NUREG-1137
Supplement No. 7

Safety Evaluation Report
related to the operation of Vogtle Electric Generating Plant, Units 1 and 2

Docket Nos. 50-424 and 50-425

Georgia Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1988

NOTICE

Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 1717 H Street, N.W.; Washington, DC 20555
2. The Superintendent of Documents, U.S. Government Printing Office, Post Office Box 37082, Washington, DC 20013-7082
3. The National Technical Information Service, Springfield, VA 22161

Although the listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC Office of Inspection and Enforcement bulletins, circulars, information notices, inspection and investigation notices; Licensee Event Reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, and NRC booklets and brochures. Also available are Regulatory Guides, NRC regulations in the *Code of Federal Regulations*, and *Nuclear Regulatory Commission Issuances*.

Documents available from the National Technical Information Service include NUREG series reports and technical reports prepared by other federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal and periodical articles, and transactions. *Federal Register* notices, federal and state legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Division of Information Support Services, Distribution Section, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, and are available there for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

NUREG-1137
Supplement No. 7

Safety Evaluation Report
related to the operation of
Vogtle Electric Generating Plant,
Units 1 and 2

Docket Nos. 50-424 and 50-425

Georgia Power Company, et al.

U.S. Nuclear Regulatory
Commission

Office of Nuclear Reactor Regulation

January 1988

ABSTRACT

In June 1985, the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-1137) regarding the application of Georgia Power Company, Municipal Electric Authority of Georgia, Oglethorpe Power Corporation, and the City of Dalton, Georgia, for licenses to operate the Vogtle Electric Generating Plant, Units 1 and 2 (Docket Nos. 50-424 and 50-425). Supplement 1 to NUREG-0737 was issued by the staff in October 1985, Supplement 2 was issued in May 1986, Supplement 3 was issued in August 1986, Supplement 4 was issued in December 1986, Supplement 5 was issued in January 1987, and Supplement 6 was issued in March 1987. The facility is located in Burke County, Georgia, approximately 26 miles south-southeast of Augusta, Georgia, and on the Savannah River.

This seventh supplement to NUREG-1137 provides recent information regarding resolution of some of the open and confirmatory items that remained unresolved following issuance of Supplement 6, and documents completion of several Unit 1 license conditions.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

FIGURES

TABLES

APPENDICES

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In June 1985, the Nuclear Regulatory Commission staff (NRC or staff) issued a Safety Evaluation Report (SER), NUREG-1137, on the application of the Georgia Power Company (hereinafter referred to as the applicant or licensee) for licenses to operate the Vogtle Electric Generating Plant, Units 1 and 2. Supplement 1 to NUREG-1137 was issued in October 1985, Supplement 2 was issued in May 1986, Supplement 3 was issued in August 1986, Supplement 4 was issued in December 1986, Supplement 5 was issued in January 1987, and Supplement 6 was issued in March 1987 in conjunction with the Unit 1 full-power license. This document, the seventh supplement to that SER (SSER 7), provides the staff evaluation of open and confirmatory items that have been resolved since SSER 6 was issued and documents the resolution of certain Unit 1 license conditions.

In this supplement, the term "licensee" refers only to Georgia Power Company as the license holder for Unit 1, as of January 16, 1987. The term "applicant" refers to Georgia Power Company as the applicant for an operating license for Unit 1 (before January 16, 1987) and for Unit 2.

Each of the sections and appendices of this supplement is designated the same as the related portion of the SER. Each section is supplementary to and not in lieu of the discussion in the SER, unless otherwise noted. Appendix A is a continuation of the chronology of this safety review and Appendix B lists reference materials cited in this document.* Appendix D lists acronyms and initialisms used in this supplement, Appendix E lists the principal contributors, and Appendix K is a continuation of errata to the SER and its supplements. Appendices C, F, G, H, I, J, L, M, N, O, P, Q, R, S, T, U, and V have not been changed by this supplement. Appendix W is new as a result of this supplement. Appendix W evaluates Revision 2 to the Unit 1 Pump and Valve Inservice Testing Program.

In addition to updating the status of unresolved items as identified in SSER 6, this supplement

- discusses the licensee's request to decrease the frequency of settlement monitoring (see Section 2.5.4.5)
- discusses the applicant's request to not calculate pipe stresses for 2-inch and smaller non-seismic Category I moderate energy piping for Unit 2 (see Section 3.6.1)
- discusses the applicant's request to apply leak-before-break technology to certain auxiliary lines for Unit 2 (see Section 3.6.3)
- discusses the Unit 2 steam generator snubber reduction (see Section 3.9.3.3)

---

*Availability of all material cited is described on the inside front cover of this report.

- discusses Revision 2 to the Unit 1 Inservice Testing Program (see Section 3.9.6 and Appendix W)

- discusses test and operational procedures for the residual heat removal system (see Section 5.4.7.5)

- discusses the deletion of the Unit 2 electrical penetration filter and exhaust system (see Section 6.5.1)

- discusses Technical Specifications for testing of Unit 2 slave relays (see Section 7.3.3.3)

- discusses the Plant Safety Monitoring System Verification and Validation Program for Units 1 and 2 (see Section 7.5.2.1)

- discusses three fire suppression system changes for Unit 2 (see Section 9.5.1)

- updates the resolution of the low-power license condition regarding potential leakage outside of containment (see Section 11.5.3)

- discusses the licensee's request to delay certain Unit 1 inital startup tests (see Section 14)

The NRC Project Manager for the operating license review through this supplement is Melanie A. Miller. The current Project Manager is Jon B. Hopkins. Each may be reached by telephone at (301) 492-7000 or by mail at the following address:

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Copies of this SER supplement are available for inspection at the NRC Public Document Room, 1717 H Street N.W., Washington, D.C. 20555, and at the local Public Document Room at the Burke County Library, 4th Street, Waynesboro, Georgia 30830.

1.7 Open Items

The SER identified 14 items in the staff review that had not been resolved with the applicant at the time that report was issued. SSER 1 fully resolved open items 3, 9, 10, and 12 and partially resolved open item 2. SSER 2 fully resolved open items 4 and 6; partially resolved open items 5, 7a, and 13; expanded open item 7a; and identified five new open items (7c and 15 through 18). SSER 3 fully resolved open items 7b and 18; partially resolved open items 1, 5, 7a, 11, and 13; expanded open item 1; and identified four new open items (7d and 19 through 21). SSER 4 fully resolved open items 7, 8, 11, 13, 15, 17, and 19; partially resolved open items 5 and 16; resolved open item 2 for Unit 1; partially resolved open item 1 for Unit 1; changed open item 20 to a license condition; and identified three new open items. SSER 5 fully resolved open items 1, 21, 23, and 24; partially resolved open items 5, 14a, 14b, and 22; changed the remaining portion of open item 14a to a license condition; and changed the remaining portion of open item 16 to a schedular exemption. SSER 6 partially resolved open item 14b and changed the remaining portion to a license condition.

This supplement fully resolves open item 22 for both units and partially resolves open item 5 for both units.

The complete list of open items is reproduced in updated Table 1.4; the current status of each item is given. For those items addressed in this supplement, the relevant section is noted.

1.8 Confirmatory Items

The SER identified 50 items that required confirmatory information and hence were not fully resolved at the time that report was issued. SSER 1 fully resolved confirmatory items 6, 8, 11, 20, 32, 45, 46, and 47. SSER 2 fully resolved confirmatory items 2, 3, 5, 16, 17, 21, 31, 34, 37, 38, 44, and 50 and added confirmatory item 51. SSER 3 fully resolved confirmatory items 4, 33, 39, 41, and 51; resolved confirmatory items 18 and 23 for Unit 1 only; added items 52 and 53; and partially resolved and expanded item 14. SSER 3 also changed confirmatory item 22 to open item 19 and confirmatory items 43, 48, and 49 to license conditions. SSER 4 fully resolved confirmatory items 1, 7, 9, 10, 12, 15, 35, 42, and 53; partially resolved confirmatory item 14; partially resolved confirmatory item 36 for Unit 1; resolved confirmatory items 24, 26, and 52 for Unit 1 and confirmatory item 27 for Unit 2; changed confirmatory item 19 to a license condition; and opened confirmatory items 54 (Unit 2 only) and 55. SSER 5 fully resolved confirmatory items 14 and 29; resolved confirmatory items 25, 28, and 36 for Unit 1; and reopened confirmatory item 27 for Unit 2. SSER 6 fully resolved confirmatory item 55 and resolved confirmatory items 13 and 30 for Unit 1. This supplement fully resolves confirmatory item 27 for Unit 2.

The complete list of confirmatory items and their status is provided in updated Table 1.5. If the confirmatory item is discussed in this supplement, the section in which it is discussed is identified.

1.9 License Condition Items

In the SER, the staff identified 11 license conditions. These issues will be cited in the operating license or Technical Specifications to ensure that NRC requirements are met during plant operation unless these conditions have subsequently been resolved. SSER 1 added license condition 12. SSER 2 added license condition 13 on fire protection. SSER 3 added license conditions 14 and 15 based on previous confirmatory items (items 43, 48, and 49) and deleted license conditions 4 and 11 because the applicant had fulfilled those requirements by including them in the Technical Specifications. SSER 4 resolved license conditions 1, 5 (Unit 1), and 6 because the applicant had fulfilled the requirements of the license conditions. SSER 4 also added license conditions 16 through 19. SSER 5 resolved license conditions 2 (Unit 1), 3, 9, and 16; added license condition 20; and added as a license condition a schedular exemption for spent fuel pool racks. SSER 6 resolved license condition 14 and added license condition 22. This supplement discusses the licensee's compliance with license conditions 12, 17, and 21. License condition 12 will need to be included in the Unit 2 license. The issue associated with license condition 17 (zinc coating of diesel fuel oil storage tanks) has also been resolved for Unit 2. License condition 21 applies to Unit 1 only. Table 1.6 is updated in this report to reflect these changes.

Table 1.4 Listing of open items (revised from SSER 6)

Item	Status	Section*
(1) Equipment qualification		
(a) Seismic equipment qualification	Partially resolved and expanded (SSER 3), resolved for Unit 1 (SSER 4)	
(b) Environmental equipment qualification	Resolved for Unit 1 (SSER 5)	
(c) Pump and valve operability assurance	Partially resolved (SSER 3), resolved for Unit 1 (SSER 4)	
(i) Aging and sequence of environmental conditions in maintenance program	Resolved (SSER 4)	
(ii) Pumps affected by static shaft analysis	Resolved (SSER 3)	
(iii) Onsite audit	Resolved (SSER 4)	
(iv) Safety injection pump operation	Opened (SSER 3), resolved (SSER 4)	
(v) Demonstrate operability of check valves	Opened (SSER 3), resolved (SSER 4)	
(vi) Uniform thread engagement	Opened (SSER 3), resolved (SSER 4)	
(2) Preservice inspection program	Partially resolved (SSER 1), resolved for Unit 1 (SSER 4)	
(3) Containment sump	Resolved (SSER 1)	
(4) Toxic gas evaluation of chemicals	Resolved (SSER 2)	
(5) Generic Letter 83-28	Partially resolved (SSERs 2, 3, 4, 5, and 7), awaiting information, and under staff review	15.8
(6) Emergency response capability--RG 1.97, Rev. 2	Resolved (SSER 2)	

*Section of this supplement in which item is discussed.

Table 1.4 (Continued)

Item	Status	Section*
(7) Fire protection items		
(a) Fire doors and dampers	Partially resolved (SSERs 2 and 3), resolved (SSER 4)	
(b) Power supplies for ventilation	Resolved (SSER 3)	
(c) Sprinkler system flushing deviation	Opened (SSER 2), resolved (SSER 4)	
(d) Fire hazards analysis	Opened (SSER 3), resolved (SSER 4)	
(8) Safe and alternate shutdown capability	Resolved (SSER 4)	
(9) Training of emergency diesel generator personnel	Resolved (SSER 1)	
(10) Diesel fuel oil storage tank cathodic protection	Resolved (SSER 1)	
(11) Licensee qualifications for operation	Partially resolved (SSER 3), resolved (SSER 4)	
(12) Retesting of simulator response (NUREG-0737, Item 1.A.2.1)	Resolved (SSER 1)	
(13) Emergency preparedness	Partially resolved (SSERs 2 and 3), resolved (SSER 4)	
(14) Human factors engineering items		
(a) Detailed control room design review	Partially resolved and changed to license condition (SSER 5)	
(b) Safety parameter display system	Partially resolved (SSERs 5 and 6), changed to license condition (SSER 6)	

*Section of this supplement in which item is discussed.

Table 1.4 (Continued)

Item	Status	Section*
(15) Arbitrary intermediate pipe break criteria	Opened (SSER 2), resolved (SSER 4)	
(16) Spent fuel pool rack design	Opened (SSER 2), partially resolved (SSER 4), schedular exemption (SSER 5)	
(17) Training program	Opened (SSER 2), resolved (SSER 4)	
(a) Mitigating core damage (NUREG-0737, Item I.A.2.1)		
(b) Instructor qualification and requalification		
(c) Licensed operator training		
(d) Nonlicensed personnel training		
(e) Records of plant personnel training		
(18) Compliance with RG 1.94	Opened (SSER 2), resolved (SSER 3)	
(19) LOCA mitigation in Modes 3 and 4	Opened (SSER 3), resolved (SSER 4)	
(20) Alternate radwaste facility	Opened (SSER 3), changed to license condition (SSER 4)	
(21) Physical security	Opened (SSER 3), resolved (SSER 5)	
(22) Seismic adequacy of plastic tie wraps	Opened (SSER 4), partially resolved (SSER 5), resolved (SSER 7)	3.8.4
(23) Verification of computer codes used to analyze ASME components	Opened (SSER 4), resolved (SSER 5)	
(24) Multiple response spectrum methodology	Opened (SSER 4), resolved (SSER 5)	

*Section of this supplement in which item is discussed.

Table 1.5 Listing of confirmatory items (revised from SSER 6)

Item	Status	Section*
(1) Correlation and analysis of data from old and new meteorological towers	Resolved (SSER 4)	
(2) Upgrade of operational meteorological measurements program	Resolved (SSER 2)	
(3) Atmospheric dispersion model for dose assessments	Resolved (SSER 2)	
(4) NSCW cooling tower seepage analysis	Resolved (SSER 3)	
(5) Details of groundwater monitoring program	Resolved (SSER 2)	
(6) Verification of FSAR commitments on compaction of Category 1 backfill	Resolved (SSER 1)	
(a) Audit of compaction control records		
(b) Submittal and evaluation of supplemental test results		
(7) Submittal and evaluation of settlement records and settlement monitoring program	Resolved (SSER 4)	
(8) Foundation competency of clay marl stratum	Resolved (SSER 1)	
(9) Steamline break analysis outside of containment	Resolved (SSER 4)	
(10) Final pipewhip and jet impingement evaluation for high-energy piping	Resolved (SSER 4)	
(11) Design documents review	Resolved (SSER 1)	
(12) Compliance with NUREG-0737, Item II.D.1	Resolved (SSER 4)	
(13) Program submittal for inservice testing of pumps and valves	Resolved for Unit 1 (SSER 6)	

*Section of this supplement in which item is discussed.

Table 1.5 (Continued)

Item	Status	Section*
(14) Pump and valve operability assurance	Partially resolved (SSERs 3 and 4), resolved (SSER 5)	
(a) Compliance with RG 1.148	Resolved (SSER 4)	
(b) Methods and standards for qualification	Resolved (SSER 3)	
(c) Qualification of pump and motor	Resolved (SSER 4)	
(d) Generic testing criteria for qualifying check valves	Resolved (SSER 4)	
(e) Administrative control of component qualification	Resolved (SSER 4)	
(f) Dependability of containment isolation (purge valves)	Resolved (SSER 5)	
(g) Long-term operability of deep draft pumps (IE Bulletin 79-15)	Resolved (SSER 4)	
(h) Issues regarding AFW turbine	Opened (SSER 3), resolved (SSER 4)	
(i) Operability of the feedwater check valve	Opened (SSER 3), resolved (SSER 4)	
(j) FSAR list of active pumps and valves	Opened (SSER 3), resolved (SSER 4)	
(k) Preservice tests prior to fuel load	Opened (SSER 3), resolved (SSER 4)	
(l) Complete qualification prior to fuel load	Opened (SSER 3), resolved (SSER 4)	
(15) Compliance with NUREG-0737, Item II.F.2	Resolved (SSER 4)	
(16) Conformance to 10 CFR 50, Appendix G, criteria (PORV setpoint curve)	Resolved (SSER 2)	
(17) Discrepancy between WCAP-10529 and FSAR	Resolved (SSER 2)	
(18) Examination of steam generator tubes	Resolved for Unit 1 (SSER 3)	

*Section of this supplement in which item is discussed.

Table 1.5 (Continued)

Item	Status	Section*
(19) Natural circulation boration and cooldown tests	Changed to license condition (SSER 4)	
(20) Target Rock valves in RVHVS	Deleted as errata (SSER 1)	
(21) Containment responses following an MSLB	Resolved (SSER 2)	
(22) Operator action in event of a small-break LOCA	Changed to open item 19 (SSER 3)	
(23) Volumetric examination of engineered safety features systems	Resolved for Unit 1 (SSER 3)	
(24) Test of engineered safeguards P-4 interlock	Resolved for Unit 1 (SSER 4)	
(25) IE Bulletin 80-06 concerns	Resolved for Unit 1 (SSER 5)	
(26) Override of isolation signals	Resolved for Unit 1 (SSER 4)	
(27) Bypass and inoperable status panel	Resolved (SSER 4), reopened (SSER 5), resolved (SSER 7)	7.5.2.4
(28) Compliance with NUREG-0737, Item II.K.3.1	Resolved for Unit 1 (SSER 5)	
(29) Capacity of each reserve auxiliary transformer to start and run the loads of both Class 1E trains	Resolved (SSER 5)	
(30) Verification test results for the adequacy of plant electric distribution system voltages	Resolved for Unit 1 (SSER 6)	
(31) Coordination and testing of circuit breakers located in the primary circuit of regulated transformers used as isolation devices	Resolved (SSER 2)	

*Section of this supplement in which item is discussed.

Table 1.5 (Continued)

Item	Status	Section*
(32) Plant-specific procedure for estimating core damage (NUREG-0737, Item II.B.3)	Resolved (SSER 1)	
(33) Demonstrate effective communications	Resolved (SSER 3)	
(34) Offsite communications	Resolved (SSER 2)	
(35) Procedures for load following test and/or maintenance	Resolved (SSER 4)	
(36) Incorporation of generic and plant-specific recommendations for TDI diesel generators	Partially resolved for Unit 1 (SSER 4), resolved for Unit 1 (SSER 5)	
(37) Procedures for ordering fuel after 5 days	Resolved (SSER 2)	
(38) Procedures for general housekeeping and maintenance	Resolved (SSER 2)	
(39) Process control program	Resolved (SSER 3)	
(40) Volume reduction system (VRS)	Resolved (SSER 7)	11.4.3
(a) VRS topical report		
(b) Potential accidents involving the VRS		
(c) VRS inputs		
(d) VRS filter testing		
(41) Compliance with NUREG-0737, Item II.K.3.31	Resolved (SSER 3)	
(42) Compliance with NUREG-0737, Item II.F.1	Resolved (SSER 4)	
(43) Compliance with NUREG-0737, Item III.D.1.1	Changed to license condition (SSER 3)	
(44) Procedures generation package	Resolved (SSER 2)	

*Section of this supplement in which item is discussed.

Table 1.5 (Continued)

Item	Status	Section*
(45) Program to minimize post-LOCA leakage from ESF system outside containment	Deleted as errata (SSER 1)	
(46) Analysis of dropped control rod event for DNB limits	Resolved (SSER 1)	
(47) Inadvertent boron dilution during Modes 3, 4, and 5	Resolved (SSER 1)	
(48) Operator action in event of an SGTR	Changed to license condition (SSER 3)	
(49) Radiological consequences of an SGTR	Changed to license condition (SSER 3)	
(50) Program to minimize ECCS equipment leakage	Resolved (SSER 2)	
(51) Generic Letter 85-12	Opened (SSER 2), resolved (SSER 3)	
(52) Seismic equipment qualification	Opened (SSER 3), resolved for Unit 1 (SSER 4)	
(a) Stress criteria for emergency and faulted conditions		
(b) Completion of seismic qualification program		
(c) Verification of as-built loads		
(d) FSAR revisions		
(53) Emergency preparedness	Opened (SSER 3), resolved (SSER 4)	
(54) Implementation of seismic separation program for Unit 2	Opened (SSER 4), awaiting information	
(55) Annunciator for high-flow signal to isolate electric steam boiler line	Opened (SSER 4), resolved (SSER 6)	

*Section of this supplement in which item is discussed.

Table 1.6 Listing of license conditions (revised from SSER 6)

Item	Status*	Section**
(1) Long-term groundwater and settlement monitoring requirements	Resolved (SSER 4)	
(2) Inservice testing of pumps and valves	Resolved for Unit 1 (SSER 5)	
(3) Final baseline report for the loose parts monitoring system	Resolved (SSER 5)	
(4) Technical Specification for maximum permissible temperature mismatch	Resolved (SSER 3)	
(5) Inservice inspection program	Resolved for Unit 1 (SSER 4)	
(6) Operability requirements for vent system in Technical Specifications	Resolved (SSER 4)	
(7) Exemption from 10 CFR 50, Appendix J, Paragraph III.D.2(b)(ii)		
(8) Exemption from 10 CFR 70.24		
(9) Operating experience on shift	Resolved (SSER 5)	
(10) Implementation and maintenance of physical security plan		
(11) Technical Specification to require four valves to be closed during refueling	Resolved (SSER 3)	
(12) Reactor vessel level instrumentation system implementation report	Completed for Unit 1 (SSER 7)	4.4.8
(13) Fire protection		
(14) Receipt of leak rate test results	Resolved (SSER 6)	
(15) Steam generator tube rupture		
(16) Natural circulation boration and cooldown tests	Resolved (SSER 5)	
(17) Replacement of zinc coating of Unit 1 diesel fuel oil storage tanks	Completed (SSER 7)	9.5.4.2
(18) TDI maintenance and surveillance items		

See footnotes at end of table.

