all requirements placed on Class 1E circuits (such as cable derating, environmental qualification, flame retardance, splicing restrictions, and raceway fill). The staff stated in the SER that pending confirmation that the non-Class 1E circuits which are designated as associated circuits meet all the requirements of Class 1E circuits (except for some items evaluated in the SER), the staff considers this item closed.

By letter dated November 27, 1985, the applicant submitted additional information on the above subject. Upon review of the information provided by the applicant, the staff concludes that the associated circuits are uniquely identified and routed with those Class 1E circuits with which they are associated. Cables utilized for these associated circuits are specified, designed, manufactured, and installed to the same criteria as Class 1E cables. The same procedures are used for the installation and inspection of safety and non-safety cables and cable terminations that enter, leave, transverse, or are within the nuclear island, and cables that are contained outside the nuclear island to meet all the requirements of Class 1E with the exception of quality control (QC) inspection. The above satisfies the guidelines outlined in Position C.4 of RG 1.75 (Rev. 2) and is acceptable.

8.3.3.5 Compliance with GDC 50

8.3.3.6.3 Compliance with RG 1.63 (Revision 2)

Circuit protection for control power (ac and dc) circuits: For control circuits which are powered from limited capacity power sources, such as control power transformers, the applicant has indicated that dual protection is not needed to protect the penetration because the short circuit versus time capacity of their power sources is within the penetration capabilities. The staff stated in the SER that, pending confirmation of this capability, this item is considered acceptable.

By letter dated November 27, 1985, the applicant provided additional information to justify not providing backup protection for the 120-V control circuits powered from control power transformers. The applicant has stated that the fault currents are limited to below the continuous current-carrying capability of the penetration conductors, because of the impedance of the control transformers. For these circuits, the staff believes that although the impedance of the control transformer limits the short-circuit current to below the continuous current-carrying capability of the penetration conductors, these control transformers cannot limit the short-circuit current indefinitely. Subsequently, by letter dated March 19, 1986, the applicant further justified its position for providing single protection for control transformer circuits. The applicant indicated that any fault on the control power transformer power circuits will appear as a ground fault on the associated 480-V system. The Seabrook Station 480-V system is a high-resistance grounded system with a maximum ground fault current of 2.92 amps, which is below the continuous current-carrying capability of the penetration conductors.

On the basis of the above information, the staff concludes that one line of overcurrent protection for 120-V control circuits powered from control power transformer is acceptable.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

In the Seabrook SER, the staff stated that its review of the applicant's fire protection program was complete. By letters dated May 2, 1983; September 14 and November 29, 1984; February 8, May 31, July 3, December 2, and December 20, 1985; and January 24, 1986, the applicant submitted additional information, including revised fire protection program and safe shutdown capability reports and requests for additional deviations from staff fire protection guidelines.

From January 27 to 31, 1986, the staff conducted a plant site audit of the applicant's fire protection program for Seabrook Station, Unit 1. Fire protection features were observed to be in various stages of completion; not any were complete at the time of the audit. As a result of the audit, a number of concerns were expressed pertaining to the applicant's commitments, justifications for particular fire protection provisions, and the degree of compliance with staff guidelines. These concerns are summarized below. The applicable sections of the staff's fire protection guidelines are referenced after each concern.

(1) Composite sheetrock/tube steel barriers serve as fire barriers in several plant areas. Fire test results were not available during the audit to substantiate the fire resistance rating of the barrier design (Section C.5.a of Branch Technical Position (BTP) CMEB 9.5-1).

(2) A number of fire barrier penetrations, including bus duct penetrations and seismic gaps, are not protected by penetration seal designs qualified by fire test (Section C.5.a of BTP CMEB 9.5-1).

(3) A number of door assemblies installed in fire barriers are not tested and approved by a nationally recognized laboratory (Section C.5.a(5) of BTP CMEB 9.5-1).

(4) Structural steel forming a part of or supporting a number of fire barriers is not protected to provide fire resistance equivalent to that required of the barrier (Section C.5.6(2)(a) of BTP CMEB 9.5-1).

(5) Charcoal filters are not protected in accordance with the guidelines of Regulatory Guide (RG) 1.52 (Section C.5.f.(4) of BTP CMEB 9.5-1).

(6) By letter dated April 1, 1982, the applicant submitted its comparison to Appendix R (10 CFR 50). During the audit, the staff informed the applicant that in view of continuing program development, this comparison was outdated. The applicant agreed to revise the comparison to reflect the current plant status.

The applicant agreed to respond to these concerns in a time frame that will support the Seabrook Station fuel load date. Resolution of these concerns will be addressed in a future supplement to the SER.

9.5.1.4 General Plant Guidelines

Building Design

By letter dated December 2, 1985, the applicant requested several deviations from Section C.5.a of BTP CMEB 9.5-1 to the extent that it states that openings in fire barriers should be protected to provide a fire resistance rating at least equivalent to that required of the barrier itself.

An unsealed 2-foot by 1-foot 8-inch trash trough runs the length of the service water pump house and passes through a fire barrier common with the circulating pump house. The staff was concerned that a fire might spread via the trough and affect safe shutdown systems on both sides of the barrier. However, because the trough is in the floor and because smoke and hot gases from a fire would tend to concentrate at the ceiling, the staff has reasonable assurance that the fire would be confined to the area of origin. In the unlikely event that a fire would spread through the trough, the applicant stated that alternate means of achieving safe shutdown, independent of these two areas, are available. On these bases, the staff concluded that the unsealed trash trough is an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

The exhaust ducts serving fire areas in the waste processing building, primary auxiliary building, containment enclosure ventilation area, and fuel storage building are not equipped with fire dampers where they pass through exterior walls into the unit plant vent stack. For a fire to spread from one area to another, products of combustion would have to flow out of the area of fire origin, into the stack, and then back into the plant via another exhaust duct. Because hot gases would tend to rise up the stack, the staff does not consider fire propagation via the undampered exhaust ducts to be a credible scenario. On this basis, the staff concluded that the lack of fire dampers at duct penetrations of the unit plant vent is an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

By letters dated December 2, 1985, and January 24, 1986, the applicant requested deviations from Section C.5.a of BTP CMEB 9.5-1 to the extent that it requires door openings in fire-rated barriers to be protected by tested fire door assemblies. The applicant identified three sets of twin leaf, tornado-missile-rated door assemblies and three sets of twin leaf pressure-rated door assemblies installed in fire-rated walls. The tornado-missile rated doors are constructed of 2-inch-thick, solid ASTM-A36 steel with a 1/2-inch by 3-inch steel astragal. The twin leaf pressure-rated door assemblies are not fire rated. However, door assemblies of identical construction in a single leaf configuration have been tested and approved. The area on each side of each of these doors is provided with fire detectors, as is described in the December 2, 1985, letter and the applicant's fire hazards analyses. The staff evaluated conditions on both sides of these doors and found no significant unmitigated fire hazard in their proximity which might represent a threat to the door's structural integrity. Because of the presence of fire detectors, the staff expects any fire to be detected in its incipient stages, before the fire propagates significantly or the room temperature rises significantly. Moreover, because of the construction of the doors, it is the staff's judgment that they are capable of confining the effects of a fire to the room of origin until the fire brigade arrives and the fire is extinguished. On these bases, the staff concluded that the non-fire-rated door assemblies identified in the applicant's December 2, 1985, and January 24, 1986, letters are an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

By letter dated January 24, 1986, the applicant requested a deviation from "the requirement that door assemblies have Underwriters Laboratory (UL) labels." In BTP CMEB 9.5-1, the staff provided guidelines which state that door assemblies in fire barriers should be tested and approved by a nationally recognized laboratory. However, the staff does not require that door assemblies bear UL labels. Therefore, a deviation from staff guidelines does not exist.

In the SER, the staff stated that fire dampers will be UL labeled. By letter dated January 24, 1986, the applicant identified three multi-section fire damper assemblies that do not bear UL labels because the overall size of each assembly exceeds that listed by UL. One of the damper assemblies is installed in the control building in the fire barrier separating the control room from the control room heating, ventilation, and air conditioning (HVAC) equipment and duct area (HVAC room). The other two damper assemblies are installed in the diesel generator building. One of these dampers is in a barrier separating two train A fire areas and one is in a barrier separating two train B fire areas. Each section of these three multi-section dampers has been individually tested and approved by UL. However, the assemblies of individual sections have not been tested.

The staff was concerned that a fire in any of the fire areas separated by one of these damper assemblies would spread to the adjacent fire area through the non-UL-labeled damper assembly and adversely affect safe shutdown. However, the staff evaluated the fire hazards and fire protection features provided on both sides of each of these dampers during the plant site audit and found no unmitigated fire hazards in their proxmity. Moreover, because the individual damper sections have been tested, the staff has reasonable assurance that the damper assemblies will operate under fire exposure conditions and will prevent the spread of fire from one fire area to another. Furthermore, in the event that one of these three damper assemblies fails to operate, allowing fire to spread into the adjacent fire area, the ability to achieve and maintain safe plant shutdown would not be affected. For a fire in the diesel generator building, plant shutdown could be achieved from either the control room or the remote shutdown panel, and for a fire in the HVAC room or the control room, plant shutdown could be achieved from the remote shutdown panel.

On these bases, the staff concludes that use of three non-UL-labeled fire damper assemblies identified in the applicant's January 24, 1986, letter is an acceptable deviation from Section C.5.a(4) of BTP CMEB 9.5-1.

Safe Shutdown Capability

The applicant provided revised information concerning fire protection for the safe shutdown capability in its report entitled "Fire Protection of Safe Shutdown Capability," Revision 2, dated December 31, 1985. The following staff safety evaluation of safe shutdown capability replaces the evaluation reported in the Seabrook SER.

The applicant's revised safe shutdown analysis states that systems needed for hot shutdown consist of redundant trains and that either one of the redundant trains would be free of fire damage, or an alternative shutdown capability would be available. The systems required for safe shutdown are those necessary to control the reactor coolant system temperature and pressure, to borate the reactor coolant system, and to provide adequate residual heat removal. For hot shutdown, at least one train of the following shutdown systems was stated to be available: (1) emergency feedwater system, (2) main steam system (specifically the main steam atmospheric relief valves), (3) reactor coolant system (specifically the pressurizer relief valves (PORVs) and heaters), and (4) chemical and volume control system (specifically the centrifugal charging pumps and borated water supply). Furthermore, for cold shutdown, at least one train of the residual heat removal system (RHRS) would be available. The RHRS would be utilized for long-term decay heat removal and would provide the capability to achieve cold shutdown within 72 hours after a fire. The safe shutdown analysis considered components, cabling, and support equipment for systems identified above which are needed to achieve shutdown. The support equipment includes the diesel generators, emergency electrical distribution system, primary component cooling water system, service water system (including ocean tunnels or cooling tower), instrument air, and necessary air handling and ventilation systems.

The applicant performed an essential cabling separation study as part of the safe shutdown analysis in order to ensure that at least one train of the above equipment and essential instrumentation would be available either from the control room or from an alternate location in the event of a fire in areas which might affect these components. Cable runs were traced through each fire area from the corresponding components to their power source. Additional equipment and electrical circuitry considered as associated, either because of a shared common power source, common enclosure, or whose fire-induced spurious operation could affect shutdown, were also identified. For the identified associated circuits, the applicant has provided circuit isolation and/or procedures to ensure that circuit failures would not prevent safe shutdown. For example, in order to prevent fire-induced spurious signals from causing a LOCA from such sources as the residual heat removal (RHR) suction line or power-operated relief valves (PORVs), power to one of the two series RHR suction line valves will be locked out during power operation. Similarly, the operator will trip the power supply breaker to the solenoid-operated PORVs from the switchgear rooms after a control room evacuation to prevent fire-induced spurious actuation of the PORVs.

During the course of the associated circuits review, the staff expressed a concern that fire-induced, multiple, high-impedance faults could result in the loss of the necessary power supply for safe shutdown equipment. The effects of multiple high-impedance faults can occur when several cables from a common bus are located in the same fire area. When a fire occurs in such an area, the resulting fire damage could cause electrical faults in the cables, but the faults may not be of low enough impedance to trip the individual circuit breakers. However, the sum of the faults may be sufficient to trip the main breaker which protects the power supply bus. If safe shutdown equipment is energized from the same bus, once the main breaker trips, this equipment will have lost its power source. The staff's review of the applicant's response to this issue is continuing. The staff will report resolution of this issue in a future SER supplement.

The adequacy of safe shutdown equipment cable separation was determined by the applicant on the basis of a computer cable routing drawing study. As a result of this analysis, the applicant noted that alternative shutdown capability was required for the control room, the cable spreading room, and the HVAC room to achieve safe shutdown, since these areas contain more than one division of safe shutdown components and a fire in one of these areas will require evacuation of the control room. In lieu of providing fire protection separation, if a fire disables the control room, cable spreading room, or HVAC room, remote shutdown panels, which are located in separate control building fire areas, provide an alternative means of achieving safe shutdown. See Section 9.5.1.5 of this supplement for further discussion. The control functions and the indications provided at the remote shutdown panels are electrically isolated or otherwise separated and independent from the control room, cable spreading room, and the HVAC room for the control room. In addition, on the basis of the cable separation study (discussed in Section 3 of the applicant's submittal, "Fire Protection of Safe Shutdown Capability," Revision 2), the applicant indicated 37 other areas of the plant where the redundant cabling for normal control and indications from the control room of various safe shutdown functions could be disabled by a single fire. For these areas, the applicant has identified alternative actions that can be taken outside the control room, independent of the fire-damaged cabling, to restore the affected shutdown functions. These manual actions can be taken at various locations and at the remote shutdown panel, as necessary.

The staff reviewed the applicant's cable separation method and audited several arrangement drawings to verify correct application of the methodology. On the basis of this review and audit, the staff concluded that the applicant adequately addressed the effects of associated circuit interaction (except as noted above with regard to multiple high-impedance faults) and that the isolation devices are adequate to ensure that such circuit interactions will not prevent or adversely affect safe shutdown. The staff further concluded that the applicant has provided an acceptable means of demonstrating that separation and/or barriers exist between redundant safe shutdown system trains or that adequate independent alternative capability is provided where necessary. Refer to further discussion in Section 9.5.1 of this supplement for adequacy of fire barriers and/or separation, fire detection, and suppression provided for additional assurance that one train of systems and equipment needed for safe shutdown will be free of fire damage, and further discussion of the alternative shutdown capability.

