December 29, 1989

MEMORANDUM FOR: Ashok C. Thadani, D/DST
James E. Richardson, D/DET
Frank J. Congel, D/DREP
Jack W. Roe, D/DLPQ
Brain K. Grimes, D/DRIS
Charles E. Rossi, D/DOEA
Lawrence J. Chandler, AGC/OGC

DISTRIBUTION w/encl:
Docket File
NRC PDR
Local PDR
PDI-3 r/f
RWessman
BBoger
MRushbrook
VNerses
OGC
EJordan
SNewberry
CMcCracken
WRegan
AGody
RErickson
BJones
JCunningham
TMarsh
JCalvo
RBellamy-RGI
JJohnson-RGI
FMiraglia w/o encl.
SVarga w/o encl.

FROM: Bruce A. Boger, Assistant Director
for Region I Reactors
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

SUBJECT: SEABROOK SER SUPPLEMENT NO. 9

Attached is a draft copy of Seabrook SER Supplement No. 9 for your review and concurrence. SSER No. 9 updates the review status of the Seabrook facility and consists of various inputs we have received from members of your staff since May 1989. This Supplement is intended to support issuance of a full power license for Seabrook Unit 1 and would be issued with the license. Preparatons are being made to issue the license for Seabrook by the end of January 1990; therefore, you are requested to provide your concurrence (or any comments or corrections) regarding SSER No. 9 to PDI-3 by COB, January 12, 1990.

SSER No. 9 does not include a few updates (e.g., close out of confirmatory items 56 and the SE on ISI reliefs). These sections will be updated as soon as possible and will be routed separately for review and concurrence.

Original signed by Stolz for Boger
Bruce A. Boger, Assistant Director
for Region I Reactors
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

Enclosure:
As stated

DF01

CONTACT: V. Nerses, X21441

9001160219 891229
PDR ADOCK 05000443
E PDC

Concurrence

PDI-3/LA	PDI-3/PM	PDI-3/D	AD/DRSP
MRushbrook	VNerses:rw	RWessman	BBoger
1/ /89	12/29/89	12/29/89	12/29/89

OFFICIAL RECORD COPY

Document Name: SER NO 9 SEA MEMO BOGER

ABSTRACT

This report is Supplement No. 9 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.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd)

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

On March 7, 1983, the U.S. 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), in July 1985 the third supplement (SSER 3), in May 1986 the fourth supplement (SSER 4), in July 1986 the fifth supplement (SSER 5), in October 1986 the sixth supplement (SSER 6), in October 1987 the seventh supplement (SSER 7), and in May 1989 the eighth supplement (SSER 8). This ninth supplement (SSER 9) provides information to update the status of the NRC review.

Each of the sections and appendices to this supplement bears the same designation as the related portion of the SER. The contents of this document are supplemental to the initial SER and SSERs 1 through 8, and not in lieu of those documents unless otherwise noted. Appendix A is a continuation of the chronology of this safety review. Appendix B lists any references other than NRC documents or correspondence between the NRC staff and the applicant cited in this supplement.* Appendix D lists acronyms and initialisms used in this supplement. Appendix F identifies the principal staff contributors and consultants. Appendix Y is a technical evaluation report prepared for the NRC staff by its contractor, EG&G Idaho, Inc., which gives the results of the staff's and EG&G's review of the applicant's response to the TMI Action Plan requirements of NUREG-0737, Item II.D.1, "Performance Testing of Relief and Safety Valves." Appendix Z is a technical evaluation report prepared for the NRC staff by its contractor, Idaho National Engineering Laboratory, in regard to the resolution of Generic Letter 83-28, Item 4.5.3, "Reactor Trip System Reliability (Testing

*Availability of reference materials cited is provided on the inside front cover of this report.

Intervals)." Appendix AA is the report of the Advisory Committee on Reactor Safeguards on the emergency plan for full-power operation of Seabrook Unit 1.

Appendices C, E, and I through X have not been changed by this supplement.

The NRC Project Manager for the Seabrook operating license review is Mr. Victor Nerses. He may be reached by telephone at (301) 492-1441 or by mail at the following address:

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

1.8 Confirmatory Issues

In Section 1.8 of the SER and its supplements, the staff noted that some items have been resolved essentially to its satisfaction but that certain confirmatory information for these items has not yet been provided by the applicant.

This supplement closes the following confirmatory items. The items and the section of this supplement that presents the results of the staff's evaluation follow.

(56) Radiation data management system (7.5.2.2)
(57) Fire protection (9.5.1.4)
(58) Control room habitability (6.4)
(60) Sampling and analyses of effluents (11.5)
(61) Containment heat removal system (6.2.2)

The remaining confirmatory items and the sections of the SER or its supplements where they are discussed are listed below. The staff has decided that the confirmatory issues listed below may be resolved after initial operation.

(6) Loose parts monitoring system (4.4.5.3)
(45) Steam generator tube rupture (15.6.3)
(49) Cable tray supports (3.7.3)
(50) Turbine system maintenance program (3.5.1.3)
(51) Inadequate core cooling, TMI Action Plan Item II.F.2 (4.4.5.4)
(54) Tests, operational procedures, and support systems (5.4.7.5)
(59) Initial test program (14)

1.9 License Condition Items

In Section 1.9 of the SER, or in its supplements, 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 license, or a limiting condition for operation in the Technical Specifications appended to the license. As of this supplement, the remaining license condition is:

(21) Safety parameter display system, TMI Action Plan Item I.D.2 (18.2)

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.9 Mechanical Systems and Components

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

In light of the thermal stratification found in the pressurizer surge line of several pressurized-water reactors (PWRs), the NRC staff issued Bulletin 88-11 on December 20, 1988. Since thermal stratification causes changes in piping stresses, fatigue life, and line deflections from those predicted in the original design, all licensees and near-term operating license applicants of PWR plants were requested to conduct visual inspection of the surge line, to update stress and fatigue analysis for ensuring compliance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), and to monitor thermal conditions and line deflections. Actions requested should be completed within the periods specified in the bulletin, unless the NRC staff considers the changes acceptable.

As noted in SSER 8, in response to the bulletin, the applicant submitted a letter dated March 7, 1989, to which were attached Westinghouse Topical Reports WCAP-12151 and -12152 and a Westinghouse surge line isometric drawing (Drawing No. SURG-W0049, "Pressurizer Surge Line of Seabrook Plant, Unit 1"). The applicant provided additional information in response to staff questions in April 1989 in Supplement 1 to WCAP-12151 and -12152. The applicant submitted a detailed plant-specific stress analysis of the surge line in a letter dated June 30, 1989, to which were attached Westinghouse Topical Reports WCAP-12305 and -12306. The submittals indicated that at Seabrook Unit 1, the applicant had conducted a walk-down after hot functional testing, instrumented sensors, and performed a quantitative assessment to show compliance with the ASME Code. The following is the staff's evaluation of information presented in the above submittals.

Section 5.1 in WCAP-12151 and -12152 indicates that no signs of distress in the supports and no indication of any crushed insulation or signs of abnormal pipe movements were found during the walkdown conducted after hot functional testing. This is positive evidence that clearances around the pipe were adequate to accommodate piping thermal deflection by stratification.

The staff reviewed the locations of thermal and displacement monitoring points. It found inconsistencies in sensor locations in the letter dated March 7, 1989; WCAP-12151 and -12152; and Drawing No. SURG-W0049. In addition, the applicant had not described their intended application. The applicant clarified these matters in a conference call, and a detailed monitoring location was provided in WCAP-12305 and -12306 in conjunction with the description of the monitoring program.

The staff reviewed a comparison of various operating parameters and thermal monitoring results at Seabrook Unit 1 with those of four similar Westinghouse-designed PWR plants for which plant-specific analyses had been performed (Tables 1 and 2 in Supplement 1 to WCAP-12151 and -12152). The staff found that the Seabrook operating parameters and monitoring results are enveloped by the four plant-specific analyses.

In the letter dated June 30, 1989, and WCAP-12305 and -12306, the staff found that temperature and displacement data obtained during recent heatup operations at Seabrook were incorporated into the bounding transient set for calculating the stratification-induced thermal stresses. The applicant indicated that the monitoring would continue during the ascension phases of the plant startup to confirm that the plant-specific data remain within the limits of the bounding transient set. The staff believes, however, that the monitoring should continue until the next refueling outage to ensure that the thermal transients used in the Seabrook surge line design are indeed bounding, since some operational transients may not take place during the startup tests.

WCAP-12305 and -12306 describe fatigue evaluations of striping effects on the surge line. Generic information from Westinghouse indicated that Westinghouse had conducted a flow test in its Waltz Mill Laboratory. Striping amplitudes and frequencies were conservatively defined on the basis of the test results.

The attenuation effects of time and distance on the amplitude of thermal striping also were considered. The staff found that the approach for assessing the striping effects is conservative and the calculation results are acceptable.

WCAP-12305 and -12306 describe the methods and procedures used in calculating stratification effects. The calculated stresses and fatigue usage factors were combined with effects of other loadings, including striping. The staff reviewed the above information and found that the approaches used are reasonable and the resultants of stresses and fatigue usage factors are within the allowable values committed to in the Final Safety Analysis Report. The values are given in Section III of the ASME Code, 1977 edition through 1979 summer addenda.

Conclusions

On the basis of its review of information provided by the applicant, the staff concludes that the applicant has made acceptable efforts to meet Action Items 2.a and 2.c in NRC Bulletin 88-11. Its efforts have demonstrated that on the basis of the bounding input from the hot functional test at Seabrook and available stratification data of four other Westinghouse plants, the surge line meets the applicable design code. However, the applicant should commit to continue monitoring the surge line until its first refueling outage to ensure that the design thermal transients and stratification temperature profiles used at this time are indeed bounding for verifying compliance with the ASME Code.

3.9.3.2 Design and Installation of Pressure Relief Devices

EG&G, Idaho, under a contract with the NRC, provided a technical evaluation report (TER) (see Appendix Y) that gives the results of the staff's and EG&G's review of the applicant's submittals in response to the TMI Action Plan requirements of NUREG-0737, Item II.D.1, "Performance Testing of Relief and Safety Valves." The staff endorses the findings in the TER. On the basis of these results, the staff concludes that the applicant has provided an acceptable response.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.2 Containment Heat Removal System

6.2.2.2 Conclusion

In SSER 7, the staff stated that it would allow operation with the present containment building spray/residual heat removal (CBS/RHR) pressure isolation short-term-action configuration until the first refueling outage, but would condition the operating license to require that the applicant perform certain long-term actions. Subsequently, in its letter dated March 30, 1989, the applicant stated that a design change is being developed that provides for long-term actions to address the staff's concerns regarding the CBS/RHR system interface. This design change involves the addition of a check valve in series with each of the four existing check valves that provide isolation at the CBS/RHR system interface. The applicant submitted a complete description of this design change for staff review and approval on May 1, 1989. The applicant also committed, on receipt of staff approval, to expedite the implementation of this design change and to try to improve the previously accepted schedule of installation before startup from the first refueling outage. On the basis of its review and evaluation of these commitments, the staff concluded in SSER 8 that the commitments were acceptable and that the license condition proposed in SSER 7 was no longer required. In SSER 8, the staff listed this item as Confirmatory Item (61).

Region I inspections, including the most recent one (week of November 11, 1989), confirmed that both short- and long-term actions have been completed. The following inspection reports document the closeout of Confirmatory Item (61): Inspection Report (IR) 50-443/88-10, IR 50-443/89-01, IR 50-443/89-08, IR 50-443/89-09, and IR 50-443/89-83.

6.4 Control Room Habitability

In Section 6.4 of SSER 7, the staff found that the inherent single-failure problem of the control room habitability system restricted operation to no greater than 5 percent of rated power and stated that, before proceeding above 5 percent of rated power, the applicant should demonstrate to the satisfaction of the NRC staff that the control building air (CBA) system provides protection in accordance with the provisions of Sections 6.4, 6.5.1, and 9.4.1 of the Standard Review Plan (SRP, NUREG-0800) and General Design Criterion (GDC) 19 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50).

In SSER 7, the staff stated that NRC inspectors had observed that the control building heating, ventilation, and air conditioning (HVAC) (CBA) system was susceptible to the single failure of 4160-V ac bus E5 or E6 in the absence of operator action and that other problems had been noted in system operation and logic that may have negated the design basis in the applicant's Safety Analysis Report. If a vital electric bus fails, the damper located on the discharge of the operable makeup air fan must be opened manually with a handwheel override operator to allow the control room to be pressurized. In this situation the control room cannot be isolated because the radiation monitors cannot function as designed. This realignment process also necessitates that the makeup air purge line valve, corresponding to the contaminated intake, be manually opened. This allows the contaminated intake to be purged with air from the clean intake when the makeup air fan restarts.

In SSER 8, the staff noted that in a letter dated March 2, 1987, the applicant committed to provide the details of modifications to the CBA system for NRC staff review before they were implemented. In a letter dated January 22, 1988, the applicant described the proposed modifications to the system and provided a reanalysis of the post-loss-of-coolant-accident radiological doses to the control room personnel as a result of the proposed modifications. In a letter dated June 17, 1988, the applicant provided additional information. In a letter dated March 30, 1989, the applicant stated that proposed technical specifications pertaining to this design change will be submitted and that this design change will be completed by September 30, 1989.

On October 2 and 3, 1989, the NRC staff inspected the modified CBA system. The staff found that the proposed additional high-efficiency particulate air filter F-8038 and the proposed bypass piping with two backdraft dampers were installed. The original two purge lines were capped off and their associated purge valves had been removed. In the applicant's report, "Control Room Area Ventilation System 18 Month Surveillance," dated September 29, 1989, the staff found that the flow balance of the modified CBA system is within the acceptance criterion of the Seabrook Technical Specifications, which is 1100 cubic feet per minute (cfm) ± 10 percent. On the basis of the surveillance report of September 29, 1989, emergency filter train A, CBA-F-38, had a total flow of 1193 cfm, which consisted of 573 cfm of makeup air and 620 cfm of recirculation air. Emergency filter train B, CBA-F-8038, had a total flow of 1173 cfm, which consisted of 579 cfm of makeup air and 594 cfm of recirculation air. These test results indicated that the makeup air was within the design value of $\leq$ 600 cfm.

A positive differential pressure (DP) between the control room and its adjacent areas is maintained in the control [illegible] during normal and emergency operational modes. The surveillance test ind[illegible] that the DP between the control room and the outside was 0.15 in. wate[illegible]ge (WG) and the DP between the control room and the cable spreading room wa[illegible] in. WG. These values are greater than the Technical Specification value [illegible].5 in. WG.

On October 3, 1989, the control room was in the emergency mode of operation because electrical bus E6 was undergoing maintenance. The staff observed that the emergency filtration train maintained a positive DP between the control room and other areas.

On the basis of the above findings, the staff concludes that the implemented modifications in the control room resulted in an acceptable surveillance test; therefore, the completion of the modifications closes Confirmatory Item (58).

In SSER 8, the staff found, on the basis of its independent analysis, that the control room operator doses are within the criteria of GDC 19. Therefore, the staff concluded that when the proposed modification is implemented, the control room habitability system will provide radiological protection in accordance with SRP Sections 6.4, 6.5.1, and 9.4.1 and GDC 19 and, hence, is acceptable. As noted previously, on October 2 and 3, 1989, the staff visited the site and verified that the modification had been implemented (Inspection Report 50-443/84-09). This completes Confirmatory Item (58).

7 INSTRUMENTATION AND CONTROLS

7.5 <u>Information Systems Important to Safety</u>

7.5.2 Specific Findings

7.5.2.4 Post-Accident Monitoring Instrumentation

The staff completed its review of the applicant's conformance to Regulatory Guide (RG) 1.97, Revision 3, by providing its safety evaluation (SSER 5) to the applicant in July 1986. The staff concluded that the applicant's design was acceptable with respect to conformance to RG 1.97, except for the following variables: accumulator tank level and pressure, containment sump water temperature, and quench tank temperature (pressurizer relief tank temperature). The staff accepted the applicant's commitments (1) to install Category 2 accumulator tank level or pressure instrumentation and (2) to either show that quench tank temperature, including the maximum expected saturation temperature, will remain functional and on scale during any accident that lifts the pressurizer relief valves or provide a range that will envelope these conditions. By letters dated May 19 and July 10, 1989, the applicant requested that the staff re-evaluate the accumulator tank level and pressure, containment sump water temperature, and quench tank temperature issues.

The staff's review of the applicant's submittals shows that the applicant either conforms to, or has provided an acceptable justification for deviations from, the guidance of RG 1.97 for the above variables. Specifically:

(1) RG 1.97 recommends Category 2 accumulator tank level or pressure instrumentation, with a range of 0 to 700 psig, to monitor the operation of the accumulator tank. The applicant has stated that it plans to upgrade the accumulator tank pressure instrumentation to satisfy the criteria of Design Category 2. This is in accordance with RG 1.97 and is therefore acceptable.

The applicant is providing accumulator tank pressure instrumentation with a range of 0 to 700 psig. The applicant states that this is adequate because the design pressure of the tank is 630 psig. On the basis of the tank design pressure, the staff finds that the range of 0 to 700 psig is adequate and acceptable.

(2) RG 1.97 recommends Category 2 containment sump water temperature instrumentation to monitor the removal of heat from the containment. The applicant is providing Category 2 containment spray heat exchanger inlet temperature instrumentation. The applicant states that the net positive suction head calculations for the containment spray and residual heat removal pumps assume saturated conditions in the containment sump. Saturated conditions result in the maximum possible sump temperature. Therefore, the containment sump water temperature is monitored at the inlet to the containment spray heat exchanger. On the basis of the justification provided by the applicant, the staff finds the alternate instrumentation acceptable.

(3) RG 1.97 recommends quench tank temperature instrumentation with a range of 50°F to 750°F to monitor the operation of the quench tank. The applicant has provided instrumentation with a range of 50°F to 350°F. The applicant states that the maximum expected saturation temperature is 338°F, which corresponds to the quench tank rupture disk pressure of 100 psig. Therefore, the instrumentation provided by the applicant is acceptable.

Conclusion

On the basis of its review of the applicant's submittals, the staff concludes that the Seabrook Unit 1 and 2 design is acceptable with respect to conformance to RG 1.97, Revision 3.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

9.5.1.4 General Plant Guidelines

Ventilation

In SSER 8, the staff noted that the applicant's fire hazards analysis indicated the need to modify the plant to incorporate charcoal filter unit detection systems and other modifications and that the applicant had committed to complete the modifications by September 30, 1989. The staff accepted the completion date committed to by the applicant, but noted that in no case shall the applicant proceed above 5 percent of rated power without completing the modifications dictated by the fire hazards analysis.

In a letter dated September 22, 1989, regarding fire protection for the heating, ventilation, and air conditioning (HVAC) system, the applicant reported that all the charcoal filter carbon monoxide fire detection (COFD) systems it had committed to install have essentially been completed, except for those detectors associated with the control building (CB) HVAC system. The applicant reported that during preoperational calibration and testing, the solid-state detectors in the COFD system for the CB HVAC system had not performed in accordance with the design specifications. The applicant concluded that the solid-state sensors are inappropriate for this application.

To resolve this problem, the applicant will install electrochemical sensors that preliminary testing has indicated will work and that satisfy existing design requirements. In discussions with the applicant, the staff was satisfied with the applicant's actions to resolve the problem.

The staff finds that the applicant's commitment to have the carbon monoxide fire detection system for the control building heating, ventilation, and air conditioning system fully operational before plant ascension into Mode 4 as required by the Technical Specifications is acceptable. This requirement to demonstrate the system fully operational each time before the plant ascends into Mode 4 is more restrictive than performing the one confirmatory test committed to by the applicant. Therefore, this issue is closed.

11 RADIOACTIVE WASTE MANAGEMENT

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

11.5.2 Evaluation Findings

The radioactive particulate and iodine sampling and analysis described in NUREG-0737, TMI Action Plan Item II.F.1, Attachment 2, represent substantial departures from the conventional design and operating concepts in the detection and measurement of plant radiological releases. This process requires the sampling system to detect, collect, and analyze representative samples of radioactive iodine and particulates in highly radioactive plant gaseous effluents during and following an accident, with overall system accuracies within a factor of 2.

Without a representative sample and analysis of the radioiodine content of plant gaseous effluents, the operator of a nuclear power plant in which a nuclear accident has occurred is faced with the alternative of calculating projected offsite doses to the population by using calculations that may be based on extremely conservative assumptions or rapidly obtaining radiation measurements in the field. The requirements of TMI Action Plan Item II.F.1 were promulgated to ensure that a plant operator would have the capability, under accident conditions, to obtain and analyze samples of the plant gaseous effluents that would be sufficiently representative of the actual discharge conditions to permit a realistic assessment of projected offsite doses to the population.

In SSER 5, the staff concluded that the design and operation of the process and effluent radiological monitoring and sampling system conform to the requirements of Attachments 1 and 2 to TMI Action Plan Item II.F.1, except for the system's capability to obtain representative iodine and airborne particulate samples. Therefore, the staff specified in the supplement the following license condition:

Before startup following the first refueling outage, the applicant shall demonstrate that the iodine/particulate sampling system is operable and will perform its intended function.

In a letter dated March 30, 1989, the applicant stated that (1) the operability of the iodine and airborne particulate sampling system for obtaining representative samples had been demonstrated with iodine and particulate transmission modeling and analyses by the applicant's contractor, Science Applications International Corporation (SAIC); (2) the SAIC modeling and analyses identified the need for a system design change to improve the transmission factors for the wide-range gas monitors; (3) the applicant had developed a system design change in accordance with the SAIC finding; (4) SAIC had remodeled and reanalyzed the system on the basis of the applicant's revised system design and demonstrated that it provided acceptable transmission factors; (5) the applicant committed to have this design change implemented by September 30, 1989; and (6) the applicant also committed to submit by May 30, 1989, a report of the SAIC modeling and analyses for the staff's review.

In SSER 8, the staff closed the license condition on the basis of the preceding commitments subject to the staff's future audit of the applicant's commitments. In a response involving the commitments, the applicant submitted with its transmittal letter of May 30, 1989, a report entitled "Radioiodine and Particle Transmission Through Selected Sampling Lines at Seabrook Station," which was prepared by SAIC. The staff performed an acceptance review of this report regarding the adequacy of the design and operation of the Seabrook system to obtain and quantify the representative samples in accordance with the requirements specified in TMI Action Plan Item II.F.1. The staff also visited the Seabrook site on October 12, 1989, and audited the installation of the modified sampling system as recommended by SAIC and the implementation of plant operating procedures to ensure the use of proper sample loss transmission factors acceptable to the staff.