Table 1.6 (Continued)

Item	Status*	Section**
(19) Monitoring of alternate radwaste facility exhaust		
(20) Detailed control room design review		
(21) Schedular exemption for spent fuel pool racks	Completed (SSER 7)	3.8.4
(22) Safety parameter display system		

*"Resolved" indicates resolution before licensing; thus the issue was never identified as a condition in the license; "Completed" indicates that the licensee has fulfilled the requirements of a conditon in the license.

**Section of this supplement in which item is discussed.

2 SITE CHARACTERISTICS

2.5 Geology and Seismology

2.5.4 Stability of Subsurface Materials and Foundations

2.5.4.5 Instrumentation and Monitoring*

As stated in the Vogtle Safety Evaluation Report (SER) (NUREG-1137), the applicant (now licensee) monitors the settlement of safety-related structures at 60-day intervals. The SER further stated that monitoring should continue through completion of construction and the first year of startup of both Units 1 and 2. The SER also contemplated some addition, subtraction, and relocation of settlement markers during that period. After the startup operation of Unit 1, but before the startup of Unit 2, the licensee has reviewed the settlement monitoring program and proposed certain modifications to that program because of the increasingly expensive and time-consuming nature of this program caused by operational interferences and installation of security barriers as discussed in its letter dated May 22, 1987.

The main modification relates to changing the measurement frequency on 62 markers on the Unit 1 side, and six markers on the Unit 2 side from the current 60-day interval to a 6-month interval. The licensee also proposes to relocate 41 markers on the Unit 2 side and 52 markers on the Unit 1 side to improve their accessibility as described in its letters dated May 22 and August 3, 1987. Finally, the licensee wants to discontinue the monitoring of two out of three markers that were installed in the Category I backfill in the power block area after heavy rains and erosion in 1979. These markers were intended to monitor any unanticipated settlement that might occur near eroded areas.

The licensee had originally committed to monitor the settlement of Category I structures by reading about 175 markers at 60-day intervals through the first year following startup of both Units 1 and 2. Although Unit 2 is not yet licensed, the licensee proposes to read 62 Unit 1 markers and 6 Unit 2 markers at 6-month intervals. The licensee has, however, justified the reduced frequency of reading the markers by referring to the time settlement plots that show that settlement of these markers has essentially stabilized. The staff has examined the settlement graphs submitted with the licensee's May 22, 1987, letter and finds that the licensee's proposal to reduce the reading frequency is acceptable for all but 11 of the 68 markers.

The staff requires that the licensee continue reading these 11 markers at 60-day intervals because they are in or near areas in which additional loading is expected to be placed before Unit 2 is licensed for operation, as discussed in the licensee's letter dated September 22, 1987. The numbers of the affected markers are 126, 127, 133, 136, 162, 223, 229, 230, 234, 268, and 269.

---

*This evaluation was previously provided to Georgia Power Company by letter dated October 20, 1987.

The staff agrees with the licensee's proposal to discontinue reading two (nos. 423-1 and 423-1B) of the three markers installed in 1979 in order to monitor unanticipated settlement in the backfill after heavy rains, because they are no longer needed. However, the licensee will continue to read the remaining marker (no. 423-1A) at 6-month intervals; it will also retain the two discontinued markers so that they will be available for any future reading, if needed.

The licensee's proposal to relocate 44 Unit 2 markers and 52 Unit 1 markers is acceptable to the staff on the basis that the licensee will properly correlate the new settlement readings with the readings in the previous locations and have this work checked and certified to be correct by qualified engineers as discussed in its letter dated September 22, 1987. The licensee has also committed not to destroy or disturb the original markers so that they are available for any future correlation. In view of the large number of markers that are proposed to be relocated (96 out of the total number of about 175 markers), the staff plans to inspect these markers and audit the correlation of the new settlement readings at a future date, preferably after some of the additional loadings are imposed on Unit 2.

On the basis of a review of the licensee's submittals, the staff approves the licensee's request to change the frequency of settlement measurements from 60-day to 6-month intervals on all but 11 of the 68 markers. The staff also approves discontinuation of the reading of markers 423-1 and 423-1B and a 6-month monitoring frequency of marker 423-1A. The staff also agrees to the relocation of 96 markers on the basis that the licensee will properly correlate the new readings with the old and have them checked by qualified engineers.

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.1 Plant Design for Protection Against Postulated Failures in Fluid Systems Outside Containment*

In Section 3.6.1 of the SER, the staff stipulated that based on the applicant's statement that all non-seismic Category I piping systems in safety-related areas were seismically supported, only cracks rather than full ruptures needed to be assumed in those moderate energy systems for flooding analyses assumptions. By letter dated June 1, 1987, the applicant submitted a revision to the Final Safety Analysis Report (FSAR) that revised its response to FSAR Question 410.15. In Question 410.15, the staff stated its position that for flooding analysis purposes, the complete failure of non-seismic Category I moderate energy piping systems should be considered in lieu of cracks in determining the worst case flooding. The applicant's original response in Amendment 9 to the FSAR indicated that all non-seismic Category I piping in safety-related structures has been supported to withstand safe shutdown earthquake (SSE) loads. It was also indicated in Amendment 9 that for SSE loading, piping stresses are calculated to consider that they are maintained within faulted allowables with certain specified exceptions. Faulted allowables are the calculated piping stress limits including the SSE contribution, identified by Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, that if the stresses are not exceeded, the piping is expected to maintain its integrity. The June 1, 1987, submittal revised the specified exceptions (for Unit 2 only) to include moderate energy non-seismic Category I piping, 2 inches and smaller. However, these lines will be supported to seismic Category I criteria.

The flooding analysis will continue to postulate through-wall leakage cracks in the Unit 2 non-seismic Category I 2-inch and smaller pipes. The applicant contends that justification for postulating cracks in these small pipes in lieu of pipe ruptures is such that crack postulation satisfies the requirements of Standard Review Plan (SRP) Section 3.6.1 and Branch Technical Postion (BTP) MEB 3-1 which states that through-wall leakage cracks should be postulated in fluid system piping designed to non-seismic standards and through-wall leakage cracks should be postulated in moderate energy fluid system piping.

The staff agrees with the applicant regarding postulating only through-wall leakage cracks in these small lines; however, it does not agree with the justification referenced. The referenced portion of BTP MEB 3-1 which discusses cracks in moderate energy non-seismic Category I piping systems of any size is meant to ensure all types of postulated pipe failures have been considered in these pipes. In some instances, a pipe crack may result in more damage due to

*This evaluation was previously provided to Georgia Power Company by letter dated August 14, 1987.

flooding than would a complete pipe rupture of th same pipe. This may occur in the case in which the full pipe rupture is immediately detectable; the leakage from the pipe crack, however, could continue for some time before it was detected.

As stated in the staff's SER for Vogtle, a complete failure (rupture) of non-seismic Category I piping systems need not be postulated because such systems are seismically supported. Because these lines continue to be seismically supported, the staff's conclusion as set forth in Section 3.6.1 of the SER remains valid and only through-wall leakage cracks need be postulated in moderate energy piping that is not designed to seismic Category I requirements. The staff, therefore, concludes that the additional exception of not calculating pipe stresses to ensure they are maintained within faulted allowables is acceptable for 2-inches and smaller non-seismic Category I moderate energy piping, and the requirements of General Design Criterion (GDC) 4, "Environmental and Missile Design Bases," are still satisfied for Vogtle Unit 2.

3.6.3 Leak-Before-Break Evaluation

By letter dated April 29, 1987, the applicant informed the staff of its intention to request a partial exemption from the requirements of Appendix A to 10 CFR 50 for Vogtle Unit 2. The exemption to be requested would permit the elimination of the dynamic effects of postulated pipe ruptures in auxiliary lines from the design basis, using fracture mechanics "leak before break" (LBB) technology. The application of LBB technology would be an alternative to providing protective devices against the dynamic loads resulting from postulated ruptures of LBB candidate lines at Vogtle Unit 2. The LBB candidate lines at Vogtle Unit 2 are the pressurizer surge line, accumulator injection line, and residual heat removal (RHR) suction line.

By letter dated July 15, 1987, the applicant submitted the technical basis for the elimination of the dynamic effects of postulated pipe ruptures in the pressurizer surge line of Vogtle Unit 2 in Westinghouse report WCAP-11531. By letters dated August 19 and September 17, 1987, the applicant submitted Addenda 1 and 2 to WCAP-11531, respectively, in response to the staff's requests for additional information in letters dated August 6 and September 9, 1987. The pressurizer surge line at Vogtle Unit 2 consists of 16-inch and 14-inch-diameter piping connected via a reducer (see Figure 4-1 in WCAP-11531).

By two letters dated October 16, 1987, the applicant submitted the technical bases for the elimination of the dynamic effects of postulated pipe ruptures in the accumulator and RHR lines of Vogtle Unit 2 in Westinghouse reports WCAP-11583 and WCAP-11599, respectively. The accumulator line at Vogtle Unit 2 consists of 10-inch-diameter piping between the accumulator tank and the reactor coolant system (RCS) cold leg (see Figures 5-1 through 5-4 in WCAP-11583 (proprietary), WCAP-11584 (non-proprietary)). The RHR line within the scope of application of LBB is the high-energy portion of the RHR line. The high-energy portion of the RHR line consists of 12-inch-diameter piping between the RCS hot leg and the first isolation valve (see Figures 5-1 and 5-2 in WCAP-11599 (proprietary), WCAP-11600 (non-proprietary)).

By means of deterministic fracture mechanics analyses, the applicant contends that postulated double-ended guillotine breaks (DEGBs) of the pressurizer surge line, the accumulator line, and RHR piping will not occur at Vogtle Unit 2, and therefore, need not be considered as a design basis for installi otective devices such as pipe whip restraints and jet impingement barriers to guard against the dynamic effects associated with such postulated breaks. No other changes in design requirements are addressed within the scope of the referenced reports; i.e., no changes to the definition of a loss-of-coolant accident (LOCA) nor its relationship to the regulations addressing design requirements for the emergency core cooling system (ECCS) (10 CFR 50.46), containment (GDC 16 and 50), other engineered safety features, and the conditions for environmental qualification of equipment (10 CFR 50.49).

Background on Leak-Before-Break Applications

The Commission's regulations until recently required that protective measures be provided against the dynamic effects of postulated pipe breaks in high-energy fluid system piping. Protective measures include physical isolation from postulated pipe rupture locations if feasible, or the installation of pipe whip restraints, jet impingement shields, or compartments. However, recent research performed by the NRC and industry, coupled with operating experience, has indicated that safety can be decreased by the placement of protective devices such as pipe whip restraints. Studies completed by Lawrence Livermore National Laboratory under contract to the NRC indicate that safety can be decreased by requiring protective devices to resist the dynamic effects associated with postulated pipe rupture. These studies are discussed in NUREG/CR-4263, "Reliability Analysis of Stiff Versus Flexible Piping, Final Project Report," dated May 1985. The placement of pipe whip restraints degrades plant safety if thermal growth is inadvertently restricted, reduces the accessibility for and effectiveness of inservice inspections, increases inservice inspection radiation dosages, and increases the cost of construction and maintenance.

An alternative to providing protective devices against the dynamic loads resulting from postulated pipe ruptures is made possible by the development of advanced fracture mechanics technology. These advanced fracture mechanics techniques deal with relatively small flaws in piping components (either postulated or real) and examine their behavior under various pipe loads. The objective is to demonstrate, by deterministic analyses, that the detection of small flaws by either inservice inspection or leakage monitoring systems is assured long before the flaws can grow to critical or unstable sizes which could lead to large break areas such as the DEGB or its equivalent. The concept underlying such analyses is referred to as LBB. There is no implication that piping failures cannot occur, but rather that improved knowledge of the failure modes of piping systems and the application of appropriate leakage detection can reduce the probability of catastrophic failure to an insignificant value.

On April 11, 1986, a final rule was published in the Federal Register (51 FR 12502), effective May 12, 1986, amending GDC 4 of Appendix A to 10 CFR 50 to allow the use of analyses to eliminate from the design basis the dynamic effects of postulated pipe ruptures of primary coolant loop piping for pressurized water reactors (PWRs). Acceptable technical procedures and criteria for the LBB technology are defined in NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," dated November 1984. This limited scope modification to GDC 4 was made by the Commission because safety and economic benefits could be quickly realized without extensive and time-consuming review and discussion if the scope was initially limited to the primary main loop piping of PWRs. Substantial evidence had already been developed to show that the LBB concept was valid for primary main coolant loops of PWRs. The Commission decided not to defer the limited application of LBB technology while the detailed provisions of the proposed acceptance criteria were being reviewed and approved. Many near-term operating license (NTOL) nuclear power plant units and operating nuclear power plant units had requested and received exemptions for eliminating the dynamic effects of postulated pipe rupture from the requirements of GDC 4.

On July 23, 1986, a proposed rule was published in the Federal Register (51 FR 26393) to further amend GDC 4 to broaden the scope to cover all high-energy piping in all nuclear power plants. The proposed amendment to GDC 4 allows exclusion from the design basis of dynamic effects associated with high-energy pipe rupture by application of LBB technology. Only high-energy piping that meets rigorous acceptance criteria in nuclear power units is covered. High-energy piping is defined as those systems having pressures exceeding 275 psig or temperatures exceeding 200°F. The proposed general acceptance criteria are based on NUREG-1061, Volume 3.

On October 27, 1987, a final rule was published in the Federal Register (52 FR 41288), effective November 27, 1987, amending GDC 4 of Appendix A to 10 CFR 50. The revised GDC 4 allows the use of analyses to eliminate from the design basis the dynamic effects of postulated pipe ruptures in high-energy piping in nuclear power units. The new technology reflects an engineering advance which allows simultaneously an increase in safety, reduced worker radiation exposures, and lower construction and maintenance costs. Implementation permits the removal of pipe whip restraints and jet impingement barriers as well as other related changes in operating plants, plants under construction, and future plant designs. Containment design and emergency core cooling requirements are not influenced by this modification. The acceptable technical procedures and criteria are defined in NUREG-1061, Volume 3.

Leak-Before-Break Evaluation Parameters

In its review of WCAP-11531 and its addenda, WCAP-11583 and WCAP-11599, the staff evaluated the applicant's analyses and materials data with regard to:

- the limiting location(s) determined by stresses in the piping, associated with the combined loads from normal operation and the SSE and the fracture toughness properties of austenitic steel piping and associated weld materials

- potential loss of load-bearing capacity by mechanisms such as crack formation (by fatigue or stress corrosion) or wall thinning (by erosion or erosion-corrosion)

- size of postulated through-wall flaws that would leak a detectable amount under normal loads and pressure

- stability of a "leakage-size flaw" under normal plus SSE loads and margin in terms of load and

- margin based on flaw size

Leak-Before-Break Evaluation Criteria

The NRC staff's criteria for evaluation of the above parameters are delineated in NUREG-1061, Volume 3. These criteria are identical to those accepted in the limited scope and broad scope modifications of GDC 4. These criteria are listed in Chapter 5.0 of NUREG-1061, Volume 3 and are as follows:

(1) The loading conditions should include the static forces and moments (pressure, deadweight, and thermal expansion) due to normal operation, and the forces and moments associated with SSE. These forces and moments and the base metal and weld tensile and toughness properites are to be used to define the locations that have the smallest margins against pipe rupture in the pipe run (anchor to anchor).

(2) For the piping run/systems under evaluation, all pertinent information should be provided which demonstrates that degradation or failure of the piping resulting from creep, corrosion, erosion-corrosion, stress-corrosion, fatigue, waterhammer, or other environmental conditions is not likely. Relevant operating history should be cited, which includes system operational procedures; system or component modification; water chemistry parameters, limits, and control; and resistance of material to various forms of stress corrosion and performance under cyclic loadings.

(3) Pipe lines are evaluated to determine whether there is a high probability of degradation or failure from indirect causes such as fires, missiles, and equipment failures, and failures of systems or components in close proximity to the pipe.

(4) The materials data provided should include types of materials and materials specifications used for base metal, weldments, and safe-ends; the materials properties including the fracture mechanics parameter "J integral" (J) resistance (J-R) curve used in the analyses; long-term effects such as thermal aging; and other limitations to valid data (e.g., J maximum and maximum crack growth). The piping materials must be free from brittle cleavage-type failure over the full range of the system operating temperature.

(5) A through-wall flaw should be postulated at the limiting locations determined from criterion (1) above. The size of the flaw should be large enough so that detection of leakage is assured using the installed leak-detection capability when the pipe is subjected to normal operational loads. NUREG-1061, Volume 3 recommends the margin on the magnitude of leakage to be no less than a factor of 10 greater than the capability of the leakage detection system.

(6) It should be demonstrated that the postulated leakage flaw is stable under normal plus SSE loads for long periods of time; that is, crack growth, if any, is minimal. The margin, in terms of applied loads, should be determined by a flaw stability analysis, i.e., that the leakage-size flaw will not experience unstable crack growth even if larger loads (larger than design loads) are applied. This analysis should demonstrate that crack growth is stable and the final flaw size is limited that a double-ended pipe break will not occur.

(7) The stability analysis should compare the leakage-size flaw to the critical-size flaw. Under normal plus SSE loads, it should be demonstrated that there is a margin of at least 2 between the leakage-size flaw and the critical-size flaw to account for the uncertainties inherent in the analyses, and leakage detection capability.

Staff Evaluation

The staff had evaluated the information presented in the submitted topical reports. The staff finds that the applicant has presented an acceptable technical justification to eliminate, as a design basis, the dynamic effects of large ruptures in the pressurizer surge line and the accumulator and RHR piping of Vogtle Unit 2.

(1) Loads and Load Combinations

Normal operating loads, including pressure, deadweight, and thermal expansion, were used to determine leak rate and leakage-size flaws. The stability analyses performed to assess margin against pipe rupture at postulated faulted load conditions were based on normal plus SSE loads.

In the leak rate analysis, the individual normal (pressure, deadweight, and thermal expansion) load components were summed algebraically. In the stability analysis of the accumulator line, the individual normal and seismic (pressure, deadweight, thermal, and SSE including seismic anchor motion) loads were summed absolutely. In the stability analysis of the pressurizer surge line and the RHR line, the individual normal (pressure, deadweight, and thermal expansion) load components were summed algebraically and the seismic (SSE including seismic anchor motion) loads were then added absolutely. The bending moments in the two principal coordinate directions and the total axial force were obtained. Then, the resultant bending moment was obtained from the square root of the sum of the squares of the principal coordinate moments.

Leak-before-break evaluations were performed for the limiting location within each of the lines between anchor points. The limiting location was determined using the recommendations in NUREG-1061, Volume 3, and is the location predicted to have the smallest margin against pipe rupture based on the material resistance to ductile flaw instability under the combined normal plus SSE loads.

On the basis of its review, the staff finds that the load definition, method of load combination, and the location for which the LBB evaluations was performed are consistent with the recommendations in NUREG-1061, Volume 3, and provide a basis acceptable to the staff for LBB evaluation at Vogtle Unit 2.

(2) Pipe Degradation Mechanisms

The applicant assessed each line to determine if there is significant potential for degradation of piping integrity during service. The degradation mechanisms evaluated were: intergranular stress corrosion cracking (IGSCC) of austenitic steel, potential for dynamic loads (e.g., waterhammer), vibratory fatigue, low-cycle thermal fatigue due to flow stratification, thermal aging effects on austenitic steel, wall thinning from erosion, creep damage, and fatigue from design transients.

For Westinghouse facilities, there is no history of service cracking or wall thinning in the reactor coolant system primary loop and connecting Class 1 lines. This operating history totals more than 400 reactor-years, including five plants each having more than 15 years of operation and 15 other plants each with more than 10 years of operation. Also, evaluation of the plant-specific design, fluid, and operating conditions indicates: (a) IGSCC in austenitic steel is not likely because the lines were constructed using techniques that produce an acceptable level of resistance to IGSCC, the fluid chemistry will be controlled during operation to minimize contaminants, and the dissolved oxygen is at a level that would normally preclude IGSCC; (b) waterhammer is unlikely because of appropriate design and operating procedures; (c) crack initiation from vibratory fatigue is unlikely because there are no identified vibration sources and there are no socket welds, which may act as crack initiators, in the lines; (d) there is little temperature difference, which minimizes flow stratification and associated low-cycle thermal fatigue; (e) degradation of austenitic steel from thermal aging is not likely because there is no cast pipe or fitting in the lines, except for a cast stainless steel nozzle on the accumulator line for which degradation from thermal aging was accounted for in the evaluation; (f) fluid conditions and use of erosion-resistant materials in the lines preclude the likelihood of wall thinning by erosion; and (g) the relatively low temperatures (less than 650°F) of the lines preclude any significant creep damage.

An assessment was also made to predict the inservice flaw growth in the lines from anticipated and postulated transient loads. The initial flaw size was determined from the Section XI (ASME Code) preservice acceptance standards and was assumed to be present in the evaluated lines before service. The transients, stress and fracture mechanics analysis methods, and the material crack-growth relationship used in the fatigue crack-growth evaluation were reviewed and accepted by the staff. The results indicate that the postulated flaw in each of the lines would remain within the end-of-design-life size criteria established by the staff.