As discussed in the SER, the staff evaluated and approved deviations from Section C.5.a of BTP CMEB 9.5-1 in the containment, the mechanical penetration area, the diesel generator building, the primary auxiliary building, and the emergency feedwater pump room that pertain to the separation and protection of redundant safe-shutdown-related systems. In Revision 2 to the safe shutdown analysis report, the applicant identified additional deviations in the containment, the mechanical penetration area, and the primary auxiliary building. For other areas, there are no significant differences between the configurations of the systems previously approved by the staff and the configurations identified in the revised report. On this basis and for the reasons stated in the SER, the staff concludes that the level of protection in the areas identified in Revision 2 of the safe shutdown analysis report is acceptable.

On the basis of the above review, the staff concludes that the functions of reactivity control, inventory control, decay heat removal, and pressure control are adequate to ensure a safe shutdown following a fire in any plant area. The staff further concludes that the post-fire safe shutdown systems, the cable separation methodology, and the fire protection of safe shutdown systems, with approved deviations, meet Section C.5.b of BTP CMEB 9.5-1 and are, therefore, acceptable, pending satisfactory resolution of the multiple high-impedence-fault concern. The staff will report on the resolution of this issue in a future SER supplement.

Alternative Shutdown Capability

The following staff safety evaluation of alternative shutdown capability supersedes the evaluation reported in the Seabrook SER. Section 3.3.2 of the applicant's report, "Fire Protection of Safe Shutdown Capability," describes the functional capability of the two remote safe shutdown panels and the associated alternate shutdown system operational locations, per Section C.5.c of BTP CMEB 9.5-1. The primary design objective of the two remote safe shutdown panels is to provide a central point to control and monitor plant shutdown in the event of control room evacuation. The panels also provide the capability to control and monitor various individual safe shutdown functions following fire damage in other fire areas. Each panel includes the capability to electrically isolate one of the redundant, separate divisions of required instrumentation indications and control functions for the necessary shutdown systems from the control room/cable spreading room. Selector switches on each remote shutdown panel allow the operator to transfer control of the equipment (controls and indications) required for safe shutdown from the control room to the shutdown panel. Transfer of control to the remote safe shutdown panels is alarmed in the control room.

The remote safe shutdown panels are located in separate fire areas in the control building. The emergency diesel generators can be started and controlled independently at the diesel generator local control panels in the diesel generator building. Capability for controlling cold shutdown support equipment and the pressurizer PORV is provided at local control stations. A number of manual operations can also be performed locally (such as manual valve operation) to achieve and maintain safe shutdown. This design ensures the capability to achieve safe shutdown, given a fire in the control room, cable spreading room, or HVAC room, since at least one train of required safe shutdown equipment will be available following a fire in any of these areas.

By letter dated September 1, 1982, the applicant stated that post-fire alternate shutdown procedures will specify manual actions required and will also address manpower requirements based on postulated fire damage to shutdown equipment following a fire in any plant area. The applicant has verified that required manual actions can be taken in sufficient time to achieve and maintain safe shutdown. During the NRC Region I safe shutdown capabilities inspection at Seabrook (conducted from January 27 through 31, 1986), the staff walked through the shutdown procedures with the operators and found the procedures acceptable. Fire brigade members are not included in the shutdown manpower requirements. The plant Technical Specifications provide for periodic testing of remote shutdown control circuits, transfer switches, and instrumentation.

In Section 3.3.5 of its safe shutdown report, the applicant stated that the operator will (1) trip the reactor, (2) trip all four reactor coolant pumps

(RCPs), and (3) close all four main steam isolation valves (MSIVs) before leaving the control room in the event of a fire in the control room, cable spreading room, or HVAC room. However, the staff expressed concern that the operators may not be able to complete all three actions before leaving the control room. By letter dated September 1, 1982, the applicant stated that a control room evacuation would be expected to be deliberate and planned, providing sufficient time for the operator to complete the three acts. Subsequently, the applicant has provided the capability to close all four MSIVs from each remote safe shutdown panel independent of fire damage to the control room. In addition, the RCPs can be tripped from outside the control room by opening the 13-kV breaker located in the nonessential switchgear room. Furthermore, the applicant indicated that failure to trip the RCPs before control room evacuation does not present an immediate concern, because their operation does not affect the integrity of the primary system. The above capability satisfies the staff's concern in this area.

The staff reviewed the design of the remote shutdown panels and other alternative shutdown control stations to determine compliance with the performance goals outlined in Section C.5.c of BTP CMEB 9.5-1. Reactivity control is initially accomplished by a manual scram before the operators leave the control room. Reactivity control is subsequently provided by adding boron via the chemical and volume control system (charging pump), controlled from the remote shutdown panel, to compensate for leakage through the RCP seals and volume shrinkage during cooldown. Reactor coolant system pressure is controlled by the use of pressurizer heaters operated from the remote shutdown panel. For control of pressure increases, the PORVs can be operated from a local panel. In hot shutdown, reactor decay heat is removed through the steam generator by the emergency feedwater system (turbine-driven emergency feedwater pump) and main steam atmospheric relief valves, which can be controlled from the remote shutdown panel. Additional local manual operations to cope with spurious operations and to provide additional control functions will be taken as necessary. Support functions in cold shutdown are provided by the cooling water system and essential service water system which are controlled at local motor control centers. Cold shutdown can be achieved within 72 hours following a fire in any plant area. This may involve replacing fire-damaged cables, but replacement of major components such as pump motors will not be required. Cables are available on site to replace those that may be damaged by fire and needed for cold shutdown.

The following direct readings of process variables are provided at the remote shutdown panels:

(1) emergency feedwater flow
(2) reactor coolant loop hot- and cold-leg temperatures
(3) steam generator level (wide range)
(4) steam generator pressure
(5) pressurizer level and pressure
(6) primary component cooling water temperature
(7) boric acid tank level
(8) wide-range neutron flux monitor

Condensate storage tank level indication is available locally at the tank. The above indications are either electrically isolated from the control room, the cable spreading room, and the other affected areas, or are provided with power from cables routed separately from those that pass through the control room, the cable spreading room, the HVAC room, or other areas, to ensure their availability in the event of a fire in those areas. As part of the review of the alternate shutdown capability and as a result of the issuance of IE Information Notice 85-09, "Isolation Transfer Switches and Post-Fire Shutdown Capability," the staff requested additional information on the design of the isolation capability for the alternate shutdown circuits. The concern identified was that the circuits needed for alternate shutdown may contain a single fuse which could fail as a result of a fire-induced short-circuit before isolation of that circuit from the control room. If the fuses fail, they would need to be replaced in order to achieve operation from the remote (alternate) shutdown panels. Such replacements are considered repairs and repairs are not permitted to achieve hot shutdown. The applicant has not provided the results of its evaluation of the existing isolation transfer switches to determine if the above situation exists. By letter dated July 3, 1985, the applicant committed to provide redundant parallel fuses in one train (train B) of equipment/component control circuits to ensure control power availability in the event the existing set of fuses fails because of damage occurring to the control room circuits before isolation at alternate shutdown locations. The staff finds the applicant's provision of redundant fuses for one of the train of circuits to be acceptable to resolve this concern.

In its report, the applicant requested a deviation from the alternate shutdown criteria of BTP CMEB 9.5-1, Section C.5.c(3), regarding independence of the alternate shutdown capability from the fire area of concern for the emergency feedwater (EFW) pump room. In the event of the loss of redundant EFW pumps because of a fire in the EFW pump room, the startup feedwater pump will be available to supply feedwater to the steam generators for post-fire hot shutdown. The startup feedwater pump is located in a separate fire area. The capability to power the startup feedwater pump from an onsite Class 1E bus during a loss of offsite power has been provided as discussed in Section 6.8 of the Seabrook SER. However, the redundant EFW control valves and associated flow transmitters, which are part of the alternate shutdown capability (flow path) utilizing the startup feedwater pump, are located in the EFW pump room. The redundant EFW control valves are separated from each other by 60 feet. These valves which are normally open, fail as is (open) and are to remain open for the initial phases of hot shutdown. Only two steam generators are required to satisfy the safe shutdown requirements, hence only two control valves, one on each of two lines need to be disabled (failed) to ensure that they remain open. The operators will prevent spurious operation (closure) of these valves by tripping the power supply breakers in train A and B switchgear rooms. On the basis of the indicated configuration, the applicant requested a deviation from the Section C.5.c(3) of BTP CMEB 9.5-1 alternate shutdown criteria.

To evaluate this deviation, and to assess damage that could result from a postulated fire in the EFW pump room, the staff inspected the area during a site visit. On the basis of its evaluation of this area, the staff concurs with the applicant's contention that a fire is unlikely to damage the redundant EFW control valves because of their separation and the lack of significant combustible loading in the area. Therefore, the staff concludes that the alternative shutdown capability provided in the event of a fire in the EFW pump room is acceptable without being independent from the fire area.

The normal safe shutdown capability may be lost for a postulated fire in the mechanical penetration/containment fan enclosure area since the use of the normal reactor coolant pump seal injection path for reactor coolant makeup may be damaged by the fire. In such an event, the use of the high-head-injection flow path would be required for makeup. The seal-injection path requires that a minimum of two of the four seal-injection valves be operable. These valves are located in the same fire area that contains the high-head-injection valves. The seal-injection valves are normally open and remain open for shutdown. The operators will prevent spurious operation (closure) of these valves by tripping the power supply breakers in the train A switchgear room. The high-head-injection valves are normally closed and may be opened to provide an alternate hot standby charging path as indicated above. The normal seal-injection path is available; therefore, the position of the high-head-injection valves during hot standby is inconsequential.

The applicant requested a deviation from the independence criteria of Section C.5.c.(3) of BTP CMEB 9.5-1 for the mechanical penetration/containment fan enclosure area, based on existing separation between the above two identified charging flow paths. The area, sectioned into compartments by concrete walls, has small openings for access. The staff inspected the mechanical penetration/containment fan enclosure area during a site visit to evaluate the requested deviation. Because of separation between the seal-injection and high-head-injection valves and low in situ combustible loadings, the staff concurs with the applicant that the present configuration will ensure post-fire safe shutdown makeup capability for a postulated fire in this area. Therefore, the staff concludes that the alternate shutdown capability for the mechanical penetration/containment fan enclosure area is acceptable without independence from the fire area.

The applicant also requested deviations from Section III.G.3 of Appendix R to 10 CFR 50 for the control room and HVAC room, to the extent that it states that a fire suppression system should be installed in an area for which alternate shutdown capability is provided. As stated in Section 9.5.1 of the Seabrook SER, the staff has reviewed the applicant's fire protection program against SRP Section 9.5.1 (NUREG-0800), which contains, in BTP CMEB 9.5-1, the staff's fire protection guidelines. BTP CMEB 9.5-1 does not include a guideline recommending such a system. Therefore, no deviation from staff guidelines exists.

The applicant has provided alternative safe shutdown capability for the service water pump building independent of cables, systems, and components in this area. Redundant safe shutdown service water pumps, discharge valves, and pumphouse cooling fans are contained in the fire area such that a fire could prevent operation of the service water system. The alternative safe shutdown equipment required to operate in the event of a fire in the service water pump building consists of the cooling tower fans, cooling tower pumps, discharge valves, cooling tower air handling system, and service water valves needed to transfer from the service water pumps to the cooling tower pumps. The operators have the capability to control and monitor all equipment needed to transfer the service water supply from the service water pumps to the cooling tower pumps. Cooling tower operation is automatically initiated on a tower actuation signal which is generated on low station service water discharge pressure. This capability is independent of postulated fire damage in the service water pump building. For further discussion of cooling tower operation, see Section 9.2.5 of the Seabrook

SER. On the basis of the above, the staff concludes that the alternative shutdown capability for the service water pump building meets Section C.5.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

On the basis of the foregoing discussion, the staff concludes that the alternative shutdown capability, with approved deviations, meets Section C.5.c of BTP CMEB 9.5.1, and is, therefore, acceptable.

Electrical Cable Construction, Cable Trays, and Cable Penetrations

In the Seabrook SER, the staff concluded that automatic sprinkler systems had been provided for cable concentrations in accordance with Section C.5.e of BTP CMEB 9.5-1. Subsequently, the staff expressed concern that the applicant may not have provided adequate fire protection in areas containing concentrations of cables. At the staff's request, the applicant submitted, by letter dated December 2, 1985, the criteria used to assess the fire hazards associated with concentrated quantities of cable insulation. The applicant's criteria adequately addressed the staff's concerns. On the basis of a review of the applicant's criteria, the staff finds this issue resolved.

Lighting and Communication

By letter dated January 24, 1986, the applicant requested deviations from Section III.J of Appendix R to 10 CFR 50 in the control room, switchgear room A, and switchgear room B. These deviations are under staff review and will be addressed in a future SER supplement.

9.5.1.5 Fire Detection and Suppression

Fire Detection

In the SER, the staff evaluated and approved deviations from Section C.6.a of BTP CMEB 9.5-1 to the extent it requires that fire detectors be installed in all safety-related areas. In the December 2, 1985, letter, the applicant identified additional safety-related areas that are not equipped with fire detectors. The staff was concerned that if a fire of significant magnitude occurred in any of these areas it would burn undetected and would damage redundant systems that are needed for safe plant shutdown. However, the subject areas do not have significant concentrations of combustible materials or unmitigated fire hazards, or they contain only one shutdown division. The staff, therefore, has reasonable assurance that in the event of a fire in any of the subject locations, safe shutdown could be achieved and maintained. The staff, therefore, concludes that the lack of areawide fire detection systems in the locations delineated in the applicant's December 2, 1985, letter is an acceptable deviation from Section C.6.a of BTP CMEB 9.5-1.

Fire Protection Water Supply System

By letter dated January 24, 1986, the applicant requested a deviation from Section C.6.b.(11) of BTP CMEB 9.5-1 to the extent that it states that the fire protection water supply should consist of at least 300,000 gallons per tank. The applicant states that 215,000 gallons of water are available for fire protection in each of the station's two fire protection water tanks. Either of these two separate water supplies can provide the largest expected water demand for any fixed fire suppression system installed in a safety-related area plus 500 gpm for hose streams for 2 hours. Therefore, the staff has reasonable assurance that an adequate water supply will be available for both automatic and manual fire suppression efforts in all safety-related areas. On this basis, the staff concludes that the existing fire protection water supplies are an acceptable deviation from Section C.6.b.(1) of BTP CMEB 9.5-1.