The Seabrook effluent radiological monitoring system is designed to provide information concerning radioactivity levels in plant gaseous discharges to the environs during normal operation of the plant as well as during and following design-basis accidents. The system consists of (1) the auxiliary and service building exhaust monitor (ASBEM); (2) the stack wide-range gas monitor, both low range (WRGM-LR) and high range (WRGM-HR); and (3) the gland steam condenser exhaust monitor (GSCEM). All sample lines for these effluent radiation monitors are made of Type 316 stainless steel and have the following as-built physical and operating characteristics:

Monitor	Length (ft)	Inside diameter (in.)	Flow rate (cfm)*	Temperature (F°)	Relative humidity (%)
ASBEM	36	0.87	3.0	110	50
WRGM-LR	122	0.61	1.7	110	50
WRGM-HR	122	0.61	1.7	110	50
GSCEM	16	0.37	1.0	135	95

The experimental values of the iodine deposition velocity and of the resuspension and fixation rates were measured using replicas of two Seabrook sample lines (WRGM-LR and GSCEM) at the SAIC testing facility to estimate the iodine transmission (loss) factors. The physical and operating characteristics of the WRGM-LR and the GSCEM were replicated experimentally. SAIC measured radioiodine concentrations and radioiodine species at the inlet and outlet of the sample test lines during the 4-hour radioiodine injection period. Following the injection period, the sample lines were purged with filtered air to measure resuspension of deposited iodine during a subsequent 22-day period.

Estimates of the deposition, fixation, and resuspension values obtained from measurements for Seabrook Station and data previously obtained for comparable sample lines from other reactor sites were used by SAIC to recommend the following gaseous radioiodine transmission factors for use at Seabrook:

Monitor	Factor
ASBEM	0.96
WRGM-LR	0.8
GSCEM	0.95
WRGM-HR	0.4 (initial)
	0.7 (equilibrium)

The transmission factor (TF) is defined as the ratio of the iodine concentration at the outlet of the sample line to that at the inlet. The lower the TF, the greater the loss of iodine as a result of the deposition of iodine in the

*cfm = cubic foot per minute

sample line. The recommended initial TF for the WRGM-HR line is 0.4. It is estimated to increase to 0.7 at equilibrium approximately 200 hours after an accident. The ASBEM, WRGM-LR, and GSCEM lines are normally in operation. The modified WRGM-HR line, which is not normally in operation, consists of two sections: the high sample flow (1.7 cfm) rate section of the WRGM-LH line and a new low sample flow (0.06 cfm) rate section from an isokinetic probe in the WRGM-LR line to the high-range monitoring skid. This modification will ensure that the highly radioactive postaccident sample would travel only a short distance (6 feet) in a small diameter (1/4-inch) at the low flow rate from the WRGM-LR line (3/4-inch-diameter).

The following radioactive iodine species distributions were measured by SAIC during the injection period, and they were compared with iodine source terms expected during and following an accident (Regulatory Guide 1.4).

Distribution	SAIC test	Regulatory Guide 1.4
Inorganic (%)	97	91
Particulate (%)	1	5
Organic (%)	2	4

Under normal reactor operating conditions, the forms of radioiodine observed in plant atmospheres and plant gaseous effluents are (1) the elemental form of iodine, which appears as the two-atom molecule I_2 and which can exist at normal ambient temperatures (50°F to 100°F) as either a gas or adsorbed on a solid (particle); (2) possibly the hypoiodous acid form HOI, as a vapor or gas; and (3) the organic form, usually assumed to be CH_3I. Historically, for design-basis-accident analyses, the staff has assumed iodine species distribution to be 5 percent particulate, 4 percent organic, and 91 percent elemental. Elemental (inorganic) iodine is the most reactive of the iodine species and the most likely to deposit in sample lines. The staff accepts the iodine species distributions used by SAIC for the transmission measurements for Seabrook.

Gaseous effluents from most nuclear plants can be described as comparatively free of particulates as the result of upstream filtration by high efficiency particulate air (HEPA) filters. At Seabrook, however, less than 45 percent of the plant stack effluent is filtered by HEPA filters. The auxiliary and service building and the gland steam condenser exhausts are filtered by the upstream HEPA filters before effluents are released to the environs. All sample lines (ASBEM, GSCEM, WRGM-LR, and WRGM-HR) are equipped with isokinetic sample probes.

SAIC calculated airborne particulate TFs through the sample lines using the computer code DUCT it had developed. The code calculations were based on (1) the length and numbers of vertical and horizontal sample lines and bends (slanted sections were considered horizontal), (2) the diameter of the line, (3) the mean fluid velocity in the line, and (4) the particle characteristics (diameter and density). At Seabrook, the particle diameter and density were not measured. SAIC instead assumed the particle density to be in the range of 1 to 3 grams per cubic centimeter with particle diameter in the range of 0.1 to 5 micrometers.

Using the preceding assumptions and the computer code calculations, SAIC recommended the following airborne particle TFs for Seabrook:

Monitor	Factor
ASBEM	0.9
WRGM-LR	0.8
WRGM-HR	0.7
GSCEM	0.9

During the site visit, the staff found that the radioiodine and particulate TFs recommended by SAIC were in use at Seabrook and had been incorporated in the following station operating procedures (SOPs):

(1) SOP No. CS-0910.10, "Gaseous Effluent Sampling," Rev. 3, October 2, 1989

(2) SOP No. CS-0925.02, "Post-Accident Activity Analysis," Rev. 1, May 19, 1988

(3) SOP No. CS-0925.07, "Post-Accident Gas Sampling," Rev. 2, October 2, 1989

On the basis of the staff's review of the SAIC report in developing the Seabrook TFs for radioiodine and particulate sample lines, along with review of SAIC's referenced reports (NUREG/CR-4786, EGG-2480, "Transport Behavior of Iodine in Effluent Radioactivity Monitoring Systems," October 1987, and NUREG/CR-1992, "In-Plant Source Term Measurements at Four PWRs," August 1981), and also of the staff's audit of the system installation and operation at the Seabrook site, the staff finds the TFs recommended by SAIC to be acceptable for use at Seabrook under accident conditions to assess projected offsite radiological consequences to the population.

Conclusion

On the basis of the above evaluation, the staff concludes that (1) SAIC Report No. 89-1422, "Radioiodine and Particle Transmission Through Selected Sampling Lines at Seabrook Station," dated May 1989, is an acceptable reference for use in the operation of the Seabrook effluent sampling system under accident conditions and (2) the design and operation of the as-built Seabrook effluent radiological monitoring and sampling system conform to the requirements of Attachment 2 to NUREG-0737, Item II.F.1. The staff's acceptance, therefore, closes Confirmatory Item (60).

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure and Qualifications

13.1.1 Management and Technical Support Organization

13.1.1.1 Corporate Organization

By letter dated July 19, 1989, New Hampshire Yankee (NHY) Division of Public Service Company of New Hampshire submitted changes to the organization of NHY. NHY is responsible for the Seabrook Station. The changes and the staff's evaluation of the changes follow.

NHY has established the new position of Senior Vice President and Chief Operating Officer. The person in this position will report directly to the President and Chief Executive Officer, NHY, and will direct the organizational units responsible for the operation and support of the Seabrook Station. In addition, the title of Vice President-Nuclear Production has been changed to Executive Director-Nuclear Production, and the title of Vice President-Engineering, Licensing and Quality Programs has been changed to Executive Director-Engineering and Licensing.

The staff finds these changes acceptable because they have not reduced the level of technical support for the Seabrook Station and they continue to meet the appropriate acceptance criteria of Section 13.1 of the Standard Review Plan (NUREG-0800).

13.3 Emergency Planning

13.3.1 Introduction

The NRC staff has completed its review of emergency preparedness for full-power licensing for the Seabrook Station. The acceptance criteria used as the basis for the staff's review are specified in Section 13.3, "Emergency Planning," of the Standard Review Plan (NUREG-0800) and include the planning standards of 10 CFR 50.47(b), the requirements of Appendix E to 10 CFR Part 50, and related implementing guidance, primarily NUREG-0654/FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated November 1980.

The Seabrook Station Radiological Emergency Plan (SSREP), the onsite plan, is discussed in Section 13.3.3. Offsite plans are discussed in Section 13.3.4 and include the New Hampshire Radiological Emergency Response Plan (NHRERP) for the New Hampshire portion of the plume exposure emergency planning zone (EPZ), the utility-prepared Seabrook Plan for Massachusetts Communities (SPMC) for the Massachusetts portion of the plume EPZ, and the Maine Ingestion Pathway Plan (MIPP) for the ingestion exposure pathway EPZ. The findings and determinations of the Federal Emergency Management Agency (FEMA) are also presented in Section 13.3.4.

The staff concludes that the Seabrook Station radiological emergency plans and preparedness meet the requirements of 10 CFR 50.47 including the 16 planning standards for onsite and offsite emergency plans; the requirements of 10 CFR Part 50, Appendix E; and the guidance criteria from NUREG-0654/FEMA-REP-1 for meeting the planning standards, and, therefore, there is reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at Seabrook.

The staff bases its conclusions on its assessment of the adequacy and implementability of the onsite plan and on its review of the FEMA findings and determinations regarding the adequacy and implementability of the State, local, and utility-prepared offsite plans. The staff assessment included (1) NRC and FEMA reviews of emergency plans, (2) NRC and FEMA evaluations of emergency preparedness exercises, (3) NRC onsite inspections of the applicant's emergency preparedness program, (4) offsite assistance and assessment visits by FEMA staff, and (5) other information provided on the record by FEMA and the applicant related to Seabrook emergency preparedness.

13.3.2 Background

The Seabrook Station plans describing the responsibilities and capabilities of the onsite emergency response organization are contained in the SSREP. The applicant has defined a plume exposure pathway EPZ that is about 10 miles in radius. The actual boundaries of the zone have been determined to take into account local conditions, primarily the jurisdictional boundaries of those communities that are within a radial distance of about 10 miles of the Seabrook site. The Seabrook plume exposure EPZ is shown in Figure 13.1.

The plume EPZ includes the States of New Hampshire and Massachusetts. Emergency plans for New Hampshire and the 17 local communities within the New Hampshire portion of the plume EPZ are contained in the NHRERP. Because of the refusal of the Commonwealth of Massachusetts to participate in the emergency planning process for Seabrook, the applicant has developed an emergency plan to compensate for the lack of participation of the Commonwealth and the six local communities within the Massachusetts portion of the plume EPZ. This plan is referred to as the Seabrook Plan for Massachusetts Communities (SPMC). The ingestion pathway EPZ for Seabrook is about 50 miles in radius and includes the States of New Hampshire, Massachusetts, and Maine.

13.3.3 Evaluation of Onsite Emergency Preparedness

The staff has reviewed the Seabrook Station Radiological Emergency Response Plan (SSREP, the onsite plan) through Revision 4, dated October 1989.* The results of prior staff reviews of the adequacy of onsite emergency preparedness are documented in Section 13.3 of the SER and subsequent supplements to the SER: SSER 1, dated April 1983; SSER 4, dated May 1986; and SSER 8, dated May 1989.

The Seabrook Station public alert and notification system (PANS) is described in the SSREP.** Primary public alerting within the plume EPZ will be accomplished

---

*This plan has not yet been docketed by the applicant. The staff reviewed an "Information Only" copy. Only minor changes have been made in SSREP, Revision 4. The applicant is to docket Revision 4 before this supplement is issued.

**A detailed description of the PANS design is given in the "Seabrook Station Public Alert and Notification System FEMA-REP-10 Design Report," dated April 30, 1988, and Addendum 1 to that report dated October 14, 1988.

Figure 13.1 Seabrook ~~P~~lume exposure emergency planning zone
? Source:

through the activation of pole-mounted fixed sirens in the New Hampshire portion of the plume EPZ and the vehicular alert and notification system (VANS) in the Massachusetts portion of the plume EPZ. Ninety-four sirens are permanently mounted in the New Hampshire EPZ. For Massachusetts, VANS will be deployed to 16 acoustic locations from 6 staging areas and 1 summertime-only satellite staging area. (See Section 13.3.4.2 for further discussion of the VANS.) Along the public beaches in Seabrook and Hampton, New Hampshire, the sirens will provide both an alert signal and public address messages. FEMA findings regarding the PANS for the New Hampshire EPZ and the VANS for the Massachusetts EPZ are given in Section 13.3.4.

Hearings on onsite emergency preparedness issues were completed in October 1986, and an Atomic Safety and Licensing Board decision was issued on March 25, 1987 (LBP-87-10). A license for fuel loading and precriticality testing was issued on October 17, 1986, and a license for low-power testing and operation not to exceed 5 percent was issued on May 26, 1989. In support of the low-power license application, the staff evaluated Seabrook emergency preparedness in accordance with the provisions of 10 CFR 50.47(d), and concluded in SSER 8 that the onsite plan for the Seabrook Station provided an adequate planning basis for an acceptable state of onsite emergency preparedness and met the requirements for issuance of a license authorizing low-power testing and operation.

Over the course of the licensing process for the Seabrook Station, some 14 inspections involving the evaluation of the onsite emergency preparedness program have been conducted by the NRC staff and documented in inspection reports, including four emergency preparedness exercise evaluations. The staff evaluation included a 2-week onsite emergency preparedness appraisal conducted in December 1985 with followup appraisals in March and June 1986. These team inspections assessed in depth the utility's emergency preparedness program and capability to implement the SSREP. All corrective actions and open items identified in the NRC inspection reports have been satisfactorily resolved. The staff will continue to conduct inspections of the onsite emergency preparedness program as part of the NRC routine inspection program following authorization for full-power operation.

Regarding evaluation of onsite exercises, the staff observed the performance of the onsite emergency response organization during the conduct of four emergency preparedness exercises: the February 1986 joint exercise of the onsite plan and the NHRERP; the December 1987 exercise of the onsite plan only; the June 28-29, 1988, full-participation exercise involving the onsite plan, the NHRERP, and the SPMC; and the September 27, 1989, partial-participation exercise involving the onsite plan and representatives of the State of New Hampshire and the New Hampshire Yankee Offsite Response Organization. The results of these exercise observations are documented in inspection reports including, for the most recent exercise, Inspection Report 50-443/89-10, in which the staff concluded that the utility's performance during the exercise demonstrated the ability to implement the emergency plan and procedures in a manner that would provide adequate protective measures for the public.

On the basis of previous staff conclusions, as documented in SSER 8, and the staff's continued technical review, inspections, and exercise evaluations, the staff finds that the SSREP meets NRC requirements and is acceptable for full-power licensing and operation.

13.3.4 Evaluation of Offsite Emergency Preparedness

The staff's evaluation of offsite emergency preparedness in this supplement is based primarily on FEMA's findings of adequacy, as reported by FEMA to the NRC. FEMA has provided its findings and determinations regarding offsite emergency preparedness for Seabrook Station to the NRC by memoranda dated December 14, 1988, and December 18, 1989. This supplement provides the staff's conclusions on offsite emergency preparedness, following staff review of FEMA's findings and determinations in regard to State, local, and utility-prepared offsite emergency response plans and preparedness.

The applicant has submitted offsite plans for the States of New Hampshire and Maine and its own utility-prepared offsite emergency plan for the Massachusetts portion of the EPZ. In accordance with the NRC/FEMA Memorandum of Understanding (50 FR 15485), the NRC staff provided these plans to FEMA and requested that FEMA review them and provide appropriate findings and determinations on offsite emergency preparedness to the NRC. FEMA's review and evaluation of these offsite plans were performed using the evaluation criteria and standards of NUREG-0654/FEMA-REP-1, Revision 1, and the standards and assumptions of Supplement 1* to that document. The assumptions in Supplement 1, which apply to the utility-prepared Seabrook Plan for Massachusetts Communities, are that in an actual radiological emergency, State and local officials who have declined to participate in emergency planning will exercise their best efforts to protect the health and safety of the public, will cooperate with the utility and follow the utility offsite plan, and have sufficient resources to implement those portions of the utility offsite plan where State and local response is necessary. These assumptions are discussed further in Section 13.3.6.

FEMA performed an integrated review and evaluation of the offsite plans and preparedness for Seabrook that included the New Hampshire Radiological Emergency Plan, the Seabrook Plan for Massachusetts Communities, the Maine Ingestion Pathway Plan, and the full-participation exercise conducted on June 28-29, 1989. 1988?
The FEMA findings and determinations for the three jurisdictional areas in the Seabrook EPZ are presented below.

13.3.4.1 New Hampshire Radiological Emergency Response Plan

The New Hampshire Radiological Emergency Response Plan (NHRERP) including plans for each of the local communities is intended to provide the State with the capability for a rapid and coordinated response to nuclear power plant emergencies in or near the State of New Hampshire including Seabrook. FEMA has reviewed the NHRERP and, in a memorandum to the NRC dated December 14, 1988, reported that when proposed enhancements to the public alert and notification system (PANS) for New Hampshire are installed and operable, the plans and preparedness for the State of New Hampshire will be adequate to protect the health and safety of the public living in the New Hampshire portion of the Seabrook EPZ by providing reasonable assurance that appropriate protective measures can be taken off

---

*Supplement 1 to NUREG-0654/FEMA-REP-1, Revision 1, issued September 1988, contains criteria for the review of utility-prepared offsite emergency plans developed in response to NRC's amended "realism" rule, 10 CFR 50.47(c)(1), effective December 3, 1987.

site in the event of a radiological emergency and are capable of being implemented. FEMA had found that the design of the alert and notification system for the New Hampshire portion of the Seabrook EPZ met the requirements of FEMA-REP-10, "Guide~~s~~ for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," November 1985; however, certain enhancements to the system had not yet been completed.

On December 18, 1989, FEMA reported that the conditions involving the PANS for the New Hampshire portion of the EPZ have been met and that the State of New Hampshire has the capability to provide an alert signal and instructional message in the New Hampshire portion of the Seabrook plume EPZ within the required time frames specified in FEMA-REP-10 and NUREG-0654/FEMA-REP-1, Revision 1, Appendix 3. The plans and preparedness for the State of New Hampshire are, therefore, adequate.

The FEMA evaluation of the NHRERP included an assessment of the State's performance during the June 28-29, 1989, full-participation exercise of the offsite emergency plans for Seabrook. The State of New Hampshire and 11 local communities within the plume EPZ participated in the exercise. New Hampshire, in accordance with its plan, implemented State compensatory actions for the six communities within the plume EPZ that chose not to participate in the exercise. (Since the exercise two additional communities have joined the planning process for Seabrook.)

see p. 13-12

By memorandum dated September 2, 1988, FEMA provided the NRC its report of the exercise. No deficiencies were identified by FEMA during the exercise. Areas requiring correction action and areas requiring further improvement were identified, and a schedule of corrective actions was established by the State of New Hampshire with FEMA.

see p. 13-12?

As part of the State of New Hampshire's protective action strategy for the Seabrook beaches under the NHRERP, the State of New Hampshire may order an early closing of area beaches as a precautionary measure at the "Alert" stage of an emergency. While this action is not ordinarily warranted at the Alert stage, it does preclude additional public access to the beaches and affords additional time for the public to depart those areas at highest risk in the unlikely event of a fast-breaking accident with the potential for a significant radiological release. Loudspeakers installed on the beaches for this purpose would be used to broadcast voice messages to the public if this option is chosen. The New Hampshire protective action of choice for the Seabrook beach area is evacuation, rather than sheltering, except for certain extremely limited and unlikely circumstances. FEMA has reviewed the NHRERP protective action strategy for beach populations and the basis for this strategy and found them to be adequate. On the basis of FEMA's finding and determinations on NHRERP beach protective action recommendations, the staff concludes that these are acceptable. The Licensing Board, in LPB-89-32, accepted FEMA's views and approved the protective action strategy.

On the basis of its review of FEMA's findings and determinations as summarized above, the staff concludes that the New Hampshire plans and preparedness provide reasonable assurance that adequate protective measures can and will be taken in the New Hampshire portion of the EPZ, and the NHRERP is acceptable for full-power operation of Seabrook Station.

Litigation Results and Licensing Board Conditions (NHRERP)

The NHRERP has been subject to extensive litigation before the Atomic Safety and Licensing Board (ASLB). FEMA filed testimony and participated in the hearings on the offsite issues raised by intervenors' contentions. The ASLB, in a Partial Initial Decision (PID) on the NHRERP (LBP-88-32, dated December 30, 1988), decided all New Hampshire emergency planning matters in controversy in the applicant's favor. The Licensing Board retained jurisdiction over a limited issue related to the effect on the evacuation time estimates (ETEs) of trips home by returning commuters. The board concluded that, subject to the satisfaction of certain conditions, the NHRERP meets the requirements of the emergency planning standards in 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50 and provides reasonable assurance that adequate protective measures can and will be taken within the New Hampshire portion of the Seabrook plume exposure pathway EPZ with respect to the issues decided in the PID.

The conditions imposed by the board in LBP-88-32 required that the Director of the Office of Nuclear Reactor Regulation verify, in conjunction with FEMA, that

(1) the State of New Hampshire has provided personnel rosters and call lists of compensatory plan and reception center emergency workers, (2) revisions to the NHRERP by the State of New Hampshire have been made as committed, (3) NHRERP revisions related to the operation of the Manchester secondary reception center and identification of additional special-facility monitors for the Manchester and Dover host communities have been made, and (4) the applicant has provided the State of New Hampshire with revised ETEs consistent with the board's findings. The NRC staff, acting in conjunction with FEMA, has verified that these conditions have been met. In a response dated December 11, 1989, FEMA reported to the NRC that the board conditions in the New Hampshire PID, all of which involve offsite emergency preparedness matters, have been satisfactorily completed.

Regarding the issue over which the board retained jurisdiction, the board, in its November 9, 1989, PID on the SPMC and 1988 graded FEMA exercise (LBP-89-32), found that returning commuters were adequately addressed through additional demonstration and sensitivity studies provided by the applicant, and stated that no further analysis or revision of the ETEs to account for returning commuters is required. In addition, the board (in LBP-89-32) concluded that the June 28-29, 1988, graded exercise demonstrated that the NHRERP is adequate and implementable.

On October 11, 1989, in ALAB-922, the Appeal Board certified to the Commission the issue of whether "testimony, which seeks to address dose reductions/ consequences that will arise under the NHRERP in the event of certain planning basis accidents, is admissible as relevant to a determination of whether...the NHRERP will achieve 'reasonable and feasible dose reduction under the circumstances' so as to provide 'reasonable assurance that adequate protective measures can and will be taken' in accordance with 10 CFR §50.47(a)." The Appeal Board certified this issue to the Commission for additional guidance as a preliminary matter before reviewing other issues in LBP-88-32, which concluded that the New Hampshire emergency plan met regulatory standards, because of "uncertainty over the resolution of this issue, which occupies a central role in this case and... emergency planning generally."

On November 7, 1989, the Appeal Board affirmed four sections of the Licensing Board's PID on the New Hampshire plan, but remanded four issues for further proceedings (ALAB-924). The remanded issues involve the following areas: letters of agreement for school teachers, the adequacy of the 1986 Special Needs Survey for the transport-dependent population, the adequacy of ETEs for advanced life support patients, and implementation details for sheltering the beach population. The Licensing Board (in LBP-89-32) reviewed these remanded issues and Appeal Board directions and concluded that they do not preclude the immediate issuance of an operating license for Seabrook.

