NUREG-0831
Supplement No. 5

Safety Evaluation Report
related to the operation of Grand Gulf Nuclear Station, Units 1 and 2

Docket Nos. 50-416 and 50-417

Mississippi Power & Light Company
Middle South Energy, Inc.
South Mississippi Electric Power Association

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

August 1984

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ABSTRACT

Supplement 5 to the Safety Evaluation Report for Mississippi Power & Light Company, et al., joint application for licenses to operate the Grand Gulf Nuclear Station, Units 1 and 2, located on the east bank of the Mississippi River near Port Gibson in Claiborne County, Mississippi, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status on the resolution of those issues that require further evaluation before authorizing operation of Unit 1 above 5% of rated power.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

In September 1981, the U.S. Nuclear Regulatory Commission staff (hereinafter referred to as the Commission, NRC, or staff) issued its Safety Evaluation Report (NUREG-0831) regarding the application by the Mississippi Power & Light (MP&L) Company, Middle South Energy, Inc., and South Mississippi Electric Power Association (licensees, hereinafter collectively referred to as licensee) for licenses to operate the Grand Gulf Nuclear Station, Units 1 and 2 (hereinafter referred to as Grand Gulf), Docket Nos. 50-416 and 50-417. The Safety Evaluation Report (SER) was supplemented in December 1981 by Supplement 1, which documented the resolution of several outstanding issues in further support of the licensing activities. On June 15, 1982, the staff issued Supplement 2 to the Safety Evaluation Report (SSER 2) in which it addressed those outstanding items required to be resolved before a low-power license for Unit 1 was issued. In addition on June 16, 1982, an operating license, NPF-13, was issued to allow Unit 1 operation at power levels not to exceed 5% of rated power. In July 1982, the staff issued Supplement 3 to the Safety Evaluation Report (SSER 3) in which it addressed those issues remaining from previous supplements and the report of October 1981 from the Advisory Committee on Reactor Safeguards (ACRS). In May 1983, the staff issued Supplement 4 to the Safety Evaluation Report (SSER 4) that addressed primarily issues that required further evaluation before authorizing operation of Unit 1 above 5% of rated power. This report is issued as Supplement 5 to the Safety Evaluation Report (SSER 5) and addresses the remaining issues from Supplement 4 that required further evaluation before authorizing operation of Unit 1 above 5% of rated power.

On January 7, 1983, the Nuclear Waste Policy Act of 1982 (PL 97-425) became effective. All utilities are required to pursue an agreement with the Secretary of Energy for the disposal of high-level radioactive waste and spent nuclear fuel. Section 302(b) of the subject law makes issuance or renewal of a license under Sections 103 or 104 of the Atomic Energy Act of 1954 contingent on either the existence of a contract with the Secretary of Energy or written affirmation by the Secretary that the applicant is negotiating in good faith for a contract. In Amendment No. 6 to Operating License NPF-13, issued on February 7, 1983, the staff added a license condition that requires MP&L to satisfy applicable requirements of the subject law. On June 28, 1983, a contract between the Secretary of Energy and System Fuels, Inc. (a subsidiary of Middle South Utilities), was finalized for the disposal of high-level radioactive waste and spent nuclear fuel from Grand Gulf. With this contract through its authorized agent, the licensee has complied with the license condition.

Each of the following sections of this supplement is numbered the same as the corresponding section of the SER and Supplements 1, 2, 3, and 4. Each section is supplementary to and not in lieu of the discussion in the SER and Supplements 1, 2, 3, and 4.