On the basis of comparison of the design, material, operational, and fluid conditions anticipated for the pressurizer surge line, the accumulator line, and the RHR piping at Vogtle Unit 2 with prior service experience and conditions that may produce degradation in nuclear piping, the staff concludes that inservice cracking and significant degradation are unlikely. Consequently, the staff concludes that LBB analysis is an appropriate basis to demonstrate that the probability of pipe rupture for these lines is acceptably low and to justify not installing protective devices against the dynamic effects of postulated pipe breaks in these lines.

(3) Indirect Sources of Pipe Rupture

Pipe degradation or failure from indirect causes such as fires, missiles, and component support failure is prevented by designing, fabricating, and inspecting reactor compartments, components, and supports to staff criteria that reduce to a low probability the likelihood of the events or their impacting safety-related components. The applicant's compliance with the criteria in the Standard Review Plan is discussed in the Vogtle FSAR, Sections 3.4.1 (flood protection), 3.5 (missile protection), 9.5.1 (fire protection), 3.9.B.3 and 5.4 (design and fabrication requirements), 5.2.4 (inservice inspection and testing), and 17.1.14 and 17.2.10 (general inspection).

(4) Materials Data

The pressurizer surge line at Vogtle Unit 2 was constructed of SA-376 TP316 wrought austenitic steel. There is no cast pipe or fitting in the surge line system. The accumulator line at Vogtle Unit 2 was constructed of SA-376 TP316 wrought austenitic steel. The accumulator line nozzle at the RCS cold leg was constructed of SA-351 CF8A cast stainless steel. The RHR line was constructed of SA-376 TP316 wrought austenitic steel. There is no cast pipe or fitting in the RHR line. The welding processes used for the three lines were gas tungsten arc weld (GTAW), submerged arc weld (SAW), and shielded metal arc weld (SMAW).

The plant-specific materials data were obtained from the certified material test reports (CMTRs) for the three lines at Vogtle Unit 2. The limiting locations for the accumulator line are at welds fabricated with the SAW process. The limiting conditions for the pressurizer surge line and RHR line are at welds fabricated with the SMAW process. The accumulator line cast stainless steel nozzle was also considered. Because the limiting locations for LBB analyses are welds in the base materials from evaluations based on item 1 of this section, "Loads and Load Combinations," the applicant estimated the elastic moduli and stress-strain relationships for the base materials and the fracture toughness properties of welds required for the LBB analyses.

For the three lines, the applicant selected the minimum room temperature yield strength from the CMTRs and then estimated the yield strength at the operating temperature based on typical yield strength versus temperature data. Then, the elastic moduli and stress-strain relationships for the base materials were estimated based on generic procedures. For the fracture toughness properties of welds, the applicant selected J-R curves from the literature. However, the applicant provided insufficient justification that the selected weld J-R curves were lower-bound estimates for Vogtle Unit 2 welds. Furthermore, the applicant used a "modified J" parameter to describe the weld J-R curve. The staff considers the "modified J" not acceptable for licensing applications without further research. The staff's requests for additional information dated August 6 and September 9, 1987 discuss this issue.

For the fracture toughness properties of thermally aged, cast stainless steel, the applicant used estimation procedures described in Westinghouse reports WCAP-10456 and WCAP-10931, Revision 1, which have been reviewed previously by the staff as discussed in letters from B. J. Youngblood, NRC, to M. D. Spence, Texas Utilities Generating Company, dated August 28, 1984 and from D. C. DiIanni, NRC, to D. M. Musolf, Northern States Power Company, dated December 22, 1986, respectively.

The staff finds that the applicant's procedures in estimating the plant-specific, lower-bound, base metal, stress-strain relationship acceptable for the LBB flaw stability analysis. Also, the staff finds the applicant's use of the average, base metal, stress-strain relationship in the LBB leak rate analysis appropriate in obtaining realistic estimates of leakage-size flaws. Although the applicant provided inadequate lower-bound weld toughness properties, the applicant also performed flaw stability analyses using a procedure that is based on industry lower-bound weld toughness properties (see item 6 below, "Margins on Load and Flaw Size").

(5) Leak Rate Criteria and Computations

The three lines at Vogtle Unit 2 are inside the containment. The applicant has proposed a leakage detection criterion that includes a detected leak rate of 1 gallon per minute (gpm) and, in accordance with the recommendation in

NUREG-1061, Volume 3, a margin of 10 was applied to this leak rate to define the leakage-size flaw used in the fracture stability analyses. The basis for the 1-gpm leak is the presence inside containment of diverse and redundant leakage-detection equipment and methods that are in compliance with Regulatory Guide (RG) 1.45, and operating experience at other Westinghouse plants.

Detected leaks will be repaired within the system limiting conditions for operation established in either Technical Specifications or administrative procedures. When leakage is detected in reactor coolant pressure boundary piping, Technical Specification 3.4.6.2 requires that the plant be in hot standby within 6 hours and in cold shutdown within the next 30 hours. Repairs would be required before restart.

The relationship between the flaw size and leak rate was estimated using computer software that includes an elastic-plastic fracture mechanics routine for determining crack opening area and a thermal hydraulics routine to compute mass flow through the postulated through-wall flaw. In Supplement 4 to NUREG-0781, "Safety Evaluation Report Related to the Operation of South Texas Project, Units 1 and 2," dated July 1987, the staff concluded that the software used to estimate leak rate is acceptable for application to LBB analysis when used with the appropriate margin on predicted leak rate.

(6) Margins on Load and Flaw Size

The applicant has performed stability analyses to determine if the leakage-size flaw is stable at 1.4 times the combination of normal plus SSE loads and if the critical-size flaw at normal plus SSE loads is at least twice as long as the leakage-size flaw. The stability analyses were performed using elastic-plastic, fracture-mechanics analysis methods, the load combination method described in item 1 of this section ("Loads and Load Combinations"), the lower-bound stress-strain relationship discussed in item 4 of this section ("Materials Data"), and the leakage-size flaw determined for each line using the leak detection criterion in item 5 of this section ("Leak Rate Criteria and Computations"). The elastic-plastic, fracture-mechanics analyses were performed using a tearing modulus (J-T) methodology based on procedures which were benchmarked and found acceptable by the staff in NUREG-1061, Volume 3.

The applicant performed a J-T analysis using thermally aged, cast stainless steel toughness properties in WCAP-10456 and WCAP-10931, Revision 1 to demonstrate the flaw stability of the accumulator line nozzle at the RCS cold leg. The results showed that there is a margin of at least 1.4 on the normal plus SSE loads for the leakage-size flaw and a margin of at least 2 between the critical through-wall flaw size and the leakage-size flaw. The staff used an elastic-plastic, fracture-mechanics, computer code developed by the staff (NUREG/CR-4572, "NRC Leak-Before-Break (LBB.NRC) Analysis Method for Circumferentially Through-Wall Cracked Pipes Under Axial Plus Bending Loads," May 1986) to verify the applicant's results and to ensure that the staff's upper bound on the applied J for a specific cast stainless steel was not exceeded, as discussed in the staff's letter to Texas Utilities Generating Company, dated August 28, 1984.

Flaw stability analyses were performed for the material conditions using the base metal, stress-strain relationship and the limiting weld, fracture toughness relationship. As discussed in item 4 of this section ("Materials Data"), the applicant provided inadequate lower-bound weld toughness properties for flaw stability evaluations. However, based on staff recommendations, the applicant also performed flaw stability analyses using a limit load analysis procedure, which has been modified by J-T analyses based on industry, lower-bound, weld-toughness properties. This modified limit load, flaw stability analysis uses the "Z-factor" correction for flux welds, which is the basis for developing allowable flaw sizes for austenitic steel piping in Article IWB-3640 of the Winter 1985 Addendum of Section XI of the ASME Code (Electric Power Research Institute Special Report NP-4690-SR, "Evaluation of Flaws in Austenitic Steel Piping," prepared by Section XI Task Group for Piping Flaw Evaluation, July 1986).

The applicant's results from the flaw stability analyses using the "Z-factor" showed that at the limiting locations of the lines, a margin against pipe rupture of at least 1.4 exists on the normal plus SSE loads for the leakage-size flaw, and the critical through-wall flaw size at normal plus SSE loads is at least twice the length of the leakage-size flaw. The staff verified the applicant's results and finds that the applicant has demonstrated margins on load and flaw size consistent with the recommendations in NUREG-1061, Volume 3.

Staff Conclusions

On the basis of its review of the information submitted by the applicant, the staff finds the pressurizer surge, the accumulator, and the RHR lines at Vogtle Unit 2 in compliance with the revised GDC 4. Thus, the dynamic effects of postulated pipe ruptures in the pressurizer surge, accumulator, and RHR lines may be eliminated from the design basis of Vogtle Unit 2. Because the final rule became effective November 27, 1987, it is not necessary for the applicant to request an exemption from GDC 4.

3.8 Design of Seismic Category I Structures

3.8.4 Other Seismic Category I Structures*

Tie Wraps in Vertical Cable Trays

In SER Supplement 4 (SSER 4), the staff identified an open item regarding the seismic adequacy of plastic cable ties used to support seismic Class 1E cables in vertical cable trays. The issues involved load capacity of the plastic cable ties and the effects of aging, embrittlement, plastic creep, etc. on the structural behavior of the ties over the life of the facility. By letter dated December 22, 1986, the applicant (now licensee) provided justification for the use of plastic cable ties during the first fuel cycle and committed to address the long-term effects of plastic cable ties by June 1, 1987. The staff partially resolved this issue in SSER 5 by concluding, based on the licensee's December 22, 1986, submittal, that the use of plastic cable ties to support Class 1E cables in vertical raceways was acceptable for the first fuel cycle. However, the adequacy of the plastic cable ties for the period beyond the first fuel cycle was considered confirmatory pending staff review of the program to address long-term effects of the plastic ties.

By letter dated May 27, 1987, the licensee responded to the remaining issue regarding long-term effects. In its May 27, 1987, response, the licensee committed to use stainless steel cable ties to support cables in vertical cable

*This evaluation was previously provided to Georgia Power Company by letter dated July 30, 1987.

trays. The stainless steel ties to be used at Vogtle Units 1 and 2 are fabricated from American Iron and Steel Institute (AISI) Type 302/304 steel which has superior corrosion resistance and mechanical properties at elevated temperatures. This material will not experience plastic creep, embrittlement, or reduction in structural strength as a result of aging or environmental conditions as might the plastic ties. The licensee has conducted static pull tests on the stainless steel ties to establish the load capacity of the tie. The test method used to establish the load capacity of cable ties for various configurations of cable bundles was previously reviewed and accepted by the staff in SSER 5. The data from these tests, together with seismic and dead loads for the cables and cable tie spacings were used to maintain a minimum safety factor of 1.3. The safety factor of 1.3 was accepted by the staff in SSER 5.

On the basis of the licensee's May 27, 1987, submittal, the staff concludes that with the use of stainless steel cable ties to support seismic Class 1E cables in vertical cable trays, the integrity of the cables will be assured over the life of the facility. The staff further concludes that the requirements of GDC 2 of Appendix A to 10 CFR 50 are satisfied by the use of the stainless steel tie wraps. These ties will be installed in Unit 1 before restart after the first refueling outage and will be installed in Unit 2 before fuel load. Therefore, open item 22 is fully resolved for both units.

Spent Fuel Pool Racks*

By Amendment 22 to the FSAR, the applicant (now licensee) indicated that a different spent fuel rack design would be used at Vogtle Unit 1. The applicant proposed to replace the original Unit 1 spent fuel pool racks having 938 fuel assembly storage locations on a center-to-center spacing of 13.0 inches with two new high-density freestanding racks having 288 fuel assembly storage locations, or approximately 1.43 cores. Each rack consists of 144 fuel assembly cells arranged in a 12-by-12 configuration, with a center-to-center spacing of 10.6 inches between fuel assemblies. Additional fuel racks with different configurations may be added to the Unit 1 spent fuel pool in the future. Any additions would have to be approved by the staff.

In SSER 2, the staff noted that the spent fuel storage facility would be an open item until the applicant provided more detailed design information. In particular, the staff stated that the applicant would have to provide the details of the rack design, including a criticality analysis, seismic analysis, materials compatibility analysis, and fuel handling accident analysis.

The applicant provided most of the requested information in Amendment 5 to the FSAR; this allowed the staff to resolve all issues regarding the design of the racks except for the seismic analysis in SSER 4. By letter dated November 28, 1986, the staff requested that the applicant provide additional information regarding the seismic analysis of the racks. By letter dated December 29, 1986, the applicant requested a schedular exemption to regulations that apply to spent fuel pool racks. In SSER 5, the staff determined that pursuant to 10 CFR 50.12(a)(1), the schedular exemption to 10 CFR 50.34(b)(2)i as it pertains to GDC 2, 61, and 62 of Appendix A to 10 CFR 50 is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Accordingly, this schedular exemption was

*This evaluation was previously provided to Georgia Power Company by letter dated July 30, 1987.

included in Vogtle Unit 1 license nos. NPF-61 dated January 16, 1987, and NPF-68 dated March 16, 1987 (low power and full power, respectively) for the time period before the racks contain irradiated fuel.

The licensee responded to the staff's November 28, 1986, request for additional information by letter dated January 21, 1987. On the basis of the staff's review of this submittal, the staff requested additional information by letter dated April 7, 1987. The licensee responded to this request by letter dated May 22, 1987, as supplemented by letter dated July 20, 1987. The licensee further provided the spent fuel rack design report by letter dated September 29, 1987. The discussion that follows is the staff's evaluation of the licensee's submittals dated January 21, May 22, July 20, and September 29, 1987.

The spent fuel pool is constructed of reinforced concrete and lined with 1/4-inch stainless steel to ensure against leakage. The spent fuel pool is located within the seismic Category I fuel handling building. The pool is approximately 50 feet long, 33.5 feet wide, and 41 feet deep.

The spent fuel will be stored in two high-density racks. Each rack consists of 144 fuel assembly cells arranged in a 12-by-12 configuration. The cell is made from 14-gauge (0.075-inch-thick) type 304 stainless steel. The nominal inside dimension of the cell is 8.8 inches square, and the length from the top of the fuel seating surface to the top of the cell funnel is approximately 168.25 inches. Storage cells are fastened and supported by two grid assemblies, also made from type 304 stainless steel, which are located at the top and bottom elevations of the racks. The racks are assembled in a checkerboard pattern with a 10.6-inch center-to-center spacing. The racks are free standing, neither anchored to the floor nor braced to the pool wall. Because the racks rest freely on the pool floor, it is necessary to determine that during seismic events the racks do not impact each other nor the walls, and are capable of maintaining their integrity. Thus, displacement and stress calculations of the racks are required. Analyses of the racks were performed on the Westinghouse Electric Computer Analysis (WECAN) Code. It is a general-purpose finite element code with capabilities of performing static, dynamic, linear, and nonlinear analyses. The WECAN Code has been audited and no errors or discrepancies were found by the NRC Vendor Program Branch as discussed in a report from G. Zech to J. Gallagher (Westinghouse) dated January 7, 1985.

Effective structural properties of an average fuel cell within the rack assembly were obtained using a three-dimensional linear structural model that represents the rack assembly. The mathematical model is shown in Figure 3.1. These structural properties were then used in a two-dimensional nonlinear seismic model to perform seismic calculations. The mathematical model is shown in Figure 3.2. Hydrodynamic mass of the fuel, the gap between the fuel and cell, the support pad boundary condition of the freestanding rack, and the assumed coefficient of friction between the support pad and pool floor were input to the WECAN Code in addition to the structural properties. A coefficient of friction equal to 0.2 was assumed to obtain the maximum sliding distance of the base of a rack. A coefficient of friction equal to 0.8 was assumed to obtain the maximum load in the rack and maximum structural deflection of the rack. On the basis of experimental test data on water-lubricated stainless steels, E. Rabinowicz concluded in "Friction Coefficients of Water-Lubricated Stainless Steels for a Spent Fuel Rack Facility," dated November 5, 1976, that a design based on friction coefficient values between 0.2 and 0.8 should cover all eventualities. Therefore, the range of coefficients of friction between 0.2 and 0.8 used by the licensee

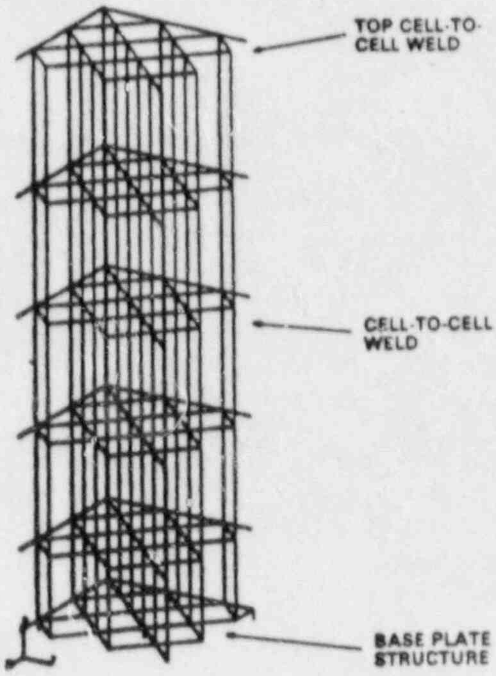

Figure 3.1 Structural model of typical fuel rack

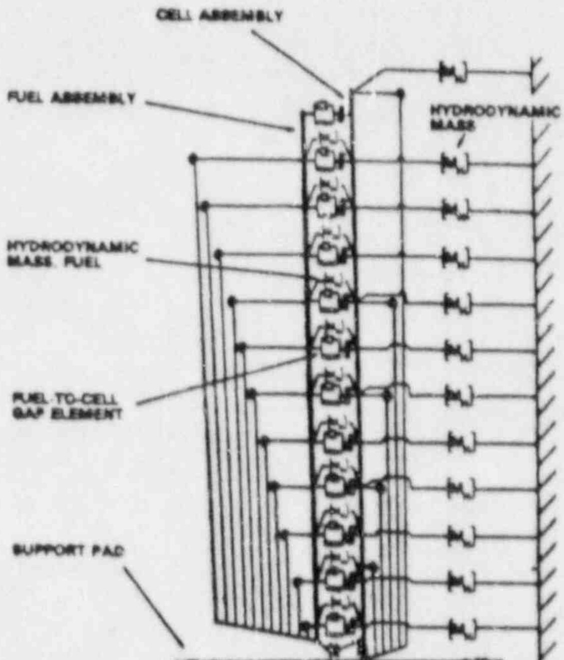

Figure 3.2 Nonlinear seismic model of typical fuel rack

is reasonable. The maximum loads thus obtained were then input to a three-dimensional structural model to obtain local stresses in the rack.

The licensee indicated that the maximum single rack sliding displacement was 0.036 inch, and the maximum lateral deflection at the top of the rack was 0.1 inch. Because the clearance between the two racks is approximately 4 inches and the minimum clearance between the racks and pool walls is 4.25 inches, it is apparent that the racks will not impact each other and the walls, because the actual clearances between the rack-to-rack and rack-to-wall are much greater than the distance due to rack sliding or deflection calculated for the safe shutdown earthquake (SSE) condition.

The licensee has provided analysis results of stresses due to the interactions between the rack and pool floor and between the fuel and cell within a rack for both operating basis earthquake (OBE) and SSE conditions. The results indicated that the maximum stresses in the liner plate and concrete floor are less than allowable stress values for the rack and pool floor interaction and that the maximum acceleration on the fuel assembly was 3.0 g. In response to the staff request as to what g levels the fuel assembly had been qualified for, the licensee stated in the submittal of July 20, 1987, that the actual maximum test load was 20 g. Therefore, the integrity of the fuel assembly will be maintained during earthquakes.

The licensee has calculated the maximum thermal stress in the rack as 4000 psi by assuming that one cell was loaded with hot fuel while the surrounding cells remained empty. When this maximum thermal stress combined with stresses associated with seismic and dead weight, the licensee stated that the total stress was still below the allowable stress value. Therefore, the integrity of the rack will be maintained during thermal and seismic conditions. During a July 15, 1987, telephone conference call, the staff questioned the validity of using 25% of critical damping for the fuel grid and asked for documentation. The licensee responded in the July 20, 1987, submittal that the grid damping value of 25% had been developed from data presented in Westinghouse document WCAP-9401-P-A, which was approved by the staff by letter dated May 7, 1981. The staff considers that the damping question has been answered and resolved.

The licensee has also performed an analysis of dropping a fuel assembly straight through a storage location, and the results indicated that the pool liner would not be perforated. The licensee did not perform the first and second types of fuel assembly accident analyses as specified in the NRC position paper, "Operating Technology Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," dated April 14, 1978, as modified on January 18, 1979. However, the licensee stated that, with the 2000 ppm boron in the pool water, there would be no deformation that could reasonably be achieved by the drop of a fuel assembly that would cause the criticality acceptance criterion of 0.95 to be exceeded. The staff has reviewed this issue and agrees with the licensee. Therefore, the staff considers that the licensee has adequately addressed the fuel assembly accident analysis requirements.

The licensee stated that the cask crane was designed in such a way that it could not pass over the spent fuel pools and, therefore, this would preclude the movement of heavy loads over the spent fuel pools. The staff considers that this design is acceptable.

The licensee stated that the methodology used for the Vogtle Unit 1 spent fuel pool analysis is the same as that which had been used for McGuire, Turkey Point, Peach Bottom, and Palisades and that the models used in the analysis are similar to those that had been used for these four plants, and that the methodology and model had been reviewed and found acceptable by the staff for the referenced plants. On October 8 and 9, 1986, the staff performed an audit at the Westinghouse, Pensacola, Florida facility for the spent fuel rack design of Palisades and was satisfied with the general methodology and mathematical models used in the analysis. The staff approval of the general methodology and analysis models was documented in the Palisades SER included in the issuance of Amendment 105, dated July 24, 1987 (Wambach, 1987; Zech, 1985).