On November 16, 1989, the Commission, in the interests of efficiency and effectiveness in resolving matters relating to the Licensing Board's authorization of the issuance of a full-power license, decided that it rather than the Appeal Board will consider all applications for stay of the Licensing Board's authorization of full power for Seabrook.

13.3.4.2 Seabrook Plan for Massachusetts Communities

The emergency plans for the Massachusetts portion of the plume EPZ are contained in the Seabrook Plan for Massachusetts Communities (SPMC). The SPMC was developed by the applicant to compensate for the lack of participation by the Commonwealth of Massachusetts and local Massachusetts communities in emergency planning for Seabrook. The SPMC was submitted by the applicant in September 1987 in conformance with the emergency planning requirements of 10 CFR 50.47(c)(1), the so-called "realism" rule, following the decision of the Commonwealth of Massachusetts and the local Massachusetts EPZ communities not to participate in emergency planning for Seabrook. The SPMC is designed to be implemented in one of three modes of operation in the event of an emergency at Seabrook: "Mode 1," which assumes the Commonwealth responds to the emergency and calls on the utility only for resources and personnel as needed; "Mode 2," which assumes that the Commonwealth delegates full authority to the utility to respond to the emergency and implement the SPMC; or a "Standby Mode," in which the utility's offsite organization stands in readiness to support the State if requested while continuing to perform accident assessment analyses.

The New Hampshire Yankee Offsite Response Organization (NHYORO) is responsible for implementing the SPMC. The NHYORO consists of emergency response personnel from New Hampshire Yankee (NHY), other utilty organizations, and various support groups and organizations with which NHY has contracts and/or letters of agreement.

Concerning the emergency plans and preparedness for Massachusetts, FEMA evaluated the utility-prepared Seabrook Plan for Massachusetts Communities and reported in a memorandum to the NRC dated December 14, 1988, that when the vehicular alert and notification system (VANS) is installed and operable, the plans and preparedness will be adequate to protect the health and safety of the public living in the Massachusetts portion of the plume EPZ by providing reasonable assurance that appropriate protective measures can be taken in the event of a radiological emergency and are capable of being implemented.

On December 18, 1989, FEMA reported to the NRC that on the basis of the current status of the alert and notification system for the Massachusetts portion of the plume EPZ, the means exist to notify the transient and resident population in that area. FEMA noted that the VANS will not become operational until January 3, 1990. FEMA stated that upon verification that the VANS is in an operational status, ~~FEMA~~ it will find the plans and preparedness for the Massachusetts portion of the plume EPZ to be adequate. FEMA as well as the NRC staff will verify that the VANS is installed and operational following the January 3, 1990, deployment of the VANS by the applicant. *

1989? up 13-8 up 13-8?

The FEMA evaluation of the SPMC included an assessment of the performance of the NHYORO, the organization responsible for implementing the SPMC, during the June 28-29, 1988, full-participation exercise of the offsite emergency plans at Seabrook. By memorandum dated September 2, 1989, FEMA provided the NRC its report of the exercise. No deficiencies were identified by FEMA during the exercise. Areas requiring corrective action and areas requiring further improvement were identified, and a schedule of corrective actions was developed by New Hampshire Yankee.

On the basis of FEMA's reported findings and determinations as summarized above and the applicant's commitment to fully staff and operate the VANS on January 3, 1990, the staff concludes that the plans and preparedness for the Massachusetts portion of the EPZ provide reasonable assurance that adequate protective measures can and will be taken in the Massachusetts portion of the EPZ, and that the SPMC is acceptable for full-power operation of Seabrook Station.

Vehicular Alert and Notification System (VANS)

Because certain local Massachusetts communities within the EPZ caused the removal of fixed, pole-mounted sirens installed by the applicant in these communities, the applicant was not able to employ the system originally installed for the purpose of public alerting. As a result, the applicant modified the original public alert and notification system (PANS, discussed in SSER 4) and developed a separate system as an alternative, the vehicular alert and notification system (VANS), for the communities in the Massachusetts portion of the EPZ.

The VANS is a mobile system of dedicated emergency vehicles with alerting sirens installed on hydraulically actuated telescoping booms mounted on a truck bed. These vehicles are maintained in a state of readiness under the control of the applicant in six designated staging areas and one summertime-only satellite staging area. The staging areas are staffed on a continuous 24-hour-per-day basis with dedicated and trained crews. The vehicles will be routinely maintained, and spare vehicles and reserve crew members are available in case of problems. Provisions have been made for operations under adverse weather conditions, and VANS operators are trained in operations and deployment of the system under all conditions.

At an "Alert" or higher emergency classification level, the NHYORO will dispatch the VANS vehicles from their staging areas to 16 predetermined acoustic locations. There the vehicles are stabilized and the sirens raised and sounded upon receiving a remote actuation signal from the NHYORO Emergency Operations Center. Each vehicle is equipped with a two-way radio, and the sirens can be manually activated if necessary. Sufficient VANS vehicles are available to provide area and sound level coverages similar to that of a fixed, pole-mounted system throughout the Massachusetts portion of the EPZ. The VANS staging areas, transit routes, and acoustic locations have been selected and field tested to ensure that the VANS vehicles can be dispatched and the sirens sounded throughout the EPZ within about 15 minutes, as required by the regulations.

Final procurement, assembly, and installation of the VANS are complete, and the applicant has committed to deploy and continuously staff the system before full-power operations. The NRC staff, in conjunction with FEMA, will verify the full operational status of the VANS and the adequacy of VANS implementation before full-power operation.

FEMA has evaluated the VANS and found the design adequate as documented in a report to the NRC dated January 23, 1989. Further findings regarding the VANS (note 1988) are included in the FEMA exercise report for the June 28-29, 1988, exercise dated September 2, 1988 (note 1988), and in the report of FEMA's evaluation of the SPMC provided to the NRC on December 14, 1988. The staff has reviewed the FEMA findings, reviewed the information provided in the SPMC and other documents by the applicant, and inspected the VANS vehicles, staging areas, and acoustic locations. On the basis of its evaluation, FEMA's reported findings, and the applicant's commitments, the staff finds the VANS is an acceptable means for meeting public alert and notification requirements and is adequate for full-power operations.

SPMC Liaison Functions

The SPMC provides for three State liaisons who are assigned responsibility for establishing communications with the Commonwealth at the State Emergency Operations Center (EOC) in Framingham, the Area I EOC in Tewksbury, and the offices of the Massachusetts Department of Public Health. The SPMC also provides for six local EOC liaisons who report to each of the local community EOCs. Responsibilities of the State and local EOC liaisons include establishing communications with the EOC Civil Defense Director/senior EOC official, apprising the EOCs of current event classification and plant conditions, requesting the status of State and local response capabilities, explaining the capabilities of the NHYORO, and in general assisting in coordinating the joint NHYORO/Massachusetts response efforts.

Litigation Results and Board Emergency Planning Items Related to the SPMC

The Licensing Board issued a PID on the SPMC and the 1988 FEMA graded exercise on November 9, 1989 (LBP-89-32). The board concluded that the SPMC meets the requirements of the Commission's emergency planning regulations and that there is reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at Seabrook. The ~~Board's~~ board's conclusion was predicated on the applicant's conformance with certain conditions, requirements, and commitments as specified in the board's findings in the PID. The board left the verification of the applicant's conformance with these provisions to the NRC staff with broad discretion in the timing and manner of conformance consistent with the board's findings. The staff reviewed the board decision and identified the emergency planning items which the staff believed should be satisfactorily resolved to support the full-power licensing schedule for Seabrook. Since all of the board items involved offsite preparedness matters, the staff requested the assistance of FEMA in verifying the closure of these items. In a response dated December 11, 1989, FEMA reported that all board items, with one minor exception, had been satisfactorily resolved. The one exception concerns assurance that the access control procedures in the New Hampshire Traffic Management Plan are consistent with those in the SPMC. The applicant has committed to submit a revised Traffic Management Plan in December 1989.

Has this been done?

Give date

In LBP-89-33, the board noted that a fifth matter, concerning the planning basis for determining the transportation needs for certain special facilities, was referred to the board in ALAB-924. The board indicated that it would require the applicant to resolve the matter. FEMA, in its December 11, 1989, response to the NRC, has confirmed that the issue has been satisfactorily resolved.

VANS contentions were litigated before the Licensing Board regarding onsite emergency planning contentions. That board, in a Final Initial Decision (LBP-89-17, dated June 23, 1989), determined that the VANS meets the requirements of emergency planning regulations and guidance.

Loss of Offsite Response Capability by NHYORO

An issue was raised during the SPMC hearings concerning the occurrence of an emergency when one or more of the companies relied on by the ORO are on strike. No direct testimony in support of this contention was filed by the intervenors and the intervenors did not cross-examine on this subject. The board concluded that there is reasonable assurance that strikes will not affect the availability of the emergency personnel relied on to staff and maintain the ORO adequately. (LBP-89-32, at 214.) Because the ORO consists entirely or primarily of emergency response personnel from New Hampshire Yankee, other utility organizations, and various support groups, the staff will impose a license condition requiring the utility to inform the NRC within 4 hours of becoming cognizant of any event or activity that would adversely affect the capability of the NHYORO to respond to an emergency at Seabrook. The notification to the NRC shall include a preliminary assessment of the potential impact of the situation on the utility's overall response capability and proposed compensatory actions to mitigate the consequences.

13.3.4.3 Maine Ingestion Pathway Plan

By letter dated December 14, 1988, FEMA reported to the NRC that the Maine Ingestion Pathway Plan (MIPP) and preparedness are adequate to protect the health and safety of the public living in the Maine portion of the Seabrook ingestion pathway EPZ by providing reasonable assurance that appropriate protective measures can be taken off site in the event of a radiological emergency and are capable of being implemented.

13.3.5 Conformance With Emergency Planning Rule 10 CFR 50.47(c)(1)

Through public announcements made by the Governor of Massachusetts in 1986, the Commonwealth of Massachusetts (and similarly, the six Massachusetts local communities within the Seabrook EPZ) declared their intention not to participate in emergency planning for Seabrook. These parties actively intervened in the licensing process to oppose the licensing of the Seabrook Station. This opposition and nonparticipation clearly established the basis for the applicant's development of a utility-sponsored offsite emergency response plan and organization designed to compensate for lack of State and local participation. The pertinent compensatory plans and procedures for the Massachusetts EPZ were submitted to the NRC by the applicant on September 18, 1987. The regulatory basis for this action is discussed below.

The emergency planning regulations were amended on November 3, 1987 (52 FR 42078) to provide criteria for the evaluation, at the operating license review stage, of utility-prepared emergency plans in situations in which State and/or local governments decline to participate in emergency planning.

10 CFR 50.47(c)(1) states, in part:

> Where an applicant for an operating license asserts that its inability to demonstrate compliance with the requirements of [10 CFR 50.47(b)] results wholly or substantially from the decision of State and/or local governments not to participate further in emergency planning, an operating license may be issued if the applicant demonstrates to the Commission's satisfaction that:
>
> (i) The applicant's inability to comply with...[NRC emergency planning] requirements...is wholly or substantially the result of the non-participation of State and/or local governments.
>
> (ii) The applicant has made a sustained, good faith effort to secure and retain the participation of the pertinent State and/or local governmental authorities, including the furnishing of copies of its emergency plan.
>
> (iii) The applicant's emergency plan provides reasonable assurance that public health and safety is not endangered by operation of the facility concerned. To make that finding, the applicant must demonstrate that, as outlined below, adequate protective measures can and will be taken in the event of an emergency. A utility plan will be evaluated against the same planning standards applicable to a State or local plan...with due allowance made both for-
>
> (A) Those elements for which State and/or local non-participation makes compliance infeasible and
>
> (B) The utility's measures designed to compensate for any deficiencies resulting from State and/or local non-participation.
>
> In making its determination on the adequacy of a utility plan, the NRC will recognize the reality that in an actual emergency, State and local government officials will exercise their best efforts to protect the health and safety of the public. The NRC will determine the adequacy of that expected response, in combination with the utility's compensating measures, on a case-by-case basis, subject to the following guidance. In addressing the circumstance where an applicant's inability to comply with the requirements of [10 CFR 50.47(b)] is wholly or substantially the result of non-participation of State and/or local governments, it may be presumed that in the event of an actual radiological emergency, State and local officials would generally follow the utility plan. However, this presumption may be rebutted by, for example, a good faith and timely proffer of an

adequate and feasible State and/or local radiological emergency plan that would in fact be relied upon in a radiological emergency.

The applicant's plan developed as a result of the nonparticipation of the Commonwealth of Massachusetts and the six local communities within the Massachusetts EPZ is discussed in Section 13.3.4.2. The Seabrook Plan for Massachusetts Communities (SPMC) is a utility-developed plan that contains measures intended to compensate for the fact that the Commonwealth of Massachusetts and local governments have refused to participate in emergency planning for Seabrook Station. The plan provides that upon being notified of an emergency by Seabrook Station, the State will either have adequate capabilities to respond, in which case the NHYORO will stand by and monitor the State and local response (Standby Mode), the State and local governments may request NHYORO resources only (Mode 1), or the State will authorize the NHYORO to implement the SPMC (Mode 2). Under the plan, the State will determine which mode is to be implemented in the event of a radiological emergency at Seabrook. The Licensing Board concluded that there is reasonable assurance of adequate coordination between the NHYORO and State and local responders in all modes of the SPMC. (LBP-89-32, at 493.) The Board also stated that the applicant had made a substantial good-faith attempt to secure and retain the cooperation of the Commonwealth in emergency planning. (Id. at 477.)

Massachusetts, through the Massachusetts Attorney General, challenged the premise that the delegation of certain powers from the Governor to the NHYORO is lawful. The board, in LBP-89-8 (February 16, 1989), found that the Governor of Massachusetts, or his designee, pursuant to the provisions of the Massachusetts Civil Defense Act, may delegate to the NHYORO sufficient powers to implement pertinent provisions of the SPMC.

On the basis of the actions of the Commonwealth of Massachusetts and local governments within the Massachusetts EPZ, the applicant's efforts to secure cooperation, and the results of FEMA's review of the SPMC and the NHYORO implementing organization, the staff concludes that the applicant has adequate bases for developing and implementing its offsite plan and organization for Massachusetts and has demonstrated conformance with the requirements of 10 CFR 50.47(c)(1).

13.3.6 Review Assumptions for Utility-Prepared Offsite Emergency Plans

FEMA's review and evaluation of the Seabrook Plan for Massachusetts Communities and the Massachusetts portion of the 1988 emergency preparedness exercise reflect three assumptions provided by the NRC staff. These assumptions are that in an actual radiological emergency, State and local officials who have declined to participate in emergency planning will

(1) exercise their best efforts to protect the health and safety of the public

(2) cooperate with the utility and follow the utility plan

(3) have sufficient resources to implement those portions of the utility offsite plan where State and local response is necessary.

The first two assumptions derive from 10 CFR 50.47(c)(1)(iii)(B) as shown above. Regarding the first assumption, the NRC accepts the reality that in an actual emergency, State and local governments will exercise their "best efforts" to protect the health and safety of the public. This presumption has been upheld by the First Circuit Court of Appeals, following a court challenge to the regulations filed by Massachusetts.

The second assumption concerns the rebuttable presumption that State and local officials in an actual emergency will generally follow the utility plan. This presumption has not been rebutted in litigation before the boards by a showing of any other way State and local officials will use their "best efforts" to protect the health and safety of the public, nor does the staff believe that Massachusetts has rebutted this presumption in any other manner.

The third assumption, concerning the sufficiency of resources, was provided to FEMA by the NRC to facilitate the FEMA review of utility-prepared offsite emergency plans. Interrogatory answers provided by Massachusetts to the NRC staff in litigation before the Licensing Board demonstrate the Commonwealth's ample resources to respond to an emergency at Seabrook. Further, the NRC staff recognizes that even though the NHYCRO has been developed with the capability and resources to function without State and local support, the Commonwealth of Massachusetts has State plans, including substantial identified resources, for use in radiological emergencies (e.g., in support of the Vermont Yankee plant, the Pilgrim plant, and the Yankee-Rowe plant). Additionally, the NHYORO is able to interface with various State agencies to identify and use existing State resources. The Licensing Board concluded that "[n]o lack of State or local resources has been shown to exist, let alone one which could prevent there being reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at Seabrook Station." (LBP-89-32.) Accordingly, the staff concludes that State and local resources are sufficient to support the implementation of the SPMC.

13.3.7 Conclusions

On the basis on its review of the Seabrook Station Radiological Emergency Plan (SSREP) for conformance with the criteria in NUREG-0654/FEMA-REP-1, the results of onsite inspections, and its evaluation of the performance of the onsite emergency response organization in implementing the SSREP during exercises, the staff concludes that the Seabrook onsite emergency plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness and meets the requirements of 10 CFR Part 50 and Appendix E thereto.

FEMA has provided its findings and determinations on the adequacy of offsite emergency planning and preparedness, based on its plan reviews, exercise observations, and analyses. FEMA has also provided verification that pertinent board conditions have been satisfactorily completed. On the basis of its review of these findings and on the basis of the applicant's commitment to make the vehicular alert and notification system (VANS) operational on January 3, 1990, the staff concludes that the Seabrook offsite emergency plans provide an adequate planning basis for an acceptable state of offsite emergency preparedness and meet the requirements of 10 CFR Part 50 and Appendix E thereto.

Since the Commonwealth of Massachusetts and the local Massachusetts governments have refused to participate in emergency planning, the applicant has developed its own utility-prepared offsite emergency plan (the SPMC). The applicant has filed documents attesting to its conformance with the requirements of 10 CFR 50.47(c)(1) regarding legal authority issues. The applicant has asserted that it has made a sustained, good-faith effort to secure the participation of the Massachusetts State and local governmental authorities. The Licensing Board considered the applicant's filings and concluded that the applicant has met the requirements of 10 CFR 50.47(c)(1). In making its overall determination on the adequacy of the utility-prepared offsite plan, the NRC, in accordance with 10 CFR 50.47(c)(1)(iii)(B), has presumed that the Commonwealth and local governments would exercise their best efforts to protect the health and safety of the public and would generally follow the utility plan in the event of an actual emergency.

The NRC staff concludes that the overall state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at the Seabrook Station, and, therefore, emergency preparedness at Seabrook is adequate to support full-power operations.

14 INITIAL TEST PROGRAM

In the SER, the staff noted that an initial test program will be conducted at the Seabrook Station to demonstrate that plant systems, structures, and components will perform in a manner that will not endanger the health and safety of the public. The criteria of Section 14 of the Standard Review Plan (NUREG-0800) were used to determine the acceptability of the applicant's test program. By letters dated November 6 and December 5, 1989, the applicant requested approval for modifications to the power ascension program and the associated revisions to Chapter 14 of the Final Safety Analysis Report (FSAR). The staff's findings are as follows:

MAIN STEAM LINE ISOLATION VALVE (MSIV) CLOSURE TEST

Regulatory Guide (RG) 1.68, Revision 2, August 1978, specifies the following:

> u. Verify operability and response times of main steam line isolation and branch steam line isolation valves. For PWRs [pressurized water reactors], justification for conducting this test at low power and/or a description of design qualification tests for valves of the same size and design may be submitted. (25%)
>
> h.h. Demonstrate that the dynamic response of the plant to the design load swings for the facility, including step and ramp changes, is in accordance with design. (25%, 50%, 75%, 100%)
>
> m.m. Demonstrate that the dynamic response of the plant is in accordance with the design for the case of automatic closure of all main steam line isolation valves. For PWRs, justification for conducting the test at a lower power level, while still demonstrating proper plant response to this transient, may be submitted for NRC staff review. (100%)

MSIV Operation

In the letter dated November 6, 1989, the applicant stated that acceptable stroke testing of the Seabrook MSIVs had been demonstrated during hot functional test PT-13. During a telephone conference call on December 12, 1989, the applicant further stated that the full-stroke testing had been accomplished without any problems. The applicant also provided the following information in the letter dated November 6, 1989: "Type/qualification tests performed by Rockwell International on valves similar to the Seabrook MSIVs demonstrate that the Seabrook MSIVs are capable of closing under design flow conditions within the required time." In the telephone conference call on December 12, 1989, the applicant stated that the "generic" valves used for comparison are Rockwell valves and that these valves were tested to 110 percent of the flow that Seabrook's valves will pass. There is no significant difference between the valves except that the generic valves were tested at 23 percent higher pressure than would be the case for a Seabrook valve test, and the throat diameter of the generic valve is about the same as ~~those at~~ the throat diameter of the Seabrook valves. In the letter dated November 6, 1989, the applicant also stated that "dimensional factors determining closing forces are virtually identical" between the generic and Seabrook valves and that comparison of stresses confirms that the stresses in the generic valves are greater than those in the Seabrook valves.

The MSIVs are part of the inservice test program and will be subjected to full-stroke testing while the plant is in Mode 3 (hot standby) following refueling outages. They also will be subjected to a 10-percent stroke test quarterly.

The staff's understanding of the information provided by the applicant is that the Seabrook valves have been demonstrated to possess acceptable test characteristics (except for testing with a significant steam flow rate), that the generic valves are sufficiently similar to Seabrook valves so that generic test data are applicable, and that the generic valves have been shown to possess acceptable closure characteristics under steam-flow conditions by means of applicable tests. The staff further notes that RG 1.68 accepts a reduced steam flow rate for testing and it is unnecessary to test at full power. Thus, the staff traditionally accepts forces associated with less than full-power flow for closure testing. The staff considers it unlikely that the closure test would uncover a valve problem when consideration is given to the full-flow generic valve tests and the similarity between valves. Consequently, the staff finds that the information supplied by the applicant is sufficient to support elimination of test ST-47 insofar as valve operability is concerned.

Plant Transient Response to MSIV Closure

In the letter dated December 5, 1989, the applicant qualified previous information by stating that the turbine trip test from 100 percent power (ST-38) does not envelope the MSIV closure test (ST-47). (The applicant had previously stated that the dynamic response of the plant to MSIV closure was bounded by the response to a turbine trip.) In discussions with the applicant, the applicant stated that the steam generator (SG) atmospheric dump valves are expected to open during the turbine trip test and the SG safety valves are expected to remain closed, although safety-valve response is not 100 percent certain. The applicant expects similar behavior during test ST-47, although the likelihood of the SG safety valves opening appears higher. Neither the turbine trip nor the MSIV test is expected to open the pressurizer power-operated relief valves. The staff notes that a manual reactor trip would be performed as soon as the MSIVs had closed, thereby reducing the impact of valve closure. The turbine trip will result in an immediate reactor trip.