Supplement 5 to the SER addresses the remaining two issues covered by license conditions that required further evaluation before authorizing operation of Unit 1 above 5% rated power. The section of this supplement in which these license conditions and issues are discussed follows:

Issue	Section	License Condition
(1) Environmental qualification	3.11	2.C.(12)(c)(i)
(2) Environmental qualification	3.11	2.C.(12)(c)(iii)

In addition, the following license conditions in Operating License NPF-13 for Grand Gulf Unit 1 have been resolved or complied with as currently written:

License Condition	Issue	Section
2.C.(3), partial	Staff performance report (5% power)	13.4
2.C.(13)	Seismic and LOCA load analysis	4.2.3.5
2.C.(30), partial	Remote shutdown panel	9.5.4.1
2.C.(44)(c)(ii)	Post accident sampling	22.2 - Item II.B.3
2.C.(44)(c)(iii)	Post accident sampling	22.2 - Item II.B.3
2.C.(45), partial	SRV test report	Appendix C

In addition, the following license conditions have been revised:

License Condition	Issue	Section
2.C.(10)	Dynamic testing	3.9.2
2.C.(18)	Inservice inspection program	5.2.4, 6.6
2.C.(19)	Containment purge	6.2.4.1
2.C.(32)	Interplant communication system	9.6.1.2
2.C.(44)(a)	Control room	Appendix E
2.C.(44)(d)	Hydrogen control	II.B.7, II.B.8

In addition, during the course of staff review, the following issues have been added as license conditions:

Issue	Section	License Condition
(1) Containment leak testing	6.2.6	2.C.(50)
(2) Emergency response facilities	13.3.2.8	2.C.(49)
(3) ADS accumulators	22.2 - Item II.K.3.28	2.C.(44)(k)

Copies of this supplement are available for public inspection at the Commission's Public Document Room at 1717 H Street, NW, Washington, D.C. and at the Hinds Jr. College, George M. McLendon Library, Raymond, Mississippi 39154. Copies of this report also are available for purchase from the sources indicated on the inside front cover.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

Operating License Condition 2.C.(10), "Dynamic Testing (Section 3.9.2, SER, SSER #2)," requires that the evaluation report for vibrational measurement and inspection programs during preoperational and initial startup testing be provided not later than June 1, 1983. This date was established based on the projected startup schedule at the time of low-power licensing. The staff review has determined that a delay in the submittal of this report was justified (Section 3.9.2, SER, SSER #4) and required the licensee to submit a revised schedule before June 1, 1983. In a letter dated May 31, 1983, the licensee proposed to amend the operating license to require submittal of this report no later than 6 months after commencement of full-power operation. The staff finds this acceptable and the license condition shall be modified to require that the evaluation report be provided no later than 6 months after full power has been achieved.

..10 Seismic and Dynamic Qualification of Seismic Category 1 Mechanical and Electrical Equipment

In Supplement 2 of the Grand Gulf SER, several commitments by the licensee were discussed regarding full qualification of several items of equipment. Of these items the fuel-handling and auxiliary platform, in-vessel rack, and the defective fuel storage container were to be qualified by December 31, 1982; also the balance-of-plant (BOP)/power generator control complex panel was to be fully qualified by December 31, 1982. By a December 22, 1982, letter from L. F. Dale (MP&L), to H. R. Denton (NRC), the licensee indicated that those two commitments would not be met on the planned schedule. The staff had discussions with the licensee on this issue and received written commitment from the licensee to fully qualify the above items before actual use in fuel-handling operation. This written commitment was provided by a letter from Dale to Denton dated October 14, 1983.

Fuel-handling and auxiliary platform, in-vessel rack, and defective fuel storage container will not be needed until the start of fuel-handling operation for first refueling outage. As long as the refueling operation is performed with fully qualified equipment, the staff finds the current commitment acceptable because the handling equipment in question does not pose any safety hazard. Full qualification in this context implies completion of documentation and replacement or refurbishment of any deficiencies, if necessary. With regard to the BOP/power generator control complex (PGCC) panels, aging was demonstrated for a service life of 1 year. By letters dated October 14 and December 28, 1983, the licensee has indicated that the BOP/PGCC panels have been fully qualified. Thus, this issue is resolved.