On the basis of the review of the licensee's submittals, the staff has concluded that the licensee has adequately and satisfactorily addressed all the issues related to the seismic adequacy of the spent fuel pool rack design at Vogtle Unit 1.

The total weight of 288 spent fuel assemblies, as currently proposed, is less than the total weight of 938 spent fuel assemblies, which was previously licensed. Therefore, the capability of the spent fuel pool structure, which has been designed and licensed for supporting 938 spent fuel assemblies, is more than adequate for supporting 288 spent fuel assemblies. The capability of the spent fuel pool structure should be reanalyzed when the total weight of spent fuel assemblies and racks exceeds the total weight of its previous design.

On the basis of the staff's acceptance of the spent fuel pool rack design submitted by the licensee, the staff has concluded that the schedular exemption included in the Unit 1 full-power license is no longer required.

3.9 Mechanical Systems and Components

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

3.9.3.3 Component Supports*

By letters dated July 1 and August 6, 1987, the applicant submitted a discussion of a proposed redesign of the steam generator upper support of the reactor coolant loop system for Vogtle Unit 2. The applicant enclosed an evaluation to verify the adequacy of the redesign and a proposed revision of the FSAR.

The support redesign and FSAR revision will permit Vogtle Unit 2 to reduce the number of large hydraulic snubbers in the steam generator support systems from five to two for all four steam generators. The technical basis for the FSAR revision is the use of the "leak-before-break" principle which would eliminate the dynamic effects of postulated pipe ruptures from the primary piping design basis. The evaluation showed that the configuration of the redesign will be able to withstand all remaining loadings, including those caused by the safe shutdown earthquake and the limiting high-energy-line breaks at branch nozzles. Specifically, the evaluation indicated that stresses in the reactor coolant loop piping are within the FSAR allowables with adequate margins of safety.

---

*This evaluation was previously provided to Georgia Power Company by letter dated October 7, 1987.

The Vogtle Unit 2 reactor coolant system consists of four reactor coolant loops (RCLs) with one steam generator per loop. An identical design was used for the supporting system of all four steam generators. The upper support is an octagonal ring girder with curved bearing surfaces placed around the steam generator shell and hung from the steam generator trunnions by four tie rods. These tie rods support the dead weight of the ring assembly and position the ring girder vertically. Three rigid struts carrying loads from the steam generator through the ring girder are anchored to the secondary shield wall to restrict the movement of the steam generator. One strut is located on each of the three sides of the steam generator not facing the reactor. Five hydraulic snubbers located parallel to the hot leg are connected to the ring girder on the reactor side of the steam generator. The snubbers will permit the unrestrained thermal loop movement to the final hot operating position. The proposed redesign effort is limited to the upper support and will reduce the number of snubbers from five to two in each support.

In Volume 3, "Guillotine Break Indirectly Induced by Earthquakes," of NUREG/CR-3660, "Probability of Pipe Failure in Reactor Coolant Loops of Westinghouse PWR Plants," the Lawrence Livermore National Laboratory performed an independent review on Westinghouse topical reports WCAP-10551 and WCAP-10552. The results indicated that the design and construction practices used in Westinghouse PWR plants will not significantly affect the probability of a double-ended guillotine break; thus the elimination of large primary loop pipe rupture as a structural design for Westinghouse PWRs can be permitted. This change results in a reduced loading level, which in turn, requires less upper support rigidity for dynamic events considered in the plant design.

Loadings considered in the redesign are those caused by deadweight, internal pressure, thermal movement, seismic events (operating basis earthquake and safe shutdown earthquake), and postulated pipe ruptures at nozzles.

The staff's evaluation of the RCL leak-before-break analysis for the original support configuration is attached to the staff's exemption to GDC 4 for Vogtle, dated February 5, 1985. A comparison has been made between the original loads and the revised loads from the steam generator upper lateral support redesign. On the basis of this comparison, it was verified that the staff's original conclusions regarding the RCL leak-before-break analysis remain valid.

The WESTDYN computer code was used as the analytic tool. This code was discussed in Westinghouse topical report WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes." The staff approved this report by letter dated April 7, 1981, from R. L. Tedesco to T. M. Anderson of Westinghouse. The mathematical models used consisted of mass and stiffness representations for all four RCLs and the reactor vessel. Three-directional seismic analyses were performed using envelope response spectra with damping values of 2% and 4% for operating basis earthquake and safe shutdown earthquake, respectively. The three-directional seismic responses were combined by the square-root-sum-of-squares (SRSS) method. Combination of closely spaced modes was conducted according to the approved FSAR method. Time-history forcing functions for the postulated breaks at five nozzles (the pressure surge, the accumulator, the residual heat removal, the main steam, and the feedwater line nozzles) were used to determine the most severe pipe rupture loading, and the SRSS method was used to combine seismic and pipe rupture loads.

The adequacy of the redesign was verified by comparing the analytic results with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section III (Code) requirements. Vogtle Unit 2 has adopted the requirements of the 1977 Code Edition up to and including the Summer 1979 addendum (Subsection NB) and the Summer 1977 addendum (Subsection NF).

The applicant's submittal confirmed that piping stresses did not exceed Code stress limits and loadings on nozzles did not exceed the allowables loading provided by the manufacturer in the equipment specifications.

Paul Munroe hydraulic snubbers were used for the upper supports. The service record of these snubbers showed that no service-oriented failures have been reported. Because Vogtle Unit 2 will follow all maintenance requirements recommended by the manufacturer, high reliability of snubber performance is expected.

The applicant redesigned the steam generator upper supports for Vogtle Unit 2 by applying approved piping analysis methods and using qualified equipment. On the basis of its review, the staff concludes that the results are acceptable. Therefore, the staff approves the redesign and the proposed revised FSAR.

3.9.6 Inservice Testing of Pumps and Valves*

In accordance with the requirements of 10 CFR 50.55a, the licensee submitted the Inservice Testing (IST) Program for Vogtle Unit 1 by letter dated July 30, 1986. As a result of staff review and comments, the licensee revised its IST Program for Vogtle Unit 1 and by letter dated October 31, 1986, submitted Revision 1 of the Vogtle Unit 1 IST Program for final staff review and approval. The staff found Revision 1 of the Vogtle Unit 1 IST Program acceptable as discussed in SSER 6.

By letters dated June 25 and August 27, 1987, the licensee submitted Revision 2 of the Vogtle Unit 1 program for staff review and approval. Revision 2 contains mostly program changes resulting from operating experiences and additional requests for relief from the ASME Code Section XI, Subsections IWP, "Inservice Testing of Pumps in Nuclear Power Plants," and IWV, "Inservice Testing of Valves in Nuclear Power Plants," requirements. The staff's evaluation and conclusions regarding Revision 2 of the Vogtle Unit 1 IST Program are provided below.

The staff's contractor, EG&G Idaho, Inc., has reviewed the licensee's submittals pertaining to Revision 2 and has prepared an evaluation of the proposed revision to the Vogtle Unit 1 IST Program (see Appendix W). The staff has reviewed the contractor's evaluation and concurs in its findings. A summary of the staff's evaluation and conclusions is presented in Table 3.1. Where appropriate, a remark is provided to clarify the conclusions.

On the basis of its review of the licensee's revised IST Program and relief requests, the staff concludes that the IST Program will provide reasonable assurance of the operational readiness of the pumps and valves covered by the IST Program to perform their safety-related functions. The staff has determined

---

*This evaluation was previously provided to Georgia Power Company by letter dated October 7, 1987.

that pursuant to 10 CFR 50.55a(g)(6)(i) granting relief from the ASME Code if its requirements are impractical, is authorized by law, and such relief will not endanger life, property, or the common defense and security. The staff also concluded that granting relief is in the public interest considering the burden that could result if the requirements were imposed on the facility. During the review of the licensee's IST Program, the staff has not identified any significant misinterpretation or omissions of Code requirements. Thus, the IST Program, Revision 2, dated June 25, 1987, as supplemented by letter dated August 27, 1987, is acceptable for implementation.

Table 3.1 Summary of Vogtle Unit 1 Inservice Testing Program Revision 2, changes and relief requests

Description of changes and/or relief requests	NRC evaluation and conclusions	Remarks
Relief Request PR-4 was added to the Program. PR-4 requests relief to measure pump vibration at different locations than those required by the Code.	Relief is granted.	Alternative method is found acceptable.
A note was added to Relief Request PR-2 to indicate that instruments to measure the Code-required flow rate will be installed before restart following the first refueling outage.	Acceptable	Change was made to comply with the Code requirement.
The range on the pressure gauges was changed from "0 psi to 15 psi" to "-15 psi to 15 psi" to indicate the ranges on the installed instruments.	Acceptable	
Deleted reference to RR-3 on valves PV-0455A and PV-0456A. On Relief Request RR-3, the reference to valves 1201-PV-0455A and 1201-PV-0456 was deleted in order to make RR-3 generic.	Acceptable	
Cold Shutdown Justification CS-35 was written to allow testing of valves 1205-HV-8716A and 1205-HV-8716B to be performed on a cold shutdown frequency.	Acceptable	Necessitated by IE Information Notice 87-01.
Cold Shutdown Justification CS-36 was written to allow testing of valves 1205-U6-001 and 1205-U6-002 to be performed on a cold shutdown frequency.	Acceptable	Necessitated by IE Information Notice 87-01.
Cold Shutdown Justification CS-37 was written to allow quarterly partial-stroke testing and full-stroke testing during cold shutdown of valves 1205-U6-009 and 1205-U6-010.	Acceptable	Necessitated by IE Information Notice 87-01.
The program was changed to delete the closed safety position for valves 1205-U6-009 and 1205-U6-010. These valves are not required to close to perform a safety function.	Acceptable	
Relief Request RR-26 was written to request relief from using mechanical exercisers to test the spray additive tank vacuum breaker valves and as subsequently withdrawn by letter dated August 27, 1987.	Relief Request withdrawal is acceptable.	

Table 3.1 (Continued)

Description of changes and/or relief requests	NRC evaluation and conclusions	Remarks
Cold Shutdown Justification CS-38 was written to allow testing of valves HV-8508A and HV-8508B during cold shutdown.	Acceptable	
The program was changed to indicate quarterly forward-flow-operability testing for valve 1208-U6-032.	Acceptable	
Cold Shutdown Justification CS-34 was written to allow full-stroke testing of valves 1208-U4-284 and 1208-U4-299 during cold shutdown and partial-stroke testing during the quarterly pump tests.	Acceptable	
The program was changed to indicate the quarterly reverse-flow-closure testing of valves 1302-U4-113, 1302-U4-114, 1302-U4-115, and 1302-U4-116.	Acceptable	
Cold Shutdown Justification CS-33 was written to allow testing of valves 1302-U4-125, 1302-U4-126, 1302-U4-127, and 1302-U4-128 to be performed on a cold shutdown frequency.	Acceptable	
The program was changed to indicate that valves 1592-U4-186 and 1592-U4-187 are normally closed and that their safety position is open.	Acceptable	
An editorial change indicated a piping and instrumentation diagram (P&ID) revision that relocated valves HV-9378 and 2420-U4-049 to P&ID 1X4DB186-4.	Acceptable	Editorial change.
The program was changed to indicate that valves HV-8208, HV-8209, HV-8211, and HV-8212 are normally closed instead of normally open. Valves HV-8211 and HV-8212 have been replaced with 1.00-inch valves.	Acceptable	
Relief Request RR-1 was withdrawn. References to RR-1 were deleted from the valve tables where appropriate.	Acceptable	Changes were made to comply with SSER 6.

4 REACTOR

4.4 Thermal-Hydraulic Design

4.4.8 Instrumentation for Detection of Inadequate Core Cooling*

License Condition 2.C(7)a of the Vogtle Unit 1 full-power license (NPF-68) required that the licensee submit the reactor vessel level instrumentation system (RVLIS) implementation report by June 1, 1987. By letter dated May 29, 1987, the licensee provided the RVLIS implementation report. The staff has reviewed the report and the supplemental information provided by the licensee's letter dated July 20, 1987, and concludes that the license condition has been satisfied. Further, based on the acceptable RVLIS implementation report which completes Vogtle Unit 1 compliance with NUREG-0737, Item II.F.2, the staff approves the Vogtle Unit 1 RVLIS installation.

---

*This evaluation was previously provided to Georgia Power Company by letter dated August 12, 1987.

5 REACTOR COOLANT SYSTEM

5.4 Component and Subsystem Design

5.4.7 Residual Heat Removal System

5.4.7.5 Tests, Operational Procedures, and Support Systems*

On January 6, 1987, the staff issued Information Notice (IN) 87-01, "RHR Valve Misalignment Causes Degradation of ECCS in PWRs," which discussed a potentially significant problem pertaining to residual heat removal (RHR) valve alignment in the low-pressure emergency core cooling system (ECCS). Specifically, closure of the RHR crossover valves or of the pump discharge valves (valves 1HV-8716A and B and 1HV-8809A and B in the simplified Vogtle flow diagram of Figure 5.1) could potentially incapacitate the RHR system by preventing injection into all four reactor coolant system (RCS) cold legs.

An enforcement conference was held with the licensee on October 21, 1987, in the Region II offices to discuss seven instances in which one of valves 1HV-8716A and B and 1HV-8809A and B had been closed at Vogtle Unit 1 between February and August 1987. In order to preclude closure of these valves in Modes 1, 2, and 3, the licensee had submitted revisions to the Unit 1 Inservice Testing (IST) Program providing cold shutdown justification for closure of these valves.** However, at the enforcement conference, based on its additional review of closure of these RHR system valves, the licensee indicated its belief that closure of the valves was technically supported and the best surveillance techniques necessitated closure of valves 1HV-8716A and B in Mode 1 and of valves 1HV-8809A and B in Mode 3. The staff informed the licensee that it could not thus manipulate these valves until the staff had reviewed and approved the analysis indicating that safety considerations continue to be met, and thereby addressing the issue raised in IN 87-01.

Subsequently, the licensee submitted its technical basis for closure of these RHR valves by letter dated October 27, 1987. The staff's evaluation of the closure of each valve follows.

---

*This evaluation was previously provided to Georgia Power Company by letter dated November 5, 1987.

**IST Program, Revision 1, submitted by letter dated October 31, 1986, provided the cold shutdown justification for valves 1HV-8809A and B. IST Program, Revision 2, submitted by letter dated August 27, 1987, provided the cold shutdown justification for valves 1HV-8716A and B, and was provided in response to IN 87-01. The staff approved Revision 1 in SSER 6 dated March 1987 and approved Revision 2 by letter dated September 22, 1987, and Section 3.9.6 and Appendix W of this report.

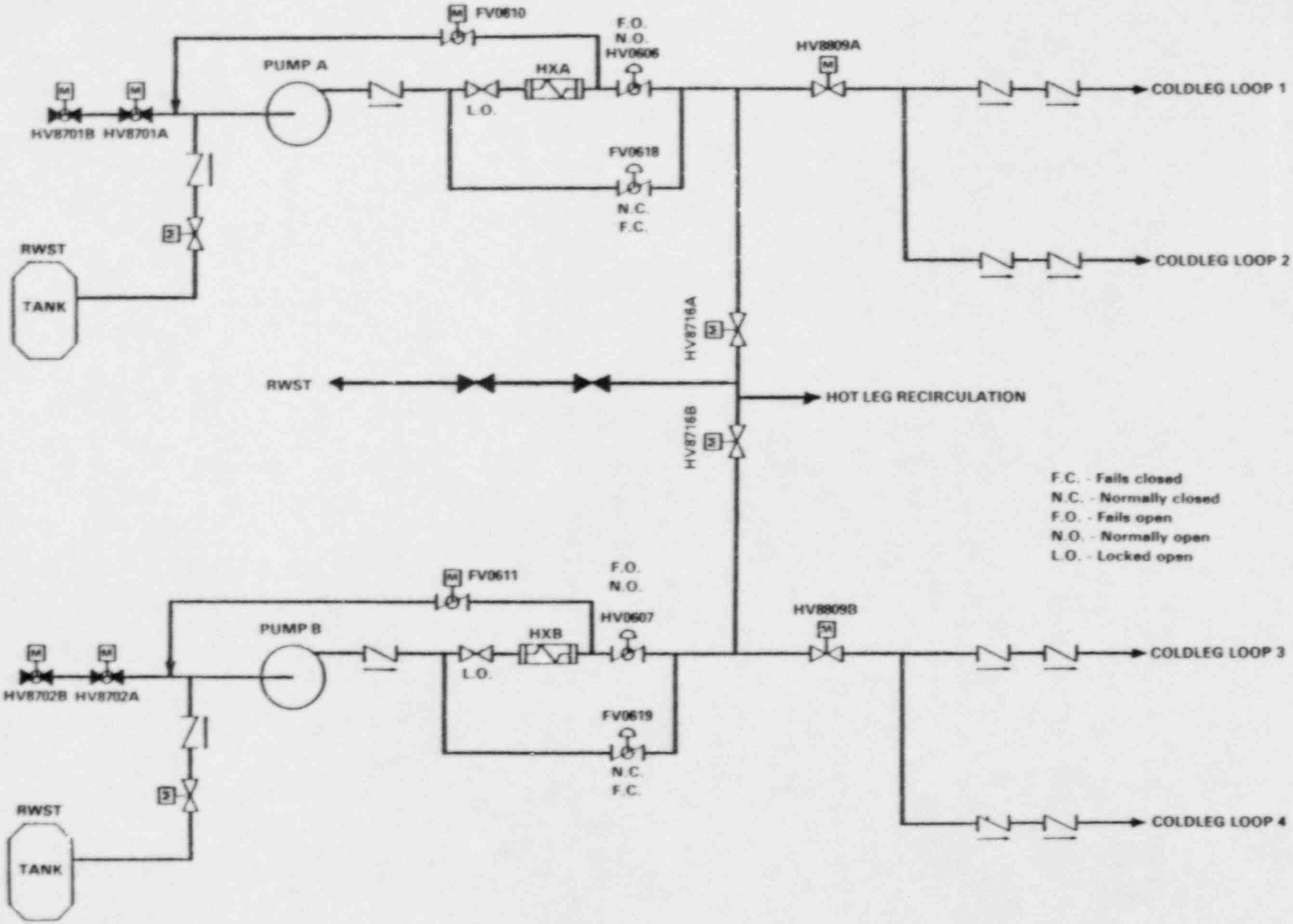

Figure 5.1 Vogtle low-pressure safety-injection system normal ECCS alignment

Closure of Valves 1HV-8716A and B in Mode 1

In its October 27, 1987, letter, the licensee described two surveillances which would require closure of valves 1HV-8716A and B. These valves are required to operate following a loss-of-coolant accident (LOCA) in order to allow initiation of hot-leg recirculation, and therefore, stroke testing of these valves at power allows detection of any valve degradation. For stroke testing, the valves would be individually closed for approximately three minutes every 90 days. In other respects, the configuration would be the same as that shown in Figure 5.1. During surveillance, additional single failures are not required to be assumed. Therefore, flow would continue to be available from two RHR pumps into all four RCS cold legs. This configuration has no impact on the capability of the RHR system to perform its function.

Closure of valves 1HV-8716A and B would also be required during Mode 1 for quarterly flow testing of the RHR pumps. During this test, the opposite RHR cross-tie valve from the pumps being tested is closed for less than two hours, and the flow path of the refueling water storage tank is opened. This configuration allows essentially full-flow testing of the pump (approximately 3000 gpm). Again, being in the surveillance mode does not require assumption of an additional single failure. Therefore, should a LOCA occur, partial flow is available into two cold legs from the pump being tested, and full flow into the remaining two cold legs is available from the RHR pump not being tested. Further, flow is available from the two intermediate-head safety-injection pumps and the two high-head charging pumps, and the operator can take action to close the open cross-tie valve in order to obtain full flow into the RCS from the pump being tested. Even if assuming that during a LOCA one of the cold legs receiving flow from the RHR pump not being tested is spilling to the broken reactor coolant loop, the total ECCS flow without operator action to close the cross-tie valve still exceeds minimum cooling requirements described in the Vogtle FSAR. The FSAR analysis assumes loss of one RHR pump, one intermediate-head safety-injection pump, and one high-head charging pump. The licensee has committed to test the RHR pumps at partial flow through the recirculation line (see Figure 5.1) if the redundant RHR pump or its associated components are inoperable.

On the basis that the period of closure of valves 1HV-8716A and B is short and that in both surveillances described above, minimum ECCS flow requirements would continue to be met, the staff concludes that closure of these valves during Mode 1 operation is acceptable.

The licensee has also committed to revise its IST Program to reflect its intent regarding RHR pump testing and thereby withdraw its cold shutdown justification associated with valves 1HV-8716A and B. The staff requires that the IST revision be submitted in a timely manner.

Closure of Valves 1HV-8809A and B in Mode 3

The licensee has proposed to close valves 1HV-8809A and B (one at a time) in Mode 3 in order to perform leak tests of the check valves downstream of valves 1HV-8809A and B on each of the RCS cold legs. In submittals dated December 9, 1985, and June 13, 1986, the licensee described an analysis for a LOCA in Mode 3 with portions of the ECCS disabled. The ECCS configuration in the analysis is more conservative than that during check valve leak testing with one 1HV-8809 valve closed. The analysis assumed that flow was available from only one RHR pump, one intermediate-head safety-injection pump, and one high-head charging pump. The analysis also assumed that automatic safety-injection actuation on low pressurizer pressure was blocked and that only automatic safety injection on containment high pressure was available. In actuality, during check valve leak testing all ECCS pumps and accumulators (above 1000 psig) are available. Also, automatic safety-injection actuation on pressurizer low pressure is available above approximately 1900 psig when the operator unblocks this signal.