The turbine trip test will result in bypassing the equivalent of 40 percent of the steam generated from a 100-percent-power condition once the turbine bypass valves are fully open. The staff understands from the applicant that the turbine stop valves are expected to close in a fraction of a second and that it will take several seconds for the bypass valves to fully open. The MSIVs take several seconds to fully close. Thus, the turbine trip test will almost instantly stop steam flow at the turbine stop valves followed by a gradual steam bypass. A small "cushion" is provided from the stop valves to the SGs by the length of the steam lines. MSIV closure results in less of an "instantaneous" transient at the valves, but there is less cushion between the valves and the SGs and the gradual steam bypass does not exist. Fission heat is terminated quickly during the turbine trip test and after a few seconds during the MSIV test.

Initially, the heat that must be rejected is roughly a factor of 3 higher in the turbine trip test. There are many similarities and some dissimilar behavior between these tests. The staff's judgment is that the dissimilarities are sufficiently small so that the turbine trip test results can be applied as a substitute for the MSIV test, provided the dissimilarities are understood.

The applicant did not provide a comparison of the expected impact of the tests on the plant. The staff believes this is necessary. Consequently, it will accept test ST-38 as satisfying the requirement of RG 1.68, Item m.m., provided the applicant compares the expected differences, ~~applicant~~ includes this information in the ST-38 test documentation (or a separate document), and factors this understanding into plant operation as appropriate. This should be accomplished before extended full-power operation. Analyses and/or applicable test data from similar plants may be used to satisfy this requirement.

NEED FOR TESTING ABILITY OF MOVABLE NEUTRON FLUX INSTRUMENTATION TO DETECT CONTROL ROD MISALIGNMENTS

RG 1.68 ~~contains~~ states the following: ~~item.~~

> i. Demonstrate capability and/or sensitivity, as appropriate for the facility design of incore and excore neutron flux instrumentation, to detect a control rod misalignment equal to or less than the technical specification limits. (50%, 100%)(PWR)

In the letter dated November 6, 1989, the applicant stated:

> The basis for this deletion is that the original requirement was imposed to demonstrate alternative instrumentation capabilities in detecting a misaligned control rod. With the advent of the digital rod position indication (DRPI) system, the need for accurate and sensitive alternative indications has been essentially eliminated. In any case, the distribution and number of the incore and excore flux instrumentation has not been changed and is identical to all Westinghouse four-loop plants since Indian Point 2. Since that time, the capability and sensitivity of the excore and incore flux instrumentation has been demonstrated numerous times.

The applicant considers the digital rod position indication (DRPI) system to be the primary means for detecting rod cluster control assembly misalignments. This system provides information on individual rod positions. The movable incore flux instrumentation provides confirmational capability. The applicant originally planned a test to obtain data on movable incore instrumentation characteristics over a range of control rod insertions at 50 percent power. In proposing to eliminate this test, the applicant stated in the letter dated ~~December~~ November 6, 1989:

> The basis for this deletion is that the original requirement was imposed to demonstrate alternative instrumentation capabilities in detecting a misaligned control rod. With the advent of the...DRPI system, the need for accurate and sensitive alternative indications has been essentially eliminated. In any case, the distribution and number of the incore and excore flux instrumentation has not been changed and is identical to all Westinghouse four-loop plants since Indian Point 2. Since that time, the capability and sensitivity of the excore and incore flux instrumentation has been demonstrated numerous times.

The staff notes that rod position monitoring is provided by two systems, the DRPI system and a group step counter system. It further notes that ~~states that~~ FSAR Section 7.7.1.3 states that the DRPI system continues to function at reduced accuracy if one channel fails, since two data channels are provided. The applicant orally informed the staff on November 22, 1989, that the movable incore instrumentation has been carefully checked during past operations and has been confirmed as providing excellent signals. The applicant used battery power to eliminate interference, and the tests were conducted at approximately 0.5 percent reactor power. During a telephone conference call on November 27, 1989, the applicant identified the following plants as not performing the misaligned-rod tests: Millstone Unit 3, Catawba Unit 2, McGuire Unit 2, Vogle Unit 2, Byron Unit 2, Braidwood Unit 2, South Texas Units 1 and 2, and Comanche Peak.

Use of battery power was an excellent step and is probably a significant reason for obtaining good data at the low indicated power level. Obtaining the data at less than 1 percent power is an accomplishment. Most such tests are conducted at about 15 percent in order to obtain good data. The staff believes that the applicant has obtained a good understanding of the performance of the incore instrumentation as a result of the identified tests and the use of this instrumentation at other plants.

The demonstrated ability to use the system and the fact that several other plants did not have to conduct the test (even though most are second units) are sufficient reasons for the staff to conclude that the intent of RG 1.68, Item i, has been satisfied and to concur in elimination of the test.

ST-22 NATURAL CIRCULATION TESTING

As part of the low-power testing program, RG 1.68 states:

> t. Performance of natural circulation tests of the reactor coolant system to confirm that the design heat removal capability exists or to verify that flow (without pumps) or temperature data are comparable to prototype designs for which equivalent tests have been successfully completed. (PWR)

In the initial paragraph of the power-ascension test description, RG 1.68 continues, "Licensees should complete low-power tests, as described in the FSAR, and evaluate and approve the low-power test results prior to beginning power-ascension tests."

In the letter dated November 6, 1989, the applicant stated:

> This test will be performed in MODE 3 utilizing decay heat to demonstrate natural circulation.... Additionally, this test will not include primary system depressurization rate measurements, charging and steam flow variations to determine subcooling effects or primary system pressure reductions to verify subcooling monitor performance.

Consistent with the above, the applicant proposes deleting the following from the FSAR:

At hot no-flow conditions the pressurizer heaters will be turned off and data will be collected to determine a depressurization rate.

Auxiliary spray will be used to partially depressurize the primary plant, and the depressurization rate will be determined. At reduced pressure the effect of changes in charging flow and steam flow on subcooling will be verified.

Conduct of Test Using Decay Heat Rather Than During Low Power

In a telephone conference call on December 12, 1989, the applicant stated that it has compared the Seabrook and Vogtle plants with respect to natural cirulation (NC) and determined them to be similar. The applicant has concluded that the NC testing at Vogtle provided data sufficient to conclude that NC flow and heat removal will occur at Seabrook. The applicant has also considered the results of the testing at Diablo Canyon and the work that was sponsored by the Westinghouse Owners Group, associated with those tests. In a telephone conference call on December 19, 1989, the applicant stated that the operators are trained on NC plant response and control and that the results of the test conducted on June 22, 1989, have been factored into operator training. This background and the available Seabrook test results are sufficient for the staff to conclude that the power ascension tests may be safely initiated before test ST-22 is conducted. The staff concludes that the operators will capably and safely cool the plant from power operation using NC cooling should this be necessary before the conduct of test ST-22. The staff further concludes that test ST-22 can be safely conducted using decay heat.

The anticipated decay heat load during the test will be about 25 MW according to the applicant. This is sufficient to obtain meaningful NC data.

Elimination of Other Test Items

In the letter dated November 6, 1989, the applicant reported that the calculated heat loss rate for Seabrook is 2.7°F/hr and for Diablo Canyon it is 7°F/hr and that these were comparable values. In a telephone conference call on December

12, 1989, the applicant stated that the Diablo Canyon calculation was conservative. Actual test results from Diablo Canyon showed a 40 psi/hr depressurization rate, which corresponds to 2.5°F/hr. This latter value is in good agreement with the calculated rate for the Seabrook plant.

The depressurization rate with auxiliary pressurizer sprays will not be determined, although the sprays will be used to control pressure during the test. The applicant considers that the most useful system depressurization information comes from analyses and that the test information is not that useful; that the calculations show that the depressurization rate is not too severe, but this is somewhat irrelevant since this is handled by procedures; and that not determining the depressurization rate with auxiliary pressurizer sprays is consistent with NC tests performed at other plants and that determining the rate is not required by RG 1.68.

The applicant has demonstrated a good understanding of pressure response and will determine the viability of pressurizer spray during NC tests by using this technique for pressure control. The staff concurs in the elimination of this part of the test.

The effect of charging flow and steam flow on subcooling will not be determined. The applicant stated that this is consistent with NC tests performed at other plants that are similar to Seabrook. The subcooling monitor will be monitored during this test.

The operators should have the benefit of understanding the effect of changes in such parameters as charging flow, water injection, and steam flow on instrument indications. Some information of this type would have been obtained during the test as originally conceived. Such information is available by means of properly constructed analyses and from tests at other plants as well as at Seabrook, although instrument response is a strong function of plant operating condition as well as plant configuration. The staff concurs in the elimination of the determination of the effects of such parameters as charging flow and steam flow, provided similar, applicable information is appropriately considered in procedures and operator training.

15 ACCIDENT ANALYSIS

15.8 Anticipated Transients Without Scram

15.8.1 Generic Letter 83-28

15.8.1.4 Reactor Trip System Reliability Improvements

Item 4.5.3, Reactor Trip System Reliability (Testing Intervals)

Generic Letter 83-28, Item 4.5.3, required that licensees confirm that on-line functional testing of the reactor trip system (RTS), including independent testing of the diverse trip feature, was being performed at all plants.

Existing intervals for on-line functional testing required by Technical Specifications were to be reviewed to determine if the test intervals were adequate for achieving high RTS availability when accounting for considerations such as (1) uncertainties in component failure rates, (2) uncertainties in common mode failure rates, (3) reduced redundancy during testing, (4) operator error during testing, and (5) component "wearout" caused by the testing.

The NRC's contractor, Idaho National Engineering Laboratory, reviewed the licensee owners group availability analyses and evaluated the adequacy of the existing test intervals, with a consideration of the above five items, for all plants. The results of this review are reported in detail in EGG-NTA-8341, "A Review of Reactor Trip System Availability Analyses for Generic Letter 83-28, Item 4.5.3, Resolution," dated March 1989 (which is included as Appendix Z in this supplement) and are summarized in this report. The results of the staff's evaluation of Item 4.5.3 and its review of EGG-NTA-8341 are as follows.

The Babcock & Wilcox, Combustion Engineering, General Electric, and Westinghouse Owners Groups submitted topical reports either in response to Generic Letter 83-28, Item 4.5.3, or to provide a basis for requesting Technical Specification changes to extend RTS surveillance test intervals. The owners groups' analyses addressed the adequacy of the existing intervals for on-line functional testing of the RTS, with the considerations required by Item 4.5.3, by quantitatively estimating the unavailability of the RTS. These analyses found that the RTS was very reliable and that the unavailability was dominated by common cause failure and human error.

The ability to accurately estimate unavailability for very reliable systems is considered extensively in NUREG-0460, "Anticipated Transients Without Scram [ATWS] for Light Water Reactors," and the ATWS rulemaking. The uncertainties of such estimates are large because the systems are highly reliable, very little experience exists to support the estimates, and common cause failure probabilities are difficult to estimate. Therefore, the staff believes that the RTS unavailability estimates in these studies, although useful for evaluating test intervals, must be used with caution.

NUREG-0460 also states that for systems with low failure probability, such as the RTS, common mode failures tend to predominate, and, for a number of reasons, additional testing will not appreciably lower RTS unavailability. First, testing more frequently than weekly is generally impractical, and increased testing could at best lower the failure probability by less than a factor of 4 compared with monthly testing. Second, increased testing could possibly increase the probability of a common mode failure through increased stress on the system. Finally, not all potential failures are detectable by testing. In summary, NUREG-0460 provides additional justification demonstrating that the current monthly test intervals are adequate to maintain high RTS availability.

Conclusion

All four vendors' topical reports have shown the currently configured RTS to be highly reliable with the current monthly test intervals. The NRC contractor has reviewed these analyses and performed independent estimates of its own that conclude that the current test intervals provide high reliability. In addition, the analyses in NUREG-0460 have shown that, for a number of reasons, more frequent testing than monthly will not appreciably lower the estimates of failure probability.

On the basis of the staff's review of the owners group topical reports, the NRC contractor's independent analysis, and the findings in NUREG-0460, the staff concludes that the existing intervals, as recommended in the topical reports, for on-line functional testing are consistent with achieving high RTS availability at all operating reactors.

16 TECHNICAL SPECIFICATIONS

In SSER 5, the staff reported the results of its review of the applicant's Technical Specification Improvement Program. The staff concluded that the information identified for incorporation in the Final Safety Analysis Report (FSAR) was the information that was approved for removal from the Technical Specifications and that the applicant had provided the requisite controls for that information.

The staff's conclusions in SSER 5 were based on its review of FSAR Section 16.3, which had been proposed by the applicant on September 10, 1986, and which the applicant stated would be incorporated in a future FSAR amendment. On June 30, 1989, the applicant submitted FSAR Amendment 62, which included revisions to FSAR Section 16.3, "Technical Specification Improvement."

The staff's review, which was to compare FSAR Amendment 62 with the FSAR Section 16.3 proposed on September 10, 1986, has confirmed that the information identified in SSER 5 and the requisite controls have been incorporated in FSAR Section 16.3 and that the controls have been implemented. On the basis of this finding, the staff concludes that issuance of FSAR Section 16.3 as included in FSAR Amendment 62 is acceptable.

18 HUMAN FACTORS ENGINEERING

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

In SSER 4, the staff concluded that the applicant had conducted a detailed control room design review (DCRDR) for Seabrook Unit 1 that satisfactorily met the requirements of Supplement 1 to NUREG-0737. Three confirmatory reviews still had to be completed. These involved (1) control room furnishings, (2) protective and emergency equipment storage, and (3) final evaluation of the control room environment. The reviews for Items (1) and (2) have been completed, and discrepancies have been corrected. Final evaluation of the control room environment will be done and reported to the NRC within 1 year after commercial operation begins. The staff requested this to allow one full cycle of heating and cooling to be experienced and to ensure plant ambient noise is evaluated at full power.

All control room improvements in regard to human engineering discrepancies (HEDs) that could affect safe plant operations have been implemented. Resolutions of all other lower priority HEDs will be implemented before startup following the first refueling outage. Considering the lower safety-significant implications of these HEDs, the staff finds this schedule acceptable.

One of the safety-issue contentions by an intervenor included, in part, a contention pertaining to the Seabrook control room design. By order of the Atomic Safety and Licensing Board (ASLB) dated September 15, 1986, a summary disposition was granted with the ASLB stating the following:

a. The displays and controls added, or to be added, to the control room as a result of the DCRDR do not increase the potential for operator error,

b. While all items addressed in the DCRDR are not currently at an optimum, i.e., incomplete, and corrective action is to be deferred until the next refueling outage, there is reasonable assurance that the safety of the population in the immediate vicinity of the plant will be protected.

This summary disposition ended any further action against the Seabrook control room design.

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

In SSER 6, the staff concluded that the safety parameter display system (SPDS) did not fully meet the applicable requirements of Supplement 1 to NUREG-0737. The supplement listed 17 issues to be addressed by the applicant.

On March 25, 1987, the ASLB addressed all 17 issues listed in SSER 6 and issued a partial initial decision on the Seabrook SPDS, stating as an order:

> If a full power operating license is authorized by the other Licensing Board that is considering offsite emergency planning issues, prior to the issuance thereof, Applicants, with respect to the Safety Parameter Display Systems, shall have:
>
> (a) dedicated the SPDS terminal so that a continuous display of the Critical Safety Functions will be achieved <u>or</u>, by means of a test function and test computer, have an SPDS display on every cathode ray tube format in the control room to continuously display the SPDS top level display (see fdg. 30, <u>supra</u>);
>
> (b) provided for continuous display of residual heat removal and hydrogen concentration critical safety function variables at the prime SPDS station (see fdg. 33, <u>supra</u>); and
>
> (c) established a radiological control screen at the prime SPDS station which, at a minimum, can be called up by the operator and will display steam line radiation and stack radiation parameters (see fdg. 36, <u>supra</u>).

In addition, several of the ASLB's findings of fact relative to the remaining issues in the supplement require action by the applicant before power operations above 5 percent or before startup following the first refueling outage and require verification by the staff.

The applicant's response to the ASLB partial initial decision was reported in SSER 7, in which the staff concluded that the SPDS modifications implemented and committed to by the applicant fully responded to the ASLB's order and findings of fact.

Because the ASLB order also specified staff verification of certain aspects of the SPDS modifications and because the applicant has been implementing the required modifications on an ongoing basis, the status of each issue is provided below.

Item (a) of the ASLB order has been implemented by the applicant and verified by the resident inspector (Inspection Reports 50-443/87-16 and 88-17). In SSER 7, the staff noted that Item (b) was completed except for software changes. Since SSER 7 was issued, the software changes have been made and it can now be reported that Item (b) has been implemented by the applicant and verified by the NRC staff (Inspection Report 50-443/89-09). Item (c) has been implemented by the applicant and verified by the resident inspector (Inspection Report 50-443/88-17).

With regard to the ASLB's findings of fact, the status is as follows:

- Finding 35 - Containment Isolation Display - Partially implemented by the applicant, except for completion of the software change, and verified by the resident inspector (Inspection Reports 50-443/87-16 and 88-17). The software change has been made and it can now be reported that Finding 35 has been implemented by the applicant and verified by the NRC staff (Inspection Report 50-443/89-09).

- Finding 36 - Radiation Control Function - Completed by the applicant and verified by the resident inspector (Inspection Report 50-443/88-17).

- Finding 37 - Heat Sink Display Format - Completed by the applicant and verified by the resident inspector (Inspection Report 50-443/88-17).

- Finding 38 - Subcriticality and Core Cooling - Completed by the applicant and verified by the resident inspector (Inspection Reports 50-443/87-16 and 88-17).

- Finding 39 - Isolation Devices Between Reactor Vessel Level Instrumentation System and SPDS - Completed by the applicant; referenced in Section 18.2 of SSER 7 and Appendix 18A of SSER 6.

- Findings 40, 41, 42 - Evaluation of Data Validation Algorithms - Completed by the applicant and verified by the NRC staff (Inspection Report 50-443/89-09).

- Findings 43, 44 - Man-in-the-Loop Evaluation - Completed; evaluation results reported in NYN-87026, dated March 6, 1987, and reviewed by the staff.

- Finding 45 - Conduct Availability Calculations - Incomplete; data to be collected during first cycle of operation.

- Findings 46, 47 - System Load Test - Incomplete; test to be performed during full-power operation under heavier load conditions.

With respect to SPDS corrective actions as imposed by the ASLB's partial initial decision dated March 25, 1987, Seabrook Station is ahead of the required implementation schedule.

19 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

During the 353rd meeting of the Advisory Committee on Reactor Safeguards (ACRS) on September 7-9, 1989, the ACRS reviewed the Seabrook Station emergency plan as well as progress on construction and testing that had occurred since the ACRS's report on low-power operation dated April 19, 1983. The ACRS Subcommittee on Seabrook also performed a review during a meeting on August 17, 1989. Transcripts of the full committee and subcommittee meetings are available for review at the NRC Public Document Room, 2120 L Street, NW, Lower Level, Washington, DC 20555, and at the Local Public Document Room at the Exeter Public Library, Front Street, Exeter, New Hampshire.

A copy of the ACRS report on full-power operation of Seabrook Station, Unit 1, dated September 13, 1989, appears in Appendix AA to this supplement. The report states the belief of the ACRS that, subject to satisfactory resolution of the issues that arose during low-power testing and corrective actions recommended by the Federal Emergency Management Agency (FEMA), there is reasonable assurance that Seabrook Station, Unit 1, can be operated at core power levels up to 3411 MWt without undue risk to the health and safety of the public. A discussion of the issues that arose during low-power testing and the FEMA-recommended corrective actions as noted in the ACRS letter of September 13, 1989, is provided below.

Issues That Arose During Low-Power Testing

On June 22, 1989, during the performance of a natural circulation test, the operating crew at Seabrook Unit 1 failed to follow test procedures and did not trip the reactor when the pressurizer level decreased below the manual trip criterion of the startup test procedure. Operations and startup test management personnel who were in the control room at the time of the event and who also were aware of the reactor test trip criterion did not take appropriate actions to terminate the test. Additionally, certain actions taken by the applicant's management personnel involved in the post-trip review and in subsequent discussions with the NRC appeared to lack an in-depth review of the cause leading to the improper conduct of the natural circulation test.

As a result of the issues that arose from this event, the Region I Administrator issued Confirmatory Action Letter (CAL) 89-11 on June 23, 1989, confirming the Region I's understanding of those actions the applicant will take in response to the event of June 22, 1989. Furthermore, the Region I Administrator directed the Region I staff to perform an augmented inspection team (AIT) review of the causes, safety implications, and associated applicant actions that led to the event or events during the natural circulation test on June 22, 1989.

On July 12, 1989, the applicant issued its response to CAL 89-11. On August 17, 1989, the AIT report was formally issued.

On July 21, 1989, intervenors filed a motion based on the event of June 22, 1989, that occurred during the natural circulation test. The motion requested a hearing before the Atomic Safety and Licensing Board (ASLB). On October 12, 1989, the ASLB denied motions to admit contentions and a hearing. The intervenors have appealed this decision.

On September 6, 1989, the staff held a public meeting with the applicant to discuss the results of the Region I inspection of the natural circulation test at Seabrook Unit 1 and to receive public comments relating to the same subject. This meeting was followed on September 7, 1989, by an enforcement conference with the applicant regarding the AIT findings. A notice of violation and proposed imposition of a $50,000 civil penalty was issued on October 25, 1989. On November 17, 1989, the applicant replied to the notice of violation and did not contest it. Currently, the staff's evaluation of the applicant's corrective actions are ongoing.

The staff and applicant agreed-on issues raised during the natural circulation test performed on June 22, 1989, are expected to be satisfactorily resolved before issuance of the full-power license. The staff's findings and conclusion will be issued in a report.

Corrective Actions Recommended by FEMA

In its report to the NRC dated December 14, 1988, FEMA identified certain actions that need to be completed before FEMA can issue its final findings regarding the adequacy of offsite plans and preparedness for Seabrook. FEMA has determined that the alert and notification systems for the public (i.e., the prompt alert and notification system (PANS) in New Hampshire and the vehicular alert and notification system (VANS) in Massachusetts) meet design requirements; however, the systems need to be implemented. FEMA has stated that when the alert and notification systems are installed and operable, the offsite plans and preparedness will be adequate to protect the health and safety of the public in the Seabrook emergency planning zone. The applicant has indicated in its presentation to the ACRS on September 8, 1989, that the modifications of the PANS sirens have been completed and that operational tests are being conducted. Since its presentation on September 8, 1989, the applicant has completed the VANS and committed to complete the implementation when it declares the VANS operational ~~deploys the staff~~ on January 3, 1990. FEMA has verified the operability of the Seabrook alert and notification systems and provided a positive finding to the NRC regarding the adequacy of the offsite plans and preparedness before full-power operation.