3.11 Environmental Qualification

By letter dated August 25, 1983, the licensee submitted information addressing compliance with License Conditions 2.C.(12)(c)(i) and 2.C.(12)(c)(iii). The NRC staff has reviewed that information and concludes that the licensee has complied with the above license conditions. The NRC staff has also reviewed License Condition 2.C.(12)(c)(ii) and determined that it is not needed, because the licensee must comply with the schedule contained in 10 CFR 50.49(g) issued January 1983. Therefore, the NRC staff will delete License Condition 2.C.(12)(c) in its entirety.

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.5 Seismic and LOCA Load Analysis

The staff has approved the General Electric (GE) topical report NEDE-21175-3 (letter from C. O. Thomas (NRC) to J. F. Quirk (GE), October 20, 1983), which described an analytical method for evaluating seismic and LOCA (loss-of-coolant accident) loads. The staff has reviewed the plant-specific values of liftoff and acceleration provided in an MP&L letter (L. F. Dale to H. R. Denton) dated October 14, 1983. The results show that the vertical liftoff is insignificant and the accelerations are within the evaluation-basis limits, thereby insuring structural integrity and control rod insertibility during seismic-and-LOCA events. Therefore, the staff concludes that the licensee has complied completely with License Condition 2.C.(13) of Operating License NPF-13 and that the seismic-and-LOCA loadings issue has been resolved satisfactorily for Grand Gulf.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

See Section 6.6 of this supplement to the Safety Evaluation Report.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.4 Containment Isolation System

6.2.4.1 Containment Purge System

Purging or venting of the Grand Gulf containment can be accomplished by either the low-volume purge system (LVPS) or the high-volume purge system (HVPS). The LVPS consists of 6-in. lines and the HVPS consists of 20-in. lines. Purging or venting of the drywell region can be accomplished by 20-in. drywell lines/penetrations. The drywell purge system can be valved in such a manner as to be part of the containment HVPS. Therefore, the drywell atmosphere can be vented either into the containment or outside the containment.

(1) Containment Purge/Vent System

As reported in Supplement 2 of the SER, the staff provided guidelines for the operation of the LVPS and HVPS. In Section II.E.4.2 of SSER 2, the staff indicated that the containment purge/vent isolation valves have been qualified to close under LOCA conditions provided that the drywell purge/vent isolation valves are closed.

(2) Drywell Purge/Vent System

The licensee has shown a need to vent the drywell for pressure control during Operating Modes 1 through 3 and a need to purge/vent the drywell in Operating Mode 3 to reduce drywell airborne activity levels for personnel entry. As reported in SSER 4, Section II.E.4.2, the licensee has demonstrated that the 20-in. drywell isolation valves are capable of closing against LOCA-induced differential pressures. In addition, the 20-in. containment purge/vent isolation valves are identical to the 20-in. drywell purge/vent valves. Therefore, the HVPS containment purge/vent isolation valves are capable of closing under LOCA conditions when the drywell purge/vent isolation valves are opened.

To ensure compliance with the guidelines summarized above, the Grand Gulf Unit 1 operating license shall have the following conditions:

(a) MP&L shall limit the use of the containment cooling system to purge the containment to 1000 hours per year for Operating Modes 1 through 3. The containment purge mode of the containment cooling system shall not be operated at the same time as the containment ventilation system while in Operating Modes 1 through 3.

(b) The drywell purge mode of the containment cooling system is to reduce the drywell airborne activity levels during personnel entry periods. The drywell supply and exhaust isolation valves also provide drywell pressure control during operating transients. The drywell supply and exhaust isolation valves shall be normally closed during Operating Modes 1 through 3.

I. To accommodate the need for drywell pressure controls, the drywell supply and exhaust isolation valves may be used during Operating Modes 1 and 2 with the following restrictions:

(1) Either the exhaust or supply line of the drywell may be opened, but both lines shall not be opened at the same time;

(2) While venting the drywell, the containment shall not be vented or purged;

(3) The total time of venting and drywell shall be limited to 5 hours per year (cumulative). This restriction will be withdrawn pending receipt and NRC approval of analyses to demonstrate acceptable consequences of the containment and the equipment within following the most limiting primary system break during venting of the drywell via the drywell supply or exhaust isolation valves.