The December 9, 1985, and June 13, 1986, submittals were evaluated by the staff in its review of open item 19 (derived from confirmatory item 22), "LOCA mitigation in Modes 3 and 4." In Section 6.3.5 of SSER 4 dated December 1986, the staff concluded that the Vogtle ECCS design is adequate for LOCA in Mode 3.

On the basis that the minimum ECCS flow requirements would continue to be met should a LOCA occur in Mode 3 with one 1HV-8809 valve closed, the staff concludes that closure of valves 1HV-8809A and B during Mode 3 operation is acceptable.

The licensee has shown, and the staff agrees, that based on analysis, closure of one of the valves in question would not render the RHR system inoperable. Rather, the minimum ECCS flow requirement would continue to be met. Therefore, the licensee can perform the surveillances discussed above in accordance with the current Technical Specification (T[illegible] 5.2 without requiring any TS modification. However, the licensee is required to include a discussion of the supporting analysis for LOCA in Mode 3 in the next FSAR amendment.

6 ENGINEERED SAFETY FEATURES

6.5 Engineered Safety Feature Atmosphere Cleanup Systems

6.5.1 System Description and Evaluation*

By letter dated June 1, 1987, the applicant transmitted a proposed revision to Sections 1.3, 3.2, and 9.4 of the Vogtle Units 1 and 2 FSAR. The proposed revision deletes the electrical penetration filter and exhaust (EPFE) system from Vogtle Unit 2. The Vogtle Unit 1 EPFE system is not affected.

The EPFE system is designed to maintain a minimum negative pressure on the electrical penetration area of the control building and minimize release of airborne radioactivity following postulated post-loss-of-coolant accident (LOCA) containment leakage by filtering potentially contaminated air from the electrical penetration area. The system consists of two 100% capacity filtration trains each designed to filter up to 6000 cfm.

Section 6.5.1 of the SER described the EPFE system as an engineered safety feature (ESF) system, and credited its charcoal adsorbers with 99% removal efficiency for all forms of radioiodine. However, in a subsequent meeting with the applicant on November 17, 1986, the staff was informed that the indicated removal efficiency for the charcoal adsorbers in the EPFE system was not used in the calculations of either post-accident (LOCA) offsite radiation dose exposures per 10 CFR Part 100, or radiation exposures to operating personnel in the control room per the dose guidelines of GDC 19. On this basis, the staff accepted the applicant's proposal to delete the 1/8-inch negative pressure requirement from the Vogtle Unit 1 Technical Specifications and to reclassify the EPFE system to a non-ESF system from an ESF system. As discussed in a telephone conference call on June 18, 1987, the applicant agreed to clarify FSAR Section 9.4.5 to clearly indicate that the Vogtle EPFE is a non-ESF system.

The electrical penetration area is normally served by the control building levels A and B normal heating, ventilation, and air conditioning (HVAC) system which has no connections to either the control room normal or emergency HVAC systems, or the Technical Support Center (TSC) HVAC system. The Vogtle control room and TSC are located on level 1 in the control building above levels A and B.

Following a design-basis LOCA, potential contaminated outside air is introduced into the control room through the control room emergency filtration system to remove radioactivity and to pressurize the control room. The outside air is also drawn into the control building levels A and B normal HVAC system for makeup air but it is not filtered. Deletion of the Unit 2 EPFE system could potentially increase airborne radioactivity concentrations at control building levels A and B because of leakage through the electrical penetrations.

---

*This evaluation was previously provided to Georgia Power Company by letter dated August 19, 1987.

As indicated above, the staff previously did not use the airborne radioactivity removal efficiencies assigned to the EPFE system in the calculations of post-LOCA offsite radiation consequences or radiation exposure to operating personnel in the control room. To evaluate the effects of deletion of the Unit 2 EPFE system, the staff assumed inleakage of unfiltered contaminated air into the control room envelope from control building levels A and B through doorways on ingress and egress, and from the control room emergency HVAC recirculation ductwork. The staff assumed 10 cfm unfiltered infiltration of contaminated air from control building levels A and B into the control room through doorway ingress and egress as delineated in the guidelines of SRP Section 6.4. This assumption is conservative because the Vogtle control room is provided with a two-door vestibule-type entry into the control room. This type of entry design significantly reduces contaminated air backflow into the pressurized control room.

The applicant provided a calculation comparison of airborne radioactivity concentration outside the control building to that inside the control building on levels A and B with a maximum total design leakage of 43.2 cubic centimeters per minute from 72 electrical penetrations. The results of this calculation indicated that the concentration inside the control building on levels A and B will be approximately 15% higher than outside the control building levels A and B because the potential leaks from the electrical penetrations will reduce the iodine protection factor for control room doses by 1.06 (6%) based on the assumed 10-cfm unfiltered air infiltration. Using this factor, the staff calculated thyroid and whole-body doses to the control room operators to still be within the guidelines of GDC 19.

The control room emergency filtration system contains two 100% capacity air filtration units each designed to filter 25,000 cfm. Each unit includes a 4-inch-deep charcoal adsorber, a control room return-air fan, and a control room air-filter-unit fan. Upon receipt of a control room isolation signal, the control room emergency filtration system will be actuated, and the normal air handling unit will be automatically tripped. Outside air required for control room pressurization is mixed with return air upstream of the filtration unit. Air within the control room envelope is recirculated continuously through the emergency filtration unit. The system design provides no potential bypass pathways around the emergency filtration units. The staff has credited the system with 99% removal efficiency for all forms of radioiodine.

The control room return-air fan takes air from the control room envelope and the outside makeup-air line and delivers it to the filtration unit. The control room filter unit fan is located adjacent to the filter housing and blows air directly into the control room envelope. Any air inleakage into the system ductwork will be filtered through the 4-inch-deep charcoal adsorber before it enters the control room envelope. The staff, therefore, assumed no unfiltered infiltration of contaminated air from control building levels A and B into the control room through the control room emergency HVAC recirculation ductwork.

Thus, the staff finds that the slightly higher (15% increase) airborne radioactivity at control building levels A and B due to post-LOCA electrical penetration leaks will not exceed the control room operator dose guidelines of GDC 19 as indicated in the guidelines of SRP Section 6.4.

On this basis, the staff concludes that the applicant's request to delete the EPFE system from Vogtle Unit 2 is acceptable because the staff's previous conclusions stated in SER Sections 6.4 and 15.6.5 are not affected, and the requirements of GDC 19 continue to be satisfied.

7 INSTRUMENTATION AND CONTROLS

7.3 Engineered Safety Features Systems

7.3.3 Specific Findings

7.3.3.3 Undetectable Failure in On-Line Testing Circuitry for Engineered Safeguards Relays

In SSER 4, the staff stated that Vogtle Unit 2 Technical Specifications, when developed and reviewed, will contain test requirements (monthly or quarterly) that reflect the status of the pending wiring modification to the engineered safeguards relay circuitry. By letter dated March 16, 1987, the applicant stated that a wiring modification per Westinghouse Field Change Notice GBEM-10554 was completed on Vogtle Unit 2 on January 30, 1987. The staff finds this change acceptable and the unique testing requirements (monthly testing of slave relays in lieu of quarterly) will not be included in the Vogtle Unit 2 Technical Specifications.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.1 Emergency Response Capability--RG 1.97, Revision 2, Requirements*

In Section 7.5.2.1 of SSER 5, the staff required the applicant (now licensee) to augment certain surveillances and procedures associated with accident-monitoring instrumentation (Regulatory Guide (RG) 1.97, Revision 2) at Vogtle Unit 1, pending completion of the verification and validation (V&V) effort for the plant safety monitoring system (PSMS). By letter dated June 1, 1987, the licensee provided details of the PSMS V&V Program. On June 29-30, 1987, the staff met with the licensee and its representatives at the Westinghouse facilities located in Monroeville, PA. The meeting was held to audit the Vogtle PSMS V&V Program. A consultant from SoHar Inc. assisted the staff during the audit.

The licensee has a microprocessor-based display system that performs post-accident monitoring at Vogtle. This display system is the PSMS, and it was manufactured by Westinghouse. The system processes plant sensor signals and outputs many of the RG 1.97, Revision 2 variables to plasma displays and external indicators, displays, cabinets, and other equipment. The PSMS consists of three types of modular components: the remote processing units, the display processing units, and the plasma displays. The system is seismically and environmentally qualified and configured to meet single-failure criteria.

The Vogtle PSMS is a functional derivative of the display developed by Westinghouse for Houston Power and Light as part of the Qualified Display Processing

*This evaluation was previously provided to Georgia Power Company by letters dated August 25 and September 17, 1987.

System (QDPS) for the South Texas Project. The development of the Vogtle PSMS occurred after the completion of the QDPS in order that all common software could be used without repeating the entire V&V process on those units. The staff's safety evaluation of the QDPS, which was found acceptable, appears in Supplement 4 to the South Texas SER (NUREG-0781) dated July 1987.

The staff evaluated the design differences between the Vogtle PSMS and the equivalent display designed and qualified for South Texas. The staff's review found hardware and software differences. In hardware, the Vogtle PSMS has a plant-specific display selection keyboard, and one output display per train as opposed to six displays for South Texas. In software, the difference consists of the plant-specific sensor inputs and variables, the display formats, and the addition of data from a reactor vessel water level instrumentation system. The Vogtle PSMS has a total of 1018 software units of which 136 units are unique to the plant. About 87% of the software units are the same as the software units in the South Texas display.

The design of the plasma display pages consists of an upper level plant status summary and four lower level displays for nuclear power, reactor vessel water level, core exit thermocouples, and pressure-temperature limits. In addition, the system provides for the display of process variable time trend histories and detailed data listings.

During its audit, the staff evaluated the organizational structure of the V&V staff and the content of the V&V Program. The vendor as well as the Vogtle V&V team made presentations on the display's design organization. The data in these presentations described the V&V activities and identified responsible personnel. The staff's review of the data concluded the organizational structure and the level of independence of the V&V team from the design team was acceptable.

The audit also evaluated the V&V Program. Westinghouse personnel made presentations to the staff on the V&V Program. The object of this program is to eliminate errors in design. The method used to verify the software modules was the same method used in the South Texas Project, which the staff found acceptable. However, the absence of verification of the software design also exists in the Vogtle program. On the other hand, this is overcome with an extensive verification of the software modules.

The method used by the validators to identify the tests for the display system was discussed by the vendor. This discussion identified the scope of the tests consisting of functional, abnormal, and prudence evaluations. The functional evaluation of the display system contained static as well as dynamic tests. Also, the validation effort focused upon the differences between the Vogtle and South Texas designs with thorough testing to validate that each sensor input algorithm had been met. For Vogtle algorithms common with those at South Texas, validation testing was performed to demonstrate that all algorithms were properly installed. This was accomplished by performing a selected subset of the South Texas tests using Vogtle plant-specific sensor inputs and variables. The staff's review of the Vogtle V&V Program confirms it is identical to the one used in the South Texas Project and that it is acceptable.

The staff evaluated the products from the V&V Program. The method used to evaluate products consisted of a walkthrough of the code for two sensor signals and an analysis of the trouble reports identified by V&V.

The walkthrough of the code used two sensor signals: auxiliary feedwater flow and cold-leg coolant temperature. The analog sensor signals were traced through the signal conditioning circuits to the multiplexers. The multiplexer converts the analog signal to a digital signal. The digital signal is then processed by the microprocessors using stored algorithms. The processed signal is then displayed on the surface of the gas plasma display. The staff's walkthrough traced the signals through the algorithms and evaluated the associated V&V activities. The staff found the V&V activities responsive to the V&V plan.

The staff analyzed the trouble reports identified by the V&V Program during verification for the type and quantity of software errors reported. The staff found the percentage of the major types of error to be consistent with published error patterns for this type of activity as discussed in IBM Technical Report TR 00.2763, dated June 10, 1974 (IBM, 1974). From this result, the staff concludes that the vendor performed an effective verification of the software.

The staff also analyzed the trouble reports identified during validation activities and found a small number of trouble reports. The staff also found no generic problems or types of errors that should have been detected during earlier verification activities. From these results, the staff concludes that the vendor performed an effective validation of the software.

During the audit, the licensee presented and discussed physical security measures and maintenance for the display system. Security measures were discussed for the remote processing units, the data processing units, and the displays. Also, security measures for the spare programmable read only memories (PROMs) were discussed.

The staff's review concludes that the physical security, maintenance, and modifications procedures for Vogtle are essentially identical to those for South Texas. These include the following:

(1) No data input devices are connected to the system in normal operation.

(2) The input keyboard used to change setpoints and limits is physically removed requiring keys, passwords, and authorization before use.

(3) All maintenance and code modifications will be performed by Westinghouse to the same standards of V&V used in the design of the display.

The staff finds the physical security, maintenance, and modification procedures for the Vogtle PSMS acceptable.

On the basis of its review of the V&V Program used to design and develop the PSMS, the staff concludes that:

(1) The Vogtle PSMS is very similar to the monitoring system developed and licensed for South Texas.

(2) An acceptable level of independence existed between the V&V team and the design team.

(3) The V&V plan used for the Vogtle PSMS is identical to the one used for the monitoring system in South Texas.

(4) The analysis of trouble reports generated from V&V activities concludes that the vendor met the goals of the V&V plan.

(5) The physical security, maintenance, and modification procedures for the system are adequate.

In terms of its evaluation of the V&V Program, the staff concludes that the Vogtle PSMS is acceptable.

By letter dated September 1, 1987, the licensee submitted information regarding the software and hardware differences between the PSMS of Vogtle Unit 1 and the PSMS of Vogtle Unit 2. In its submittal, the licensee stated that only five units of code related to the Unit 2 plasma displays were affected by minor software changes. In addition, no trouble or clarification reports were generated in either the verification or validation process for these Unit 2 changes. On the basis of its review of this information, the staff concludes that its acceptance of the Vogtle PSMS V&V effort as discussed in its letter of August 25, 1987, remains unchanged.

7.5.2.4 Bypass and Inoperable Status Panel

In the SER, the staff indicated that the applicant had committed to have bypassed and inoperable status indicate in both control rooms for the fuel handling building engineered safety features heating, ventilation, and air conditioning system which is shared between both units. Installation of the modification was identified as a confirmatory item. After the staff resolved this issue in SSER 4 for Unit 2, the applicant informed the staff that the modification for Unit 2 was not yet complete, thereby revising an earlier letter indicating installation was complete. Therefore, in SSER 5 the staff reopened this confirmatory item.

By letter dated October 15, 1987, the applicant informed the staff that the required modification for Unit 2 has been completed. On this basis, the staff concludes that confirmatory item 27 is satisfactorily resolved for Unit 2.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection*

By letter dated July 7, 1987, the applicant proposed three changes to the Vogtle Unit 2 fire suppression system. The three proposed changes are:

(1) Revise sprinkler hanger design based on the results of seismic testing for qualification purposes rather than analytical means as done previously.

(2) Revise the criteria for placement of in-tray sprinkler protection to include them only in the cable spreading rooms.

(3) Revise the fire suppression flushing procedures, which provides an alternate to flushing of the sprinkler system piping.

The applicant's position is that the proposed changes will not compromise the ability of the fire protection systems to perform their intended function during a fire.

9.5.1.5 Fire Detection and Suppression

Sprinkler and Standpipe Systems

Fire protection guidance furnished by the staff does not require a licensee to postulate a fire and earthquake simultaneously. However, in many areas, fire suppression systems are classified as seismic two-over-one (2/1) systems. This means that their integrity during and after a seismic event should be ensured so as not to jeopardize the integrity of adjacent equipment and structures that may be essential for safe shutdown of the plant. Automatic sprinkler systems installed in areas containing safety-related equipment or components, therefore, must be designed and installed so that they will not fail during an earthquake and damage the safety-related equipment or components. The automatic sprinkler systems of Unit 1 were designed and installed to meet strict support stiffness and piping deflection criteria. However, the "Standard for the Installation of Sprinkler Systems," NFPA-13, published by the National Fire Protection Association, permits use of more flexible supports, including sway bracing, for sprinkler systems that may be subject to seismically induced vibratory loadings. A recent experimental effort performed by ANCO Engineers, Inc. (ANCO) for Bechtel Western Power Corporation successfully demonstrated that the rod-suspended sprinkler systems at the South Texas Project were capable of withstanding simulated seismic events in excess of predicted design criteria without collapse.

*This evaluation was previously provided to Georgia Power Company by letter dated October 26, 1987.

In order to verify the adequacy of the more flexible sprinkler hanger design proposed for Unit 2, the applicant contracted with ANCO to test three segments of actual Unit 1 sprinkler systems. The three test assemblies chosen were representative of actual installed systems, and each consisted of approximately 40 feet of feed main with several branch lines and a simulated deluge valve connection. Supports and sway braces for each test assembly were designed and installed using NFPA-13 recommendations. All supports incorporated standard off-the-shelf hardware, including swivel connections to act as pins at the top of the supports.

The assemblies were tested on the ANCO R-4 shake table. Each was subjected to dynamic loadings equivalent to five operating basis earthquakes (OBEs), after several scaling earthquakes to include the effects of fatigue, and one safe shutdown earthquake (SSE). Each test assembly was hydrostatically tested before and after the first OBE test to demonstrate functionality. Finally, each of the test assemblies was subjected to dynamic loadings equivalent to 1.2 x SSE and 1.4 x SSE to demonstrate survivability and to establish a design margin. Test results indicated that the fragility limits of the test assemblies exceeded the capacity of the shake table and far exceeded the seismic design criteria of the site. The staff finds the above test procedure and test results to be acceptable.

The staff also agrees with the applicant's proposed FSAR changes related to the above. The proposed changes are contained in Inserts B, C, E, and F to Attachment 4 of the applicant's letter dated July 7, 1987.

On the basis of the above evaluation, the staff finds that these tests demonstrated that automatic sprinkler fire suppression systems designed and installed in accordance with NFPA-13, using rod type hangers and sway bracing, will be able to withstand the design seismic loadings and, therefore, are acceptable.

Section 1-11.1.1 of NFPA-13, "Standard for the Installation of Sprinkler Systems," reads as follows:

> 1-11.1.1 Underground mains and lead-in connections to system risers shall be flushed before connection is made to sprinkler piping in order to remove foreign materials which may have entered the underground piping during the course of the installation. For all systems, the flushing operation shall be continued until water is clear.

The purpose of this flushing is to ensure that foreign materials that may have entered the underground piping during construction do not enter the sprinkler system piping.

The applicant performed the flushing operations of the underground mains and lead-in connections at Unit 1 while they were connected to the sprinkler systems. This deviation from the provisions of NFPA-13 resulted in an open item being added in SSER 2 that was later closed in SSER 4. For Unit 2, the applicant is proposing a different method of ensuring that the underground mains and lead-in piping to fire suppression systems are properly flushed, and that foreign material does not enter the suppression system piping. The proposal for Unit 2 provides for the use of test blanks, as follows:

(1) A test blank will be installed between the system isolation valve and preaction sprinkler valve before the system is installed.

(2) The test blanks will be visible when installed and controlled through the use of drawings, procedures, and inspections.

(3) Test blanks will be removed after header piping is verified clean.

By telephone conference call on September 2, 1987, the staff was assured by the applicant that the test blanks will be so installed as to permit flushing of all portions of the underground main and system lead-in piping utilizing flushing flow rates in accordance with Section 1-11.1.2 of NFPA-13. Considering that information, the staff agrees with the applicant's proposed approach to use test blanks to prevent introduction of foreign materials into sprinkler system piping during flushing operations of the underground mains and lead-in piping to the sprinkler systems.

The staff also agrees with the FSAR changes proposed by the applicant as contained in Attachment 4 of its letter of July 7, 1987, and applicable to flushing of underground mains and system lead-in piping. The applicable proposed changes are contained in Insert D to FSAR Table 9.5.1-9 (sheet 2 of 16).

On the basis of the above evaluation, the staff finds that the proposed changes in procedures for flushing underground mains and lead-in piping to system users will satisfy BTP CMEB 9.5-1 (NUREG-0800), Section C.6.b.(1) and the referenced NFPA-24, "Standard for the Installation of Private Fire Service Mains and Their Appurtenances," Section 8-8 and are, therefore, acceptable.

9.5.1.6 Fire Protection of Specific Plant Areas

Cable Spreading Rooms

FSAR Section 9.5.1.2.1.4 addresses fire suppression design criteria for cable trays containing safe shutdown cables and specifies in-tray directional spray nozzles above each tray.

On the basis of additional staff guidance, and as a result of more refined methods of evaluating cable tray fire hazards and protection required (including test results from industry and NRC-sponsored research programs), the applicant realized that the protection provided for Unit 1 safe shutdown cables was unnecessarily conservative. Therefore, the applicant has proposed alternative design criteria for protecting cable trays throughout Unit 2. The applicant proposes that design of automatic sprinkler protection for cable trays in Unit 2 be based upon the following criteria:

(1) The area coverage boundaries for suppression systems will be in accordance with that identified on fire area drawings (FSAR Figures 9A-1 through 9A-46).

(2) In the cable spreading rooms, in-tray directional spray nozzles will be provided. Area protection at the ceiling will provide coverage for the first three safety-related trays in a vertical stack, and in-tray protection will be provided for the remaining safety-related trays starting with the fourth tray in the stack and ending with the last tray in the stack (typical Unit 1 design).