As indicated in the staff's presentation to the ACRS, FEMA has been requested to assist the NRC in the verification of conditions specified by the ASLB in the Partial Initial Decision issued on December 30, 1988 (LBP-88-32) on the New Hampshire Radiological Emergency Response Plan. The board conditions involve personnel rosters and emergency worker call lists, revisions of the New Hampshire Radiological Emergency Response Plan, identification of additional special-facility monitors for host communities, and revised evacuation time estimates. The board conditions must be satisfactorily resolved before a full-power license is issued for Seabrook. FEMA has verified that the board conditions have been satisfactorily resolved and has issued on December 21, 1989, a report to that effect to the NRC.

FEMA has also identified corrective actions that are not required for full-power operation. These corrective actions are related to FEMA's evaluation of the full-participation exercise on June 28 and 29, 1988, at Seabrook. As indicated in a status report issued by FEMA in December 1988, the States of New Hampshire and Maine and the New Hampshire Yankee Offsite Response Organization have provided action plans, milestone dates, and commitments for corrective actions. FEMA is working closely with the States and the applicant to complete these corrective actions. Some of the corrective actions have been completed, and others will be completed before the next biennial exercise.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW

May 9, 1989	Letter from applicant concerning licensed simulator instructor.
May 10, 1989	Letter from applicant concerning periodic notification of review for changes affecting the aircraft hazard analysis.
May 11, 1989	Letter from applicant concerning radiation data management system isolation qualification documentation.
May 12, 1989	Letter from applicant concerning inadequate core cooling monitoring system (NUREG-0737, Item II.F.2).
May 19, 1989	Letter from applicant concerning pressurizer relief tank temperature indication.
May 21, 1989	Letter to applicant concerning low-power physics tests.
May 22, 1989	Letter from applicant concerning notification of purchase of securities required by Seabrook supplementary pre-operational decommissioning trust.
May 23, 1989	Letter to applicant concerning changes to Technical Specifications.
May 24, 1989	Letter from applicant concerning certification of Technical Specifications for Seabrook Unit 1.

May 26, 1989	Letter to applicant issuing the 5-percent low-power license (NPF-67) with Appendix A (Technical Specifications) and Appendix B (Environmental Protection Plan).
May 30, 1989	Letter from applicant concerning 10 CFR 50.59 quarterly report.
May 30, 1989	Letter from applicant transmitting Indemnity Agreement B-106.
May 30, 1989	Letter from applicant concerning operability of iodine/ particulate sampling system (NUREG-0737, Item II.F.1).
May 31, 1989	Letter from applicant transmitting a response to NRC Bulletin 88-10, "Nonconforming Molded Case Circuit Breakers."
June 9, 1989	Letter to applicant transmitting 20 copies of SSER 8 for Seabrook.
June 15, 1989	Letter from applicant transmitting response to NRC Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs."
June 15, 1989	Letter to applicant concerning anticipated transient without scram (ATWS) rule 10 CFR 50.62.
June 20, 1989	Letter to applicant transmitting technical evaluation report on performance testing of relief and safety valves (NUREG-0737, Item II.D.1).
June 30, 1989	Letter from applicant transmitting a followup response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification."

July 3, 1989	Letter from applicant concerning notification of change in licensed operator status.
July 6, 1989	Letter from applicant concerning ATWS mitigation system.
July 10, 1989	Letter from applicant concerning safety injection accumulator pressure and containment sump water temperature instrumentation.
July 12, 1989	Letter from applicant concerning response to Generic Letter 89-06, "Task Action Plan Item I.D.2, Safety Parameter Display System."
July 19, 1989	Letter from applicant concerning reorganization of New Hampshire Yankee (NHY).
July 19, 1989	Letter from applicant concerning Security Event Log.
July 24, 1989	Letter from applicant concerning response to Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning."
July 28, 1989	Letter to applicant transmitting emergency planning and preparedness safety evaluation for Seabrook.
August 1, 1989	Letter from applicant concerning notification of change in licensed operator position.
August 4, 1989	Letter from applicant concerning notification of change in licensed operator status.
August 11, 1989	Letter from applicant concerning response to NRC Bulletin 88-10.

August 11, 1989	Letter from applicant requesting exemption from requirement of 10 CFR Part 50, Appendix E, Section IV.F.1, in regard to conduct of exercise of onsite emergency plans within 1 year before full-power operating license is issued.
August 31, 1989	Letter from applicant forwarding quarterly report of 10 CFR 50.59 safety evaluations for April-June 1989.
September 1, 1989	Letter from applicant concerning Security Event Report 89-S02-00, "Security Computer Unavailability Due to Lightning Strike."
September 6, 1989	Letter to applicant transmitting safety evaluation for Generic Letter 83-28, Item 4.5.3, "Reactor Trip System Reliability," regarding on-line functional testing of the reactor trip system.
September 13, 1989	Advisory Committee on Reactor Safeguards letter on Emergency Plan for full-power operation of Seabrook Unit 1.
September 14, 1989	Letter from applicant transmitting Licensee Event Report (LER) 89-010-00, "Engineered Safety Feature Actuation - Diesel Generator Start."
September 21, 1989	Letter from applicant requesting license amendment regarding plant instrument air cross-connect to containment building air monitor.
September 22, 1989	Letter from applicant concerning heating, ventilation, and air conditioning charcoal filter fire protection.
September 25, 1989	Letter from applicant concerning inoperability of containment post-loss-of-coolant-accident (post-LOCA) area monitor.
October 5, 1989	Letter from applicant concerning LER 89-011-00, "Unsealed Penetrations in the CST [Condensate Storage Tank] Enclosure."

October 5, 1989	Letter to applicant transmitting an amendment to indemnity agreement for Seabrook Unit 1.
October 17, 1989	Letter from applicant concerning completion of plant modifications associated with SSER 8 Confirmatory Items (56), (58), and (60).
October 19, 1989	Letter from applicant transmitting Amendment 3 to Indemnity Agreement B-106
October 20, 1989	Letter from applicant guaranteeing payments of deferred premiums.
October 23, 1989	Letter from applicant concerning inoperability of containment post-LOCA area monitor.
October 24, 1989	Letter to applicant concerning the safety evaluation on Seabrook surge line stratification.
October 30, 1989	Letter from applicant concerning Security Event Log.
October 30, 1989	Letter from applicant concerning Inservice Test Program, Revision 1.
October 31, 1989	Letter from applicant clarifying request for additional information transmitted to the NRC staff on October 17, 1989.
November 1, 1989	Letter from applicant responding to Generic Letter 88-20.
November 1, 1989	Letter from applicant concerning NUREG-0737, Item II.F.1, and Science Applications International Corporation report.
November 6, 1989	Letter from applicant concerning NHY power ascension test program and revisions to Chapter 14 of the Final Safety Analysis Report.

November 6, 1989	Letter from applicant concerning modifications to atmospheric steam dump valves.
November 6, 1989	Letter from applicant transmitting a response to Generic Letter 89-07.
November 17, 1989	Letter from applicant replying to a notice of violation.
November 21, 1989	Letter from applicant transmitting the Seabrook Station Physical Security Plan, Revision 8.
November 22, 1989	Letter from applicant concerning notification of change in licensed operator status.
November 22, 1989	Letter from applicant transmitting Facility Operating Report (LER) 89-13-00, "Noncompliance With Technical Specification Action Requirements."
November 22, 1989	Letter from applicant transmitting a request for license amendment; applicability for auxiliary feedwater system and atmospheric relief valves.
November 29, 1989	Letter from applicant requesting withdrawal of license amendment; plant instrument air cross-connect to containment air system.
November 29, 1989	Letter from applicant updating information on IE Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings."
November 30, 1989	Letter from applicant transmitting 10 CFR 50.59 quarterly report.
December 5, 1989	Letter from applicant concerning elimination of main steam isolation valve closure test (ST-47).

December 7, 1989	Letter from applicant transmitting an erratum to reply to a notice of violation.

APPENDIX B

REFERENCES

American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, 1977 edition through 1979 summer addenda.

Federal Emergency Management Agency, FEMA-REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," November 1985.

Westinghouse Electric Corporation, Topical Report WCAP-12151 (proprietary) and WCAP-12152 (nonproprietary), "Assessment of Thermal Stratification for the Seabrook Unit 1 Pressurizer Surge Line," February 1989; Supplement 1 to WCAP-12151 and WCAP-12152, "Additional Information in Support of the Assessment of Thermal Stratification for the Seabrook Unit 1 Pressurizer Surge Line," April 1989.

---, WCAP-12305 (proprietary) and WCAP-12306 (nonproprietary), "Evaluation of Thermal Stratification for the Seabrook Unit 1 Pressurizer Surge Line," June 1989.

APPENDIX D

ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
AIT	augmented inspection team
ASBEM	auxiliary and service building exhaust monitor
ASLB	Atomic Safety and Licensing Board
ATWS	anticipated transient(s) without scram
CAL	confirmatory action letter
CB	control building
CBA	control building air
CBS	containment building spray
cfm	cubic foot per minute
CFR	Code of Federal Regulations
COFD	carbon monoxide fire detection
CST	condensate storage tank
DCRDR	detailed control room design review
DP	differential pressure
DRPI	digital rod position indication
EG&G	EG&G Idaho, Inc.
EOC	Emergency Operations Center
EP	emergency preparedness
EPZ	emergency planning zone
ETE	evacuation time estimate
FEMA	Federal Emergency Management Agency
FSAR	Final Safety Analysis Report
GSCEM	gland steam condenser exhaust monitor
HED	human engineering discrepancy
HEPA	high efficiency particulate air
HVAC	heating, ventilation, and air conditioning
IR	inspection report
MIPP	Maine Ingestion Pathway Plan
MSIV	main steam line isolation valve
NC	natural circulation
NHRERP	New Hampshire Radiological Emergency Response Plan
NHY	New Hampshire Yankee
NHYORO	New Hampshire Yankee Offsite Response Organization

PANS	public alert and notification system
PID	partial initial decision
PWR	pressurized water reactor
RG	regulatory guide
RHR	residual heat removal
RTS	reactor trip system
SAIC	Science Applications International Corporation
SER	safety evaluation report
SG	steam generator
SOP	station operating procedure
SPDS	safety parameter display system
SPMC	Seabrook Plan for Massachusetts Communities
SSER	supplemental safety evaluation report
SSREP	Seabrook Station Radiological Emergency Plan
TER	technical evaluation report
TF	transmission factor
TMI	Three Mile Island
VANS	vehicular alert and notification system
WG	water gauge
WRGM-HR	wide-range gas monitor - high range
WRGM-LR	wide-range gas monitor - low range

APPENDIX F

NRC STAFF CONTRIBUTORS AND CONSULTANTS

Name	Title	Review branch
F. Allenspach	Operations Engineer	Performance & Quality Evaluation Branch
A. Chu	Project Engineer	Project Directorate I-3
R. Eckenrode	Section Chief	Human Factors Assessment Branch
G. Hammer	Mechanical Engineer	Mechanical Engineering Branch
S. Hou	Senior Mechanical Engineer	Mechanical Engineering Branch
F. Kantor	Section Chief	Emergency Preparedness Branch
B. Marcus	Electrical Engineer	Instrumentation & Control Systems Branch
C. Moon	Senior Reactor Engineer	Technical Specifications Branch
V. Nerses	Project Manager	Project Directorate I-3
R. Serbu	Health Physicist	Emergency Preparedness Branch
A. Toalston	Electrical Engineer	Electrical Systems Engineering Branch

The following contractor personnel contributed to this report:

C. Finem~~o~~an, EG&G Idaho, Inc.

D. Mackowick, EG&G Idaho, Inc.

C. Nalezny, EG&G Idaho, Inc.

J. Schroeder, EG&G Idaho, Inc.

APPENDIX Y

TMI ACTION - NUREG-0737 (II.D.1)
RELIEF AND SAFETY VALVE TESTING

EGG-NTA-8430
Rev. 1

TECHNICAL EVALUATION REPORT
TMI ACTION--NUREG-0737 (II.D.1)
RELIEF AND SAFETY VALVE TESTING
SEABROOK NUCLEAR STATION - UNITS 1 AND 2
DOCKET NOs. 50-443 AND 50-444

C. P. Fineman
C. L. Nalezny

May 1989

Idaho National Engineering Laboratory
EG&G Idaho, Inc.
Idaho Falls, Idaho 83415

Prepared for the
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Under DOE Contract No. DE-AC06-761D01570
FIN No. D6005
TAC No. 63393

ABSTRACT

In the past, safety and relief valves installed in the primary coolant system of light water reactors have performed improperly. As a result, the authors of NUREG-0578 (TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations) and, subsequently, NUREG-0737 (Clarification of TMI Action Plan Requirements) recommended that programs be developed and completed to: (a) reevaluate the functional performance capabilities of Pressurized Water Reactor (PWR) safety, relief, and block valves and (b) verify the integrity of the pressurizer safety and relief valve piping systems for normal, transient, and accident conditions. This report documents the review of those programs by the Nuclear Regulatory Commission (NRC) and their consultant, EG&G Idaho, Inc. Specifically, this report documents the review of the Seabrook Nuclear Station, Units 1 and 2, Licensee response to the requirements of NUREG-0578 and NUREG-0737. This review found the Licensee provided an acceptable response reconfirming that General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 have been met for the subject equipment. It should also be noted this review was made for both Units 1 and 2. However, the applicability of this review to Unit 2 is dependent on the verification that the Unit 2 as-built system conforms to the Unit 1 design reviewed in this report.

FIN No. D6005--Evaluation of CW Licensing Actions--NUREG-0737, II.D.1

Summary

The failure of a power-operated relief valve (PORV) to reseat was a significant contributor to the Three Mile Island (TMI-2) sequence of events. This failure, plus other previous instances of improver valve performance, led the task force which prepared NUREG-0578 and NUREG-0737 to recommend that programs be developed to reexamine the functional performance capabilities of Pressurized Water Reactor (PWR) safety, relief, and block valves. The task force also recommended the programs verify the integrity of the pressurizer safety and relief valve piping systems for normal, transient, and accident conditions. This was deemed necessary to reconfirm that the General Design Criteria 14, 15, and 30 of 10 CFR 50, Appendix A, have indeed been satisfied for the subject equipment.

This report documents the review by EG&G Idaho, Inc., of the Seabrook Nuclear Station, Units 1 and 2, Licensee response to the requirements of NUREG-0578 and NUREG-0737. The Licensee submittals were reviewed to determine the applicability of the test valves and test conditions to the plant valves and inlet conditions. The operability of the test valves was reviewed to determine the operability of the plant valves. The Licensee's analysis of the pressurizer discharge piping was reviewed to determine if acceptable stress limits were met for valve discharge transients.

The Licensee met the requirements of NUREG-0578 and NUREG-0737. The Licensee participated in the development and execution of an acceptable test program. The tests were successfully completed under operating conditions which bounded the most probable maximum forces expected from anticipated design basis events. The test results and piping analyses showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program that are applicable to Seabrook Nuclear Station, Units 1 and 2, and the pressure boundary component design criteria were not exceeded. Review of the Licensee's justifications indicated direct applicability of the test valve performance to the in-plant valves and systems intended to be covered by the test program. The plant specific piping was shown by analysis to be acceptable. Therefore, the Licensee reconfirmed that General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 have been met for the subject equipment.

PREFACE

This report was prepared for the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation, by EG&G Idaho, Inc., NRC Regulatory Technical Assistance Unit.

CONTENTS

TECHNICAL EVALUATION REPORT

TMI ACTION--NUREG-0737 (II.D.1)

RELIEF AND SAFETY VALVE TESTING

SEABROOK NUCLEAR STATION - UNITS 1 AND 2

DOCKET NOs. 50-443 AND 50-444

1. INTRODUCTION

1.1 Background

In the past, safety and relief valves installed in the primary coolant system of light water reactors have performed improperly. There were instances of valves opening below set pressure, valves opening above set pressure, and valves failing to open or reseat. From the past instances of improper valve performance, it is not known whether they occurred because of a limited qualification of the valve or because of a basic unreliability of the valve design. It is known that the failure of a PORV to reseat was a significant contributor to the Three Mile Island (TMI-2) sequence of events. These facts led the task force which prepared NUREG-0578 (Reference 1) and, subsequently, NUREG-0737 (Reference 2) to recommend that programs be developed and executed to: (a) reexamine the functional performance capabilities of Pressurized Water Reactor (PWR) safety, relief, and block valves and (b) verify the integrity of the pressurizer safety and relief valve piping systems for normal, transient, and accident conditions. These programs have been deemed necessary to reconfirm that General Design Criteria 14, 15, and 30 of 10 CFR 50, Appendix A, were indeed satisfied for the subject equipment.

1.2 General Design Criteria and NUREG Requirements

General Design Criteria 14, 15, and 30 require (a) the reactor primary coolant pressure boundary be designed, fabricated, and tested so as to have an extremely low probability of abnormal leakage; (b) the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions are not exceeded during normal operation or anticipated operational occurances events; and (c) the components, which are part of the reactor coolant pressure boundary, be constructed to the highest quality standards practical.

To reconfirm the integrity of overpressure protection systems and thereby assure compliance to the General Design Criteria, the NUREG-0578 position was issued as a requirement in a letter dated September 13, 1979, by the Division of Licensing (DL), Office of Nuclear Reactor Regulation (NRR), to all operating nuclear power plants. This requirement has since been incorporated as Item II.D.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements," which was issued for implementation on October 31, 1980. As stated in the NUREG reports, each PWR Licensee or Applicant shall:

1. Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

2. Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2.

3. Choose the single failures such that the dynamic forces on the safety and relief valves are maximized.

4. Use the highest test pressures predicted by conventional safety analysis procedures.

5. Include in the relief and safety valve qualification program the qualification of the associated control circuitry.

6. Provide test data for NRC staff review and evaluation, including criteria for success or failure of valves tested.

7. Submit a correlation, or other evidence, to substantiate the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must also be considered.

8. Qualify the plant specific safety and relief valve piping and supports by comparing to test data and/or performing appropriate analyses.

2. PWR OWNER'S GROUP RELIEF AND SAFETY VALVE PROGRAM

In response to the NUREG requirements previously listed, a group of utilities with PWRs requested the assistance of the Electric Power Research Institute (EPRI) in developing and implementing a generic test program for pressurizer power-operated relief valves, safety valves, block valves, and associated piping systems. Public Service Co. of New Hampshire (PSNH), the owner of the Seabrook Nuclear Station (SNS), Units 1 and 2, was one of the utilities sponsoring the EPRI Safety and Relief Valve Test Program. The results of the program, which are contained in a series of reports, were transmitted to the NRC by Reference 3. The applicability of those reports is discussed below.

Electric Power Research Institute developed a plan (Reference 4) for testing PWR safety and relief valves under conditions which bound actual plant operating conditions. Electric Power Research Institute, through the valve manufacturers, identified the valves used in the overpressure protection systems of the participating utilities and representative valves were selected for testing. The valves included a sufficient number of the variable characteristics so that their testing would adequately demonstrate the performance of the valves used by utilities (Reference 5). Electric Power Research Institute, through the Nuclear Steam Supply System (NSSS) vendors, evaluated the FSARs of the participating utilities and arrived at a test matrix which bounded the plant transients for which overpressure protection would be required (Reference 6).

The utilities that participated in the EPRI Safety and Relief Valve Test Program also obtained information regarding the performan of PORV block valves (Reference 7). A list of valves used or intended or use in participating PWR plants was developed. Seven block valves believed to be representative of the block valves utilized in the PWR plants were selected for testing. Additional tests were performed by Westinghouse Electro-Mechanical Division (WEMD) on valve models they manufacture (Reference 8).

Electric Power Research Institute contracted with Westinghouse Corporation to produce a report on the inlet fluid conditions for pressurizer safety and relief valves in Westinghouse designed plants (Reference 9). Because SNS, Units 1&2, were designed by Westinghouse, this report is relevant to this evaluation.

Several test series were sponsored by EPRI. Power-operated relief valves and block valves were tested at the Duke Power Company Marshall Steam Station located in Terrell, North Carolina. Only steam tests were conducted at the Marshall Station. Block valves, therefore, were tested at Marshall only for full flow, full pressure steam conditions. Water flow tests were performed by WEMD on four valve models manufactured by them. Conditions ranged from 60 to 600 gpm and 1500 to 2600 psi differential pressure. Additional PORV tests were conducted at the Wyle Laboratories Test Facility located in Norco, California. Safety valves were tested at the Combustion Engineering Company Kressinger Development Laboratory located in Windsor, Connecticut. The results of the relief and safety valve tests are reported in Reference 10. The results of the block valve tests are reported in References 7 and 8.

The primary objective of the EPRI Valve Test Program was to test each of the various types of primary system safety valves used in PWRs, for the full range of fluid conditions under which they may be required to operate. The conditions selected for test (based on analyses) were limited to steam, subcooled water, and steam to water transition. Additional objectives were to (a) obtain valve capacity data, (b) assess hydraulic and structural effects of associated piping on valve operability, and (c) obtain piping response data that could ultimately be used for verifying analytical piping models.

The EPRI test program was not designed to provide information on valve reliability. The EPRI program plan (Reference 4) states, "During the course of the specified tests, each valve will be subjected to a number of operational cycles. However, it should be noted that the test program, to be completed by July, 1981, is not intended to provide valve lifetime, cyclic fatigue or statistical reliability data."

NRC staff approval of the program is contained in Reference 11. Reference 11 states the staff has concluded the EPRI program produced sufficient generic safety valve and PORV performance information to enable utilities to comply with the plant specific information requirements in NUREG-0737, Item II.D.1. Transmittal of the test results meets Item 6 (provide test data to the NRC) of Section 1.2 in this report.

3. PLANT SPECIFIC SUBMITTAL

Public Service Co. of New Hampshire submitted their SNS, Units 1&2, evaluation report on the pressurizer safety valves, PORVs, PORV block valves, and piping on March 17, 1986 (Reference 12). Additional information on the piping analysis was submitted on June 1, 1986 in Reference 13. A request for additional information was transmitted to PSNH on March 31, 1987 (Reference 14), to which the Licensee responded on November 23, 1987 (Reference 15). Additional information was supplied by PSNH on May 8, 1989 and May 30, 1989 (References 16 and 17). The NRC requested the Licensee follow-up the May 30, 1989 conference call (Reference 17) with a letter documenting the information provided during the call.

4. REVIEW AND EVALUATION

4.1 Valves Tested

Seabrook Nuclear Station, Units 1 and 2, each utilize three safety valves and two PORVs in the overpressure protection system. In addition, each of them employ two PORV block valves. The safety valves are Crosby Model HB-BP-86 6M6 valves with steam internals. The PORVs are 3 in. by 6 in. Garrett straight through solenoid actuated valves. Only the PORVs have hot water seals upstream of the valves. The block valves are Westinghouse Model 3GM99 motor operated gate valves with Limitorque SB-00-15 motor operators.