Sprinkler and Standpipe Systems

By letter dated December 2, 1985, the applicant requested a deviation from Section C.6.c of BTP CMEB 9.5-1 to the extent that it requires that components used in fire protection systems be UL listed or Factory Mutual (FM) approved. Valves for the fire protection systems that serve seismic Category I standpipes do not meet these guidelines. The steel valves installed are designed to specifications outlined in ANSI/ASTM B31.1. The staff concludes that these valves will provide at least the same level of protection as UL-listed or FM-approved valves and is, therefore, an acceptable deviation from Section C.6.c(1) of BTP CMEB 9.5-1.

9.5.1.6 Fire Protection of Specific Plant Areas

Containment

By letter dated February 8, 1985, the applicant requested a deviation from Section C.7.a of BTP CMEB 9.5-1 from providing a container for the oil collection systems which will contain the entire inventory of the reactor coolant pump/lube oil systems.

Each of the four reactor coolant pumps contains approximately 240 gallons of oil. Two oil collection tanks, each having a capacity of 320 gallons, have been provided. Each tank serves two pumps. Each tank can hold the inventory of one pump plus 25%. However, if the lube oil systems for two pumps connected to the same tank were to fail simultaneously, there would be an excess of 160 gallons of oil per tank. To contain this excess oil, a seismically designed dike has been built around each tank. The tanks and their dikes are located so that the excess oil does not present a fire exposure hazard to any safety-related equipment. Additionally there is no ignition source near the diked areas. The staff concurs with the applicant that this combination of features is an acceptable deviation from Section C.7.a of BTP CMEB 9.5-1.

Control Room

In the SER, the staff approved the installation of carpeting with an ASTM E-84 flame spread rating of 25 in the control room. During the plant site audit, the applicant informed the staff that the carpeting installed had been tested in accordance with ASTM E-648, "Standard Test Method for Critical Radiant Flux of Floor-Covering Systems Using A Radiant Heat Energy Source," instead of ASTM E-84.

Direct correlation with the ASTM E-84 test results cannot be made. However, ASTM E-648 test results indicate that the proposed carpet presents no greater hazard than the previously approved carpet. The average critical radiant flux was determined to be greater than or equal to 0.45 watts/cm^2 by ASTM E-648. Therefore, the carpet is classified by the National Fire Protection Association

(NFPA) as a Class I interior floor finish. The staff concludes that the installation of this carpet will not decrease the level of fire safety in the control room and is, therefore, an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

9.5.1.8 Summary of Approved Deviations from BTP CMEB 9.5-1

The following deviations from BTP CMEB 9.5-1 were approved in the Seabrook Station SER:

- carpet in the control room

- lack of an automatic fire suppression system and 20-foot separation between redundant safety-related equipment required for safe shutdown in certain fire areas.

- lack of fixed suppression systems in the service water pump house, intake and discharge structure, and emergency feedwater pump building

- lack of fire detectors in the control room logic cabinets, containment operating floor, diesel generator air intake areas DG-F-3E-A and 3F-A, primary auxiliary building fire zones PAB-F-42 filter areas and PAB-F-1K-Z pipe chase, turbine building ground floor elevation 21 feet 0 inch and mezzanine elevation 50 feet 0 inch, service water cooling tower fire area CT-F-3-0, and the waste processing building fire areas W-F-2A-Z and 2B-Z

- drains in the switchgear rooms

- 1500-gallon diesel fuel day tanks

- fuel oil storage tanks in the diesel generator building

On the basis of the above evaluation, the staff concludes that the following additional deviations are acceptable:

- lack of independence for the alternate shutdown capability from certain fire areas (9.5.1.4)

- non-fire-rated wall (9.5.1.4)

- lack of fire dampers in certain HVAC ducts (9.5.1.4)

- non-fire-rated special-function doors (9.5.1.4)

- non-UL-labeled dampers in certain fire areas (9.5.1.4)

- lack of automatic fire suppression and 20 feet of separation between redundant shutdown systems in containment, the primary auxiliary building, and the mechanical penetration/containment fan enclosure area (9.5.1.4)

- lack of areawide fire detection in certain fire areas (9.5.1.5)

- fire protection water supply tanks' capacity less than 300,000 gallons (9.5.1.5)

- non-UL-listed water supply valves (9.5.1.5)

9.5.1.9 Conclusions

The following items are unresolved:

- concerns raised during the staff's plant site audit of the applicant's fire protection program for Seabrook Station, Unit 1

- multiple high-impedance-faults concern

- emergency lighting deviations

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.1 Emergency Diesel Engine Auxiliary Support Systems (General)

(3) Vibration of Instruments and Controls

By letter dated February 1, 1983, in response to a staff concern regarding vibration-induced wear of diesel generator controls and instrumentation, the applicant committed to do the following:

(1) Qualify all equipment whose failure could degrade operation or cause shutdown of the engine, or

(2) Remove the "relay and terminal box" from the engine skid and mount as a free-standing, floor-mounted panel, or

(3) Qualify equipment within the relay and terminal box during preoperational or qualification testing to confirm that actual equipment vibration is within the tolerances specified as acceptable by the manufacturer.

In the Seabrook SER, the staff found the above three alternatives acceptable. Furthermore, if alternatives 1 or 3 were used to resolve the issue, the staff required the applicant to submit the test results for staff review and evaluation.

By letter dated February 24, 1986, the applicant notified the staff that alternative 1 was used, and provided the test results for qualifying the control devices mounted in the relay and terminal panel. The applicant's test program involved measuring the vibration from diesel generator operation, and then using this result to age the controls in a laboratory for an expected 40-year lifetime.

The test program showed that the controls are qualified for their location. On the basis of the staff's evaluation of the test program and results, the staff concludes that its concern over vibration-induced wear of diesel generator controls and instrumentation has been satisfactorily resolved.

10 STEAM AND POWER-CONVERSION SYSTEM

10.3 Main Steam Supply System

10.3.6 Main Steam and Feedwater Materials

The staff concludes that the main steam and feedwater system materials are acceptable and satisfy the relevant requirements of 10 CFR 50.55a, General Design Criteria 1 and 35 (Appendix A to 10 CFR 50) and Appendix B to 10 CFR 50. This conclusion is based on the following.

The applicant selected materials for Class 2 and 3 components of the steam and feedwater systems that satisfy Appendix I of Section III of the ASME Boiler and Pressure Vessel Code, as well as Parts A, B, and C of Section II of the Code. Conformance to the recommendations of Regulatory Guide (RG) 1.85, "Materials Code Case Acceptability--ASME Section III, Division 1," is discussed in Section 5.2.1.2 of this supplement.

Fracture toughness testing was not indicated as having been performed on all of the ferritic materials in the main steam and feedwater systems. However, on the basis of the results of impact testing by other applicants of the same specification steels, and other correlations of the metallurgical characterizations of these materials with the fracture toughness data presented in NUREG-0577, the staff concludes that the fracture toughness properties of the ferritic materials in the main steam and feedwater systems will have adequate margin against the possibility of nonductile behavior or rapidly propagating failure.

The applicant has met most of the requirements of RG 1.71, "Welder Qualification for Areas of Limited Accessibility," or has offered alternatives to the regulatory positions that the staff has reviewed and found to be acceptable (see SER Section 5.2.3). The onsite cleaning and cleanliness controls during fabrication follow the recommendations given in RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the requirements of ANSI Standard N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," or the staff has reviewed the applicant's alternative approaches and finds them acceptable, as discussed in Section 5.2.3 of the SER.

11 RADIOACTIVE WASTE MANAGEMENT

11.5 Process and Effluent Monitoring

In Section 11.5 of the Seabrook SER it was indicated that the applicant would be required to submit details of the effluent monitoring system in terms of its conformance with Table 2 and Position C of Regulatory Guide 1.97. The applicant has provided this information. The staff finds that the Seabrook plant conforms to Table 2 and Position C in terms of effluents resulting from accidents.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure and Qualifications

13.1.1 Management and Technical Support Organization

13.1.1.1 Corporate Organization

The Public Service Company of New Hampshire (PSNH) is the principal owner of the Seabrook Station and is responsible for the operation of both Seabrook units. New Hampshire Yankee (NHY), a division of PSNH, is responsible for the actual operation of the Seabrook Station. PSNH has contracted for certain operational services from the Nuclear Services Division (NSD) of Yankee Atomic Electric Company (YAEC, YNSD). The organizational interface of these three entities for the Seabrook Station is shown in Figure 13.1.

The NHY President and Chief Executive Officer, who reports to the PSNH President and Chief Executive Officer, is the individual who holds overall responsibility for the safe operation of the Seabrook Station. Reporting to the NHY President and Chief Executive Officer are the NHY Senior Vice President and the YAEC President and Chief Executive Officer.

Reporting to the NHY Senior Vice President are the Vice President Nuclear Production, the Director of Construction, the Director of Engineering and Licensing, and a Vice President in charge of Administrative Services, who is responsible for interfacing with the YAEC Quality Assurance Department. The Senior Vice President, Mr. William B. Derrickson, has had about 15 years of nuclear power plant experience with Florida Power and Light Company. His assignments included one as Project General Manager for modification for Turkey Point Nuclear Power Plant and one as Project General Manager responsible for construction of St. Lucie Unit 2.

The Vice President Nuclear Production has full-time responsibility for the operation of the Seabrook Station. Reporting to the Vice President Nuclear Production to implement this responsibility are the Seabrook Station operations staff, a Nuclear Services Group, a Nuclear Information Systems Group, a Nuclear Quality Group, the Seabrook Training Center personnel, and a Seabrook Startup Test Department. The Vice President Nuclear Production has had about 20 years of nuclear power experience, including about 4 years as Assistant Station Superintendent of Vermont Yankee.

The Nuclear Services Group is composed of a Manager and a staff of at least two operations engineers. The group functions in direct support of the station in the areas of licensing, health physics, emergency planning, training, and operations.

The Nuclear Information Systems Group is responsible for the development, implementation, and operation of computerized information systems.

The Nuclear Quality Group has overall responsibility for ensuring that the Seabrook Operational Quality Assurance Program is effectively implemented by all organizations performing work on safety-related systems and equipment at Seabrook Station.

The Training Center, under the direction of the Training Center Manager, primarily provides license training and requalification training for the Seabrook operators. The Training Center has a site-specific simulator. Under the Training Center Manager is an Operational Engineering Section (OES), which will provide an independent review and assessment of station activities related to nuclear activities. This function is further described in Section 13.4 below.

The Startup Test Department, which reports to the Vice President Nuclear Production, will manage and provide overall direction for the initial program. A Joint Test Group (JTG) consists of site representatives of the Startup Test Department, the Seabrook Station Operations staff, and the Nuclear Services Division of YAEC. The representative from the Startup Test Department will act as Chairman of the JTG. The JTG will be responsible for the review of preoperational test procedures and the results of preoperational tests.

At the time of the start of initial fuel loading, the JTG will be dissolved and the Station Operations Review Committee (SORC) will be responsible for the review and approval of the startup test procedures and the results of startup tests.

The applicant has stated that the minimum qualification requirements for individuals authorized to direct testing during the test program are a bachelor's degree in engineering or in a related science with a minimum of 1 year of experience acquired in testing, operation, and maintenance of power-generating facilities for the direction of preoperational tests, and a minimum of 2 years of experience for the direction of startup tests.

The NRC staff recommends that the applicant consider assigning approval authority for preoperation and startup tests and test results to a management individual rather than to a group or committee. The staff requires that the minimum qualification requirements for an individual that has authority to direct tests should include 1 year of nuclear power plant experience.

The Seabrook Station staff is described in Section 13.1.1.2.

The Director of Construction serves as the focal point for all construction activities and is responsible for directing the completion of construction of the Seabrook project. The Director of Engineering and Licensing serves as the focal point for all engineering and licensing activities related to the construction of the Seabrook Station. The Vice President in charge of administrative services is responsible for interfacing with the YAEC Quality Assurance Department for the construction of the Seabrook Station.

The YAEC President and Chief Executive Officer, through the NSD, provides engineering support for the operation of the Seabrook Station. YAEC has experience gained during the construction of the Seabrook Station, along with that gained while supporting three other Yankee plants (Yankee Nuclear Power Station, Vermont Yankee, and Maine Yankee).

PSNH and YAEC have developed and produced a document known as the "Second Memorandum of Agreement," which delineates the specific operational services supplied by YAEC for NHY and the working relationship between the two organizations for the period of the operating license. An appendix to the memorandum of agreement provides a detailed listing of support activities broken down into nine broad categories. These are environmental (radiological and nonradiological), engineering, quality assurance, nuclear material, projects, operational services, licensing, nuclear engineering, and information services.

YNSD will provide 37 dedicated and a total of 99 equivalent YNSD personnel to perform operations support services. The personnel dedicated to Seabrook represent about 15% of the present YNSD technical resources; they would not be shifted from their Seabrook responsibilities without the approval of senior management. Additional staffing needs for Seabrook would be met either from the YNSD resources maintained to meet the requirements of Seabrook and three other plants (Maine Yankee, Vermont Yankee, and Yankee Nuclear Power Station), or, in the case of special projects, through contracts with consultants and technical firms routinely used to supplement the YNSD staff.

On the basis of its review of the Seabrook corporate organization, the staff concludes, except as noted above, that the applicant has an acceptable organization to manage and support the operation of the facility under both normal and abnormal conditions.

13.1.2.2 Operations

The Operations Manager is responsible for the operation of both units and for the safety and operation of the units' equipment. The Operations Manager has the authority to order a shutdown of either unit when a shutdown is required to protect the health and safety of the station staff and the public. The Operations Manager will hold a Senior Reactor Operator (SRO) license for both units.

The Assistant Operations Manager directs the activities of the Shift Superintendents, the unit Shift Supervisor/trainees, day Shift Superintendents, and the Waste Facility Supervisor. The Assistant Operations Manager also will hold an SRO license for both units and will be empowered, as well, to order the shutdown of either unit as required. The Assistant Operations Manager will act for the Operations Manager if the Operations Manager is absent.

The responsibilities of the Operations Administrative Supervisor are described in the applicant's February 18, 1982, letter to R. L. Tedesco, NRC. The Operations Administrative Supervisor will relieve the unit Shift Supervisors of routine administrative responsibilities including payroll, vacation scheduling, and overtime administration. These activities will be shared between the Operations Administrative Supervisor and the Shift Superintendent.