(3) For electrical cable chases and tunnels, sprinklers will be provided at the ceiling designed to discharge 0.3 gpm per square foot over the most remote 3000 square feet or area within the cutoff fire boundaries, whichever is less.

(4) For other areas containing three safety-related cable trays or less in a vertical stack, sprinklers will be provided at the ceiling design to discharge 0.21 gpm per square foot over the most remote 1500 square feet or area within the cutoff fire boundary, whichever is less (typical Unit 1 design).

(5) For other areas containing more than three safety-related cable trays in a vertical stack, sprinklers will be provided at the ceiling designed to discharge 0.3 gpm per square foot over the most remote 3000 square feet or area within the cutoff fire boundaries, whichever is less.

Except for cable spreading rooms, cable tray installations generally are considered to have low to moderate fuel loads (80,000 Btu/ft^2 of floor area being equivalent to a 1-hour fire). Based upon the low to moderate fuel loading in the cable trays throughout the plant, and an increased water density discharge design criteria for ceiling sprinklers in Unit 2 compared to the lower water density discharge design criteria used for ceiling sprinklers in Unit 1, the staff agrees with the applicant that in-tray sprinkler protection does not have to be provided in areas other than the cable spreading room.

The staff also agrees with the FSAR changes proposed by the applicant as they relate to these changes in automatic sprinkler protection. The proposed FSAR changes accepted by the staff are shown as Insert A to Attachment 4 of the applicant's letter of July 7, 1987.

On the basis of the above evaluation, the staff finds that the proposed changes in design criteria for sprinkler protection for cable trays containing safe shutdown cables meets the guidelines of BTP CMEB 9.5-1 (NUREG-0800), Section C.5.e, is consistent with protection designs that have been accepted at other nuclear power plants, will provide adequate fire suppression protection for safe shutdown cables, and is, therefore, acceptable.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.2 Emergency Diesel Engine Fuel Oil Storage and Transfer System (Specific)*

License Condition 2.C(8) was included in the Vogtle Unit 1 full-power license (Facility Operating License NPF-68), dated March 16, 1987, because of staff concern that the reaction products of the acidic impurities in diesel fuel oil with the zinc inorganic coating of the storage tanks might cause plugging of lines and fuel injectors in diesel generators. The license condition states:

---

*This evaluation was previously provided to Georgia Power Company by letter dated October 15, 1987.

Prior to restart following the first refueling, GPC shall (1) replace the zinc coating in the diesel generator fuel oil storage tanks with a coating which does not contain zinc or (2) by March 1, 1988 provide an acceptable justification to the staff that the present fuel oil storage tank zinc-based coating will not affect the operability and reliability of the diesel generators over the life of the plant as specified in IE Circular 77-15.

Also, Technical Specification Surveillance Requirement 4.8.1.1.2f requires sampling and analysis of new fuel oil and oil in the storage tanks to verify that the neutralization number is less than 0.2 and the mercaptan content is less than 0.01%.

By letters dated July 13, September 30, and October 15, 1987, the licensee provided information justifying the continued use of the inorganic zinc coating on the fuel tanks. This information included the following items:

(1) The inorganic zinc coating substantially extends the life of steel storage tanks by delaying the onset of corrosion and by reducing the corrosion rate. The lowered corrosion rate results in less particulate contamination in the fuel oil.

(2) The staff concern arose in part because of the discussion in IE Circular 77-15 of a clogged strainer in the fuel line to the diesel generator at the Cooper Station. The circular states that fuel oils are degraded by contact with metal such as zinc, which "has a tendency to form soluble soaps in the fuel oil which are deposited on the diesel engine's injector nozzles. A buildup of this deposit will eventually degrade the engine's performance." The circular also states that "[t]he presence of water in the fuel oil promotes the growth of fungi or slime that also degrades the fuel and has the potential for clogging filters."

    The licensee's letter of July 13, 1987, noted that the Cooper Station event could not have been caused by zinc because the steel Cooper tanks are not coated internally. According to the licensee, the diesel engine manufacturer makes no recommendations regarding the use of zinc coatings on storage tanks; it only specifies the use of No. 2 diesel fuel oil. The inorganic zinc coating manufacturer has stated that the "coating can be used with diesel fuel as long as the neutralization number is no greater than 0.4 and the mercaptan content is no greater than 0.01%." Analyses by the licensee of ten samples of fuel oil in Vogtle Unit 1 storage tanks A and B ranged from 0.06 to 0.10 for the neutralization number, with an average of 0.08. The average mercaptan content in ten samples was 0.0005%.

    No water was visible in 13 of 15 fuel oil samples. Only a trace of water was visually detectable in the remaining two samples. The Technical Specifications require sampling of the fuel oil in the storage tanks at least once every 31 days to verify that the particulate contamination is less than 10 mg/liter.

(3) Duplex fuel oil filters are installed in the fuel line with provisions to measure the differential pressure across the filter in use. A high differential pressure would be annunciated in the control room, and an operator would switch from one filter element to the other.

(4) Diesel generator "pop" tests are performed on the fuel injectors every 18 months to check the spray pattern from the fuel injectors. As part of this test, all injectors are disassembled, cleaned, and inspected. Any damaged or worn parts are replaced. The inspection procedure will include provisions for the analysis of any significant deposits of zinc.

(5) In accordance with the Technical Specifications, the tank is checked for the presence of water at least once every 31 days and, if found, the water is removed from the storage tank sumps.

The staff has reviewed the information provided in the licensee's letter of July 13, 1987, and found it to be consistent with information from other industry and literature sources. Protective coating experts consulted by the staff agree that the preferred coating to protect against the corrosion of steel storage tanks by fuel oil is inorganic zinc without a top coat. The staff's research has not uncovered any problems of plugging of diesel generator fuel injectors.

Filter Clogging by Insolubles

With regard to the staff's original concern about clogging lines and filters with corrosion products or metallic soaps, the licensee's provision of a duplex filter with control room annunciation of excessive differential pressure across the filter element in operation is adequate to protect against a line clogging incident of the type that occurred at the Cooper Station. The Technical Specification requirements to monitor and control the neutralization number and concentrations of particulates, mercaptans, and water in fuel oil provide assurance that the rate of accumulation of filter-clogging corrosion products or oil degradation products will be slow.

Fuel Injector Plugging by Soluble Zinc Compounds

With regard to the concern about soluble zinc soaps (principally zinc naphthenates), the chemical literature indicates that they have beneficial effects as combustion improvers and fungicides (Kirk-Othmer, 1978).

To provide a quantitative basis for considering the problem of soluble zinc naphthenates, the staff requested that the licensee take samples of the fuel oil in the storage tanks and have them analyzed for soluble zinc. By letter dated September 30, 1987, the licensee reported the following results:

Date	Tank	Zinc (ppm)
8/22/87	A	7.2
8/22/87	B	6.6
9/11/87	A	7.2
9/11/87	B	5.6

There are no specific standards for allowable limits on zinc concentration in fuel oil. The American Society for Testing and Materials (ASTM) specification for allowable total concentration of inorganic constituents in

No. 2 diesel fuel is 10 ppm. The licensee's letter of September 30, 1987, stated that the total inorganic material, including the zinc, in the fuel oil tested was less than 10 ppm.

References to the use of naphthenates as "combustion improvers" that reduce the concentrations of soot, smoke, and incompletely burned fuel, indicate that concentrations of metallic naphthenates (usually mixtures) in the range of 5 to 40 ppm are effective (ASME, 1975; Ogawa, 1974; and Ivanov, 1973). Higher concentrations of up to 1300 ppm are used for high sulfur fuels (0.9%). Unfortunately, these studies do not provide any specific information on the long-term plating or deposition behavior of these additives on injector nozzles. It is likely, however, that more complete combustion with less soot and smoke would correspond to a lesser tendency toward deposition and plugging. In a conference telephone call on October 6, 1987, the licensee stated that an inspection of the injection nozzles after several hundred hours of diesel operation detected no signs of deposition or plugging of the nozzles.

From the measured neutralization numbers, the equivalent concentration of zinc, dissolved as zinc naphthenate, can be calculated. For a neutralization number of 0.08, the corresponding dissolved zinc concentration would be approximately 47 ppm. The fact that the zinc concentration in the fuel oil after storage in the Vogtle Unit 1 zinc-lined tanks for approximately two years is only 6 to 7 ppm indicates either a very slow reaction or a self-limiting one. It may be that naphthenic acids react at appreciable rates only with oxidized zinc compounds such as ZnO and $Zn(OH)_2$, but not with zinc metal. Another possibility is that the outer silicate layers of the coating protect the zinc in the inner coating layers from contact with naphthenic acids.

In summarizing the considerations about dissolved zinc naphthenates, no evidence has been found that dissolved concentrations of 6 to 7 ppm zinc would tend to deposit on and plug diesel generator fuel injectors. To the contrary, some studies indicate that these concentrations of zinc naphthenate would act as combustion improvers with more complete combustion and less formation of soot and smoke. The Technical Specification limits placed on the allowable concentrations of acidic constituents and water in fuel oil serve to lessen the likelihood of the buildup of excessive concentrations of dissolved zinc. The ASTM standard of less than 10 ppm total inorganic material in No. 2 diesel fuel oil reflects industrial experience that this level of inorganic content is acceptable. In view of the high solubility of zinc naphthenate in fuel oil and its special property of improving combustion, the ASTM limit of 10 ppm inorganic material may be unduly conservative in the case of zinc naphthenate. On the basis of the new information on dissolved zinc available since the issuance of IE Circular 77-15, the staff concludes that the current levels of dissolved zinc in the diesel fuel storage tanks are acceptable.

Corrosion

With regard to the effects of inorganic zinc coating on the corrosion of the steel storage tanks, the staff agrees with the analysis provided by the licensee. In industrial practice, inorganic zinc protective coatings are widely accepted as the most satisfactory way to provide long-term protection of underground steel tanks against corrosive attack by the acidic constituents of fuel oil. The Technical Specification limits on the allowable concentrations of acidic constituents and of water prevent the accumulation of high concentrations of these corrosion-enhancing materials in the fuel oil.

The corrosion product zinc naphthenate is itself a corrosion inhibitor. It also has fungicidal activity and thus helps to control microbiological corrosion in any water phase that may collect in the storage tank sumps. These anticorrosion activities are further advantages deriving from the presence of the inorganic zinc tank lining.

Conclusion

On the basis of the considerations discussed above, the staff has concluded that the licensee has provided an acceptable justification that the inorganic zinc coating on the fuel storage tanks will not adversely affect the operability and reliability of the diesel generators over the life of the plant. These considerations include:

- new information on industrial experience with fuel oil tanks coated with inorganic zinc and on the combustion-improving properties of zinc naphthenate

- the addition of duplex fuel line filters to remove corrosion products or degradation products that could plug the fuel line

- surveillance procedures to check the quality of the fuel oil, to monitor the differential pressure across the fuel line filter, and to inspect the diesel generator fuel injectors for zinc deposits

Accordingly, License Condition 2.C(8) to Operating License NPF-68 is considered resolved. This evaluation also applies to Vogtle Unit 2.

To ensure that the fuel oil storage and delivery systems remain operable and reliable, the Technical Specifications related to fuel oil quality, including the limits on neutralization number and mercaptan content, should remain in effect. In addition, the licensee should continue to monitor the differential pressure across the filter element in the fuel line as stated in its July 13, 1987, letter. The proposed Vogtle Unit 2 Technical Specifications should include the same specifications regarding fuel oil quality, and Unit 2 should also monitor the differential pressure across the fuel line filter.

11 RADIOACTIVE WASTE MANAGEMENT

11.4 Solid Waste Management System

11.4.3 Evaluation Findings

In the SER (NUREG-1137), the staff noted that it had not completed its review of the Aerojet Energy Conversion Company's (AECC's) Topical Report No. AECC-3-NP concerning the radioactive waste volume reduction system (VRS) employed at Vogtle. The staff tentatively concluded, however, based on the extent of the review of the topical report at that time, that the VRS at Vogtle was acceptable. This, therefore, was stated to be a confirmatory item pending more detailed staff review of the topical report.

The confirmatory item associated with the VRS involved four issues. The first issue concerned completing the review of the topical report. By letter dated August 28, 1986, the staff provided its evaluation to the vendor, AECC, stating that the staff finds the report acceptable for referencing in license applications. The vendor issued the approved report, Topical Report No. AECC-3-P-A, in November 1986.

The second issue dealt with potential accidents involving the VRS. By letter dated April 4, 1985, the applicant (now licensee) discussed two accidents: a small leak or malfunction resulting in the airborne release of a portion of the dry product inventory of the VRS and the complete rupture of the recycle holdup tank which contains the largest inventory of significant isotopes. The applicant's calculation indicates that the calculated offsite doses from these accidents are small fractions of the numerical guide provided to meet the criterion "as low as is reasonably achievable" in Appendix I to 10 CFR Part 50. The staff finds acceptable, therefore, the resultant doses to an individual in an unrestricted area resulting from the VRS accidents.

The third issue concerned the applicant's proposal to not limit sulfur input to the VRS to 0.3% as suggested by the staff in its review of an earlier AECC report, Topical Report AECC-2-NP. There are no similar restrictions on the sulfur content of feed materials in AECC-3-NP. The applicant stated that the limit is not applicable to its system because it is not constructed of stainless steel which is susceptible to acidic corrosion, active pH control was added to the Vogtle VRS to neutralize acid gases, and the vendor confirmed that for all Vogtle proposed feed rates and composition there is no acid gas problem. The staff finds the licensee's pH control provision to be acceptable to overcome potential acid gas generation.

The final issue concerned initial installation testing of the high-efficiency particulate air (HEPA) filters and charcoal adsorber as discussed in Regulatory Guide (RG) 1.140 in accordance with American National Standards Institute Standard N510-1975. The applicant indicated that it would perform a visual inspection before installation but that neither an accurate airflow distribution test nor dioctyl phthalate and tracer tests can be performed. AECC-3-NP stated that, based on the configuration of the cylindrical filter housing, the location of the air inlet above the first HEPA filter, and the straight-through flow configuration through single elements in series, the air flow distribution should be nearly uniform. The staff finds, therefore, that based on the filter configuration and the insignificant dose to an individual in an unrestricted area due to a VRS accident, the licensee's exceptions to RG 1.140 are acceptable.

The staff has completed its review of this confirmatory item based on the review of the accepted topical report and finds that the VRS at Vogtle is acceptable in accordance with the criteria of Standard Review Plan (SRP) Section 11.4. Therefore, this item is closed.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

11.5.3 TMI-2 Action Plan Requirements*

By letter dated March 9, 1987, the licensee submitted the results of an examination for potential leakage outside containment to fulfill the requirements of NUREG-0737, Item III.D.1.1 as stipulated in license condition 2.C(8)a of the Vogtle Unit 1 low-power license (NPF-61) dated January 16, 1987. In that letter, the licensee stated that a supplemental report would be submitted following completion of testing of the positive displacement pump and valve 1HV-3258 of the post-accident sampling system. In Section 11.5.3 of SSER 6, the staff concluded that a subsequent submittal on the above items would be acceptable and that the low-power license condition was satisfied.

By letter dated April 20, 1987, the licensee submitted its supplemental report leakage measurement of the positive displacement pump and valve 1HV-3258. The licensee indicated that no leakage was detected from either the pump or the valve. On the basis of its review of the licensee's April 20 submittal, the staff concludes that the requirements of NUREG-0737, Item III.D.1.1 are fully satisfied.

*This evaluation was previously provided to Georgia Power Company by letter dated May 19, 1987.

14 INITIAL TEST PROGRAM*

In the SER dated June 1985, the staff concluded that the applicant's (now licensee) Initial Test Program was acceptable. In SSER 5 dated January 1987, the staff concluded that certain changes to the Initial Test Program were acceptable. Since that SSER, the licensee has made further changes to the Vogtle Unit 1 Initial Test Program described in letters dated May 21, June 5, June 19 (2 letters), September 4, and October 2, 1987 which were submitted in accordance with license condition 2.C(3).

By letter dated May 21, 1987, the licensee modified the Process and Effluent Radiation Monitoring System Test (FSAR Section 14.2.8.2.28) to specifically address those monitors that either perform safety-related functions or provide safety-related diagnostic indications. Because the substance of this test has not changed, the staff finds this modification acceptable.

The remainder of the changes described in the May 21, 1987, letter, as well as the changes discussed in the June 5 letter and both June 19 letters, are minor in nature and acceptable to the staff.

The changes to the Initial Test Program discussed in the September 4 and October 2 submittals are each addressed below.

(1) FSAR Section 14.2.8.2.25, "Automatic Steam Generator Level Control Test"

By letter dated October 2, 1987, the licensee has stated that further testing of the automatic steam generator level control system, in addition to that demonstrated during various transients conducted at 30% and 75% power, is not planned. However, the staff requires that the automatic steam generator level control test be conducted during the load swing test at 100% power (see Item 2 below) in accordance with RG 1.68, Appendix A.5.s.

(2) FSAR Section 14.2.8.2.27, "Load Swing Test"

RG 1.68, Appendix A.5.h.h provides an acceptable approach for each facility to demonstrate that "the dynamic response of the plant to the design load swings for the facility...is in accordance with design." In FSAR Sections 14.2.8.2.27, Load Swing Test, and 14.2.1, the licensee adequately described and committed to perform such tests before commercial operation. By letter dated October 2, 1987, the licensee has deleted the load swing from 100% power test. The staff finds no basis for deleting this test. This test provides an acceptable approach for demonstrating the acceptable plant response in accordance with RG 1.68, Appendix A.5.h.h and further was used as a basis by the staff to allow the licensee exemption from demonstrating acceptable plant response to the most severe credible feedwater temperature reduction in accordance with RG 1.68, Appendix A.5.k.k (FSAR Section 1.9.68.2). It is the staff's position that the

*This evaluation was previously provided to Georgia Power Company by letter dated October 8, 1987.

licensee conduct a -10% load swing from 100% power test and a subsequent +10% load swing test from 90% power as soon as practicable but not later than October 31, 1987, in accordance with FSAR Sections 1.9.68.2 and 14.2.8.2.27 and RG 1.68, Appendix A.5.h.h and A.5.k.k.

(3) FSAR Section 14.2.8.2.52, "Large Load Reduction Test"

FSAR Section 14.2.12.2.18, "Large Load Reduction Test," describes 50% load reductions from various power levels. By letter dated October 2, 1987, the licensee deleted the 50% load reduction from 100% power test. The 50% load reduction test from full power is not a specifically required test, and therefore, the staff finds this acceptable.

(4) FSAR Section 14.2.8.2.54, "Steam Generator Moisture Carryover Test"

By letter dated September 4, 1987, the licensee stated that the referenced test cannot be completed without placing the secondary plant polishing system out of service for 12 hours, which the secondary plant chemistry is unable to support at this time. The steam generator moisture carryover test is not a specifically required test and, therefore, does not have to be conducted during the initial test program. The staff finds modification of this test acceptable.

(5) FSAR Section 14.2.8.2.48, "Thermal Expansion Test"

By letter dated October 2, 1987, the licensee deferred the verification that during cooldown, plant components return to their approximate baseline cold position until entering cold shutdown on October 12, 1987, as part of the planned maintenance outage. Although this test could have been performed during conduct of the Remote Shutdown Preoperational Test (FSAR Section 14.2.8.1.105) performed during the initial plant test program, deferral of this portion of the test does not impact the health and safety of the public. The staff finds this change acceptable.

(6) FSAR Section 14.2.8.2.43, "Dynamic Response Test"

By letter dated September 4, 1987, the licensee deferred the verification of main steam system piping dynamic response to the rapid closure of the turbine stop valves from 100% power. In its October 2, 1987, letter, the licensee indicated that it plans to conduct this verification during a plant trip from full power on October 9, 1987, to be conducted in conjunction with the planned maintenance outage. Although this test could have been performed during conduct of the Plant Trip From 100% Power Test (FSAR Section 14.2.8.2.53) performed during the initial plant test program, deferral of this test does not impact the health and safety of the public. The staff finds this change acceptable.

(7) FSAR Section 14.2.8.2.50, "Power Ascension Test Sequence"

By letters dated September 4 and October 2, 1987, the licensee deferred completion of the power ascension test sequence documentation pending completion of the power ascension testing. This is acceptable to the staff contingent upon resolution of the items in this evaluation.

(8) FSAR Section 14.2.8.2.55, "Plant Performance Test"

By letter dated October 2, 1987, the licensee stated that adjustments will continue to be made to plant systems to improve plant efficiency but that no further testing as part of the power ascension test program is planned. Continued conduct of this test does not impact the health and safety of the public, and the staff finds this change acceptable.

By letter dated October 8, 1987, the staff directed the licensee to conduct the tests identified in Items 1, 2, 5, and 6 as soon as practicable but not later than October 31, 1987.

By letter dated October 27, 1987, the licensee informed the staff that a failed reactor coolant pump motor would prevent the unit from starting up after the planned maintenance outage until about October 30, 1987, rather than the original schedule of October 22, 1987. Because of the delay, the licensee indicated that it would not be able to complete the remaining startup tests (load swing test at 100% power and automatic steam generator level control test) by October 31, 1987, as directed in the staff's letter of October 8, 1987. The licensee committed to complete the tests within 3 to 5 days of reaching 100% power after the outage. The staff concludes this schedule is acceptable. Subsequently, the resident inspectors indicated that the licensee initiated the test on November 9, 1987, and completed it early on November 10, 1987.

15 ACCIDENT ANALYSES

15.8 Anticipated Transients Without Scram

Generic Letter 83-28 was issued by the staff on July 8, 1983. It describes intermediate-term actions to be taken by licensees and applicants to address the generic issue raised by the two anticipated transients without scram that occurred at Unit 1 of Salem Nuclear Power Plant.