The safety valve used at SNS, Units 1&2, the Crosby Model HB-BP-86 6M6 valve, was tested in the EPRI program. The safety valves at SNS, Units 1&2, are mounted on short vertical pipes to prevent the formation of water seals at the valve inlets. The valve internals are those designed for steam service. The valve was tested on a long inlet piping configuration with and without loop seal, which bounds the SNS, Units 1&2, installation. The test valve had loop seal internals. Only the material used in the valve seats differs, and this does not affect valve operability within the limited number of cycles in the test program. In Reference 17, PSNH stated the ring settings for the Crosby 6M6 valves at SNS, Units 1&2, were factory set ring settings. The results from the EPRI tests with factory ring settings can, therefore, be used to demonstrate operability of the safety valve.

The Garrett PORVs used at SNS, Units 1&2, are of the same design as the valve tested by EPRI but have differences that do not affect valve operability. Those differences include inlet, outlet, seat, and cage flow hole areas. These differences affect flow capacity but not operabililty. Other differences that do not affect valve operability include internal versus external solenoid tubing and piloting of the cage directly on the valve body rather than indirectly to the body through the bonnet. Therefore, the test valve is considered to be representative of the plant valves.

The block valves used in SNS, Units 1&2, are the same design as the valve tested in the EPRI test program, a Westinghouse 3GM99 block valve. The valve was tested by EPRI in a horizontal configuration. The valve is designed for use in either a horizontal or vertical orientation. The plant valves have Limitorque SB-00-15 motor operators, which is the Limitorque operator used with the test valve. During EPRI testing, the 3GM99 block valve operator was rewired for limit closure on valve position rather than on torque and the yoke was redesigned. Public Service Co. of New Hampshire stated similar changes were made to the Seabrook valves. The test valve is, therefore, representative of the plant valves.

Based on the above, the test valves are considered to be applicable to the SNS, Units 1&2, valves and to have fulfilled the requirements of Items 1 and 7 of Section 1.2 in this report regarding applicability of the test valves.

4.2 Test Conditions

The valve inlet fluid conditions that bound the overpressure transients for Westinghouse-designed PWR plants are identified in Reference 9. The transients considered in this report include FSAR, extended high pressure injection, and low temperature overpressurization events. The plant specific conditions for these events discussed in this section are taken from Reference 9. The conditions applicable to SNS, Units 1&2, are those identified for a four-loop plant.

For FSAR transients resulting in steam discharge through the safety valves, the pressurizer experiences a peak pressure of 2555 psia (loss-of-load transient) and a maximum pressurization rate of 144 psi/s (locked rotor transient). The maximum expected backpressure is 560 psia.

In the EPRI testing program, the Crosby HB-BP-86 6M6 safety valve was subjected to two steam tests with a long inlet configuration. Of these tests, one test (1411) is applicable to the Crosby valves at SNS, Units 1&2, because the ring settings in this test (-77, -18) are representative of the plant ring settings and the test was performed with a drained loop seal. In this test the valve opening pressure was 2410 psia, the pop pressure was

2420 psia, and the peak tank pressure reached 2664 psia. The pressurization rate was 300 psi/s, the peak backpressure was 245 psia, and the blowdown was 8.2%. The test inlet fluid conditions for this steam test, except for the backpressure, are representative of the expected conditions for FSAR transients resulting in steam discharge for the safety valves. The Crosby 6M6 valve performance with high backpressure can be assessed using Test 929, a cold loop seal/steam test. The peak backpressure in this test, 710 psia, develops after the loop seal is discharged and full steam flow has been established. Other conditions for this test, peak tank pressure, 2726 psia, and pressurization rate, 319 psi/s, also bound the SNS, Units 1&2, inlet conditions.

For FSAR transients resulting in steam discharge, the PORVs will open at a pressure somewhat above the opening setpoint of 2350 psia. The maximum pressurizer pressure is 2532 psia (loss-of-load) and maximum pressurization rate is 130 psi/s (locked rotor) when the safety and relief valves actuate.

The Garrett test PORV was subjected to thirteen steam tests, one transition test, and two water seal simulation tests in the EPRI test program. In the steam tests, the maximum pressure at valve opening ranged from 2415 to 2760 psia. The valve opening pressure for the steam-water transition test was 2760 psia. The two water seal tests were conducted at initial pressures of 2755 and 2760 psia and inlet fluid temperatures of 130 and 293°F. The plant PORV water seal temperature is predicted to be about 250°F (Reference 15). The maximum back pressure for these tests ranged from 25 to 875 psia. The test fluid conditions in the steam and water seal tests on the PORVs are representative of FSAR transients.

The limiting FSAR transient, with respect to water flow through the safety valves and PORVs, is the feedwater line break (FWLB). The Westinghouse inlet conditions report (Reference 9) originally provided SNS, Units 1&2, inlet conditions for the FWLB transient. These conditions included maximum pressurizer pressure, 2504.9 psia, maximum liquid surge rate, 275.1 gpm, maximum pressurization rate, 3.0 psi/s, and liquid temperatures ranging from 568.7 to 584.1°F. Subsequently, PSNH provided revised FWLB liquid temperature conditions in Reference 16. This information indicated the liquid temperature would range from 603 to 605°F.

The Crosby 6M6 valve was subjected to one transition test (931a) with ring settings applicable to those at SNS, Units 1&2. This test included a loop seal upstream of the valve; however, with respect to valve operability, this test can be used to evaluate the plant valves without loop seals. The peak pressure and pressurization rate in the test were 2578 psia and 2.5 psi/s. The tank water temperature was 641°F. After the valve closed, the system was repressurized and the the valve cycled on 635°F water (Test 931b). In addition, one water test (932) was run with ring settings applicable to those in the plant valves. The peak pressure and pressurization rate was 2520 psia and 3.0 psi/s. The tank water temperature was 515°F. These conditions bound those at the plant.

The Garrett PORV was subjected to one transition test and three high pressure water tests. In the transition test, the peak pressure was 2760 psia and the water temperature was 653°F. In the water tests, the pressure ranged from 2640 to 2760 psia and water temperatures ranged from 249 to 648°F. The above conditions bound those expected for the plant PORVs.

The limiting extended High Pressure Injection (HPI) event is a spurious activation of the safety injection system at power. However, in this event, the PORVs and safety valves open on steam, and liquid discharge would not be observed until the pressurizer became water solid. According to Reference 9, this would not occur for at least 20 minutes into the event, which allows ample time for operator action. Thus, the potential for liquid discharge in extended HPI events can be disregarded.

Low temperature overpressurization (LTOP) events challenge only the PORVs since they are used to mitigate such transients. The fluid conditions for these events can vary between steam and subcooled water because of administrative requirements for maintaining a steam bubble in the pressurizer during low temperature operations. The plant specific range of potential fluid conditions for low temperature overpressure events was not provided by PSNH. Low temperature overpressurization conditions in Reference 9 for similar four-loop Westinghouse plants were reviewed, and bounding conditions were selected to evaluate the performance of the SNS, Units 1&2, PORVs. These conditions include pressures from approximately 350 to 2350 psia and inlet fluid conditions varying from subcooled liquid to saturated steam.

In addition to the high pressure water, steam, and transition tests previously mentioned, the PORV was subjected to two low pressure water tests. The test pressures were 683 and 686 psia, while the valve inlet temperatures were 94 and 460°F. These test conditions, together with the test conditions in the high pressure tests, sufficiently encompass the range of expected fluid conditions for LTOP events at SNS, Units 1&2.

The block valves are required to operate over a range of fluid conditions (steam, steam-to-water, water) similar to those of the relief valves. However, the block valves were tested only under full pressure steam conditions (to 2485 psia). Based on testing preformed by Westinghouse (Reference 8), with similar internal materials under full pressure steam conditions, the required torque to open or close the valve: (a) depends almost entirely on the differential pressure across the valve disk, (b) is rather insensitive to momentum loading, (c) is nearly the same for water or steam, and (d) is nearly independent of the flow. Thus, full pressure steam tests are adequate to show valve operability for steam and water conditions.

Two transient conditions not part of the design basis are anticipated transients without scram (ATWS) and feed and bleed decay heat removal. The response of the overpressure protection system to ATWS and the operation of the system during feed and bleed decay heat removal are not considered in this review. Neither the Licensee nor the NRC have evaluated the performance of the system for these events.

The presentation above demonstrates that the test conditions bounded the conditions for the plant valves and verifies Items 2 and 4 of Section 1.2 in this report were met, in that conditions for the operational occurrences were determined and the highest predicted pressures were chosen for the tests. The presentation also verifies that the portion of Item 7, which requires showing test conditions are equivalent to those prescribed in the FSAR, was met.

4.3 Operability

As discussed in the previous section, the safety valves and PORVs are required to operate over a range of full pressure steam, steam to water transition, and subcooled water fluid conditions. The valves were tested for the range of required conditions in the EPRI test program. The block valves are also required to operate for steam and liquid flow conditions. The valves were subjected to full pressure steam tests, the results of which apply also to liquid flow.

In one applicable steam test (1411), the safety valve opened at 2410 psia (-3.6% of the setpoint), was stable, and achieved 107% of rated steam flow at 3% accumulation and 92% of rated lift. The valve closed with 8.2% blowdown. In Test 929, the loop seal test used to bound the valve performance with high backpressures, the valve was stable on steam and achieved 110% of rated flow at 3% accumulation and 93% of rated lift. The valve closed with 5.1% blowdown. Thus, in the applicable tests, the valve performed its safety function of opening, relieving pressure, and closing.

A FWLB can result in high pressure and temperature liquid discharge through the safety valves. A loop seal/transition test (931a) and two water discharge tests (931b and 932) were used to bound the expected behavior of the plant valves. In Test 931a, the valve opened at 2570 psia (+2.8% of the set pressure), fluttered or chattered during loop seal discharge, stabilized during steam and water discharge, and closed. The valve blowdown was not available for this test. At 2415 psia with 641°F water, the valve passed 2355 gpm of liquid with the valve at 56% of rated lift. In Test 931b, the valve opened on 635°F water, chattered during opening, stabilized, and closed with 4.8% blowdown. The liquid flow rate in Test 931b was not recorded. In Test 932, the valve opened and immediately began to chatter. The valve chattered for 6.5 s before the test was terminated by manually opening the valve. This test used 515°F water. Because the pressurizer safety valves are designed for steam relief, valve chatter when passing highly subcooled water is not unexpected. The temperatures expected in a

FWLB at SNS, Units 1&2, (603 to 605°F) fall between the available test data at 640 and 515°F. However, based on engineering judgement, the SNS, Units 1&2, FWLB temperatures are close enough to the hot water EPRI tests to conclude the SNS, Units 1&2, safety valves will operate satisfactorily during a FWLB.

Bending moments as high as 298,750 in-lb (Test 908) were induced on the discharge flange of the Crosby 6M6 test valve, which had no adverse effect on valve performance. Since this applied moment exceeds the maximum estimated bending moment of 71,749 in-lb for the SNS, Units 1&2, valves (Reference 13), the performance of the plant valves is also expected to be unaffected by bending moments imposed during discharge transients.

As stated earlier, the observed blowdown in the applicable EPRI test was 8.2%, which exceeds the design value of 5%. Thus, it must be demonstrated that extended blowdown will not impact plant safety and valve operability. From a valve operability standpoint, filling the pressurizer with saturated water is not a concern. In the EPRI tests, the Crosby 6M6 safety valves at SNS, Units 1&2, were shown to be operable with steam, steam/water transition, and saturated water inlet conditions. Blowdown of 8.2% from a valve setpoint of 2500 psia should not present a challenge to plant protection equipment; therefore, this was not considered a safety concern. A second concern with extended blowdown is the possibility of voiding in the primary coolant system causing a significant loss of decay heat removal capability. To resolve this concern, three approaches were taken. First, if 8.2% blowdown occurs from a set pressure of 2500 psia, the primary pressure would decrease to 2295 psia. At 2295 psia, the saturation temperature is 655°F. The hot leg temperature would have to increase to this temperature before any hot leg voiding could occur. Therefore, significant voiding of the hot leg is not expected to occur due to the 8.2% versus 5% blowdown. Second, to consider the primary system response if voiding should occur, a NRC study of natural circulation (NC) test data was reviewed (Section 6.10.1 of Reference 18). The NRC study applies to PWRs with U-tube steam generators like SNS, Units 1&2. The study was based on NC data from experiments covering a wide range of possible accident or transient conditions that may occur in a PWR system; it also considered test facilities of widely different scale. NRC staff concluded the test data showed the various modes of NC (single-phase, two-phase, and reflux) were able to keep the core cool as long as an adequate secondary heat sink is maintained and there is sufficient primary system mass inventory to keep the core covered with a two-phase mixture. Thus, if any voiding of the primary due to extended blowdown should occur it would not endanger the core because forced circulation (early in the transient) and NC (late in the transient) would remove the decay heat. Finally, Westinghouse provided the results of an analysis that considered the effects of two or three stuck open safety valves (Reference 19). The analysis showed that even if this worst case condition for safety valve blowdown should occur (i.e., the valve sticks open) the emergency core cooling systems were able to keep the core covered and cool. Therefore, the extended blowdown observed in the EPRI tests does not impact plant safety or valve operability.

For the test to be an adequate demonstration of safety valve stability, the test inlet piping pressure drop should exceed the plant pressure drop. The test inlet pressure drop for the Crosby 6M6 valve on the loop seal configuration was 263 psid on opening and 181 psid on closing. The values calculated for the SNS, Units 1&2, safety valves were 122 and 80 psid for opening and closing, respectively (Reference 15). Therefore, the plant valves should be as stable as the test valves.

For all tests on the Garrett PORV, the valve opened and closed on demand. Total valve opening times were less than 1.24 s and closing times were less than 2.35 s. After testing was completed, the valve was inspected. Based on the limited number of cycles in the test program, there was no damage observed that would affect the future performance of the valve. Based on valve performance during testing, the PORVs were shown to operate under expected fluid transient conditions.

A bending moment of 33,200 in-lb was induced on the discharge flange of the Garrett test PORV, which has nearly the same valve body as the plant PORV. This moment had no adverse effect on valve performance. The maximum calculated bending moment for the SNS, Units 1&2, valves is 86,040 in-lb (Reference 13). However, the PWR Safety and Relief Valve Test Program Valve Selection Justification Report (Reference 5) stated that the Garrett straight through PORV is designed to operate with the maximum valve deformation. A Garrett analysis of bending moments as large as 380,000 in-lb showed that valve operability would not be affected. Consequently, even though the EPRI tests only subjected the Garrett PORV to 33,200 in-lb, the valve is expected to operate with the higher induced moments expected under transient conditions.

The PORV block valve must be capable of closing over a range of steam and water conditions. As described in Section 4.2 of this report, high pressure steam tests are adequate to bound operation over the full range of inlet conditions. As described in Section 4.1 of this report, the tests conducted on the 3 in. Westinghouse Series 99 valve and SB-00-15 operator demonstrate the operability of the plant valve provided the plant block valve operator is adjusted to produce the maximum torque and wired for limit closure. The test valve was cycled successfully at full steam pressure with full flow. It was shown to open and close successfully with full operator torque (References 7 and 8). The plant block valves were modified to provide sufficient closing thrust as determined in the Westinghouse test program (Reference 15). Therefore, the tests are considered to have demonstrated acceptable valve operation.

NUREG-0737, Item II.D.1, states that the PORVs and their associated control circuitry shall be qualified for design basis accidents and transients. The EPRI test program included the PORV control circuitry attached directly to the valve in its test program (Reference 20), but did not include the circuits away from the valve (pressure sensing devices, cables, transmitters, etc.). The individual utilities still need to meet the NUREG-0737, Item II.D.1, requirements for the circuits away from the valve. Based on Reference 11, the NUREG requirement for environmental qualification of those circuits was to be met by including them in the program to meet the licensing requirements of 10 CFR 50.49. If the PORV control circuits are included in the 10 CFR 50.49 program, specific testing to meet the NUREG-0737 requirements is not necessary. The Licensee included the PORV controls in the SNS, Units 1&2, environmental qualification program (Reference 15). This meets the environmental qualification requirements for the control circuitry. With respect to the qualification of the control circuits during normal operation, testing of the PORV control circuits is required by the inservice testing program under 10 CFR 50.55a. Including the circuits in this program meets the requirement to qualify the PORV control circuitry during normal operation.

The facts presented above demonstrate that Item 1 (conducting tests for valve qualification) and Item 7 (considering the affects of discharge piping on operability) of Section 1.2 in this report were met. Meeting the requirements of 10 CFR 50.49 and 50.55a are adequate to satisfy Item 5 of Section 1.2 in this report regarding the PORV control circuitry.

4.4 Piping and Support Evaluation

This evaluation covers the piping and supports upstream and downstream of the safety valves and PORVs extending from the pressurizer nozzle to the pressurizer relief tank. The piping was designed for deadweight, internal pressure, thermal expansion, earthquake, and safety and relief valve discharge conditions. The calculation of the time histories of hydraulic forces due to valve discharge, the method of structural analysis, and the load combinations and stress evaluation are discussed below.

4.4.1 Thermal Hydraulic Analysis

Pressurizer fluid conditions were selected for use in the thermal hydraulic analysis such that the calculated pipe discharge forces would bound the forces for any of the FSAR, HPI, and low temperature overpressurization events, including the single failure that would maximize the forces on the valve.

The safety valve and PORV discharge transients were analyzed in six separate cases. These cases included: (1) the relief and safety valves open sequentially at their respective set points, (2) the three safety valves discharge saturated steam and the relief valves remain closed, (3) the two relief valves discharge steam and experience a transition to saturated water plus a subsequent actuation during which 567°F water is discharged; the safety valves remain closed, (4) the three safety valves discharge 567°F water and the relief valves remain closed, (5) the two relief valves discharge 329°F water at 2400 psia and the safety valves remain closed, and (6) one relief valve discharges 329°F water at

2400 psia while the other relief valve and the safety valves remain closed. This approach is acceptable because it covers the type of valve actuations and conditions which are possible at SNS, Units 1&2.

Because water seals are maintained upstream of the PORVs, the water seal/steam discharge condition would generate the highest loads on the PORV piping system when the water seal is expelled and forced down the discharge piping. The steam discharge cases analyzed for the safety valves, combined with the water condition analyzed for the safety valves (which were representative of the coldest fluid temperatures expected at the valve inlet based on Reference 9), adequately represent the conditions expected for the safety valve piping system as discussed below. Therefore, the selection of these cases as the limiting conditions for the evaluation of the piping loads is considered adequate.

For these analyses, saturated steam at a maximum pressure of 2555 psia was assumed to be discharged through the safety valves. The conditions for the PORVs were saturated steam at a maximum pressure of 2532 psia. Hot water seals (250°F) were assumed upstream of the PORVs. For water discharge, the safety valve conditions were 567°F water at a maximum pressure of 2507 psia and the PORV conditions were 567°F water at 2403 psia and 329°F water at 2400 psia.

The thermal hydraulic analysis for SNS, Units 1&2, used 567°F water based on the FWLB water temperatures in Reference 9. As noted in Section 4.2 of this report, new FWLB water temperatures (603 to 605°F) were provided in Reference 16. During a conference call between the NRC staff, EG&G Idaho, Inc., and PSNH (Reference 17), PSNH stated the effects of the higher FWLB water temperatures on the piping thermal hydraulic analysis were assessed by a series of RELAP5/TULIP calculations (see below). The calculations looked at water temperatures of 605 and 650°F. This review showed the forces calculated using the 567°F water bound those expected from the 605 and 650°F water. Therefore, the forces for the original analysis bound the forces that would be generated based on the new FWLB temperature conditions and 650°F water, and a new analysis is not needed.

The thermal hydraulic analysis was performed using the RELAP5/MOD1 computer code. RELAP5 calculates the thermal hydraulic properties of the fluid as a function of time in each control volume and at each junction of the analysis model. The RELAP5 results are then input into the TULIP computer code to obtain the time histories of the fluid forces acting at the two ends of a pipe segment. RELAP5 is widely used in the industry and was shown to be an adequate tool for predicting piping discharge loads (Reference 21). The TULIP program generates force time histories from RELAP5 output. In Reference 15, the Licensee provided verification of TULIP's capability to generate force histories.

The key input parameters and assumptions made in the thermal hydraulic analysis, such as the valve flow area, the RELAP5 model node spacing, the valve opening time, time step size, etc., were reviewed and considered acceptable. The valve opening time for the safety valves was 0.01 s on steam and 0.02 s for water. These times are representative of those measured in the EPRI tests for these inlet conditions (valve opening time in the applicable steam test was 0.007 s and on water the valve opening time ranged from 0.012 to 0.021 s). The valve flow area used in the safety valve discharge analysis was calculated to produce the flow corresponding to 112% of the rated flow which is adequate for the Crosby valves used at SNS, Units 1&2. The PORVs were assumed to open in 0.01 s for steam and 0.625 s for water discharge. These opening times are faster than those measured in the EPRI tests and thus are conservative. The flow rate used in the analysis for the PORVs, 303,000 lbm/h at 2400 psia, is 144% of the valve rated flow at this pressure. This is considered to be conservative. The inlet pipes to the safety valves were modeled without loop seals while the water seals upstream of the PORVs were modeled. This represents the actual plant condition. The thermal hydraulic analysis is considered adequate for predicting the safety valve and PORV discharge loads.

4.4.2 Stress Analysis

The structural responses of the piping system due to safety valve/PORV discharge transients were calculated using the static method applying the maximum load for each leg enveloped from the six transient cases discussed in Section 4.4.1 of this report. The applicable load was applied to each leg individually including the forces on adjacent legs using a dynamic load factor (DLF) of 1.5. The DLF of 1.5 was determined as follows. The fundamental frequency and period for each piping segment was determined. The duration time for the impulse force in each leg was determined and assumed to be a triangular pulse. Then the ratio of duration time and period was calculated for each segment and this ratio used to determine the DLF based on Reference 22. For the ratios found the DLFs ranged from 0.2 to 1.5. A DLF of 1.5 was used for conservatism. The peak forces for each segment were determined for the various transients analyzed. The peak forces were applied simultaneously to each segment even though the peak forces may not occur simultaneously. This approach is consistent with that taken in the SNS, Units 1&2, FSAR.

The static analysis was performed using the computer program ADLPIPE-D. The program was verified using NUREG/CR-1677 benchmark problems (References 23 and 24).

The piping upstream of the safety valves and PORVs was analyzed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division I, 1977 Edition with Addenda through December 31, 1977. The downstream piping was analyzed to the requirements of the ASME and ANSI B31.1 Power Piping Codes. The load combinations and stress limits for the upstream and downstream piping are equivalent to those recommended by EPRI (Reference 25). The piping stress summary presented by the Licensee compared the highest stresses in the piping against the applicable stress limits. All stresses were within the applicable stress limits.