The applicant has committed to provide enough personnel to staff a five-shift crew rotation. Each operating shift crew will normally consist of a Shift Superintendent (SRO) and, for each unit, one unit Shift Supervisor (SRO), two control room operators (with reactor operator (RO) licenses) and two auxiliary operators (nonlicensed). When applicbale an additional SRO will be on shift to supervise refueling activities. As a result of the lessons learned from the Three Mile Island accident, the staff requires that licensees provide onshift engineering expertise. This may be provided by a separate individual (Shift Technical Advisor, STA) who has a bachelor's degree or equivalent and training in plant accidents and transients. A Commission Policy Statement on Engineering Expertise on Shift allows the role of the STA to be combined with one of the SROs on shift, if certain training and educational criteria are met. The applicant proposes to use the dual-role SRO/STA. However, the applicant has not committed to have the Shift Superintendent or unit Shift Supervisor meet the educational requirements of the Commission Policy Statement on Engineering Expertise on Shift. Therefore, the staff considers this an open item.

The Commission is concerned about the possible lack of hot operating experience among the operators on shift at newly licensed nuclear power plants. This has led to an evaluation of the onshift operating experience proposed by the applicant.

Dialogue with the industry was begun in late 1983 to find a way of ensuring that each operating shift at a newly licensed plant had at least one senior operator with previous hot operating experience. On February 24, 1984, an industry working group representing utilities with nuclear power plants under construction or ready for operation presented a proposal to the Commission on the amount of previous operating experience considered to be the minimum desirable on each shift and how that experience could be obtained. On June 14, 1984, the Commission accepted the industry proposal with certain clarifications. Information regarding the Commission action was forwarded to the industry as Generic Letter 84-16, dated June 27, 1984. The objective is to ensure that, at the time of fuel load, each operating shift will have at least one licensed senior operator with a minimum of 6 months of hot operating experience, including 6 weeks of operation above 20% of rated power level and startup/shutdown experience.

Information from the applicant regarding the operating experience of licensee candidates was provided at a meeting with the NRC staff on May 10, 1985. The information was docketed by a meeting summary from the NRC Project Manager for Seabrook Unit 1, dated June 18, 1985.

The applicant has identified six Shift Superintendents and four alternates who will be used on shift to satisfy the hot participation experience guidelines of Generic Letter 84-16. On the basis of information provided by the applicant in the FSAR (through Amendment 54) and at the May 10, 1985, meeting, the staff has reached the following conclusions:

(1) Five Shift Superintendents and two alternates exceed the minimum operating experience guidelines of Generic Letter 84-16.

(2) The sixth Shift Superintendent meets the minimum guidelines of Generic Letter 84-16 with one exception: his operating experience was at a boiling water reactor (BWR) rather than a pressurized water reactor (PWR). However, by virtue of his extensive operating experience (e.g., RO for 3½ years; participation in four reloads; experience with plant modifications and procedures; participation in numerous startups and shutdowns; experience with reactor physics testing, system hydrostatic testing, and Technical Specification surveillance testing), the staff considers him sufficiently experienced to supervise the shift activities at an operating PWR.

(3) The remaining two alternate Shift Superintendents are enrolled in a Seabrook Station Hot Experience Equivalence Program. The applicant considers that the program meets the intent of Generic Letter 84-16, although it does not give participants a full 6 months at an operating PWR. The staff has reviewed the applicant's Hot Experience Equivalence Program and concludes that it does provide participants with a solid foundation of operating experience. However, it falls short of meeting the intent of Generic Letter 84-16, which sets a goal of a minimum of 6 months of experience at an operating plant. Thus, the staff concludes that credit for operating experience cannot be granted solely on the basis of completion of the Hot Experience Equivalence Program. However, the applicant still has six Shift Superintendents and two alternates who do meet the minimum experience guidelines of Generic Letter 84-16. This is enough qualified individuals to allow the applicant to meet the requirements of Generic Letter 84-16 on each shift at plant startup.

    To ensure conformance with Generic Letter 84-16, the staff will condition the Seabrook Unit 1 license to require operating experience on shift.

Thus on the basis of its review, the staff has concluded that, except as noted above, personnel of the applicant's operational organization are technically qualified to manage, operate, and maintain the Seabrook Station.

13.1.2.3 Technical Services

The Technical Manager directs and controls the activities of three department managers and supervisors: Maintenance Manager, Health Physics Supervisor, and Assistant Technical Service Manager.

The Maintenance Manager is responsible for all station mechanical and electrical maintenance work required for safe, efficient and dependable service from Units 1 and 2. The Maintenance Manager will establish a program of preventive maintenance, corrective maintenance, surveillance testing, and record-keeping, as required by the station license, approved station procedures, and/or other station requirements. The Maintenance Manager will be assisted by the Radioactive Waste Utilities Supervisor, Maintenance Department Supervisor, and Instrument and Controls Department Supervisor.

The Health Physics Department Supervisor is the Station Radiation Protection Manager and, as such, has the responsibility and authority to report to the Station Manager on any aspect of the Radiation Protection Program or its implementation as the Health Physics Department Supervisor deems necessary. The Health Physics Department Supervisor also is responsible for monitoring station activities for compliance with health physics-related regulations and programs.

The Assistant Technical Services Manager reports directly to the Technical Services Manager and assists in directing, coordinating, and monitoring all activities within the Technical Services Group. The Assistant Technical Services Manager is responsible for the coordination, direction and monitoring of the Chemistry, Reactor Engineering, Computer Engineering, and Engineering Services Departments.

The Reactor Engineering Department Supervisor is responsible for the analysis of core performance to ensure operation of the station within the limitations of the facility license. The Reactor Engineering Department Supervisor will calculate reactivity requirements, evaluate the thermal-hydraulic performance of the reactor cores, specify control rod patterns, prepare fuel movement sequences, and be responsible for fuel accountability.

The Engineering Services Department Supervisor is responsible for the general engineering and quality engineering support services performed on site. A multidisciplined staff of graduate engineers perform a wide spectrum of activities including initiation and preparation of design change requests, preparation and review of safety-related procedures, test performance and inspection, and implementing assigned engineering programs.

The Chemistry Department Supervisor has the direct responsibility for ensuring that the nuclear and steam portions of the station operate within the appropriate water quality specifications. The Chemistry Department Supervisor is responsible for water treatment and water conditioning for specific station needs, as well as for verifying that all liquid, resin, and gaseous wastes are properly analyzed and processed for station reuse or disposal.

The applicant has also committed to require the involvement of the Technical Services staff in the Initial Test Program. This involvement will include assignment of staff personnel to the YNSD startup group, the assumption of preoperational test responsibilities, verification of design and installation, chemistry support, procedure review, test data evaluation, and operational maintenance support of plant systems.

13.2 Training

13.2.1 Licensed Operator Training Program

The applicant's requalification program was found acceptable in the SER (March 1983). Since the SER was issued, the requalification program has been further upgraded in Amendment 55 to the Final Safety Analysis Report (FSAR), and in commitments provided by the applicant in a letter dated December 16, 1985. The staff's evaluation of the revisions made to the requalification program since the SER was issued follows.

13.2.1.2 Operator Requalification

In Section 13.2.1.2, the requalification program was divided into the following areas:

- annual requalification exam
- on-the-job training
- change and/or revision review
- emergency operating procedure review
- simulator training
- retraining lectures for license holders
- performance evaluation and review

In Amendment 55 to the FSAR, the applicant revised Section 13.2.1.3, "Licensed Operators--Requalification Training," to be prepared within the framework of a systems approach to training. The content and schedule of the training is to be established by the Seabrook Training Center's Curriculum Development Committee (CDC) with a minimum of 10 weeks per 2-year cycle being dedicated to the license program. Requalification training is to be conducted on a modular basis with at least ten 1-week modules being presented every 2 years.

The revised requalification program will consist of four interrelated elements, a description of which will follow:

- requalification examinations
- on-the-job training
- preplanned lecture series
- special retraining programs

A. Requalification Examinations

(1) Written examinations will be administered to all licensed individuals upon the completion of each requalification module.

(2) Demonstrative examinations will be scheduled for each module and may be either simulator evaluations, oral examinations, or in-plant walk-throughs.

B. On-the-Job Training

On-the-job training will consist of the following activities:

- required reactivity manipulations and plant evolutions
- design change, procedure revision, and industry experience review
- abnormal and emergency operating procedure review
- simulator exercises
- in-plant training

C. Preplanned Lecture Series

A formal classroom lecture series, including exams, will be conducted each year as part of the requalification program. The lecture series will cover two general areas:

- fundamentals and system review
- procedures and administrative controls

D. Special Retraining Programs

Specific retraining programs may be necessary for certain licensees who fail the exams or perform in an unsatisfactory manner. The applicant has designed a three-tiered program of progressive corrective actions to upgrade knowledge and skills identified as deficient. The three levels of the academic reviews are:

(1) staff counselor interviews
(2) alert status review board
(3) performance review board

Performance Evaluation and Review

Although not described as one of the interrelated elements, performance evaluation and review will be monitored at least once a year. Each licensed operator will be observed and evaluated while responding to either real or simulated abnormal or emergency conditions.

Conclusion

All requalification training areas which were identified in the SER have been incorporated into the revised program submitted by the applicant in Amendment 55 to the FSAR. On the basis of its review, the staff find the applicant's revision to the requalification training program acceptable. Acceptance criteria for this review included the applicable portions of NUREG-0737, "Clarifications of TMI Action Plan Requirements"; NUREG-0800, "Standard Review Plan"; 10 CFR 55; Appendix A to 10 CFR 55; and Regulatory Guide 1.8.

13.3 Emergency Planning*

13.3.1 Background

The staff's initial evaluation of the applicant's emergency plan is provided in Section 13.3 of the SER for the Seabrook Station, NUREG-0896, Supplement No. 1, April 1983. In SSER 1, the staff identified items requiring resolution or additional information. The applicant has provided the staff with additional or revised information in letters dated June 27, 1983, January 18, 1984, March 14, 1984, and July 30, 1985. On July 25, 1985, the applicant submitted Amendment 55 to the FSAR which included extensive revisions to the Seabrook Radiological Emergency Plan (plan). On July 25, 1985, the applicant also submitted the New Hampshire Yankee Nuclear Production Emergency Response Program Manual (NPER) which contains the detailed emergency plan implementing procedures referred to as emergency response procedures (ERs). On August 21, 1985, the applicant transmitted Chapter 9 to the NPER which consists of an ER entitled Corporate Response Organization and Support. On April 2, 1986, the applicant submitted additional information on the emergency action levels that was requested by the staff and on April 11, 1986, appropriate changes were incorporated into the plan by Amendment 58 to the FSAR. All of the submitted material has been reviewed and evaluated by the NRC staff who have also made site visits in conjunction with their evaluation.

The applicant's capability to implement the plan including a review of the ERs was evaluated by the NRC Region I staff during the onsite emergency preparedness implementation appraisal conducted on December 9-13, 1985 and documented in Inspection Report No. 50-443/85-32. A followup appraisal was conducted on March 24-28, 1986 and documented in Inspection Report No. 50-443/86-18.

An exercise involving the applicant and New Hampshire was conducted at Seabrook on February 26, 1986. The NRC reported in Inspection Report No. 50-443/86-10 that the applicant's emergency response actions demonstrated during the exercise were adequate to provide appropriate protective measures for the public. The staff will provide its review of FEMA's findings on the Seabrook/New Hampshire exercise in a supplement to the SER as well as the Massachusetts exercise to be conducted before a license authorizing operation above 5% of rated power is issued.

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*Section 13.3 was not edited. An NRC memorandum (April 25, 1986) from T. M. Novak (Division of PWR Licensing-A) to E. S. Christenbury (Hearing Division, OELD) states: "Since the technical staff and I (by this memo) have concurred with these SSER-4 inputs, these inputs will be published without further changes."

The applicant's responses to the items previously identified by the staff in SSER 1 as requiring resolution or additional information are discussed below. The order of presentation corresponds to the listing of the items in Section 13.3 of the SSER 1. The staff's conclusions are provided in Section 13.3.3 of this supplement.

During the hearings held in August 1983, certain emergency planning documents relied upon by the parties required updating, revision or completion as noted in Board Order ASLBP No. 83-471-02-OL, dated October 4, 1985. The staff's evaluation of the revised and additional information submitted by the applicant in response to the Board Order is included below in Sections 13.3.2.3 and 13.3.2.8.

13.3.2 Emergency Plan Evaluation

13.3.2.1 Assignment of Responsibility (Organizational Control)

Item requiring resolution:

- ° Updated state and local plans must be submitted to the NRC.

On February 18, 1986, the applicant submitted the offsite plans for the State of New Hampshire and local communities. The submittal included the bulk of the radiological emergency response plan for New Hampshire, draft plans for the seventeen (17) New Hampshire communities situated within the Seabrook plume exposure pathway Emergency Planning Zone (EPZ) and those of the six (6) "host communities" located in New Hampshire. On March 4, 1985, the applicant submitted the remaining portions of the New Hampshire plan with the exception of an updated evacuation time estimate (ETE) study.

This item will remain open until the State of Massachusetts and associated local emergency plans are submitted to the NRC as well as the ETE study for New Hampshire. The offsite plans will be reviewed by FEMA whose findings and determinations will be provided in a future supplement to the SER prior to authorization for operation above 5% of rated power.

Based on information in the emergency plan, the staff reported in SSER 1 that letters of agreement with New Hampshire and Massachusetts State agencies having radiological emergency responsibilities and functions will be maintained in a future appendix to the applicant's plan. During the onsite appraisal held on March 24-28, 1986, the applicant informed the staff that letters of agreement with the States of New Hampshire and Massachusetts were being prepared and would be submitted after being signed by the respective states. The letters will be incorporated in a future revision to Appendix D of the plan.

This is an open item pending the submittal of the letters of agreement referring to the concept of operations developed between the applicant and the States of New Hamsphire and Massachusetts. Resolution of this item is required before a license authorizing operation above 5% of rated power is issued.

13.3.2.2 Onsite Emergency Organization

Item requiring resolution:

° Updated letters of agreement with local fire, hospital and ambulance service must be submitted to the NRC.

Appendix D to the plan includes letters of agreement with Exeter Hospital, Exeter, New Hampshire, and with Brigham and Women's Hospital, Boston, Massachusetts, for the treatment of contaminated injured individuals. Appendix D also has a letter of agreement with the Seabrook Fire Department to provide fire-fighting assistance at Seabrook Station when requested. In addition, Appendix D includes a letter of agreement with United Engineers and Construction (UE&C) Project Construction office to provide emergency medical transportation.