II. During Operating Mode 3, drywell personnel access may be necessary for short periods of time. In order to reduce drywell airborne activity levels, it may be necessary to use the containment cooling system in a drywell purge mode to adhere to the requirements of 10 CFR 20. To accommodate drywell pressure control or reduce drywell activity levels in Operating Mode 3, MP&L shall limit operation of the drywell purge mode of the containment cooling system and use of the drywell supply and exhaust isolation valves for venting of the drywell to 90 hours per year total (cumulative).

(c) Prior to startup following the first refueling outage, MP&L shall provide for NRC review a reevaluation of the need to use the containment purge mode of the containment cooling system. This study should include, but not be limited to, data gathered during the first fuel cycle related to airborne activity level (as low as reasonably achievable (ALARA)), overall containment air quality, and personnel access to containment. Based on the above cited study, MP&L shall propose the purge criteria to be used for the remainder of the plant life.

6.2.6 Containment Leakage Testing

As reported in Supplement 1 of the SER, the staff concluded that the applicant's proposed leak testing program meets the requirements of Appendix J to 10 CFR 50 and is acceptable. However, the design details for the feedwater leakage control system (FWLCS) had not been reviewed before the issuance of SSER 1. The applicant stated that the FWLCS would provide post-accident sealing of both feedwater lines thus precluding the need to perform "Type C" leak testing (Appendix J) of the feedwater isolation valves.

The FWLCS is a manually activated system and is estimated by the licensee to be effective in approximately one hour after the onset of a LOCA. The licensee has not demonstrated satisfactorily that drywell leakage does not exist through the feedwater isolation valves in the early phase of the postulated event. In essence, the feedwater lines have not been tested according to the requirements of Appendix J to 10 CFR 50. To ensure satisfactory resolution of this outstanding concern regarding containment leak testing, the Grand Gulf operating license shall have the following license condition:

2.C.(50) Containment Leak Testing (Section 6.2.6 SSER #5)

MP&L shall perform "Type C" leak tests (Appendix J, 10 CFR 50), with an air or nitrogen test fluid, at the next scheduled outage of sufficient duration for the following containment isolation valves of the reactor feedwater system: F010 A, B; F032 A, B; F030 A, B; F063 A, B. Additionally, containment isolation valves, F065 A, B, shall be leak tested according to the above stated requirements at the next scheduled test for these valves. Prior to startup following the first refueling outage, MP&L shall either demonstrate why the containment isolation valves mentioned above should not be "Type C" leak tested or integrate these isolation valves in the Type C test program of the Technical Specification.

6.4 Control Room Habitability

In the Grand Gulf SER of September 1981, the staff stated that chlorine was identified as a potential problem to control room operators. This potential problem existed not from transportation accidents but from stored, bottled chlorine on site. The instrumentation for chlorine detection and automatically isolating the control room also was evaluated in the SER and the staff concluded that the control room habitability system was adequate.

On June 7, 1983, in License Event Report (LER) 83-064, the licensee informed the staff that the amount of stored chlorine on site had increased significantly. The FSAR states that approximately 20 ft^3 (at 100 psig) of gaseous chlorine will be stored on site for use in the sewage treatment plant. This amount was used as part of the basis for the evaluation of potential chlorine accidents. Currently, there may be as many as eight fully charged 150-lb cylinders or a maximum of 1,200 lbs of liquid chlorine on site located no closer than 225 m from the control room air intakes.

The staff has reviewed the licensee's submittal and has confirmed that the control room ventilation system is still in compliance with Regulatory Guides (RGs) 1.95 and 1.78. This increase in chlorine storage on site does not invalidate the basis of the staff conclusions as reported in the SER.