The structural code governing the upstream support design is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, 1971 Edition with Addenda through Winter 1973. The load combination equations were consistent with the load combination equations in the EPRI Submittal Guide (Reference 25), and the resulting stresses were less than the code allowables. The downstream supports were discussed in Reference 17. The governing code for the downstream supports is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, Class 3, 1971 Edition with Addenda through Winter 1973. These downstream supports were analyzed according to the plant design requirements. This includes summing the maximum loads for all the transients the supports undergo (normal, seismic, valve discharge, etc.) and comparing it to the allowable. The allowable load was taken to be approximately 80% of the ASME Code, Subsection NF, Class 3 allowable. The ASME allowable was increased by 1.33 to account for seismic effects if needed. Use of this approach is considered to be more conservative than using the load combinations and allowables recommended by EPRI. Public Service Co. of New Hampshire also stated that a load identified as a loss-of-coolant accident load in Reference 15 was actually the load due to valve discharge. Based on a review of the information provided by PSNH, all supports met code requirements.

4.4.3 Piping and Support Summary

The selection of a bounding case for the piping evaluation demonstrates the requirements of Item 3 of Section 1.2 in this report were met. The piping and support stress analysis verifies Item 8 was also met.

5. EVALUATION SUMMARY

The Licensee for SNS, Units 1&2, provided an acceptable response to the requirements of NUREG-0737, Item II.D.1. Therefore, the Licensee has reconfirmed that the General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 were met with regard to the safety valves, PORVs, and block valves. The rationale for this conclusion is given below.

The Licensee participated in the development and execution of an acceptable test program. The program was designed to qualify the operability of prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated operational occurances and design basis events. The generic test results and piping analyses showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program that are applicable to SNS, Units 1&2, and the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the Licensee's justifications indicated direct applicability of the prototypical valve and valve performance to the in-plant valves and systems intended to be covered by the generic test program. The plant specific piping was shown by analysis to be acceptable.

Thus, the requirements of Item II.D.1 of NUREG-0737 were met (Items 1-8 of Section 1.2 in this report). Therefore, the Licensee demonstrated by testing and analysis for the subject equipment that: (a) the reactor primary coolant pressure boundary will have a low probability of abnormal leakage (General Design Criterion No. 14), (b) the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) were designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion No. 15), and (c) the valves and associated components were constructed in accordance with high quality standards (General Design Criterion No. 30).

This review was made for both SNS, Units 1&2. However, the applicability of this review to Unit 2 is dependent on the verification that the Unit 2 as-built system conforms to the Unit 1 design reviewed in this report.

6. REFERENCES

1. TMI-2 Lessons Learned Task Force, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979.

2. Clarification of TMI Action Plan Requirements, USNRC, Division of Licensing, NUREG-0737, November 1980.

3. Letter, D. P. Hoffman, Consumers Power Co. to H. Denton, NRC, "Transmittal of PWR Safety and Relief Valve Test Program Reports," September 30, 1982.

4. Program Plan for Performance Testing of PWR Safety and Relief Valves, Electric Power Research Institute, July 1980.

5. EPRI PWR Safety and Relief Valve Test Program, Valve Selection/Justification Report, MPR Associates, Inc., EPRI NP-2292, December 1982

6. PWR Valve Program Staff, EPRI PWR Safety and Relief Valve Test Program, Test Condition Justification Report, EPRI NP-2460, December 1982

7. Marshall Electric Motor Operated Block Valve, Intermountain Technologies, Inc., NP-2514-LD, July 1982.

8. J. A. Drake, M. A. Leri, EPRI Summary Report: Westinghouse Gate Valve Closure Testing Program, Engineering Memorandum 5683, WEMD EM 5683, Revision 1, March 31, 1982.

9. Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves in Westinghouse-Designed Plants, Westinghouse Electric Corp., EPRI NP-2296, December 1982.

10. EPRI Valve Test Program Staff, EPRI PWR Safety and Relief Test Program, Safety and Relief Valve Test Report, EPRI NP-2628-SR, December 1982.

11. Letter W. J. Dircks, NRC Staff, to NRC Commissioners, "Adequacy of Safety and Relief Valve Testing and Performance," SECY-83-270, July 5, 1983.

12. Letter J. DeVincentis, PSNH, to V. S. Noonan, NRC, "NUREG-0737 Task II.D.1, Performance Testing of Boiling Water Reactor and Pressurized Water Reactor Relief and Safety Valves," March 17, 1986.

13. Letter J. DeVincentis, PSNH, to V. S. Noonan, NRC, "NUREG-0737 Task II.D.1, Performance Testing of Boiling Water Reactor and Pressurized Water Reactor Relief and Safety Valves; Additional Information," June 1, 1986.

14. Letter V. Nerses, NRC, to R. J. Harrison, PSNH, "Request for Information Regarding NUREG-0737, Item II.D.1, Performance Testing of Relief and Safety Valves, Seabrook Units 1 and 2," March 31, 1987.

15. Letter G. S. Thomas, PSNH, to USNRC Document Control Desk, "NUREG-0737, Task II.D.1, Performance Testing of Relief and Safety Valves," November 23, 1987.

16. Letter G. S. Thomas, PSNH, to USNRC Document Control Desk, "NRC Request for Additional Information Regarding NUREG-0737, Item II.D.1," NYN-89057, May 8, 1989.

17. Conference call between EG&G Idaho, Inc., USNRC, and PSNH, May 30, 1989.

18. Compendium of ECCS Research for Realistic LOCA Analysis, USNRC, Division of Systems Research, NUREG-1230, December 1988.

19. Safety Valve Contingency Analysis in Support of the EPRI Safety/Relief Valve Testing Program--Volume 3: Westinghouse Systems," Westinghouse Electric Corp., EPRI NP-2047-LD, Interim Report, October 1981,

20. Letter R. C. Youngdahl, Consumers Power, to D. G. Eisenhut, USNRC, "PWR Utilities' Position on NUREG 0737, Item II.D. 1, Performance Testing of Boiling-Water Reactor and Pressurized-Water Reactor Relief and Safety Valves (NUREG 0578, Section 2.1.2)," December 15, 1980.

21. Application of RELAP5/MOD1 for Calculation of Safety and Relief Valve Discharge Piping Hydrodynamic Loads, Intermountain Technologies, Inc., EPRI-2479, December 1982.

22. J. M. Biggs, Introduction to Structural Dynamics.

23. T. Bezler, M. Hartzman, and M. Reich, Piping Benchmark Problems, Dynamic Analysis Uniform Support Motion Response Spectrum Method, NUREG/CR-1677, Volume 1, August 1980.

24. T. Bezler, M. Subudhi, and M. Hartzman, Piping Benchmark Problems, Dynamic Analysis Independent Support Motion Response Spectrum Method, NUREG/CR-1677, Volume 2, August 1985.

25. EPRI PWR Safety and Relief Valve Test Program Guide for Application of Valve Test Program Results to Plant-Specific Evaluations, Revision 2, MPR Associates, Inc., Interim Report, July 1982.

APPENDIX Z

TECHNICAL EVALUATION REPORT: A REVIEW OF REACTOR TRIP SYSTEM AVAILABILITY ANALYSES FOR GENERIC LETTER 83-28, ITEM 4.5.3, RESOLUTION

EGG-NTA-8341

TECHNICAL EVALUATION REPORT: A REVIEW OF REACTOR TRIP SYSTEM AVAILABILITY ANALYSES FOR GENERIC LETTER 83-28, ITEM 4.5.3, RESOLUTION

David P. Mackowiak
John A. Schroeder

EG&G Idaho, Inc.
Idaho Falls, Idaho 83415

FIN D6001: Evaluation of Conformance to Generic Letter 83-28 for ORs (Project 2)

ABSTRACT

The Idaho National Engineering Laboratory (INEL) conducted a technical review of the commercial nuclear reactor licensees' responses to the requirements of the Nuclear Regulatory Commission's (NRC's) Generic Letter 83-28 (GL 83-28), Item 4.5.3. The results of this review, if all plants are shown to be covered by an adequate analysis, will provide the NRC staff with a basis to close out this issue with no further review. The licensees, as the four vendors' Owners' Groups, submitted analyses to the NRC either directly in response to GL 83-28, Item 4.5.3, or to provide a basis for requesting changes to the Technical Specifications (TS) that would extend the Reactor Protection System (RPS) surveillance test intervals (STIs). To conduct the review, the INEL defined three criteria to determine the adequacy, plant applicability, and acceptability of the results. The INEL examined the Owners Groups' reports to determine if the analyses and results met the established criteria. Fort St. Vrain's responses to Item 4.5.3 were also reviewed. The INEL review results show that all licensees of currently operating commercial nuclear reactors have adequately demonstrated that their current on-line RPS test intervals meet the requirements of GL 83-28, Item 4.5.3.

SUMMARY

The two anticipated transient without scram (ATWS) events at the Salem Nuclear Power Plant in February of 1983, focused the attention of the Nuclear Regulatory Commission (NRC) on the generic implications of ATWS events. The NRC then published Generic Letter 83-28 (GL 83-28) which listed the actions the NRC required of all licensees holding operating licenses and others with respect to assuring the reliability of the Reactor Protection System (RPS). GL 83-28, Item 4.5.3, required licensees to demonstrate by review that the current on-line functional testing intervals are consistent with achieving high reactor trip system (RTS) availability. The licensees responded to the GL 83-28, Item 4.5.3, requirements as Owners Groups with reports either in direct response to Item 4.5.3, or with a technical basis for requesting extensions to the surveillance test intervals (STIs) that generally included the Item 4.5.3 required reviews.

The NRC's Instrumentation and Control Systems Branch (ICSB), Office of Nuclear Reactor Regulation (NRR), requested the Idaho National Engineering Laboratory (INEL) to review the licensee availability analyses and evaluate the overall adequacy of the existing test intervals. INEL review results showing general compliance with Item 4.5.3 will provide the NRC with a basis to close out Item 4.5.3 without further review.

For the review, the INEL defined three acceptance criteria, reviewed the licensees topical reports, contractor review reports, and NRC safety evaluations, and determined the adequacy of the analyses and the RTS availability estimates with regard to the review criteria.

The INEL review criteria to determine the licensees' Item 4.5.3 compliance were, (1) the five areas of concern of Item 4.5.3, (2) the analyses' plant applicability, and (3) the NRC's RTS electrical unavailability base case estimates from the ATWS Rulemaking Paper, SECY-83-293.

Each Owners Groups' reports were reviewed to ensure that all five areas of concern from Item 4.5.3 were either included in the analyses or shown not to be significant with regard to RTS availability. The INEL review also ensured that the individual plants' differences from the analysis' models were taken into account and their effects were shown not to significantly affect RTS unavailability. The Fort St. Vrain responses to Item 4.5.3 were also reviewed.

The Owners Groups' RTS unavailability estimates were compared to the NRC's ATWS Rulemaking generic RTS unavailability estimates to determine the acceptability of the Owners Groups' conclusions that high RTS availability was demonstrated in the analyses.

The results of the INEL review showed that all licensees of currently operating commercial nuclear reactors have adequately demonstrated that their current on-line surveillance test intervals are consistent with achieving high RTS availability.

ACRONYMS

ATWS	Anticipated Transient Without Scram
B&W	Babcock & Wilcox
BNL	Brookhaven National Laboratory
CE	Combustion Engineering
GE	General Electric
HTGR	High-Temperature Gas-Cooled Reactor
ICSB	Instrumentation and Control Systems Branch
INEL	Idaho National Engineering Laboratory
LWR	Light Water Reactor
NFSC	Nuclear Facility Safety Committee
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PORC	Plant Operations Review Committee
PSC	Public Service Company of Colorado
PWR	Pressurized Water Reactor
RSSMAP	Reactor Safety Study Methodology Applications Program
RPS	Reactor Protection System
RTS	Reactor Trip System
SER	Safety Evaluation Report
STI	Surveillance Test Interval
TER	Technical Evaluation Report
W	Westinghouse

CONTENTS

TABLES

TECHNICAL EVALUATION REPORT: A REVIEW OF REACTOR TRIP SYSTEM AVAILABILITY ANALYSES FOR GENERIC LETTER 83-28, ITEM 4.5.3 RESOLUTION

1. INTRODUCTION

1.1 Historical Background

In February of 1983, two events occurred at the Salem Nuclear Generating Station that focused Nuclear Regulatory Commission (NRC) attention on the generic implications of anticipated transient without scram (ATWS) events.

First, on February 22, during startup of Unit 1 an automatic trip signal generated as a result of a steam generator low-low level failed to cause a reactor scram. The reactor was tripped manually by an operator almost coincidentally with the automatic trip signal, so the fact that the automatic trip had failed to cause a scram went unnoticed.

Three days later on February 25, both of the scram breakers at Unit 1 failed to open on an automatic reactor protection system (RPS) scram signal. The operators took action to control this second ATWS and succeeded in terminating the incident in about 30 seconds. Subsequent investigation related the failure of the Unit 1 RPS to cause a scram to sticking of the undervoltage trip attachment in the scram circuit breakers.

As a result of these events the NRC Executive Director for Operations directed the staff to undertake three related activities: (1) an evaluation of when and under what conditions the Salem plants would be allowed to restart; (2) a fact finding report of the events at Salem 1 and the circumstances leading to them; and (3) a report on the generic implications of these events.

To address (3) above an interoffice, interdisciplinary group was formed including members from the Office of Nuclear Reactor Regulation's

(NRR's) Division of Licensing, Division of Systems Integration, Division of Human Factors Safety, Division of Engineering, Division of Safety Technology, the Office of Inspection and Enforcement, the Office for Analysis and Evaluation of Operational Data, and NRC's Region I Office. This group published NUREG-1000[1] as a result of their efforts to resolve the following questions: (1) is there a need for prompt actions to address similar equipment in other facilities; (2) are the NRC and its licensees learning the safety management lessons; and (3) how should the priority and content of the ATWS Rule be adjusted.

As a result of the NUREG-1000 findings, the NRC issued Generic Letter 83-28[2] (GL 83-28). The actions described in GL 83-28 address issues related to reactor trip system (RTS) reliability. The actions covered fall into the following four areas: (1) Post-Trip Review, (2) Equipment Classification and Vendor Interface, (3) Post-Maintenance Testing, and (4) Reactor Trip System Reliability Improvements.

Item 4, above, is aimed at assuring that vendor-recommended reactor trip breaker modifications and associated reactor protection system changes are completed in pressurized water reactors (PWRs), that a comprehensive program of preventive maintenance and surveillance testing is implemented for the reactor trip breakers in PWRs, that the shunt trip attachment activates automatically in all PWRs that use circuit breakers in their reactor trip systems, and to ensure that on-line functional testing of the reactor trip system is performed on all light water reactors (LWRs).

The specific requirements of GL 83-28, Item 4.5.3, are that existing intervals for on-line functional testing required by Technical Specifications shall be reviewed to determine if the intervals are consistent with achieving high RTS availability when accounting for considerations such as: (1) uncertainties in component failure rates; (2) uncertainties in common mode failure rates; (3) reduced redundancy during testing; (4) operator errors during testing; and (5) component "wear-out" caused by testing.

The Babcock & Wilcox (B&W), Combustion Engineering (CE), General Electric (GE), and Westinghouse (W) Owners Groups have submitted topical reports either in response to GL 83-28, Item 4.5.3,[3,4] or to provide a basis for requesting RTS surveillance test interval (STI) extensions.[5,6,7,8,9,10,11] In general, the owners groups' analyses were not done on a plant specific basis. Instead, the analyses addressed a particular class of reactor trip system and then discussed the applicability of the analysis to specific product lines. The NRC reviewed these reports for, among other things, their applicability to GL 83-28, Item 4.5.3 and summarized their findings in Safety Evaluation Reports[12,13] (SERs).

1.2 Review Purpose

This report documents a review of the Owners Groups' topical reports, the NRC SERs, and other analyses done at the Idaho National Engineering Laboratory (INEL) by personnel in the NRC Risk Analysis Unit of EG&G Idaho, Inc. The INEL conducted the review at the request of the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Instrumentation and Control Systems Branch (ICSB). The review was performed to determine if the Owners Groups' analyses demonstrated high RTS availability for the current test intervals, if the analyses included the five areas of concern from GL 83-28, and if all of the plants were covered by the analyses. The results of the review, if all plants are shown to be covered by an adequate analysis, would provide the NRC with a basis for closing out GL 83-28, Item 4.5.3, for all U.S. commercial nuclear reactors without further review.

The body of this report presents the review and its findings with regard to the stated objectives. Section 2 describes the criteria used in the review to determine the adequacy of the analyses. The review methodology is discussed in Section 3. Section 4 presents the review results. The review conclusions are given in Section 5.

2. REVIEW CRITERIA

To conduct a review, one must have criteria, or standards, on which a judgment or decisions may be based. In this section, the INEL availability analyses review criteria are presented.

GL 83-28 established the three criteria used in the INEL review. GL 83-28 stated that: (1) all licensees et al., (2) must demonstrate high RTS availability for the current test intervals by documented review when (3) accounting for such considerations as the five areas of concern listed in Section 1.1. While GL 83-28 established all three criteria, it only defined two of them--who had to do a review and what the review had to take into account. The third and most subjective criterion, "high availability", was not defined.

To establish a definition of high availability, the INEL used the electrical unavailability base case estimates presented in Table A-1 of Appendix A to SECY-83-293.[14] Unavailability is defined as 1.0 minus availability. A low unavailability is equivalent to a high availability. Most analyses calculate a system unavailability rather than an availability. Therefore, our criteria for a "high availability" will be expressed in terms of low unavailability for compatibility. These RTS unavailability estimates from Reference 14 were used for two reasons. First, they were used because they were developed by the NRC's ATWS Task Force as a reevaluation of the bases for the RTS unavailabilities used in ATWS rule value-impact evaluations. Second, as stated in Reference 14, this NRC analysis

> "...bases the RTS unavailabilities on worldwide experience to date. It is believed that this gives a reasonable estimate of RTS unavailability that includes the common cause contributions that are believed to dominate. The experience based values are distributed across the four vendor designs based on a comparative reliability analysis that evaluates the major differences among the designs."

The estimates from the NRC ATWS analysis provide a framework with which to consider the topical report analyses estimates. The numerical estimates in the SECY-83-293 for the four vendors combined with the five areas of concern from GL 83-28, Item 4.5.3, form the criteria used for this review to determine if the vendors' analyses and estimates met the requirements of Item 4.5.3.

3. REVIEW METHODOLOGY

The INEL conducted this review by examining the vendors' topical reports (References 3, 4, 5, 6, 7, 8, 9, 10, and 11), the technical evaluation reports[15,16,17,18] (TERs) done as a part of the NRC topical report review process, the NRC's SERs (References 12 and 13), and NUREG/CR-5197, Evaluation of Generic Issue 115, "Enhancement of Westinghouse Solid State Protection System."[19] This was done for three reasons. First, the reports were examined to find out whether or not the vendors' analyses addressed the areas of concern from Item 4.5.3 and reflected a high RTS availability. Second, they were examined to determine what plants were covered by the vendors' analyses. Third, the Generic Issue 115 report provided an independent, updated estimate of the availability of the W solid state RTS for comparison to the review criteria.

For the plants covered by the vendors' analyses or the NUREG/CR-5197 analysis, the appropriate analysis and availability were compared to the review criteria established in Section 2. If the analysis adequately addressed the areas of concern and demonstrated a high RTS availability, the plant was accepted as having met the requirements of GL 83-28, Item 4.5.3. The results of the comparisons for plants covered by a vendor analysis are given by vendor in Section 4.

For plants not directly covered by a vendor's analysis, an acceptable means was found to extend the analyses to cover the plants. This was done for two plants: Clinton 1 (GE) and Maine Yankee (CE). The means by which the analyses were extended to cover these two plants are also discussed by vendor in Section 4.

One plant, Fort St. Vrain, a high temperature, gas-cooled reactor (HTGR), was not covered by any of the four vendors' analyses and required special consideration. The INEL examined the responses from Fort St. Vrain required by GL 83-28, Item 4.5.3 to determine if the responses demonstrated an acceptably high RTS availability. The review of the Fort St. Vrain responses is given in Section 4.6.

4. REVIEW RESULTS

This section summarizes the results of the INEL review of the vendors' analyses with regard to the five areas of concern and plant applicability. The vendors' estimates of RTS availability are compared to the review availability criteria. Also, some insights concerning RTS availability, gained from an examination of RTS importance measures from selected PRAs, are examined.

4.1 B&W Plants

The issues of GL 83-28, Item 4.5.3, were addressed by the B&W Owners Group and the results were submitted to the NRC by the individual utilities in their responses to GL 83-28. Topical Report BAW-10167 (Reference 5) was submitted to the NRC to provide a technical basis for increasing the on-line STIs and allowed outage times (AOTs) for B&W RTS instrument strings. The analysis presented in BAW-10167 was built upon the previous analysis done to address the GL 83-28, Item 4.5.3 issues. However, some information that was resolved in the generic letter analysis was not repeated in the subsequent Topical Report because it was not relevant to the proposed Technical Specification changes. To make BAW-10167 applicable to both GL 83-28, Item 4.5.3 and STI/AOT issues, the Owners Group submitted BAW-10167, Supplement 1 (Reference 6), to the NRC. Supplement 1 completed the B&W analysis by addressing all remaining Item 4.5.3 issues. The BAW -10167 and Supplement 1 analyses included the implementation of the automatic shunt trip on the reactor trip circuit breakers as required by GL 83-28, Item 4.3.

The INEL has previously reviewed the BAW-10167 and Supplement 1 analyses and documented the review in a TER, EGG-REQ-7718 (Reference 15). For the TER, sensitivity studies which included all of the Item 4.5.3 areas of concern were conducted on the RTS models. The sensitivity study results showed the models to be insensitive to variations in the failure rates associated with the Item 4.5.3 areas of concern.

The INEL reviewed BAW-10167, BAW-10167, Supplement 1, and the TER and determined that the B&W analyses adequately covered all five areas of concern and that all currently operating B&W reactors are included.

4.2 CE Plants

Licensees with CE reactors responded to the requirements of GL 83-28, Item 4.5.3, as the CE Owners Group by submitting CE NPSD-277 (Reference 3) to the NRC. The NPSD-277 RTS availability analysis specifically included all five areas of concern and all currently operating CE reactors except Waterford 3, which was not in commercial operation until September 1985.

The CE Owners Group also submitted CEN-327 (Reference 7) to provide licensees with a basis for requesting RTS STI extensions. This later analysis expanded on the simplified models of NPSD-277 to include all RTS input parameters. All currently operating CE plants except Maine Yankee were covered in the CEN-327 analysis. The CEN-327 STI analysis specifically included the NPSD-277 analyses of the Item 4.5.3 areas of concern except component "wear-out" during testing. The CEN-327 analysis showed that the major contributors to RTS unavailability for the four plant classes are common cause failures of the trip circuit breakers which are tested on a monthly basis.