The staff finds that the applicant has provided adequate information in the emergency plan on agreements with support agencies. When the UE&C organization leaves the site, the NRC Region I staff will verify that the applicant has made acceptable provisions for continued ambulance support service.

13.3.2.3 Emergency Classification System

Item requiring resolution:

° The applicant committed to develop Emergency Action Levels (EALs) appropriate to Seabrook design and operational features, and to incorporate these EALs into a future revision to the plan.

In addition to the item requiring resolution from SSER 1, changes or additions to Section 5.0 of the plan related to the EALs were identified in the ASLB hearing to be submitted by the applicant for staff evaluation. The affected items were as follows: (a) the set points in the tables of EALs; (b) employment of additional radiation level indicators in EAL determination; and (c) correlation of the assessment/classification scheme with Appendix 1 to NUREG-0654 including two alleged misclassifications.

Section 5.0 of the plan, as modified by Amendment 58 to the FSAR, provides a description of the Emergency Classification System. The system uses a symptomatic approach to classification through the use of color-coded Critical Safety Function (CSF) status trees which indicate the severity of an off-normal condition and are available to operators on the Safety Parameter Display System. Emergency action levels have been developed which relate to levels of challenge to any of the five CSFs: Subcriticality, Core Cooling, Heat Sink, Reactor Cooling System Integrity, and Containment Integrity . The challenge is identified by measurable and observable indications of station conditions, such as pressure, temperature and liquid level. Miscellaneous emergency station conditions that do not directly challenge a CSF have been identified and event-specific EALs have been developed (e.g., fire, security, natural events). In some cases, a combination of miscellaneous conditions or a combination of a miscellaneous condition with a CSF result in a specific emergency classification. Emergency Procedure ER-1.1, Classification of Emergencies, specifies the plant status and instrument set points for each initiating condition. A complete set of EALs including instrument set points is included in the plan and procedures.

The initiating conditions for plant emergency situations include a comprehensive set of radiation level indicators including additional monitors as recommended by the staff. The list is as follows:

Steam Generator Blowdown Monitor
Steam Generator Blowdown Flash Tank Drain Monitor
Condenser Air Ejector Monitor
Steam Line Monitor
Letdown Monitor
Containment Hi Range Monitor
Containment Manipulator Crane Monitor
Spent Fuel Pool Monitor
Plant Vent Monitor

ER-1.1 includes Form ER-1.1.A, Emergency Classification Flow Chart, which depicts the complete classification system of critical safety functions and miscellaneous emergency conditions on one chart. The classification flow chart contains all of the initiating conditions listed in ER-1.1, and provides the operator with a simplified picture of the entire classification scheme. ER-1.1 was reviewed during the onsite emergency preparedness appraisal as documented in Inspection Report No. 50-443/86-18. NRC Region I will verify that corrective actions identified during the review of ER-1.1 are completed prior to fuel load. The applicant has also correlated the initiating conditions of the Seabrook classification system with those of Appendix 1 of NUREG-0654.

The staff has reviewed the description of the Seabrook emergency classification and action level system in the plan, the implementing procedure for classification, and the Seabrook-NUREG-0654 correlation. The staff has also discussed the classification system with the Seabrook Shift Superintendents who have contributed to the development of the system and would be the persons on shift to use the system. The staff has determined that the emergency classification and EAL scheme, as modified by Amendment 58 to the FSAR, meets the guidance criteria of NUREG-0654 and provides an adequate planning basis for an acceptable level of emergency preparedness. The modified EAL scheme also rectifies the two alleged misclassifications referenced in the Board Order of October 4, 1985. By letter dated April 18, 1986, the applicant committed to incorporate the modified EALs into procedure ER-1.1 by April 24, 1986.

13.3.2.4 Notification Methods and Procedures

Item requiring resolution:

- Describe the means to provide early notification and clear instruction to the populace within the plume exposure Emergency Planning Zone (EPZ).

Appendix E to the plan includes a description of the means to provide early notification and clear instructions to the populace in the plume exposure EPZ. Public alerting and notification will be accomplished through the activation of sirens, witn simultaneous emergency messages broadcast by designated local radio stations.

A total of 133 new electronic sirens will be installed in the plume exposure EPZ to perform the initial alerting function. These will be complemented by seven mechanical sirens recently installed in the City of Newburyport, Massachusetts.

Sirens in the State of New Hampshire will be activated by radio from the Rockingham County Police Dispatch Center in Brentwood, New Hampshire. Those in Massachusetts will be activated from State Police Troop A Headquarters in Framingham, Massachusetts. The 23 cities and towns in the plume exposure EPZ will also have the capability to activate the sirens within their boundaries, if necessary. As an additional backup, there will be a means for siren activation at Seabrook Station as well.

The electronic sirens have a public-address capability. Along the public beaches from Newbury, Massachusetts, north through Hampton, New Hampshire, siren locations have been chosen so that the sirens can provide both an alerting tone and a public-address message to notify transient beach users who may not have immediate access to commercial radio receivers. Supplementing the sirens, tone-activated radio receivers will be provided to institutions such as schools, hospitals, and major employers within the plume exposure EPZ.

In Appendix E to the plan, the applicant specifies that the design of the public alerting system for the Seabrook plume exposure EPZ follows the guidance in Appendix 3 of NUREG-0654. In order to verify the design guidance that was used, selected measurements were made by the applicant of ambient background noise, and outdoor sound propagation was computed for a variety of local weather conditions.

Section 11.2 of the plan specifies that installation and testing of the prompt alerting system is scheduled for completion prior to fuel load. In addition, in Appendix E to the plan the applicant specifies that a public information program has been underway since July 1985 to acquaint residents of and visitors to the EPZ of the prompt alerting system and what to do if they hear the sirens.

The staff finds that the applicant's means for alerting and providing clear instructions to the public in the plume exposure EPZ as described in the emergency plan provides an adequate planning basis for an acceptable state of emergency preparedness. The NRC Region I staff will confirm that the prompt alerting system is installed and operational prior to fuel loading. The conformance of the overall alert and notification system with the guidance of Appendix 3 to NUREG-0654 will be verified by FEMA in the course of its review and administrative approval of offsite emergency preparedness under 44 CFR 350 of FEMA's rules.

13.3.2.5 Public Education and Information

Item requiring resolution:

- ° Distribute educational information on emergency planning to the public. Draft copies must be submitted to NRC when available.

On March 4, 1986, the applicant submitted the New Hampshire draft public information material (e.g., brochure, calendar and telephone book inserts). This material was also sent to FEMA and will be evaluated during the course of FEMA's review of state and local plans. The material for the State of Massachusetts is still under development.

This will remain an open item until the public information material for the State of Massachusetts is submitted to the NRC (and FEMA) and the New Hampshire and Massachusetts materials are distributed to the public within the plume exposure pathway EPZ. Resolution of this item is required before a license authorizing operation above 5% of rated power is issued. The applicant has committed to distribute information pamphlets prior to fuel load to all residents in the plume exposure EPZ and to also make the information available to transients.

13.3.2.6 Emergency Facilities and Equipment

Items requiring resolution:

- ° A future revision of the plan must include checklists and location of emergency equipment.
- ° The applicant must furnish emergency response facility information in accordance with the requirements of Supplement 1 to NUREG-0737.

Section 6.1 of the plan includes the following information on ERFs:

Technical Support Center (TSC)

A TSC has been established in the Control Building adjacent to the Control Room to direct post-accident evaluation and assist in the recovery actions. The TSC is habitable to the same degree as the Control Room for postulated accident conditions. The TSC will have the capability to access and display station parameters, including the Safety Parameter Display System (SPDS), independent from actions in the Control Room. The TSC is included in the station emergency communications network. The TSC will have access to the station Final Safety Analysis Report, the station Radiological Emergency Plan and procedures, and a complete set of system prints, system flow diagrams, cable/wiring diagrams and equipment specifications. The TSC will have the capability to assess radiological habitability conditions by monitoring for direct radiation and airborne particulates, and sampling for airborne radioiodines. A layout of the TSC is provided in Figures 6.3, 6.4, and 6.5 of the plan to show that the TSC is sufficient to accommodate NRC and utility response personnel, equipment and documentation.

Operational Support Center (OSC)

The OSC, located on the first floor of the Administration and Service Building, provides a general assembly/dispatch area for assigned station manpower needed to effect protective and corrective actions in support of the emergency situation. The OSC is included in the station emergency communications network. Emergency equipment will be provided at the Radiation Controlled Area (RCA) Control Point located within the OSC.

Emergency Operations Facility (EOF)

The applicant has relocated the EOF from the basement of the onsite Seabrook Station Education Center to the Public Service of New Hampshire fossil-fueled power station in Newington, New Hampshire, approximately 14 miles north of Seabrook. The EOF is shown in Figure 6.7 of the plan. Part of the EOF has been assigned as the State of New Hampshire Incident Field Office.

The EOF is included in the station emergency communications network which links all emergency response organization facilities, monitoring and assistance teams dispatched from the EOF, and offsite agencies. The EOF will have the capability to access and display station parameters, including the Safety Parameter Display System, independent of both the TSC and Control Room. Copies of selected building prints and general building arrangements, all emergency planning arrangements applicable to Seabrook Station including area maps, emergency response procedures, emergency plans of states and locals, and the station FSAR will be available in the EOF.

The EOF has sufficient assembly space and is designed to accommodate the recovery organization, and the responding representatives from government and industry, responsible for corrective action to terminate or limit onsite damage and offsite consequences. The EOF will serve as the base of operations for station material control, coordination of industry support, and establishment of a long-term organization to recover from the accident conditions and results. The EOF can serve as a centralized meeting location for key representatives from offsite authorities and station management. The EOF, TSC and OSC were used during the emergency preparedness exercise on February 26, 1986.

Appendix F of the plan contains a list of emergency equipment maintained in each of the station's emergency response facilities, the TSC, OSC and EOF.

Based on information in the applicant's emergency plan and procedures, the findings of the onsite emergency plan implementation appraisal, and on observations made during the February 26, 1986 exercise, the staff finds that, on an interim basis, the Seabrook emergency response facilities are adequate to support a response effort in the event of an emergency. The NRC Region I staff will verify that the corrective actions identified in the appraisal are completed on a schedule to support licensing.

Supplement 1 to NUREG-0737 (issued via Generic Letter No. 82-33) indicates that the NRC will conduct post-implementation reviews of the final emergency response facilities (ERFs) and provides all licensees and applicants with the requirements and guidance against which the ERFs will be evaluated. The staff will conduct a post-implementation appraisal of the Seabrook ERFs in accordance with the provisions of Supplement 1 to NUREG-0737 on a schedule to be developed between the applicant and the NRC.

13.3.2.7 Accident Assessment

Items requiring resolution:

- Establish EALs for each example initiating condition in Appendix 1 of NUREG-0654.

- Describe the post-accident sampling system, the inplant iodine instrumentation, and the effluent sampling and analysis system.

Incorporate data from these systems into emergency response procedures for radiological assessment purposes.

Section 5.0 of the plan and ER-1.1, Classification of Emergencies, describe the applicant's EAL scheme and its implementation. The applicant has correlated the Seabrook EALs with the initiating conditions in Appendix 1 of NUREG-0654 as indicated in Section 13.3.2.3 of this report.

Section 10.1 of the plan describes the use of effluent monitoring instrumentation for radiological assessment for two monitored release pathways, the primary vent stack and the main steam lines. In addition to these monitored pathways, high-range containment area monitors are capable of measuring the exposure rate within the containment. The noble gas effluent monitor has an upper range of 10^5 uci/cc. The containment monitoring system consists of redundant monitors with an ionization chamber with a range of 10^0 to 10^7 R/hr. The post-accident sampling system and radiological instrumentation are described in detail in the FSAR in accordance with the requirements of NUREG-0737. Data from this instrumentation are utilized in the ER series of procedures to assess the consequences of an accident.

The staff has reviewed the information in the emergency plan and procedures and concludes that the applicant has adequately responded to the identified items.

13.3.2.8 Protective Response

Items requiring resolution:

- Describe the capability for monitoring and decontamination of plant evacuees and their vehicles at the plant and at the offsite assembly area.
- List equipment and its location for individuals remaining or arriving on the site for respiratory protection, protective clothing and radioprotective drugs.
- Provide the information required by Sections J.10.a and J.10.m of NUREG-0654.

Section 10.4.3 of the plan describes station decontamination facilities located in the OSC at the RCA Control Point. Showers, soap, brushes and survey instruments for personnel monitoring are available. The plan describes the decontamination capability at the Route 107 Warehouse and the EOF consisting of washcloth decontamination of personnel and vehicle washing by a hose connection to a water source near the remote assembly area, the Route 107 Warehouse.

Appendix F of the plan contains lists of equipment and supplies including protective clothing, respiratory equipment and potassium iodide tablets maintained in each of the station emergency facilities for the use of personnel arriving at or remaining on site.

Criterion J.10.a of NUREG-0654 specifies that maps showing pertinent emergency response information be included in the emergency plans. Appendix C of the plan shows major evacuation routes. Section 7.1 of ER-5.2, Site Perimeter and

Offsite Monitoring and Environmental Sampling, contains Figure 1 entitled "Offsite Monitoring Team Grid Map". Figure 1 of ER-5.4 is a map of the 10 mile emergency planning zone with letter designators for sub areas and sectors.

Criterion J.10.m of NUREG-0654 specifies that the bases for the choice of recommended protective actions should be included in the emergency plans. Sections 9.2 and 10.2 of the plan and ER-5.4, Protective Action Recommendations, address the elements of criterion J.10.m.

An item identified in the Board Order related to the hearing concerned the alleged omission from the applicant's emergency plan of recommended protective measures to accompany the different EALs. Section 9.2 of the plan describes the response actions for each emergency class and Section 10.2 discusses protective action recommendation criteria. Section 9.2.3 of the plan states that station conditions will be continually assessed and protective action recommendations to offsite authorities will be made on the basis of this assessment according to ER-5.4 "Protective Action Recommendations." This could involve station conditions related to the potential for radiological impact prior to the occurrence of an actual release. ER-5.4 includes the instruction that for a General Emergency or an emergency without radiological releases in progress, protective action recommendations shall be made based upon station conditions. In addition, protective action recommendations must be transmitted to state authorities within 15 minutes of a change in emergency classification. Form ER-5.4B of ER-5.4, entitled General Emergency/Station Parameter Protective Action Recommendation Worksheet, lists recommended protective actions of shelter and/or evacuation for areas around the plant based on the actual or potential magnitude of the radiation source. The magnitude of the source, i.e., core damage and resulting radiation release into containment, is related to containment and personnel hatch area radiation monitors in Form ER-5.4B.