Generic Letter 83-28, Item 2.1*

Item 2.1 requires the licensee to confirm that all reactor trip system (RTS) components are identified, classified, and treated as safety related and that an effective vendor interface program is established for these components as indicated in the following statement:

> Licensees and applicants shall confirm that all components whose functioning is required to trip the reactor are identified as safety-related on documents, procedures, and information handling systems used in the plant to control safety-related activities, including maintenance, work orders, and parts replacement. In addition, for these components, licensees and applicants shall establish, implement and maintain a continuing program to ensure that the vendor information is complete, current and controlled throughout the life of the plant, and appropriately referenced or incorporated in plant instructions and procedures.

The applicant (now licensee) responded to the requirements of Item 2.1 by letters dated November 8, 1983, and May 20, 1985. The May 20 submittal was in response to the staff's request for additional information dated March 18, 1985.

In the initial submittal, the applicant committed to meeting the staff position regarding equipment classification and the vendor interface program. In the latter submittal, the applicant stated that the RTS components are indicated as safety related in the Vogtle FSAR and had been identified as safety related on the applicable electrical diagrams and in the equipment index, that maintenance activities and work orders involving safety-related components were designated as such on associated documents, and that procedural controls were established to ensure that maintenance and procurement activities associated with safety-related components would be treated as safety-related activities.

For the vendor interface program, the applicant stated that a Vogtle operating experience program had established controls to ensure that Westinghouse (nuclear steam supply system (NSSS)) technical bulletins used to communicate technical

---

*This evaluation was previously provided to Georgia Power Company by letter dated July 29, 1987.

information and recommendations are reviewed and controlled for the life of the plant, and that these controls contain provisions to ensure positive feedback to Westinghouse.

On the basis of its review of these responses, the staff finds that the licensee's statements confirm that a program exists for identifying, classifying, and treating components that are required for performance of the reactor trip function as safety related. Further, a program exists to ensure that Westinghouse (NSSS) technical bulletins are reviewed and controlled for the life of the plant, and that these controls contain provisions to ensure positive feedback to Westinghouse. This program meets the requirements of Item 2.1 of Generic Letter 83-28, and is therefore acceptable. Thus, Item 2.1 is resolved for both Units 1 and 2.

Generic Letter 83-23, Items 3.1.1, 3.1.2, 3.2.1, 3.2.2, and 4.5.1

By letters dated November 8, 1983 and August 26, 1986, the applicant provided information regarding compliance with Items 3.1.1, 3.1.2, 3.2.1, 3.2.2, and 4.5.1 of Generic Letter 83-28. The staff evaluated the licensee's responses against the NRC positions described in the generic letter for completeness and adequacy. The staff found the applicant's responses incomplete and required additional information to determine acceptability. These deficiencies were transmitted to the applicant by letter dated December 31, 1986, and in SSER 5.

The licensee's supplemental responses to Items 3.1.1, 3.1.2, 3.2.1, 3.2.2, and 4.5.1, submitted by letters dated January 15 and June 9, 1987, were reviewed and found acceptable.

Delineated below are the results of the staff's evaluations and a brief summary of the licensee's supplemental responses:*

- Item 3.1.1

Item 3.1.1 requires licensees and applicants to submit the results of their review of test procedures, maintenance procedures, and Technical Specifications to ensure that postmaintenance operability testing of safety-related components in the reactor trip system is required to be conducted and that the testing demonstrates that the equipment is capable of performing its safety functions before being returned to service.

The licensee (then applicant) stated in its final response dated January 15, 1987, that procedures had been established which require postmaintenance testing of the reactor trip switchgear. The response also stated that test procedures had been developed to utilize the solid-state protection system panel or the main control board trip handswitch to demonstrate operability of the reactor trip switchgear. During its review, the staff did not interpret the licensee's trip switchgear statement to encompass all safety-related components in the reactor trip system. The licensee's use of "reactor trip switchgear" instead of reactor trip system components was discussed during a telephone conversation

*These evaluations were previously provided to Georgia Power Company by letter dated July 7, 1987.

between the licensee and the staff on June 1, 1987. The licensee's representative stated that the term "reactor trip switchgear" meant all safety-related components in the reactor trip system. This was confirmed by letter dated June 9, 1987. On this basis, the licensee's response is acceptable.

- Item 3.1.2

Item 3.1.2 requires licensees and applicants to submit the results of their check of vendor and engineering recommendations to ensure that any appropriate test guidance is included in the test and maintenance procedures or the Technical Specifications, where required.

The licensee's (then applicant) supplemental response to Item 3.1.2, dated January 15, 1987, stated that procedures are written referencing vendor manuals, if applicable, and when procedures are reviewed, the review criteria requires that the procedure be reviewed against applicable vendor manuals. The licensee also indicated that engineering and vendor recommendations were checked to ensure that appropriate test guidance has been included in the test and maintenance procedures or the Technical Specifications. The licensee's response to Item 3.1.2 is acceptable.

- Item 3.2.1

Item 3.2.1 requires licensees and applicants to submit a report documenting the extending of test and maintenance procedures and Technical Specifications review to ensure that postmaintenance operability testing of all safety-related equipment is required to be conducted and that the testing demonstrates that the equipment is capable of performing its safety functions before being returned to service.

The licensee's (then applicant) supplemental response to Item 3.2.1, dated January 15, 1987, stated that maintenance of safety-related systems/components is controlled and processed via Maintenance Work Order procedures. These procedures provide controls that require postmaintenance testing of safety-related systems/components to prove their operability. The licensee also stated that it has completed a review of test and maintenance procedures and appropriate Technical Specifications to ensure that the testing demonstrates that the equipment is capable of performing its safety function. The licensee's response to Item 3.2.1 is acceptable.

- Item 3.2.2

Item 3.2.2 requires licensees and applicants to submit the results of their check of vendor and engineering recommendations to ensure that any appropriate test guidance is included in the test and maintenance procedures or the Technical Specifications, where required.

The licensee's response to Item 3.2.2, dated January 15, 1987, states that procedures are written referencing vendor manuals and when procedures are reviewed they are checked against the applicable manual. The licensee indicated that vendor manuals are controlled by Administrative Procedure 00108-C and that vendor and engineering recommendations are reviewed and are included in the test and maintenance procedures or the Technical Specifications. The licensee's response to Item 3.2.1 is acceptable.

° <u>Item 4.5.1</u>

Item 4.5.1 requires that online functional testing of the reactor trip system including independent testing of the diverse trip features be performed. The breaker undervoltage and shunt trip features in Westinghouse plants should be included.

The licensee's (then applicant) supplemental response to Item 4.5.1, dated January 15, 1987, states that a surveillance procedure has been developed which verifies the capability of the undervoltage and shunt trip features to independently trip the reactor trip breakers. The surveillance test is performed each month, and each train is tested at least once every 62 days on a staggered test basis. The response stated that a Westinghouse automatic shunt trip panel had been added to the reactor trip switchgear cabinets and provides the capability to independently test the undervoltage and shunt trip devices. The licensee's response to Item 4.5.1 is acceptable.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW
OF VOGTLE UNITS 1 AND 2 OPERATING LICENSE REVIEW

February 26, 1987	Letter from Georgia Power Company (GPC) concerning deferral of Technical Specification requirements - extended range neutron flux monitors.
March 2, 1987	Letter from GPC responding to miscellaneous electrical and instrumentation concerns.
March 4, 1987	Letter from GPC responding to request for additional information relative to IE Bulletin 85-03.
March 6, 1987	Letter from GPC concerning Unit 2 piping penetration area filtration and exhaust system.
March 10, 1987	Letter from GPC forwarding supplement to response to miscellaneous electrical and instrumentation issues.
March 13, 1987	Letter from GPC forwarding revision to Emergency Plan implementing procedures.
March 16, 1987	Letter from GPC concerning slave relay testing.
March 16, 1987	Letter to GPC forwarding Facility Operating License NPF-68 authorizing full-power operation.
March 17, 1987	Letter from GPC forwarding outstanding submittals list.
March 18, 1987	Letter from GPC concerning confirmatory measurements program.
March 18, 1987	Letter from GPC designating points of contact for implementation of 10 CFR 73.57.
March 20, 1987	Letter from GPC notifying staff that Unit 2 fuel load date has been changed to February 1989.
March 24, 1987	Letter to GPC forwarding Supplement 6 to SER.
March 27, 1987	Letter from GPC concerning Nuclear Training and Qualification Plan.
March 27, 1987	Letter from GPC concerning rod withdrawal limits.

March 27, 1987	Letter from GPC forwarding Amendment 7 to Physical Security and Contingency Plan.
March 27, 1987	Letter from GPC concerning Security Plan revisions.
March 30, 1987	Letter from GPC concerning Physical Security Plan.
April 2, 1987	Letter from GPC concerning changes in Initial Startup Test Program.
April 6, 1987	Letter from GPC concerning security program enhancements.
April 7, 1987	Letter to GPC requesting additional information on spent fuel pool rack seismic design (open item 16, "Spent fuel pool rack design").
April 10, 1987	Letter from GPC concerning control room preliminary environmental survey (license condition 2.C(7)c).
April 14, 1987	Letter from GPC forwarding 1987 annual financial reports.
April 17, 1987	Meeting with GPC to discuss potential proposal to apply leak-before-break technology to branch lines in Unit 2 and to remove certain Unit 2 steam generator snubbers. (Summary issued April 22, 1987.)
April 27, 1987	Letter to GPC notifying it of NRC reorganization.
April 27, 1987	Letter from GPC forwarding outstanding submittals list.
April 28, 1987	Meeting with GPC at site to discuss the Unit 1 startup history. (Summary issued May 4, 1987.)
April 28, 1987	Letter from GPC forwarding Revision 3 of the Offsite Dose Calculation Manual.
April 29, 1987	Letter from GPC concerning Unit 2 auxiliary line pipe break elimination program.
May 4, 1987	Letter to GPC concerning control room preliminary environmental survey (license condition 2.C(7)c).
May 5, 1987	Letter from GPC forwarding revision to Emergency Plan implementing procedures.
May 6, 1987	Letter from GPC forwarding FSAR Amendment 33.
May 11, 1987	Generic Letter 87-08, "Implementation of 10 CFR 73.55 Miscellaneous Amendments and Search Requirements."
May 14, 1987	Letter from GPC forwarding outstanding submittals list.
May 21, 1987	Letter from GPC concerning changes in Initial Startup Test Program.

May 22, 1987	Letter to GPC concerning Unit 2 steam generator snubber reduction and auxiliary line break elimination program.
May 22, 1987	Letter from GPC concerning SER open item 16, "Spent fuel pool rack design."
May 22, 1987	Letter from GPC concerning settlement monitoring program.
May 22, 1987	Meeting with GPC to discuss outstanding licensing actions. (Summary issued June 5, 1987.)
May 27, 1987	Letter from GPC concerning support of cables in vertical cable trays (open item 22, "Seismic adequacy of plastic tie wraps").
May 28, 1987	Letter from GPC concerning support of cable in vertical raceways (open item 22, "Seismic adequacy of plastic tie wraps").
May 29, 1987	Letter from GPC responding to license condition 2.C(7)a regarding reactor vessel level instrumentation system for Unit 1.
June 1, 1987	Letter from GPC concerning plant safety monitoring system verification and validation.
June 1, 1987	Letter from GPC concerning pipe break criteria for flooding analyses for Unit 2.
June 1, 1987	Letter from GPC concerning Unit 2 electrical penetration filter and exhaust system.
June 2, 1987	Letter from GPC forwarding revision to Emergency Plan implementing procedures.
June 3, 1987	Letter from GPC concerning Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves."
June 4, 1987	Meeting with GPC to discuss the Unit 2 analysis of the steam generator snubber reduction and the leak-before-break methodology on the surge line. (Summary issued June 25, 1987.)
June 4, 1987	Generic Letter 87-09, "Sections 3.0 and 4.0 of the Standard Technical Specifications (STS) on the applicability of limiting conditions for operation and surveillance requirements."
June 4, 1987	Letter to GPC requesting additional information regarding offsite medical services.
June 5, 1987	Letter from GPC concerning changes in Initial Startup Test Program.
June 8, 1987	Letter from GPC forwarding Security Plan revision.

June 9, 1987	Letter from GPC concerning SER open item 5, "Generic Letter 83-28."
June 9, 1987	Letter from GPC concerning 1987 emergency preparedness exercise.
June 9, 1987	Letter from GPC concerning leak rate test final report.
June 10, 1987	Letter from GPC concerning 1987 emergency preparedness exercise.
June 12, 1987	Generic Letter 87-10, "Implementation of 10 CFR 73.57, Requirements for FBI Criminal History Checks."
June 16, 1987	Letter to GPC concerning Unit 1 operating history.
June 17, 1987	Letter from GPC forwarding outstanding submittals list.
June 17, 1987	Letter from license forwarding Security Plan amendment.
June 19, 1987	Generic Letter 87-11, "Relaxation in Arbitrary Intermediate Pipe Rupture Requirements."
June 19, 1987	Letter from GPC concerning changes in Initial Startup Test Program, regarding flux map test.
June 19, 1987	Letter from GPC concerning changes in Initial Startup Test Program, regarding at-power intercomparison of reactor protection system inputs and plant computer outputs test.
June 23, 1987	Letter to GPC forwarding Amendment 1 to NPF-68. Amendment modifies Technical Specifications to increase the shutdown margin requirements shown in Figure 3.1-2 and changes the title of that figure.
June 24, 1987	Letter from GPC concerning offsite medical services for Unit 2.
June 25, 1987	Letter from GPC forwarding revision to Inservice Testing Program.
June 25, 1987	Letter from GPC concerning preservice inspection summary report.
June 26, 1987	Letter from GPC concerning Unit 2 auxiliary line pipe break elimination programs.
June 29-July 1, 1987	Meeting with GPC to audit the Plant Safety Monitoring System Verification and Validation Program. (Summary issued July 20, 1987.)
July 1, 1987	Letter from GPC concerning Unit 2 steam generator upper support design.

July 7, 1987	Letter from GPC concerning Unit 2 fire suppression system changes.
July 7, 1987	Letter to GPC concerning resolution of Generic Letter 83-28, Items 3.1.1, 3.1.2, 3.2.1, 3.2.2, and 4.5.1.
July 8, 1987	Letter from GPC concerning Unit 2 auxiliary line pipe break elimination programs.
July 9, 1987	Generic Letter 87-12, "Loss of Residual Heat Removal (RHR), While the Reactor Coolant System (RCS) Is Partially Filled."
July 10, 1987	Letter from GPC concerning temporary Technical Specification relief.
July 13, 1987	Letter from GPC concerning diesel fuel oil storage tanks coating (License Condition 2.C(8)).
July 13, 1987	Letter to GPC concerning report to the Commission on Unit 1 Readiness Review Pilot Program.
July 14, 1987	Letter to GPC concerning staff review of Offsite Dose Calculation Manual, Revision 3.
July 15, 1987	Letter from GPC concerning radiological consequences of Unit 2 electrical penetration filter and exhaust system deletion.
July 15, 1987	Letter from GPC concerning program to eliminate pipe breaks in auxiliary lines at Unit 2.
July 20, 1987	Letter from GPC concerning SER open item 16, "Spent fuel pool rack design."
July 20, 1987	Letter from GPC concerning reactor vessel level instrumentation system (license condition 2.C(7)a).
July 22, 1987	Letter from GPC forwarding "Special Report on the Unit 1 Initial Operating History."
July 23, 1987	Letter from GPC concerning radiological consequences of Unit 2 electrical penetration filter and exhaust system deletion.
July 24, 1987	Letter from GPC forwarding outstanding submittals list.
July 24, 1987	Letter to GPC forwarding emergency Amendment 2 to NPF-68. Amendment modifies the Technical Specifications to delete references to phase "A" containment isolation on a containment area high-range radiation signal from Specification 3/4.3.2 and also to correct references which are no longer applicable because of that deletion.
July 27, 1987	Letter from GPC concerning Unit 2 pipe break criteria for flooding analyses.

July 28, 1987	Letter from GPC concerning reorganization.
July 29, 1987	Letter to GPC concerning staff acceptance of response to Generic Letter 83-28, Item 2.1.
July 30, 1987	Letter from GPC concerning anticipated transients without scram modifications.
July 30, 1987	Letter to GPC concerning staff acceptance of stainless steel ties for the use in vertical cable trays (open item 22, "Seismic adequacy of plastic tie wraps").
August 3, 1987	Letter from GPC concerning settlement monitoring program.
August 4, 1987	Generic Letter 87-14, "Operator Licensing Examinations."
August 6, 1987	Letter to GPC requesting additional information on elimination of dynamic effects of postulated pressurizer surge line pipe ruptures from design basis for Unit 2.
August 6, 1987	Letter from GPC concerning Unit 2 steam generator upper support design.
August 6, 1987	Letter to GPC concerning request for withholding information from public disclosure.
August 10, 1987	Letter from GPC concerning outstanding submittals list.
August 12, 1987	Letter to GPC concerning conformance to Unit 1 license condition 2.C(7)a, "Compliance with NUREG-0737, Item II.F.2."
August 14, 1987	Letter to GPC requesting additional information on the Inservice Inspection Program for Unit 1.
August 14, 1987	Letter to GPC concerning acceptance of revised pipe break criteria for flooding analyses for Unit 2.
August 17, 1987	Five letters to GPC concerning request for withholding information from public disclosure.
August 19, 1987	Letter to GPC concerning staff acceptance of Unit 2 electrical penetration filter and exhaust system deletion.
August 20, 1987	Letter to GPC requesting additional information on settlement monitoring program.
August 21, 1987	Letter from GPC concerning Offsite Dose Calculation Manual.
August 25, 1987	Letter to GPC requesting status of implementation of approved regulatory initiatives.
August 25, 1987	Letter to GPC concerning staff acceptance of verification and validation of plant safety monitoring system.

August 27, 1987	Letter from GPC modifying Revision 2 to Unit 1 Inservice Testing Program.
August 31, 1987	Letter from GPC forwarding summary report of Initial Startup Test Program.
August 31, 1987	Letter from GPC forwarding Amendment 34 to FSAR.
September 1, 1987	Letter from GPC concerning plant safety monitoring system verification and validation.
September 4, 1987	Letter from GPC concerning digital metal impact monitoring system.
September 4, 1987	Letter from GPC concerning status of Initial Startup Test Program.
September 8, 1987	Letter from GPC responding to NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants."
September 9, 1987	Letter to GPC requesting additional information on dynamic effects of postulated pressurizer surge line pipe ruptures from design basis for Unit 2.
September 14, 1987	Letter from GPC forwarding outstanding submittals list.
September 15, 1987	ASLAB issues Decision affirming LBP-86-28 and LBP-86-41.
September 15, 1987	Meeting with GPC at GPC's offices to discuss status of Vogtle and Hatch licensing actions. (Summary issued September 25, 1987.)
September 17, 1987	Letter to GPC concerning staff acceptance of PSMS V&V Program for Unit 2.
September 17, 1987	Letter from GPC forwarding correction to Offsite Dose Calculation Manual.
September 17, 1987	Letter from GPC concerning program to eliminate pipe breaks in auxiliary lines at Unit 2.
September 18, 1987	Letter from GPC responding to Generic Letter 87-12, "Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) Is Partially Filled."
September 22, 1987	Letter from GPC concerning program to monitor settlement.
September 22, 1987	Letter to GPC concerning staff acceptance of the Inservice Testing Program, Revision 2, for Unit 1.
September 22, 1987	Letter to GPC concerning staff acceptance of Units 1 and 2 Offsite Dose Calculation Manual, Revision 4.
September 23, 1987	Letter to GPC concerning Special Report on the Initial Operating History of Unit 1.

September 23, 1987	Letter to GPC granting request for withholding information from public disclosure.
September 23, 1987	Letter to GPC concerning request for withholding information from public disclosure.
September 25, 1987	Letter from GPC concerning Corporate Emergency Plan Implementing Instruction Revision.
September 28, 1987	Letter from GPC forwarding revision to Emergency Plan Implementing Procedures.
September 30, 1987	Letter from GPC responding to request for implementation status.
September 30, 1987	Letter from GPC concerning diesel fuel oil storage tank coating (license condition 2.C(8)).
October 2, 1987	Letter from GPC concerning status of Initial Startup Test Program.
October 6, 1987	Letter from GPC concerning cable separation within panel
October 7, 1987	Letter to GPC concerning staff acceptance of Unit 2 steam generator snubber reduction.
October 8, 1987	Letter to GPC concerning Unit 1 Initial Startup Test Program.
October 13, 1987	Letter from GPC concerning management change.
October 15, 1987	Letter from GPC concerning diesel fuel oil storage tank coating (license condition 2.C(8)).
October 15, 1987	Letter to GPC concerning staff acceptance of technical justification regarding the adequacy of diesel fuel oil storage tank zinc coating (license condition 2.C(8)).
October 15, 1987	Letter from GPC concerning confirmatory item 27, "Bypass and inoperable status panel."
October 16, 1987	Letter from GPC concerning Unit 2 auxiliary line pipe break elimination program and forwarding WCAP-11583 and WCAP-11584.
October 16, 1987	Letter from GPC concerning Unit 2 auxiliary line pipe break elimination program and forwarding WCAP-11599 and WCAP-11600.
October 20, 1987	Letter to GPC concerning staff review of proposed modifications to settlement monitoring program.
October 21, 1987	Letter from GPC providing additional information on the Inservice Inspection Program.