In both NPSD-277 and CEN-327, the CE RPS designs are grouped into four classes by signal processing and trip device differences, otherwise the logic and physical layouts of the RTS are the same for all RTS plant classes. In NPSD-277, Maine Yankee is included in RPS Plant Class 2. In CEN-327, Waterford 3 is included in RPS Plant Class 3. Between NPSD-277 and CEN-327, all of the CE plants are included in plant classes analyzed in CEN-327. This review considers the analysis and results in CEN-327 adequate for Item 4.5.3 resolution for all classes of CE plants.

The INEL has previously reviewed CEN-327 with regard to STI extension effects and documented the review in a TER, EGG-REQ-7768 (Reference 16). The results of sensitivity studies done for the TER show the models to be insensitive to an order of magnitude increase in the component independent failure rates. The insensitivity to increased component failure rates along with the CE analysis results showing trip circuit breaker common cause failures to be the major contributor to RTS unavailability provides a a basis for this review to conclude that RTS test-induced component wear-out is not an issue at CE reactors.

The INEL reviewed CEN-327 and the TER and determined that the CE analyses have adequately covered all five areas of concern or they have been shown not to contribute to RTS unavailability and that all currently operating CE reactors are included.

4.3 GE Plants

Licensees with GE reactors responded to the GL 83-28, Item 4.5.3 requirements as the BWR Owners' Group by submitting NECD-30844 (Reference 4) to the NRC. The RTS availability analysis specifically included the five areas of concern and covered both generic relay and solid-state RTS designs which includes all currently operating BWRs. GE stated that the relay RPS configurations for BWR plants have the same primary design features. Therefore, the generic relay RTS models used in NECD-30844 do not differ significantly from the specific BWR plants. GE used the Clinton 1 drawings for the solid-state RTS models. Since Clinton 1 is currently the only GE plant with a solid state RTS, no plant unique analysis is necessary.

The BWR Owners' Group also submitted NECD-30851P (Reference 8) to the NRC. The analysis in this second report used the base case results from NECD-30844 to establish a basis for requesting revisions to the current Technical Specifications for the RTS. The INEL had previously reviewed NECD-30844 and NECD-30851P with regard to both Item 4.5.3 and STI extension acceptability and documented the review in a TER, EGG-EA-7105 (Reference 17). Due to insufficient information, the INEL review could not complete the solid-state RTS review and accepted only the relay RTS analysis results. The NRC reviewed the topical reports and the TER and issued an SER (Reference 12). The NRC accepted the analysis results as a reference for TS changes related to the RTS and as resolution to GL 83-28, Item 4.5.3, for GE relay plants only. The INEL later completed the solid state RTS analysis review and issued Rev 1 to the TER (Reference 18), thus accepting the analyses for all classes of GE plants.

This review examined both GE analyses and the Rev 1 TER and determined that all five areas of concern are included in the analyses and that all currently operating GE reactors are included.

4.4 Westinghouse Plants

Licensees with Westinghouse reactors did not respond directly to the requirements of GL 83-28, Item 4.5.3. Prior to the Salem ATWS, they had submitted WCAP-10271 (Reference 9) to the NRC to provide a basis for requesting changes to the Technical Specifications regarding the RTS. The Westinghouse methodology attempted to balance safety and operability and was applied to a typical Westinghouse four loop reactor plant with a solid state RTS in WCAP-10271. The methodology was extended to cover RTSs for two, three, and four loop plants with either relay or solid state logic in WCAP-10271, Supplement 1 (Reference 10).

The NRC reviewed the Westinghouse topical reports with the assistance of Brookhaven National Laboratory (BNL) and issued an SER (Reference 13) limiting their acceptance to changes to only the analog channel STIs at Westinghouse plants.

The W methodology used fault trees to model the RTS. The models included the following five major contributors to RTS trip unavailability:

1. Unavailability of components due to random failures

2. Unavailability of components due to test

3. Unavailability of components due to unscheduled maintenance

4. Unavailability of components due to human error

5. Unavailability of components due to common cause failure.

While the W analysis did not directly include any sensitivity studies concerning these five areas, the component unavailabilities were increased as the test interval length increased. The STI analysis results showed a factor of 3 to 5 increase in the RTS unavailability estimates for the longer test interval. Two conservatisms exist in the models that are relevant: first, no credit was taken for early failures that would be detected and, second, no credit was taken for the diversity inherent in the W RTS design. These two conservatisms, had they been included in the model, would cause the increase in the RTS unavailability estimates to be smaller than the observed factors.

Test-induced component wear-out was not addressed in any manner in the W RTS analysis. However, the RTS analyses done by the other vendors, References 3, 4 and 6, specifically investigated the effects of this issue on RTS unavailability. Despite the differences among the other vendors' RTS designs, they all found the effects of test induced component wear-out on RTS unavailability to be insignificant. Based on the other vendors' analyses, the INEL concluded that the effects of test-induced component wear-out on W RTS unavailability would also be insignificant. Therefore, the INEL considers all W plants to be covered by adequate analyses.

4.5 Quantitative Review of Vendors' RTS Availabilities

So far, only the adequacy of the vendors' analyses has been discussed. No determination has been made of the acceptability of the numerical estimates from the various RTS availability analyses. In this section, the INEL review considers the four Owners Groups' RTS availability estimates to determine if they are indeed indicative of "high availability."

In Table 1, the four vendors' RTS unavailability estimates are compared to the review estimates of low unavailability as defined in Section 2. The B&W and GE vendors' estimates are given as an overall RTS unavailability per demand by plant model and RTS type, respectively. The CE and W vendors' estimates are given on a similar basis with an additional consideration that was not necessary for the B&W and GE analyses. In the CE and W analyses, RTS unavailability was estimated for all input parameters. For the CE and W unavailability estimates in Table 1, the INEL used the unavailability estimates for high pressurizer pressure, the parameter analyzed in Reference 19 as the limiting parameter for an ATWS in terms of the number of input channels and diversity of trip signal.

The differences in the relative values of the three PWR vendors' RTS unavailability estimates can be attributed to design differences among the RTSs. B&W and CE RTSs have four analog channel inputs for each monitored parameter with four trip logic channels while W RTSs have three or four analog channel inputs for each parameter with only two trip logic channels. The 2 of 4 analog channels for the B&W and CE RTS designs are inherently more reliable than the 2 of 3 analog channels for some parameters in the W design. Also the 2 of 4 trip logic in the B&W and CE RTSs is more reliable than the W 1 of 2 trip logic. The combination of these two design differences make the W RTS unreliability somewhat higher than the other vendors' RTS unavailabilities.

The comparison shows the B&W, CE, and GE RTS unavailability estimates are lower than the NRC's estimates while the W estimates are the same as the NRC's. The INEL review recognizes the Vendors' estimates and the NRC's estimates are influenced by a number of factors. These factors include, (1) the data uncertainties for both the NRC and Vendors analyses, (2) the scarcity of actual RTS failures world wide, (3) the modeling assumptions and simplifications used by both the NRC and the Vendors, and (4) the differing levels of model development between the NRC analysis and the Vendors' analyses and between different Vendors' analyses. These factors

TABLE 1. COMPARISON OF VENDOR AND NRC RTS UNAVAILABILITY ESTIMATES[a]

Vendor	Vendor RTS Unavailability Estimates (Failures/Demand)	NRC RTS Unavailability Estimates[b] (Failures/Demand)
B&W		
Davis Bessie Model	1E-10[c]	3E-5[d]
Oconee Class Model	1E-6[c]	3E-5[d]
CE		
Plant Class 1	2E-7[e]	2E-5
Plant Class 2	3E-6[e]	2E-5
Plant Class 3	3E-6[e]	2E-5
Plant Class 4	2E-6[e]	2E-5
GE		
Relay Plants	3E-6[f]	2E-5
Solid-state Plants	3E-6[f]	2E-5
W		
Relay Plants	5E-5[g]	5E-5[d]
Solid-state Plants	5E-5[g]	5E-5[d]

a. All estimates are rounded off to one significant digit.

b. From Reference 14, Table A-1, base case RTS electrical unavailability estimates.

c. From Reference 5, base case.

d. Includes automatic shunt trip on the reactor trip circuit breakers.

e. From Reference 7, Tables 4.1-1, 4.2-2, 4.1-3, and 4.1-4, respectively; base case test interval, high pressurizer pressure unavailability estimate.

f. From Reference 4.

g. From Reference 19, solid state RTS base case. Applied to relay-plants based on similarity of design (see Reference 11, Section 3.2.2 and 3.2.3).

help explain the differences between the Vendors' and the NRC's point estimates of RTS availability.

4.6 Fort St. Vrain

Fort St. Vrain responded to GL 83-28, Item 4.5.3 in a letter to Eisenhut dated November 4, 1983[20], stating:

> "Existing intervals for on-line functional testing required by the Technical Specifications are currently under review by Public Service Company of Colorado (PSC) and the Nuclear Regulatory Commission Region IV staff. The current testing frequency at Fort St. Vrain has been dictated by the Nuclear Regulatory Commission staff." (Underline added)

In response to a request for information from the NRC concerning the Fort St. Vrain responses to GL 83-28 previously sent, PSC sent the following reply to the NRC in a letter to Johnson, dated June 12, 1985[21]:

> "Existing intervals for the on-line testing required by the Technical Specifications were reviewed by Public Service Company of Colorado. A Technical Specification change to Limiting Conditions for Operation 4.4.1 (Plant Protective System) and its associated surveillance requirements (SR 5.4.1) are currently being reviewed by the Plant Operations Review Committee (PORC). This Technical Specification change is expected to be approved by the PORC and the Nuclear Facility Safety Committee (NSFC) by June 30, 1985.. As part of the development process for these proposed changes to the Technical Specifications, on-line functional testing requirements were reviewed based on past experience. Possible changes to the testing intervals in certain cases where available test data may support such changes has (sic) been discussed at length with the Nuclear Regulatory Commission staff. The Nuclear Regulatory Commission staff has informed Public Service Company of Colorado that no such changes would be acceptable at this time."

The INEL review interpreted these responses from Fort St. Vrain to mean the NRC has established Fort St. Vrain's RTS current test intervals, the current test intervals have been evaluated by PSC, and the NRC will not allow changes to the test intervals at this time.

From these responses, the INEL concluded that Fort St. Vrain has conducted the review required by GL 83-28, Item 4.5.3, and that the NRC considers the PSC and NRC reviews adequate to meet the Item 4.5.3 requirements.

5 REVIEW CONCLUSIONS

All four LWR vendors have submitted topical reports either in response to GL 83-28, Item 4.5.3, or to provide a basis for RTS STI extensions, or both. For the most part, these reports have addressed all of the issues in Item 4.5.3. Licensees not covered by the topical reports have submitted individual responses to Item 4.5.3.

The analyses in the topical report have shown the currently configured RTSs to be highly reliable with the current test intervals and prior to implementing some of the requirements of GL 83-28. Implementation of these additional requirements will reduce the ATWS risk even further.

The INEL has reviewed the relevant topical reports, TERs, SERs, additional analyses, and the individual licensee submittals with regard to GL 83-28, Item 4.5.3, requirements and the review criteria. Based on that review, the INEL concludes that all licensees of currently operating commercial nuclear power plants have adequately demonstrated that their current RTS test intervals are consistent with achieving high RTS availability.

6. REFERENCES

1. U.S. Nuclear Regulatory Commission, Generic Implications of ATWS Events at the Salem Nuclear Power Plant, NUREG-1000, April 1983.

2. U.S. Nuclear Regulatory Commission Letter, D. G. Eisenhut to All Licensees et al., Required Actions Based on Generic Implications of Salem ATWS Events, Generic Letter 83-28, July 8, 1983.

3. Combustion Engineering, Reactor Protection System Test Interval Evaluation, Task 486, CE NPSD-277, December 1984.

4. S. Visweswaran et al., BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3, NECD-30844, January 1985.

5. R. S. Enzinna et al., Justification for Increasing the Reactor Trip System On-line Test Interval, BAW-10167, May 1986.

6. R. S. Enzinna et al., Justification for Increasing the Reactor Trip System On-line Test Interval, Supplement Number 1, BAW-10167, Supplement Number 1, February 1988.

7. Combustion Engineering, RPS/ESFAS Extended Test Interval Evaluation, CEN-327, May 1986.

8. W. P. Sullivan et al., Technical Specification Improvement Analyses for BWR Reactor Protection System, NECD-30851P, May 1985.

9. R. L. Jansen et al., Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, WCAP-10271, January 1983.

10. R. L. Jansen et al., Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, Supplement 1, WCAP-10271, Supplement 1, July 1983.

11. R. L. Jansen et al., Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, Supplement 1-P-A, WCAP-10271, Supplement 1-P-A, May 1986.

12. U.S. Nuclear Regulatory Commission Memorandum, G. C. Lainas to E. J. Butcher, Acceptance for Referencing of General Electric Company (GE) Topical Reports NECD-30844, "BWR Owners' Group Response to NRC Generic Letter 83-28," and NECD-30851P, "Technical Specification Improvement Analyses for BWR Reactor Protection System," April 28, 1986.

13. U.S. Nuclear Regulatory Commission Letter, C. O Thomas to J. J. Sheppard, Acceptance for Referencing of Licensing Topical Report WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation Systems," February 21, 1985.

14. U.S. Nuclear Regulatory Commission, Amendments to 10 CFR 50 Related to Anticipated Transients Without Scram (ATWS) Events, SECY-83-293, July 19, 1983.

15. J. P. Poloski and S. D. Matthews, Review of B&W Owner's Group Analyses for Increasing The Reactor Trip System On-line Test Interval, EGG-REQ-7718, September 1988.

16. D. P. Mackowiak and B. L. Collins, A Review of the Combustion Engineering Evaluation For Extending the RPS and ESFAS Test Intervals, EGG-REQ-7768, September 1988.

17. R. E. Wright and B. L. Collins, A Review of the BWR Owners' Group Technical Specification Improvement Analyses for the BWR Reactor Protection System, EGG-EA-7105, January 1986.

18. R. E. Wright and B. L. Collins, A Review of the BWR Owners' Group Technical Specification Improvement Analyses for the BWR Reactor Protection System, EGG-EA-7105, Rev 1, March 1987.

19. D. A. Reny et al., Evaluation of Generic Issue 115, Enhancement of the Reliability of Westinghouse Solid State Protection Systems, NUREG/CR-5197, January 1989.

20. Public Service Company of Colorado Letter, O. R. Lee to D. G. Eisenhut, Response to Generic Letter 83-28, November 4, 1983.

21. Public Service Company of Colorado Letter, J. W. Gham to E. H. Johnson, Response to Generic Letter 83-28, June 12, 1985.

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

September 13, 1989

The Honorable Kenneth M. Carr
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Chairman Carr:

SUBJECT: EMERGENCY PLAN FOR FULL-POWER OPERATION OF THE SEABROOK STATION, UNIT 1

During the 353rd meeting of the Advisory Committee on Reactor Safeguards, September 7-9, 1989, we reviewed the Seabrook Station emergency plan as well as progress on construction and testing that has occurred since our April 19, 1983 report. Our subcommittee on Seabrook considered the emergency plan during a meeting on August 17, 1989. During our review, we had discussions with representatives of the licensee, the NRC staff, the Federal Emergency Management Administration (FEMA), and intervenor groups. We also had the benefit of the documents referenced.

In our previous report, we provided our conclusion that the Seabrook Station could be operated at up to five percent of its design power of 3411 MWt. We also noted that the emergency plan for the plant had not been completed at the time of the report, and thus we had not reviewed it.

The licensee, in formulating the emergency plan for the plant, has had to take account of the fact that The Commonwealth of Massachusetts and some of the local government entities within the state of New Hampshire have chosen not to participate in emergency planning and in the emergency exercises that have been held.

FEMA, after evaluating that part of the emergency plan dealing with the offsite population, has concluded that the plan is acceptable, although some corrective actions have been specified. In its evaluation, FEMA included measures taken by the licensee to devise a system for providing information to people in areas within the 10-mile emergency planning zone where local authorities have not accepted this responsibility. Consideration was also given to plans, made by the licensee, for other emergency actions that might be required in case of a major accident. Major consideration was given to plans for evacuating the beach areas within the 10-mile zone, in case an accident occurs at a time when there is a significant transient beach population.

The NRC staff has evaluated the licensee's planning and the training of the licensee's staff for dealing with emergencies. Practice exercises have been held. The staff is prepared to recommend approval of the licensee's emergency plan, including that part of the plan that has been evaluated by FEMA.

Emergencies that would require site evacuation are low-probability events. The licensee's analyses predict that, even with peak occupancy of the beaches and other areas, the emergency planning zone can be evacuated in less than eight hours. This should provide appropriate radiological dose savings and complies with NUREG-0654, Revision 1 (referenced). The Seabrook Station emergency plan appears to meet the standards that have been formulated by FEMA and by the NRC.

We observe that, if an accident occurs that requires implementation of a significant part of the emergency plan, it is likely to be an accident not specifically planned for. Thus, the emergency plan, even though it is designed to respond to site emergencies as defined in NUREG-0654, is valuable not only because it can respond to postulated scenarios. Its principal value results from the fact that it requires that decisions be made prior to an emergency, such as who is responsible for making decisions during the course of an emergency, what communication systems are available, what resources, human and otherwise, are available, and how, within some limits, the organization can function. Given such planning, it is much more likely that even the unexpected can be dealt with successfully. This observation is well encapsulated in the statement by former President Eisenhower, "Plans are worthless, but planning is everything."

It is also necessary to recognize that in spite of all the precautions that are taken, there is some small residual risk. We do not believe that this risk is unacceptable or is significantly greater than that at other densely populated sites.

The ACRS believes that subject to satisfactory resolution of the issues that arose during low-power testing and corrective actions recommended by FEMA, there is reasonable assurance that Seabrook Station, Unit 1, can be operated at core power level up to 3411 MWt without undue risk to the health and safety of the public.

Sincerely,

Forrest J. Remick
Chairman

References:

1. Public Service Company of New Hampshire, Seabrook Station, "Final Safety Analysis Report," Volumes 1-15, with amendments 1 through 61.
2. U.S. Nuclear Regulatory Commission, NUREG-0896, "Safety Evaluation Report Related to the Operation of Seabrook Station, Units 1 and 2," with supplements 1 through 8.

3. U.S. Nuclear Regulatory Commission, Supplement to the Safety Evaluation Report for the Seabrook Station (TAC #M63391), July 27, 1989.
4. Public Service Company of New Hampshire and Yankee Atomic Elecric Company, PLG-0300, "Seabrook Station Probabilistic Safety Assessment," Volumes 1-6, December 1983.
5. U.S. Nuclear Regulatory Commission and Federal Emergency Management Agency, NUREG-0654/FEMA-REP-1, Rev. 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," November 1980.
6. Written Comments dated July 11, 1989 from Board of Selectmen, Town of Essex, Massachusetts, regarding unresolved reactor safety issues.
7. Written Comments dated August 16, 1989 from Leslie B. Greer, Attorney General's Office, the State of Massachusetts, submitting documents on emergency plans that have been submitted to ASLB and ASLAP.
8. Written Comments dated August 16, 1989 from Board of Selectmen, Town of Manchester, Massachusetts, joining concern expressed in Essex Board of Selectmen letter of July 11, 1989.
9. Written Comments dated August 18, 1989 from Matthew Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding ACRS meeting on Seabrook Nuclear Power Plant.
10. Written Comments dated August 21, 1989 from Diane Curran, representing the New England Coalition on Nuclear Pollution, regarding opposition to licensee's request for an exemption from the requirement to exercise the onsite emergency plan within a year prior to issuance of operating license.
11. Written Comments dated August 24, 1989 from Congressman Nicholas Mavroules in support of Essex Board of Selectmen letter dated July 11, 1989.
12. Written Comments dated August 28, 1989 from Patricia Pierce-Bjorklund, presenting visual evidence companion to the Essex Board of Selectmen letter of July 11, 1989.
13. Written Comments dated September 5, 1989 from Matthew T. Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding Seabrook Station Emergency Planning.
14. Written Comments dated September 6, 1989 from Robert A. Backus representing the Seacoast Anti-Pollution League regarding Seabrook Station Emergency Planning.
15. Written Comments dated September 6, 1989 from Diane Curran representing the New England Coalition on Nuclear Pollution regarding Seabrook Emergency Planning.
16. Written Comments dated September 6, 1989 from Matthew T. Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding ACRS/Seabrook Station Emergency Planning.
17. Videotape provided on September 8, 1989 by Mimi Fallon, Seacoast Anti-Pollution League, regarding evacuation considerations at the Seabrook Station.

3. U.S. Nuclear Regulatory Commission, Supplement to the Safety Evaluation Report for the Seabrook Station (TAC #M63391), July 27, 1989.
4. Public Service Company of New Hampshire and Yankee Atomic Elecric Company, PLG-0300, "Seabrook Station Probabilistic Safety Assessment," Volumes 1-6, December 1983.
5. U.S. Nuclear Regulatory Commission and Federal Emergency Management Agency, NUREG-0654/FEMA-REP-1, Rev. 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," November 1980.
6. Written Comments dated July 11, 1989 from Board of Selectmen, Town of Essex, Massachusetts, regarding unresolved reactor safety issues.
7. Written Comments dated August 16, 1989 from Leslie B. Greer, Attorney General's Office, the State of Massachusetts, submitting documents on emergency plans that have been submitted to ASLB and ASLAP.
8. Written Comments dated August 16, 1989 from Board of Selectmen, Town of Manchester, Massachusetts, joining concern expressed in Essex Board of Selectmen letter of July 11, 1989.
9. Written Comments dated August 18, 1989 from Matthew Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding ACRS meeting on Seabrook Nuclear Power Plant.
10. Written Comments dated August 21, 1989 from Diane Curran, representing the New England Coalition on Nuclear Pollution, regarding opposition to licensee's request for an exemption from the requirement to exercise the onsite emergency plan within a year prior to issuance of operating license.
11. Written Comments dated August 24, 1989 from Congressman Nicholas Mavroules in support of Essex Board of Selectmen letter dated July 11, 1989.
12. Written Comments dated August 28, 1989 from Patricia Pierce-Bjorklund, presenting visual evidence companion to the Essex Board of Selectmen letter of July 11, 1989.
13. Written Comments dated September 5, 1989 from Matthew T. Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding Seabrook Station Emergency Planning.
14. Written Comments dated September 6, 1989 from Robert A. Backus representing the Seacoast Anti-Pollution League regarding Seabrook Station Emergency Planning.
15. Written Comments dated September 6, 1989 from Diane Curran representing the New England Coalition on Nuclear Pollution regarding Seabrook Emergency Planning.
16. Written Comments dated September 6, 1989 from Matthew T. Brock, Attorney General's Office, The Commonwealth of Massachusetts, regarding ACRS/Seabrook Station Emergency Planning.
17. Videotape provided on September 8, 1989 by Mimi Fallon, Seacoast Anti-Pollution League, regarding evacuation considerations at the Seabrook Station.