Based on a review of the pertinent information in the emergency plan and procedures, the staff concludes that the applicant's methodology for developing recommended protective measures is in conformance with the guidance of NUREG-0654.

13.3.2.9 Medical and Public Health Support

Items requiring resolution:

- Confirm that a properly trained first aid person is available on each operating shift.
- Letters of agreement for local and backup hospitals and for ambulance service must be submitted.
- A further description of first aid facilities including supplies, layout, capacity, and access to decontamination capabilities must be provided.

Section 10.5.1 of the plan states that a minimum of two Emergency Medical Technicians will be onsite at any one time to provide 24 hour emergency response coverage.

Appendix D of the plan includes letters of agreement with Exeter Hospital, Exeter, New Hampshire and with Brigham and Women's Hospital, Boston, Massachusetts. Appendix D also includes a letter of agreement with UE&C to provide ambulance service.

Section 10.5.1 of the plan states that station medical facilities are provided in the first aid station located adjacent to the RCA Control Point where decontamination facilities are also located. The station is equipped with cabinets, sink, water closet and examination area as well as consumable medical supplies, examination table and examination equipment, stretcher, resuscitator, basins and refrigerator.

The staff has reviewed the information in the emergency plan and concludes that the applicant has adequately responded to the identified items.

Offsite Emergency Planning Medical Services

In a recent decision, GUARD v. NRC, 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR §50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the public offsite exposed to dangerous levels of radiation. The Commission has now provided guidance to be followed in determining compliance with this regulation pending its determination of how it will proceed in response to the Court's remand. In particular, the Commission directed that Licensing Boards, and in uncontested cases, the staff, should consider the uncertainty attendant to the Commission's interpretation of this regulation, especially in regard to its interpretation of the term "contaminated injured individuals." In GUARD, the Court left open to the Commission the discretion to reconsider whether that term should include members of the offsite public exposed to dangerous levels of radiation and, thus, whether arrangements for this population of individuals are required at all. For this reason, the Commission observed that it may reasonably be concluded that "no additional actions should be taken now on the strength of the present interpretation of that term." Accordingly, the Commission observed that it can be found "that any deficiency which may be found in complying with a finalized post GUARD planning standard (b)(12) is insignificant for the purposes of 10 CFR §50.47(c)(1)." In this regard, the Commission, as a generic matter, noted the low probability of accidents which might result in exposure of members of the offsite public to dangerous levels of radiation as well as the slow development of adverse reactions to overexposure. See, Emergency Planning; Statement of Policy, 50 FR 20892, May 21, 1985.

Consistent with the foregoing Statement of Policy, on January 29, 1986, the applicant submitted a list of medical service facilities for the involved offsite response jurisdictions. On March 12, 1986, the applicant committed to fully comply with the Commission's response to the Court's remand.

Accordingly, on the basis of the factors identified by the Commission in its Statement of Policy, the staff has determined that the requirements of 10 CFR §50.47(c)(1) have been satisfied so as to warrant issuance of the operating license pending further action by the Commission with respect to the requirements of 10 CFR §50.47(b)(12). FEMA will confirm that the offsite plans contain a list of medical service facilities during the course of their review of the plans.

13.3.3 Conclusion

The staff concludes that the Seabrook Station Emergency Plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness, and meets the requirements of 10 CFR 50 and Appendix E thereto for issuance of a license authorizing fuel loading and operation up to 5% of rated power. The staff's conclusions on the resolution of certain other items related to offsite preparedness, as identified in Section 13.3.2, will be provided in a future supplement to the SER prior to authorization for operation above 5% rated power.

After receiving the findings and determinations made by FEMA on state and local emergency response plans and preparedness, the staff will provide its overall conclusion on the status of onsite and offsite emergency preparedness for the Seabrook Station in a supplement to the SER prior to operation above 5% of rated power.

13.4 Operational Review

13.4.1 Station Operations Review Committee

The SER stated that the members of the Station Operations Review Committee (SORC) would meet the qualification requirements in Section 4.4.6 of ANS 3.1 (draft revisions, December 1979). However the qualification requirements for the SORC members now are described in Section 13.1.3 of the FSAR.

13.4.2 Nuclear Safety Audit and Review Committee (NSARC)

The membership of Nuclear Safety Audit and Review Committee (NSARC) described in the SER has been revised. The NSARC will be composed of at least five individuals whose qualifications will meet the qualifications in Section 4.7.1 of ANSI N18.1-1978. the NSARC will be operational 6 months before Unit 1 fuel load. The applicant's charter and operating procedures for the NSARC will be made available for staff review.

The NSARC will report to the Senior Vice President NHY. A quorum will consist of the chairman and four other members. The collective expertise of the quorum will be appropriate for the activities being reviewed. The NSARC will meet at least quarterly during the first year of plant operation and once every 6 months thereafter. The assigned responsibilities of the NSARC will cover the nine areas described for such review groups by the Standard Technical Specifications for Westinghouse PWRs (NUREG-0452, Revision 4). Audits of predetermined facility activities under the cognizance of the NSARC will be performed. Final acceptance of the Seabrook NSARC is subject to NRC approval of the facility's proposed Technical Specification.

13.4.3 Independent Safety Engineering Group (Operational Engineering Section)

The functions of the Independent Safety Engineering Group described in the SER will be performed by the Operational Engineering Section (OES), which will implement the functions of TMI Action Plan Item I.B.1.2. The OES will be composed of five full-time engineers located on the site; it will perform certain plant activities independent of those reviews performed by the SORC and the NSARC.

The general functions of the OES include the examination of plant operating characteristics, NRC issuances, and licensing information service advisories; maintaining surveillance of plant operation and maintenance activities; and performing independent review and audits of plant activities. The OES will report to the Training Center Manager. Qualifications of the OES members will meet or exceed the requirements in Section 4.4 of ANS 3.1 (a bachelor's degree in engineering and 2 to 4 years of experience in their field, including 1 to 2 years of nuclear experience).

The staff has reviewed the provisions for the OES and finds them acceptable because they meet the acceptance criteria of Section 13.4 of NUREG-0800.

13.5 Station Administrative Procedures

13.5.1 Administrative Procedures

NUREG-0660 (the TMI Action Plan) and NUREG-0737 (the clarification of TMI Action Plan requirements) require that procedures be written and approved to implement the following items:

- I.A.1.2 Shift Supervisor Responsibility
- I.C.2 Shift Turnover Procedures
- I.C.3 Shift Supervision Responsibility
- I.C.4 Control Room Access
- I.C.5 Feedback of Operating Experience
- I.C.6 Verification of Correct Performance of Operating Activities

The SER indicated that final acceptance of the applicant's commitment to implement these items was subject to approval of the facility's proposed Technical Specifications and the acceptance of the clarifications to RG 1.33, Revision 2 (February 1978), given in Appendix A to FSAR Chapter 17. In describing the administrative procedures, the applicant referenced these two documents. The applicant committed to implement the TMI Action Plan items in Section 13.5.1.3 of Amendment 45 to the FSAR. Each item is addressed below. Paragraph numbers refer to paragraphs in FSAR Section 13.5.1.3.

- I.A.1.2 Shift Supervisor Responsibility

  This item requires that the non-safety duties of the Shift Supervisor be delegated to non-licensed personnel on shift. Paragraph 2 commits to address I.A.1.2 in an administrative procedure.

- I.C.2 Shift Relief and Turnover Procedures

  This item requires formalization of shift relief procedures including implementation of a shift turnover check list. Paragraph 4 commits to address the requirements of I.C.2.

- I.C.3 Shift Supervision Responsibility

  This item requires that the responsibilities for both supervisors and operators be clearly defined. Paragraph 2 commits to fulfill this requirement in an administrative procedure.

- I.C.4 Control Room Access

  This item requires that the authority be established for limiting access to the control room to those essential personnel required for safe power plant operation. Paragraph 4 commits to developing administrative procedures to address I.C.4.

- I.C.5 Feedback of Operating Experience

  This item gives detailed steps on how the applicant shall prepare procedures to ensure that operating information pertinent to plant safety originating both within and outside the utility organization is continually supplied to operators and other personnel and is incorporated into training and retraining programs. NUREG-0737 clarifies this position to emphasize the assessment, screening, prioritization, and prompt distribution of this information. Paragraph 2 commits to address I.C.5.

- I.C.6 Verification of Correct Performance of Operating Activities

  This item requires that procedures be established to ensure that an effective system of verifying correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. NUREG-0737 clarified this position by identifying ANSI N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants" (with selected supplemental provisions), as an acceptable program for verifying operating activities. Paragraph 7 commits to preparing procedures to address I.C.6.

The staff review indicates that the applicant's latest draft of the proposed Technical Specifications is consistent with the FSAR commitments and the positions stated in the TMI Action Plan. The review also indicates that Appendix 17A of the FSAR does not seek any exceptions to the positions taken in FSAR Section 13.5.1.3. Therefore, there is no longer a need to tie approval of these items to final acceptance of the Technical Specifications or the RG 1.33 exceptions. Thus, on the basis of its review, the staff finds the applicant's responses to Items I.A.1.2 and I.C.2 through I.C.6 acceptable with two exceptions. Initial inspection of Items I.C.5 (Procedures for Feedback of Operating Experience to Plant Staff) and I.C.6 (Guidance on Procedures for Verifying Correct Performance of Operating Activities) indicates that neither item has been implemented. In addition, other than making the FSAR commitments, the applicant has not started developing programs to fulfill these commitments. Therefore, on the basis of these findings and the proximity to licensing, even though the FSAR (Amendment 45) fully commits to implementation of these items, the staff considers I.C.5 and I.C.6 confirmatory issues pending substantive initiative on the part of the applicant to establish effective programs in each area.

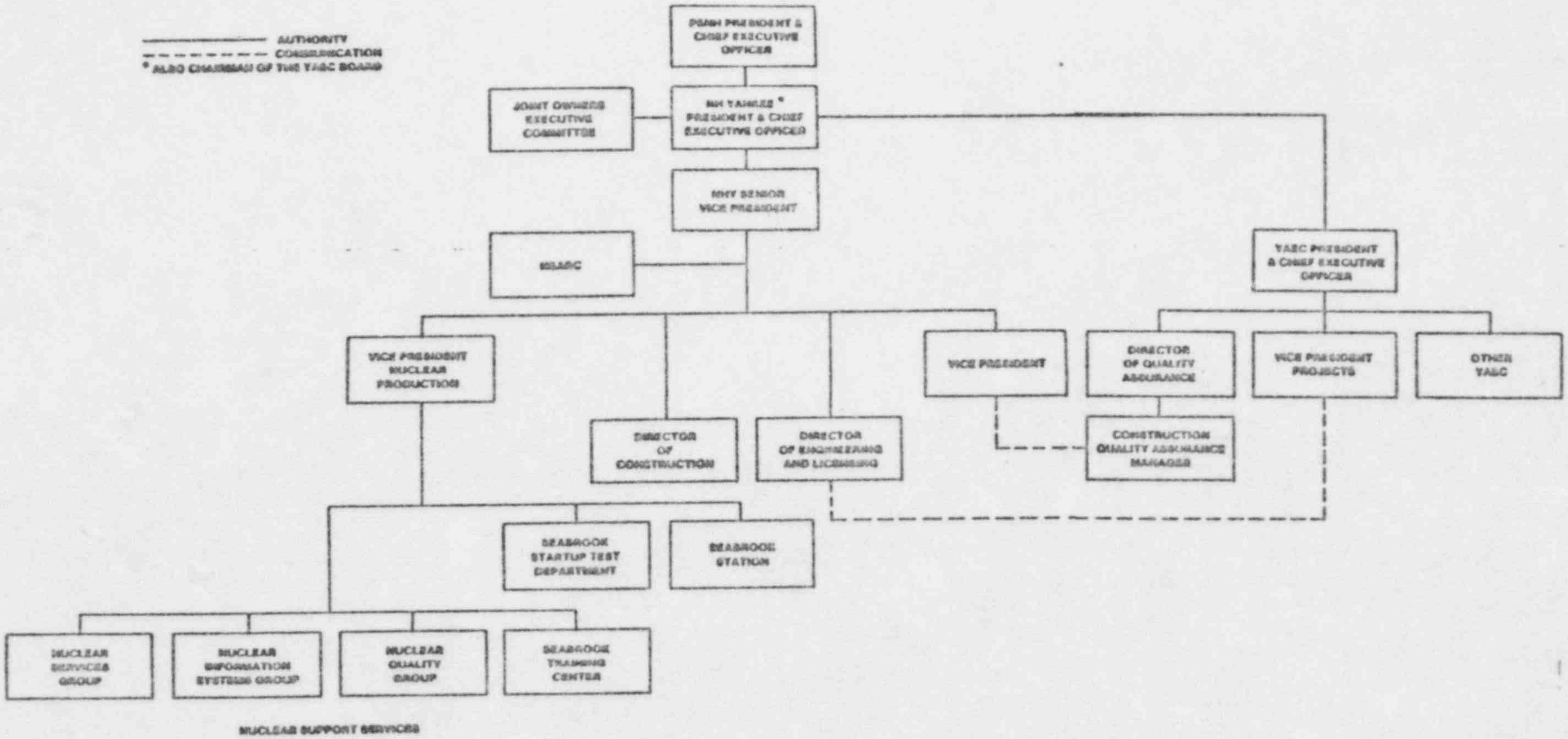

Figure 13.1 Organizational interface for Seabrook Station

15 ACCIDENT ANALYSES

The staff review of the accident analyses for Seabrook Units 1 and 2 was presented in the SER. However, in a letter from John DeVincentis to Vincent S. Noonan dated February 12, 1986, the applicant submitted a revised containment leak rate and bypass leakage fraction. As a result of this revision, the staff re-evaluated the expected offsite doses for a loss-of-coolant accident (LOCA) due to containment leakage. On the basis of its reevaluation, the staff determined that the new LOCA doses and control rod ejection accident doses are within the exposure guidelines of 10 CFR 100.11.