October 26, 1987	Letter to GPC concerning staff acceptance of Unit 2 fire suppression system changes.
October 27, 1987	Letter from GPC concerning reclassification of reference letter GN-1205, dated December 4, 1986.
October 27, 1987	Letter from GPC forwarding affidavit for reference letter GN-429, dated October 12, 1984.
October 27, 1987	Letter from GPC concerning status of Initial Startup Test Program.
October 27, 1987	Letter from GPC concerning ECCS surveillance testing - valve manipulations.
October 27, 1987	Letter from GPC forwarding emergency plan procedure revision.
October 29, 1987	Letter from GPC concerning steam line break outside containment.
November 2, 1987	Letter from GPC concerning Unit 1 Inservice Inspection Program.
November 4, 1987	Letter from GPC concerning Preservice Inspection Program, Revision 2.
November 5, 1987	Letter to GPC concerning residual heat removal system surveillance testing.
November 6, 1987	Letter to GPC requesting additional information on Generic Letter 83-28, Item 2 2.2.
November 10, 1987	Letter from GPC concerning Unit 2 Readiness Review Program.
November 10, 1987	Letter from GPC forwarding Security Plan revisions.
November 11, 1987	Letter from GPC concerning battery room spray.
November 17, 1987	Letter to GPC granting request for withholding information from public disclosure.
November 18, 1987	Letter from GPC concerning anticipated transients without scram modifications.
November 18, 1987	Letter from GPC forwarding outstanding submittals list.
November 19, 1987	Letter from GPC forwarding Security Plan revision.
November 20, 1987	Letter to GPC forwarding Amendment 3 to NPF-68. Amendment modified the Technical Specifications to revise the action requirements for inoperable fuel handling building post-accident ventilation system actuation instrumentation.

November 23, 1987	Letter from GPC concerning communication system.
November 24, 1987	Letter from GPC responding to request for information on miscellaneous amendments/search requirements.
November 30, 1987	Letter from GPC forwarding Supplement 1 to Summary Report of Startup Test Program.
December 4, 1987	Letter from GPC concerning ECCS surveillance testing - proposed FSAR revisions.
December 7, 1987	Letter from GPC concerning correspondence service list.
December 21, 1987	Letter from GPC concerning removal of control room temporary gypsum board fire wall.
December 21, 1987	Letter from GPC concerning clarification of FSAR Section 9.5.3 - Emergency Lighting.
December 21, 1987	Letter from GPC concerning derated embed plates.
December 22, 1987	Letter from GPC forwarding revisions to Emergency Plan Procedure.
December 23, 1987	Letter from GPC concerning spent fuel racks.
December 28, 1987	Letter from GPC forwarding outstanding submittals list.

APPENDIX B

REFERENCES

ASME, 1975	American Society of Mechanical Engineers, Paper No. 75-WA/CD-7, R. D. Giammar et al., "The Effect of Additives in Reducing Particulate Emissions From Residual Oil Combustion," for meeting Nov. 30 - Dec. 4, 1975, pp. 75-86.
Generic Letter 83-28	U.S. Nuclear Regulatory Commission, "Required Actions Based on Generic Implications of Salem ATWS Events," Generic Letter 83-28, July 8, 1983.
Generic Letter 85-12	U.S. Nuclear Regulatory Commission, "Implementation of TMI Action Item II.K.3.5, 'Automatic Trip of Reactor Coolant Pumps'," Generic Letter 85-12, June 28, 1985.
IBM, 1974	IBM, "Design and Code Inspections and Process Control in the Development of Programs," Technical Report 00.2763, June 10, 1974.
IE Bulletin 79-15	U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, "Deep Draft Pump Deficiencies," Bulletin 79-15, July 11, 1979.
IE Bulletin 80-06	U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, "Engineered Safety Feature (ESF) Reset Controls," Bulletin 80-06, March 13, 1980.
IE Circular 77-15	U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, "Degradation of Fuel Oil Flow to the Emergency Diesel Generator," Circular 77-15, November 23, 1977.
Ivanov, 1973	K. I. Ivanov et al., "Effect of metal-containing additives on the concentration of sulfur trioxide in products of the combustion of liquid sulfur-containing fuels," <u>Teploenergetika</u>, 1973, pp. 85-87.
Kirk-Othmer, 1978	R. E. Kirk and D. F. Othmer, <u>Kirk-Othmer Encyclopedia of Chemical Technology</u>, Third Edition, Vol. 15, pp. 749-752; Vol. 8, pp. 44-48, John Wiley and Sons, New York, 1978.
NRC, 1979	U.S. Nuclear Regulatory Commission, "Operating Technology Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," Position paper (April 14, 1978), modified on January 18, 1979.

NUREG-0737	U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements, NUREG-0737," November 1980.
NUREG-0781	U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the Operation of South Texas Project, Units 1 and 2," Supplement 4, July 1987.
NUREG-0800	U.S. Nuclear Regulatory Commission, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," LWR Edition, July 1981.
NUREG-1061	U.S. Nuclear Regulatory Commission, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," Vol. 3, November 1984.
NUREG/CR-3660	U.S. Nuclear Regulatory Commission, "Probability of Pipe Failure in Reactor Coolant Loops of Westinghouse PWR Plants," Vol. 3, "Guillotine Break Indirectly Induced by Earthquakes," February 1985.
NUREG/CR-4263	U.S. Nuclear Regulatory Commission, "Reliability Analysis of Stiff Versus Flexible Piping, Final Project Report," May 1985.
NUREG/CR-4572	U.S. Nuclear Regulatory Commission, "NRC Leak-Before-Break (LBB.NRC) Analysis Method for Circumferentially Through-Wall Cracked Pipes Under Axial Plus Bending Loads," May 1986.
Ogawa, 1974	H. Ogawa, "Mineral oil, especially heavy oil, additive--containing heavy metal naphthenates catalytically accelerating combustion," Japanese Patent 74042886, November 18, 1974.
Rabinowicz, 1976	E. Rabinowicz, "Friction Coefficients of Water-Lubricated Stainless Steels for a Spent Fuel Rack Facility," November 5, 1976 (available in NRC Public Document Room).
WCAP-8252	Westinghouse Electric Corp., "Documentation of Selected Westinghouse Structural Analysis Computer Codes," Revision 1, May 1977.
WCAP-9401-P-A	Westinghouse Electric Corp., "Verification Testing and Analyses of the 17x17 Optimized Fuel Assembly," August 1981.
WCAP-10529	Westinghouse Electric Corp., "COMS, Cold Overpressure Mitigating Systems," February 1984.
WCAP-10551	Westinghouse Electric Corp., "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Alvin W. Vogtle Units 1 and 2," May 1984. (See WCAP-10552 for a nonproprietary version of this report.)

WCAP-10552 Westinghouse Electric Corp., "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Alvin W. Vogtle Units 1 and 2," May 1984.

WCAP-11531 Westinghouse Electric Corp., "Technical Bases for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Vogtle Unit 2," July 1987.

WCAP-11583 Westinghouse Electric Corp., "Technical Bases for Eliminating Accumulator Line Rupture as the Structural Design Basis for Vogtle Unit 2," October 1987 (proprietary).

WCAP-11584 Westinghouse Electric Corp., "Technical Bases for Eliminating Accumulator Line Rupture as the Structural Design Basis for Vogtle Unit 2," October 1987 (nonproprietary).

WCAP-11599 Westinghouse Electric Corp., "Technical Bases for Eliminating RHR Line Rupture From the Structural Design Basis for Vogtle Unit 2," October 1987 (proprietary).

WCAP-11600 Westinghouse Electric Corp., "Technical Bases for Eliminating RHR Line Rupture From the Structural Design Basis for Vogtle Unit 2," October 1987 (nonproprietary).

Wambach, 1987 U.S. Nuclear Regulatory Commission, Letter from T. V. Wambach to K. W. Berry (Consumers Power Co.), Subject: Amendment to Provisional Operating License No. DPR-20 (TAC No. 60844), July 24, 1987.

Zech, 1985 U.S. Nuclear Regulatory Commission, Letter from G. Zech to J. Gallagher (Westinghouse), January 7, 1985.

APPENDIX D

ACRONYMS AND INITIALISMS

AECC	Aerojet Energy Conversion Company
AFW	auxiliary feedwater
AISI	American Iron and Steel Institute
ANCO	ANCO Engineers, Inc.
ANSI	American National Standards Institute
ASLAB	Atomic Safety and Licensing Appeal Board
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BTP	branch technical position
CFR	Code of Federal Regulations
CMTR	certified material test report
DEGB	double-ended guillotine break
DNB	departure from nucleate boiling
ECCS	emergency core cooling system
EPFE	electrical penetration filter and exhaust
ESF	engineered safety feature
FSAR	Final Safety Analysis Report
GDC	general design criterion(a)
GPC	Georgia Power Company
GTAW	gas tungsten arc weld
HEPA	high efficiency particulate air
HVAC	heating, ventilation, and air conditioning
IE	Office of Inspection and Enforcement
IGSCC	intergranular stress corrosion cracking
IN	Information Notice
IST	inservice testing
LBB	leak before break
LOCA	loss-of-coolant accident
MSLB	main steam line break
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NSCW	nuclear service cooling water
NSSS	nuclear steam supply system
NTOL	near-term operating license

OBE	operating basis earthquake
P&ID	piping and instrumentation diagram
PORV	power-operated relief valve
PROM	programmable read only memory
PSMS	plant safety monitoring system
PWR	pressurized water reactor
QDPS	qualified display processing system
RCL	reactor coolant loop
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RTS	reactor trip system
RVHVS	reactor vessel head vent system
RVLIS	reactor vessel level instrumentation system
RWST	refueling water storage tank
SAW	submerged arc weld
SER	Safety Evaluation Report
SGTR	steam generator tube rupture
SMAW	shielded metal arc weld
SPDS	safety parameter display system
SRP	Standard Review Plan
SRSS	square-root-sum-of-squares
SSE	safe shutdown earthquake
SSER	Supplement to Safety Evaluation Report
STS	Standard Technical Specifications
TDI	Transamerica Delaval, Inc.
TER	Technical Evaluation Report
TMI-2	Three Mile Island, Unit 2
TS	technical specification
TSC	Technical Support Center
VRS	volume reduction system
V&V	verification and validation
WECAN	Westinghouse Electric Computer Analysis

APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This supplement to the Vogtle Safety Evaluation Report is a product of the NRC staff and its consultants. The NRC staff members and consultants listed below were principal contributors to this report.

Name	Title	Unit
D. Notley	Fire Protection Engineer	Chemical Engineering Branch
N. Merriweather	Reactor Inspector	Engineering Branch, Division of Reactor Safety, Region II
F. Burrows	Electrical Engineer	Instrumentation and Control Systems Branch
D. Lasher	Electrical Engineer	Instrumentation and Control Systems Branch
R. Ramirez	Senior Human Factors Engineer	Human Factors Assessment Branch
S. Lee	Materials Engineer	Materials Engineering Branch
Y. Huang	Senior Mechanical Engineer	Mechanical Engineering Branch
H. Shaw	Mechanical Engineer	Mechanical Engineering Branch
J. Lee	Reactor Engineer (Nuclear)	Plant Systems Branch
W. LeFave	Senior Reactor Engineer (Nuclear)	Plant Systems Branch
S. Kirslis	Project Engineer	Project Directorate II-3
M. Miller	Project Manager	Project Directorate II-3
C. Willis	Senior Health Physicist (Reactor)	Radiation Protection Branch
T. Huang	Reactor Engineer (Nuclear)	Reactor Systems Branch

Name	Title	Unit
S. Sun	Nuclear Engineer	Reactor Systems Branch
L. Beltracchi	Senior Human Factors Engineeer	Reliability and Human Factors Branch, RES
J. Ma	Structural Engineer	Structural and Geotechnical Engineering Branch
R. Pichumani	Civil Engineer	Structural and Geotechnical Engineering Branch
N. Romney	Civil Engineer	Structural and Geotechnical Engineering Branch

Consultants

R. Gruel, Battelle Pacific Northwest Laboratories

F. Farmer, Idaho National Engineering Laboratory

H. Rockhold, Idaho National Engineering Laboratory

J. Frawley, SoHaR, Inc.

APPENDIX K

ERRATA TO THE SAFETY EVALUATION REPORT AND ITS SUPPLEMENTS

Page	Paragraph*	Line	Change
SER			
1-13	--	17	Change "12.3.4.2" to "12.5.2"
13-11	3	6	Change "appliant's" to "applicant's"
Supplement 5			
1-2	--	--	After Item (8) add "(9) discusses a schedular exemption regarding the spent fuel pool (see Section 9.1.2)" and renumber the items that follow accordingly
Supplement 6			
iii	1	2	Change "Georigia" to "Georgia"

*Full paragraph

APPENDIX W

LETTER REPORT,
TECHNICAL EVALUATION OF REVISION 2 CHANGES
FOR PUMP AND VALVE INSERVICE TESTING PROGRAM,
VOGTLE ELECTRIC GENERATING PLANT, UNIT 1

Pump Relief Request

The licensee has requested relief from the Section XI (1983 Edition through Summer 1983 Addenda), IWP-4510 requirement that the direction of vibration measurements be in the horizontal or vertical direction for component cooling water pumps P4-001, P4-002, P4-003, P4-004, P4-005, and P4-006; safety injection pumps P6-003 and P6-004; centrifugal charging pumps P6-002 and P6-003; and auxiliary feedwater pumps P4-001, P4-002, and P4-003, and has proposed that two permanently mounted vibration transducers on each pump installed 45 degrees from the vertical and 90 degrees from each other be utilized for vibration measurements.

Licensee's Basis for Requesting Relief. Each of these pumps has two permanently mounted vibration transducers (or pickups) installed 45 degrees from the vertical and 90 degrees from each other. Both transducers are used in the quarterly pump testing. Any increase in pump vibration in either the horizontal or vertical direction is detected by both transducers.

Evaluation. Utilizing two permanently mounted vibration transducers installed 45 degrees from the vertical and 90 degrees from each other to measure vibration for these pumps will give information equivalent to or better than the information obtained from the utilization of one measurement point in the horizontal or vertical direction as required by the Code. Based on the determination that it would be burdensome to the licensee if the Code requirement were imposed and that the licensee's proposed alternative testing will detect vibration changes in a manner equal to or better than the Code requirement, relief may be granted as requested.

(pages 2-4, 2-5, 2-8, 2-10, and 3-4 in the Vogtle IST Program Manual)

NOTE: The parenthesized page numbers are those of the Vogtle IST Program Manual that have been changed.

Additional Cold Shutdown Justifications for Valves

Charging pump alternate miniflow isolation valves HV-8508A and HV-8508B (category B) cannot be exercised during power operation since the valves are interlocked with the volume control tank discharge valves LV-0112B and LV-0112C and these valves cannot be exercised during power operation due to interruption of pressurizer level control and possible subsequent plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages (pages 4-27 and 6-38).

Boric acid transfer pump discharge check valves U4-284 and U4-299 (category C) cannot be full-stroke exercised during power operation as full flow would adversely affect RCS boron concentration which could result in plant shutdown. These valves will be partial-stroke exercised quarterly and full-stroke exercised during cold shutdowns and refueling outages (pages 4-29 and 6-34).

Residual heat removal (RHR) pump discharge check valves U6-009 and U6-010 (category C) cannot be exercised during power operation as the RHR pumps cannot overcome RCS operating pressure. These valves cannot be exercised with full flow to the refueling water storage tank as the required valve lineup would place the plant in an unanalyzed condition outside its established design basis. These valves will be partial-stroke exercised quarterly and full-stroke exercised during cold shutdowns and refueling outages (pages 4-23 and 6-37).

RHR pump suction from the refueling water storage tank (RWST) check valves U6-001 and U6-002 (category C) cannot be exercised during power operation as the required valve lineup would place the plant in an unanalyzed condition outside its established design basis (see IE Information Notice No. 87-01). These valves will be full-stroke exercised during cold shutdowns and refueling outages (pages 4-23 and 6-36).

RHR pump discharge cross-connect isolation valves HV-8716A and HV-8716B (category B) cannot be exercised during power operation as failure in the closed position would place the plant in an unanalyzed condition outside its established design basis (see IE Information Notice No. 87-01). These valves will be full-stroke exercised during cold shutdowns and refueling outages (pages 4-22 and 6-35).

Auxiliary feedwater system feedwater bypass check valves U4-125, U4-126, U4-127, and U4-128 (category C) cannot be exercised during power operation as flow verification can only be verified during injection of auxiliary feedwater into the steam generators during cold shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages (pages 4-44 and 6-33).

Other Program Revisions Not Addressed in TER

Concerning pump relief request 3, the boric acid pump suction pressure gages were identified in revision 1 to have a range of 0 to 15 psig. The actual range of these gages is -15 to 15 psig and the pump relief request was changed to reflect this. This change has no programmatic effect upon pump relief request 3 and this relief request will not have to be re-evaluated (page 3-3).

A note was added to pump relief request 2 to indicate that Supplement No. 6 of the Safety Evaluation Report requires that instruments to measure the Code required flow rate be installed before restart following the first refueling outage. This change has no programmatic effect upon pump relief request 2 and this relief request will not have to be re-evaluated (page 3-2).

The specific reference to the PORVs for valve relief request 3 has been deleted in order to make this relief request for rapid acting valves generic. This change has no programmatic effect upon valve relief request 3 and this relief request will not have to be re-evaluated (pages 4-7 and 5-3).

The closed safety position was deleted for RHR pump discharge check valves U6-009 and U6-010 as these valves are not required to close to perform a safety function. RHR pump miniflow valves FV-0610 and FV-0611 are normally open and allow flow to the suction side of the pumps regardless of the position of valves U6-009 and U6-010 (page 4-23).

The quarterly reverse flow closure testing of auxiliary feedwater to steam generator check valves U4-113, U4-114, U4-115, and U4-116 has been added (page 4-43).

The quarterly forward flow operability testing for chemical and volume control to regenerative heat exchanger check valve U6-032 has been added (pages 4-28 and 5-16).

The program was changed to indicate that safety-related chillers chilled water cooler pump check valves U4-186 and U4-187 are normally closed and that their safety position is open (page 4-54).

A P&ID revision which relocated valves HV-9378 and U4-049 to P&ID 1X4DB186-4 necessitated an editorial change (page 4-60).

The program was changed to indicate that sample valves HV-8208, HV-8209, HV-8211, and HV-8212 are normally closed instead of normally open. Sample valves HV-8211 and HV-8212 have been replaced with one inch valves (page 4-61).

Valve relief request 1 was withdrawn as per Supplement No. 6 of the Safety Evaluation Report. References to this relief request were deleted from the valve tables and valve relief request section where appropriate (pages 4-5, 4-6, 4-7, 4-11, 4-12, 4-13, 4-24, 4-26, 4-27, 4-28, 4-33, 4-34, 4-35, 4-36, 4-41, 4-45, 4-49, 4-50, 4-57, 4-60, and 5-1).

NRC FORM 335 (2-84) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

SEE INSTRUCTIONS ON THE REVERSE

1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any): NUREG-1137 Supplement No. 7

2. TITLE AND SUBTITLE: Safety Evaluation Report related to the Operation of Vogtle Electric Generating Plant, Units 1 and 2

3. LEAVE BLANK

4. DATE REPORT COMPLETED: MONTH January, YEAR 1988

5. AUTHOR(S)

6. DATE REPORT ISSUED: MONTH January, YEAR 1988

7. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code):
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

8. PROJECT/TASK/WORK UNIT NUMBER

9. FIN OR GRANT NUMBER

10. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code): Same as 7 above

11a. TYPE OF REPORT

b. PERIOD COVERED (Inclusive dates)

12. SUPPLEMENTARY NOTES: Pertains to Docket Nos. 50-424 and 50-425

13. ABSTRACT (200 words or less)

In June 1985, the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-1137) regarding the application of Georgia Power Company, Municipal Electric Authority of Georgia, Oglethorpe Power Corporation, and the City of Dalton, Georgia, for licenses to operate Vogtle Electric Generating Plant, Units 1 and 2 (Docket Nos. 50-424 and 50-425). Supplement 1 to NUREG-0737 was issued by the staff in October 1985, Supplement 2 was issued in May 1986, Supplement 3 was issued in August 1986, Supplement 4 was issued in December 1986, Supplement 5 was issued in January 1987, and Supplement 6 was issued in March 1987. The facility is located in Burke County, Georgia, approximately 26 miles south-southeast of Augusta, Georgia, and on the Savannah River.

This seventh supplement to NUREG-1137 provides recent information regarding resolution of some of the open and confirmatory items that remained unresolved following issuance of Supplement 6, and documents completion of several Unit 1 license conditions.

14. DOCUMENT ANALYSIS - a. KEYWORDS/DESCRIPTORS: Vogtle Electric Generating Plant, settlement monitoring, pipe stress, leak-before-break technology, steam generator snubber reduction, Inservice Testing Program, residual heat removal system, electrical penetration filter and exhaust system, slave relays, plant safety system, fire suppression system, potential leakage, and delay of initial startup tests

b. IDENTIFIERS/OPEN-ENDED TERMS

15. AVAILABILITY STATEMENT: Unlimited

16. SECURITY CLASSIFICATION: (This page) Unclassified; (This report) Unclassified

17. NUMBER OF PAGES

18. PRICE

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST CLASS MAIL
POSTAGE & FEES PAID
USNRC
PERMIT No. G-67

120555078877 1 1AN
US NRC-OARM-ADM
DIV OF PUB SVCS
POLICY & PUB MGT BR-PDR NUREG
W-537
WASHINGTON DC 20555

NUREG-1137, Supp. No. 7 SER RELATED TO THE OPERATION OF VOGTLE ELECTRIC GENERATING PLANT UNITS 1 AND 2 JANUARY 1988