SER Section 15.6.5.1 and Table 15.1, "Radiological consequences of design-bases accidents"; Table 15.2, "Assumptions used for rod ejection accident"; and Table 15.5, "Assumptions used in the calculation of LOCA doses," have been revised on the basis of the revised containment leak rate and bypass leakage fraction.

15.6 Decrease in Reactor Coolant Inventory

15.6.3 Steam Generator Tube Rupture

The SER indicated that the applicant was to provide additional information to support the results of the steam generator tube rupture (SGTR) analysis. The SGTR analysis was identified as an outstanding issue in Section 1.7 of the SER.

According to a letter dated November 13, 1985, the applicant is a member of a subgroup of utilities within the Westinghouse Owners Group (WOG) that is generically addressing the licensing issues associated with a steam generator tube rupture (SGTR) event. The schedule called for completion of the final topical report by early 1986. After the staff approves the WOG report, the applicant will perform a plant-specific evaluation using the appropriate methodology to address the staff concerns stated in the SER. The applicant will submit the results of these analyses to the staff before the end of the first refueling outage at Seabrook Unit 1. The applicant asked that the staff remove the SGTR issue from the list of outstanding issues and approve interim operation of Seabrook Unit 1 during the first cycle.

On the basis of its review of the applicant's November 13, 1985, letter, the staff agrees that the SGTR analysis issue should be removed from the Seabrook outstanding issues and that operation at full power during the first cycle is justified, as discussed below.

Partial results of the WOG study on SGTR (WCAP-10698) have been submitted for staff review. In its preliminary evaluation of the WOG study (in a letter dated September 17, 1985), the staff stated that the WOG program is responsive to its concerns and that the methodology is acceptable. The staff believes that reasonable assurance exists that the results of the WOG work on the SGTR will resolve all staff concerns regarding the subject.

The reviews addressed in WCAP-10698 and its Supplement 1 were performed with credit for operator action based on Revision 1 of the Emergency Response Guidelines (ERGs). Seabrook Station's Emergency Operating Procedures are based on Revision 1 of the ERGs.

The probability of an SGTR is low early in plant life when the tubes are new. The design-basis SGTR event involves a number of very conservative, stylized assumptions. The probability of the design-basis SGTR occurring during the first cycle is, therefore, very low.

Thus, the staff considers that the final resolution of the SGTR analysis is a confirmatory issue.

15.6.5 Loss-of-Coolant Accident

15.6.5.1 Containment Leakage Contribution

The Seabrook Station includes a containment design to minimize the leakage of fission products from a postulated design-basis LOCA. The dual-containment design consists of a post-tensioned concrete primary containment vessel with a carbon steel liner and a reinforced concrete cylindrical structure that completely encloses the primary containment. Another engineered safety feature (ESF) is the containment spray system, which has a sodium hydroxide (NaOH) additive to enhance the removal of iodine in the containment after a LOCA. The staff's calculation of the consequences of the hypothetical LOCA used the conservative assumptions of Positions C.1.a. through C.1.3 of Regulatory Guide (RG) 1.4, Revision 2, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors."

The applicant estimated that it will take 3.6 minutes following an actuation signal to draw down the pressure of the annulus area of the secondary containment to a negative pressure of -0.25 in. water gauge (wg). Consistent with the requirements of Standard Review Plan (SRP) Section 6.5.3, the staff assumed that the primary containment leaked directly to the environment until the -0.25-in. wg subatmospheric pressure was attained. Thereafter, the primary containment was assumed to leak directly to the secondary containment (except for any bypass leakage), where it would be processed by the ESF containment was assumed to leak at a rate of 0.15% per day for the first 24 hours and 0.075% per day after 24 hours. The analysis took into account radiological decay during holdup in the containment, mixing in the containment, and iodine decontamination by the ESF spray system. A list of assumptions used in the calculation of the LOCA doses is given in Table 15.5.

15.9 TMI Action Plan Requirements

15.9.7 II.K.3.1/II.K.3.2 Installation and Testing of Automatic PORV Isolation System/Reporting on Overall Safety Effect of PORV System

The SER stated that "as a response to II.K.3.2, the applicant recommends against the installation of automatic PORV isolation and references a generic Westinghouse Owners Group submittal."

As a result of its review of this WOG submittal, the staff agrees with the applicant that the automatic PORV isolation system is not necessary. Thus, these items are closed.

Table 15.1 Radiological consequences of design-basic accidents (revised from SER)

Postulated accident	Exclusion area boundary, rems		Low population zone, rems	
	Thyroid	Whole body	Thyroid	Whole body
Loss of coolant				
Containment leakage				
0-2 hr	89	2.0	--	4
0-8 hr			51	1
8-24 hr			22	0.4
24-96 hr			21	0.1
96-720 hr			20	0.1
Total containment leakage			114	2.0
ECCS component leakage			0.2	0.7
Total	89	2.0	114	2.7
Steamline break outside secondary containment				
Long-term operation case (Case 1)	4.3	<1.1	3.7	<1.1
Short-term operation case (Case 2)	3.3	<1.0	4.5	<1.0
Control rod ejection				
Containment leakage pathway	18.4	<0.8	41.2	<0.7
Secondary system release pathway	4.1	0.4	3.5	0.2
Fuel-handling accident in fuel-handling area	3.9	0.3	1.0	<1.0
Small-line break	13	<1.0	3	<1.0

Table 15.2 Assumptions used for rod ejection accident (revised from SER)

Parameter and unit of measure	Quantity
Power, MWt	3654
Containment free air volume, ft^3	2.70×10^6
Containment leak rate, %/day for	
0-24 hr	0.15%/day
After 24 hr	0.07%/day
Filter efficiencies, %	
Elemental iodine	99
Organic iodine	85
Particulate iodine	99
Primary to secondary leakage time, hr	8
Primary coolant volume, gal	76,000
Peaking factor	1
Total decontamination factor for iodines	100
Filtered leakage fraction, %	40
Bypass leakage fraction, %	60
Atmospheric dispersion factors, χ/Q sec/m^3	
0-2 hr	2.7×10^{-4}
0-8 hr	6.6×10^{-5}
8-24 hr	4.8×10^{-5}
24-96 hr	2.3×10^{-5}
96-720 hr	8.0×10^{-6}
Exclusion boundary distance, m	914
Low population zone distance, m	2030

Table 15.5 Assumptions used in the calculation of LOCA doses (revised from SER)

Parameter and unit of measure	Quantity
<u>Containment leakage</u>	
Power level, MWt	3654
Operating time, yr	3
Fraction of core inventory available for containment leakage, %	
Iodine	25
Noble gases	100
Initial iodone compostion in containment, %	
Elemental	91
Organic	4
Particulate	5
Containment leak rate, %/day	
0-24 hr	0.15
After 24 hr	0.075
Bypass leakage fraction, %	0.6
Primary containment volume, ft^3	
Sprayed volume	2.3×10^6
Unsprayed volume	4.1×10^5
Containment mixing rate, cfm	13,660
Maximum elemental iodine decontamination factor	100
Spray removal coefficients/hr	
Elemental iodine	10
Particulate iodine	0.45
Organic iodine	0
Filter efficiencies for iodine in the enclosure building cleanup system, %	
Elemental and particulate	99
Organic	85
Relative concentration values, sec/m^3	
0-2 hr at the exclusion area boundary	2.7×10^{-4}
0-8 hr at the LPZ boundary	6.6×10^{-5}
8-24 hr at the LPZ boundary	4.8×10^{-5}
24-96 hr at the LPZ boundary	2.3×10^{-5}
96-720 hr at the LPZ boundary	8.0×10^{-6}
<u>ECCS leakage outside containment</u>	
Sump volume, gal	302,000
Flash fraction	0.1
Leak rate, gph (in the FSAR)	2.0
Leak duration, hr	720
Delay time, hr	0.50
Filter efficiency for iodine, %	
Elemental and particulate	99
Organic	85

18 HUMAN FACTORS ENGINEERING

18.1 Control Room Design Review (TMI Action Plan Item I.D.1)*

DISCUSSION

As specified in Supplement 1 to NUREG-0737, Seabrook Station is required to complete its DCRDR prior to licensing. SER Supplement No. 3 dated July 1985 (Ref. 1) indicated that the DCRDR process for Seabrook was nearly complete and listed the specific areas in which the review was incomplete. Subsequently, PSNH has completed most of these reviews and has made several submittals (Ref. 2, 3, 4) describing the results and recommending improvements. The improvements have been prioritized and a schedule for implementation provided. All improvements for human engineering discrepancies (HEDs) potentially affecting safe plant operations will be accomplished prior to loading fuel. A change to the Video Alarm System (VAS) color coding scheme to make it more consistent with the other control room CRTs will be accomplished prior to commercial operation. All other lower priority HED resolutions will be implemented prior to startup from the first refueling outage.

The remaining reviews to be accomplished and schedules for corrective actions are as follows:

1. Control room furnishings, their adequacy, obstacles to operator movement, and presence of unnecessary furnishings and equipment have been reviewed in the simulator with no HEDs identified. Subsequent to completion of installation of furnishings in the control room a review will be conducted by PSNH and any HEDs found will be resolved prior to startup from the first refueling outage.

2. Protective and emergency equipment storage space has been reviewed and judged adequate. Once equipment has been purchased and installed, the storage facilities will be re-evaluated by PSNH. Any HEDs found will be resolved prior to startup from the first refueling outage.

3. Final evaluation of the control room environment (temperature, humidity, airflow, acoustic noise, auditory signals) will be completed and reported to the NRC for confirmatory review within one year after commercial operation is achieved. This will allow one full cycle of heating and cooling to be experienced and will ensure plant noise is evaluated at full power. Should any HEDs be identified, proposed resolutions and a schedule for implementation of corrective actions will be included in the report.

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*Sections 18.1 and 18.2 were not edited. An NRC memorandum (April 25, 1986) from T. M. Novak (Division of PWR Licensing-A) to E. S. Christenbury (Hearing Division, OELD) states: "Since the technical staff and I (by this memo) have concurred with these SSER-4, inputs, these inputs will be published without further changes."

Staff confirmation will be required to ensure the satisfactory completion of these reviews and implementation of corrective actions.

CONCLUSIONS

The staff concludes that PSNH has conducted a DCRDR for Seabrook Station, Unit 1 that satisfactorily meets the requirements of Supplement 1 to NUREG-0737. The remaining reviews are confirmatory in nature, as are the scheduled implementation of proposed corrective actions and improvements. The staff further concludes that, with these improvements, the potential for operator error leading to serious consequences as a result of human factors considerations in the control room will be sufficiently low to permit safe operation of Seabrook Station, Unit 1.

REFERENCES

1. NUREG-0896, Supplement No. 3, dated July 1985, "Safety Evaluation Report Related to The Operation of Seabrook Station, Units 1 and 2."

2. PSNH Letter SBN-839 dated July 17, 1985 to G. W. Knighton from J. DeVincentes, "Supplemental Information as a Result of Continued Detailed Control Room Design Review (DCRDR) at Seabrook Station."

3. PSNH Letter SBN-914 dated December 27, 1985 to V. S. Noonan from J. DeVincentes, "Detailed Control Room Design Review (DCRDR) at Seabrook Station (SER Outstanding Issue No. 19)."

4. PSNH Letter SBN-948 dated February 20, 1986 to V. S. Noonan from J. DeVincentes, "Detailed Control Room Design Review (DCRDR) at Seabrook Station (SER Outstanding Issue No. 19)."

18.2 Safety Parameter Display System (TMI Action Plan Item I.D.2)*

NRC Task Action Plan Item I.D.2 requires all licensees and applicants for an operating license to provide a safety parameter display system (SPDS) (NUREG-0660, NUREG-0737, and Supplement 1 to NUREG-0737). Implementation is to be on a schedule negotiated with the staff. The purpose of the SPDS is to continuously display information from which the plant safety status can be readily and reliably assessed. The principal function of the SPDS is to aid control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. A written SPDS safety analysis shall be prepared describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which include symptoms of severe accident.

The applicant's SPDS safety analysis report was submitted January 6, 1986 and additional information was provided by letter dated April 2, 1986. The report and additional information are under review by the staff to confirm: (1) the adequacy of the parameters selected to be displayed to detect critical safety functions; (2) that means are provided to ensure that the data displayed are

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*See footnote on preceding page.

valid; (3) the adequacy of the design and installation of the system from a human factors perspective; (4) the adequacy of the verification and validation (V&V) program to ensure a reliable SPDS; and (5) the adequacy of isolation devices to provide an acceptable interface between Class 1E safety-related instrumentation systems and the SPDS. An audit of the system is scheduled for May 20-22, 1986, at which time the staff should be able to resolve many of the open issues.

The applicant has proposed a June 30, 1986 implementation date for the Seabrook SPDS and this is acceptable to the staff. However, some items identified in the staff review may not be resolved by that time. A schedule, approved by the staff, will be required for the resolution of these items. If necessary, a license condition will be established to ensure that any remaining items identified by the staff during its audit review will be implemented by the licensee prior to restart following the first refueling outage.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW

July 3, 1985	Letter to applicant regarding modified Class 2 and Class 3 pipe support program.
July 8, 1985	Letter to applicant advising that only schedular exemption (GDC 4) requests are being processed.
July 10, 1985	Letter from applicant modifying request for exemption from GDC 4.
July 12, 1985	Letter from applicant regarding its Probabilistic Safety Assessment.
July 22, 1985	Letter to applicant regarding identification of vital equipment.
July 25, 1985	Letter from applicant advising of dates when plant will be ready for site audits.
July 25, 1985	Letter from applicant in response to SER confirmatory issue 40, inadvertent boron dilution.
July 26, 1986	Letter from applicant transmitting proposed draft Technical Specifications.
July 26, 1985	Letter from applicant transmitting proposed draft Technical Specifications.
July 30, 1985	Letter from applicant forwarding response to requests for information on radiological emergency plan.
July 31, 1985	Letter to applicant transmitting SSER 3.
August 7, 1985	Meeting with applicant concerning seismic qualification and pump and valve operability program's status and schedule. (Summary issued October 30, 1985.)
August 15, 1985	Letter from applicant regarding cable raceway system damping.
August 19, 1985	Letter from applicant transmitting information data package to support Caseload Forecast Panel visit.
August 21, 1985	Transmittal of partial revision to emergency plan implementing procedures.

August 23, 1985	Letter from applicant transmitting "A Risk-Based Evaluation of Technical Specifications for Seabrook Station" and "Evaluation of Technical Specification 3/4.3.4 Turbine Overspeed Protection System."
August 26, 1985	Letter from applicant requesting certificate of pollution control facilities.
August 30, 1985	Letter from applicant requesting approval to implement ASME Code, Section III, Division 1, 1983 Edition, up to Winter 1983 Addenda, for application to specific technical issues.
September 4-6, 1985	Caseload Forecast Panel visit. (Summary issued September 23, 1985.)
September 19, 1985	Letter to applicant transmitting draft report of Phase II review of Probabilistic Safety Assessment.
September 20, 1985	Letter from applicant forwarding information on solid radwaste handling system (SER outstanding issue 14).
September 20, 1985	Letter from applicant transmitting a response to request for additional information on heavy load handling system.
September 24, 1985	Letter to applicant advising of acceptability of use of later edition and addenda of ASME Code Section III.
September 24-26, 1985	Meeting with applicant to discuss completion of power systems confirmatory issues.
September 27, 1985	Meeting with applicant to review current plant completion schedule, plant construction status, plant licensing open issues, and site tour.
September 30, 1985	Letter from applicant forwarding responses to outstanding issues of concern regarding materials engineering and status list of active review items.
October 2, 1985	Meeting with applicant and personnel from Brookhaven National Laboratories to discuss review of Probabilistic Safety Assessment.
October 10, 1985	Letter from applicant transmitting supplemental response to staff request for additional information (210.89).
October 10, 1985	Letter from applicant regarding compliance with NUREG-0737.

October 15, 1985	Letter to applicant forwarding initial selection by Pump and valve Operability Review Team of equipment supplied by the balance of plant vendor, and the initial selection by the Seismic Qualification Review Team, and initial selection by both teams (PVORT and SQRT) of equipment supplied by nuclear steam supply system.
October 17, 1985	Letter from applicant transmitting information related tp SQRT/PVORT site audit.
October 25, 1985	Letter to applicant providing interim guidance on Emergency Planning Standard 10 CFR 50.47(b)(12).
October 28, 1985	Letter to applicant transmitting Technical Evaluation Report of response to Generic Letter 83-28, Item 1.2.
October 28, 1985	Letter to applicant transmitting request for additional information on operator requalification program.
October 31, 1985	Letter from applicant transmitting revised NUREG-0612, "Control of Heavy Loads."
November 1, 1985	Letter from applicant transmitting construction status report.
November 1, 1985	Letter to applicant transmitting First Draft Technical Specifications.
November 4-6, 1985	Site audit/review of seismic qualification of safety-related equipment and review operability qualification of pumps and valves.
November 6, 1985	Meeting with applicant to discuss power systems review of associated circuits.
November 6, 1985	Letter from applicant transmitting information on containment purge and vent valve operability.
November 12, 1985	Transmittal by applicant of revised emergency plan implementing procedures.
November 12-15, 1985	Meeting with applicant to discuss proposed Technical Specifications.
November 13, 1985	Letter from applicant concerning outstanding issue 17, plant performance during a steam generator tube rupture.
November 14, 1985	Meeting with applicant to discuss review of its Probabilistic Safety Assessment.
November 20, 1985	Meeting with applicant to discuss instrumentation and controls review.

November 21, 1985	Letter from applicant concerning voltage regulation study.
November 22, 1985	Issuance of exemption from a portion of General Design Criterion 4 of Appendix A to 10 CFR 50 regarding the need to analyze large primary loop pipe ruptures as a structural design basis.
November 26, 1985	Letter to applicant summarizing September 4-5 Caseload Forecast Panel visit.
November 26, 1985	Letter from applicant transmitting the construction status report.
December 3, 1985	Meeting with applicant to hear its presentation on cable tray testing and qualification program.
December 17, 1985	Letter from applicant concerning table of risk-based changes included in the proposed Seabrook Station Technical Specifications.
December 24, 1985	Letter to applicant concerning Seabrook Operational QA Program.
December 24, 1985	Letter to applicant concerning Seabrook operating experience on shift.
December 24, 1985	Letter to applicant concerning safety evaluation for Generic Letter 83-28, Items 3.1.3 and 3.2.3 (Post-Maintenance Testing), for Seabrook.
December 26, 1986	Letter from applicant responding to integrated design inspection.
December 27, 1986	Letter from applicant concerning detailed control room design review (DCRDR) at Seabrook Station (SER outstanding issue 19).
December 31, 1986	Letter from applicant concerning SQRT/PVORT; site audit - meeting summary response.
December 31, 1986	Letter from applicant concerning level measurement error (SER outstanding issue 10).
December 31, 1986	Letter from applicant concerning inservice testing (IST) of pumps and valves (SER outstanding issue 4).
December 31, 1986	Letter from applicant concerning instrumentation and control for safe shutdown (SER outstanding issue 11).
January 6, 1986	Letter from applicant concerning NUREG-0737, Item I.D.2, plant safety parameter display console.

January 7, 1986	Letter to applicant concerning Technical Specification, request for additional information.
January 14, 1986	Representatives from NRC and PSNH meet in Bethesda, Maryland, to discuss cable tray qualification program. (Summary issued February 10, 1986.)
January 17, 1986	Letter from applicant concerning revisions to FSAR Section 8.2 - Off-Site Power System.
January 28 & 29, 1986	Representatives from NRC and PSNH meet in Bethesda, Maryland, to discuss sections of the Seabrook Technical Specifications. (Summary issued February 24, 1986.)
January 29, 1986	Letter from applicant concerning a response to interim guidance on emergency planning standard 10 CFR 50.48 (b)(12) regarding Seabrook Station.
January 31, 1986	Letter from applicant concerning response to request for additional information regarding risk-based Technical Specification changes.
February 5, 1986	Letter from applicant concerning Seabrook startup test program.
February 14, 1986	Letter from applicant transmitting a construction status report for Seabrook Station, Units 1 and 2.
February 14, 1986	Letter from applicant concerning meeting notes on instrumentation and control systems.
February 14, 1986	Letter from applicant concerning Shift Technical Advisor (STA); TMI Action Plan Item I.A.1.1 (SER outstanding issue 16).
February 14, 1986	Letter to applicant concerning seismic qualification review of equipment
February 18, 1986	Letter from applicant transmitting the Radiological Emergency Response Plans, State of New Hampshire and affected New Hampshire communities.
February 20, 1986	Letter from applicant concerning detailed control room design review (DCRDR) at Seabrook Station (SER outstanding issue 19).
February 24, 1986	Letter from applicant concerning NUREG-0737, Task II.F.2, "Instrumentation for Detection of Inadequate Core Cooling."
February 24, 1986	Letter from applicant concerning diesel generator control panel mounts (SER confirmatory issue 30).
February 24, 1986	Letter from applicant concerning resolution of power system confirmatory issue SER Section 8.3.1.1.3, Item (2) (SER confirmatory issue 22).

February 24, 1986	Letter from applicant concerning steam generator tube plugging analysis.
February 25-27 1986	Representatives from NRC and PSNH meet at the Seabrook site in Seabrook, New Hampshire, to review test procedures and results for selected equipment, examine configuration and mounting and determine whether compliance with established criteria has been demonstrated. (Summary issued April 11, 1986.)
February 27, 1986	Representatives from NRC and PSNH meet in Bethesda, Maryland, to discuss the proposed rewriting of Standard Technical Specifications for Sections 3/4.2.2, 3/4.2.3, 3/4.2.4, and 3/4.2.5. (Summary issued April 7, 1986.)
February 28, 1986	Letter from applicant concerning level measurement error (SER outstanding issue 10).
March 5, 1986	Letter from applicant concerning radiological emergency response plans, State of New Hampshire communities: additional information.
March 6, 1986	Letter from applicant concerning NUREG-0737, Item II.B.3, "Post-Accident Sampling Capability," Criterion (2) - Core Damage Assessment Methodology.
March 11, 1986	Letter to applicant concerning request for additional information (RAI) related to periodic testing (related to RAI 420.17).
March 11, 1986	Letter from applicant concering Radiological Emergency Response Plans, State of New Hampshire and affected New Hampshire communities: additional information.
March 12, 1986	Letter from applicant concerning "Additional Response to Interim Guidance on Emergency Planning Standard 10 CFR 50.47(b)(12) Regarding Seabrook Station."
March 13, 1986	Letter to applicant concerning Seabrook Probabilistic Safety Assessment (PSA) Review.
March 13, 1986	Letter to applicant concerning Seabrook unresolved licensing issues.
March 14, 1986	Letter from applicant concerning containment structural integrity test.
March 17, 1986	Letter to applicant concerning a request for additional information - emergency action levels.
March 17, 1986	Letter from applicant concerning NUREG-0737, Item II.D.1, "Performance Testing of Boiling Water Reactor and Pressurized Water Reactor Relief and Safety Valves."

March 18, 1986	Letter from applicant concerning Seabrook fire protection program.
March 19, 1986	Representatives from NRC and PSNH meet at the Seabrook site in Seabrook, New Hampshire, to discuss technical issues covered by applicant's cable tray support qualification program. (Summary to be issued.)
March 19, 1986	Letter from applicant concerning resolution of power systems confirmatory items.
March 20, 1986	Letter from applicant concerning seismic qualification review of equipment.
March 21, 1986	Letter from applicant concerning NRC review of Seabrook Station security plan.

APPENDIX B

BIBLIOGRAPHY

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---, letter to V. S. Noonan, NRC, "Detailed Control Room Design Review (DCRDR) at Seabrook Station (SER Outstanding Issue No. 19), December 27, 1985.

---, letter to V. S. Noonan, NRC, "Detailed Control Room Design Review at Seabrook Station (SER Outstanding Issue No. 19)," February 20, 1986.

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U.S. Nuclear Regulatory Commission, Generic Letter 83-28, D. G. Eisenhut, NRC, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983.

---, Generic Letter 84-16, "Adequacy of On-Shift Operating Experience for Near-Term Operating License Applicants," June 27, 1984.

---, NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," revised periodically.

---, NUREG-0484, "Methodology for Combining Dynamic Responses," Revision 1, May 1980.

---, NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," October 1979.

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---, NUREG-0660, "TMI Action Plan," May 1980.

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APPENDIX D

ACRONYMS AND INITIALISMS

ANSI	American National Standards Institute
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
BOP	balance of plant
BTP	Branch Technical Position
BWR	boiling-water reactor
CBS	containment building spray
CDC	Curriculum Development Committee
CFR	Code of Federal Regulations
CHR	containment heat removal
CRT	cathode-ray tube
CSF	critical safety function
CVC	chemical and volume control
DCRDR	detailed control room design review
EAL	emergency action level
ECC	emergency core cooling
EDO	Executive Director for Operations
EFW	emergency feedwater
EOF	Emergency Operations Facility
EPZ	emergency planning zone
ER	emergency response
ERF	emergency response facility
ESF	engineered safety feature
ETE	evacuation time estimate
FEMA	Federal Emergency Management Agency
FM	Factory Mutual
FSAR	Final Safety Analysis Report
GDC	General Design Criterion(a)
HED	human engineering discrepancy
HVAC	heating, ventilation, and air conditioning
IEEE	Institute of Electrical and Electronics Engineers
INEL	Idaho National Engineering Laboratories
IST	inservice testing

JTG	Joint Test Group
LOCA	loss-of-coolant accident
MSIV	main steam isolation valve
NFPA	National Fire Protection Association
NIS	nuclear instrumentation system
NPER	Nuclear Production Emergency Response (Program Manual)
NRC	U.S. Nuclear Regulatory Commission
NSARC	Nuclear Safety Audit and Review Committee
NSD	Nuclear Services Division
NSSS	nuclear steam supply system
NYH	New Hampshire Yankee
OES	Operational Engineering Section
OSC	Operational Support Center
PORV	power-operated relief valve
PSI	preservice inspection
PSNH	Public Service Company of New Hampshire
PSRV	pseudo-relative velocity
PVORT	Pump and Valve Operability Review Team
PWR	pressurized-water reactor
RAT	reserve auxiliary transformer
RCA	radiation-controlled area
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RG	regulatory guide
RHR	residual heat removal
RHRS	residual heat removal system
RMW	reactor makeup water
RO	reactor operator
RTD	resistance temperature device
RTS	repetitive task sheet
SEPP	Supplemental Examination Program Plan
SER	Safety Evaluation Report
SGTR	steam generator tube rupture
SI	safety injection
SNPP	Salem Nuclear Power Plant
SOE	sequence of events
SORC	Station Operations Review Committee
SPDS	safety parameter display system
SQRT	Seismic Qualification Review Team
SRO	senior reactor operator
SRP	Standard Review Plan
SSER	supplement to the Safety Evaluation Report
SSPS	solid-state protection system
STA	shift technical advisor
TSC	Technical Support Center

UAT	unit auxiliary transformer
UE&C	United Engineers and Construction
UL	Underwriters Laboratory
VAS	video alarm system
V&V	verification and validation
WG	water gauge
WOG	Westinghouse Owners Group
YAEC	Yankee Atomic Electric Company
YNSD	Yankee Nuclear Support Division

APPENDIX F

NRC STAFF CONTRIBUTORS

The NRC staff members listed below were principal contributors to this report.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Enclosure 2

APR 25 1986

MEMORANDUM FOR: Edward S. Christenbury
Director & Chief Counsel
Hearing Divison, OELD

FROM: Thomas M. Novak, Acting Director
Division of PWR Licensing-A

SUBJECT: ASLB MATTERS PERTAINING TO SEABROOK UNIT 1

Attached for your transmittal to the Board are the following SSER-4 inputs:

1. Emergency planning providing the staff's review and evaluation of emergency action levels, and

2. Equipment qualification providing the staff's review and evaluation of post-accident time.

Per E. Reis' request, I have enclosed a memo from Eisenhut to Sheppard pertaining to the staff's review of the Westinghouse's emergency response guidelines. I understand Reis intends to provide this memo to the Board as an indication of the status of this issue.

Also attached are draft SSER-4 inputs on I.D.1 (Control Room Design Review) and I.D.2 (Plant Safety Parameter Display System). Reis plans to discuss these items with the State of New Hampshire, which has a contention (NH-10) regarding these items, to determine whether the State of New Hampshire considers the information, when formally issued in SSER-4, would be sufficient to have them withdraw their contention.

Since the technical staff and I (by this memo) have concurred with the SSER-4 inputs, these inputs will be published withhout further changes.

T M Novak

Thomas M. Novak, Acting Director
Division of PWR Licensing-A

Enclosures:
As stated