6.6 Inservice Inspection of Class 2 and 3 Components

Operating License Condition 2.C(18), "Inservice Inspection Program (Sections 5.2.4.1 and 6.6, SER, SSER #2)," requires that the initial inservice inspection (ISI) program be submitted by the licensee not later than June 30, 1983. This date was established on the basis of an earlier projected startup schedule. Examinations to be performed during the initial ISI program generally commence during the first refueling outage. In letters of May 31, 1983, and March 16, 1984, the licensee proposed to amend the operating license to require submittal of the ISI document by April 1, 1984, and August 1, 1984, respectively. The staff review has determined that submittal of the ISI program by September 1, 1984, is acceptable on the basis of the projected commercial operating date for this plant.

7 INSTRUMENTATION AND CONTROL

7.8 Response to Inspection and Enforcement Bulletins and Other Safety Concerns

J. Reactor Protection System Instrumentation Technical Specifications

From a comparison of the instrumentation operability requirements contained in the Grand Gulf, Unit 1, Technical Specifications to the instrumentation specification tables included in the Final Safety Analysis Report (FSAR), the staff found that in some cases the Technical Specifications included only one-half the total number of channels provided. By a September 12, 1983, letter from A. Schwencer (NRC) to J. McGaughy (MP&L), the staff requested the licensee to confirm that the single-failure criterion can be satisfied for each case where the minimum number of operable channel requirements of the Technical Specifications is less than the total number of channels provided for each reactor protection system trip function.

By letters dated October 11, 1983, from J. McGaughy (MP&L) to H. R. Denton (NRC) and October 14, 1983, from L. F. Dale (MP&L) to H. R. Denton, the licensee provided the results of his review of this item. The licensee reviewed the Grand Gulf, Unit 1, Technical Specifications requirements for the reactor trip, isolation actuation, emergency core cooling actuation and reactor core isolation cooling (RCIC) actuation instrumentation. From the results of this review, the licensee found that in most cases the FSAR incorrectly states the number of instrument channels provided and proposed to submit corrections in the annual FSAR update. For the RCIC actuation instrumentation the licensee proposed a change to the Technical Specifications to increase the number of instrument channels required to be operable from two to four, thus enhancing RCIC reliability and plant safety.

On the basis of the results of his review, the licensee has confirmed that the single-failure criterion is satisfied for the reactor trip, isolation actuation, emergency core cooling actuation, and RCIC actuation instrumentation when the requirements of the Technical Specifications are met. With the additional information provided and incorporation of the proposed changes to the Technical Specifications, the staff considers this issue resolved.

Certain action statements in the Grand Gulf, Unit 1, Technical Specifications permit continued plant operation with fewer than the required minimum number of channels operating, provided that the inoperable instrument channels are tripped. From discussions with the licensee's representatives, the staff found that, in some cases, placing a channel in the tripped condition includes lifting leads and using temporary jumpers.

By a September 12, 1983, letter from A. Schwencer to J. McGaughy, the staff requested that licensee to confirm that the licensing criteria (e.g., physical separation, qualification) are not compromised where leads are lifted or jumpers are installed.

By an October 14, 1983, letter from L. F. Dale (MP&L) to H. R. Denton (NRC), the licensee stated that he does not normally use lifted leads or temporary jumpers to place the actuation instrumentation channels of safety-related systems in the tripped condition. However, if jumpers or lifted leads are used, the modification is considered temporary and administrative procedures such as an engineering work order would be used to authorize the work. To resolve the staff's concern, the licensee has proposed to review the facilities administrative procedures to ensure that seismic, environmental, and separation criteria are considered when making temporary modifications under an engineering work order. Plant procedures were revised, as necessary, in procedures dated November 30, 1983, to accomplish this commitment. On the basis of the procedural revisions, the staff considers this issue resolved.

The Grand Gulf, Unit 1, Technical Specifications surveillance requirements include provisions for frequently calibrating certain reactor protection system instrumentation channel components. The Rosemont trip units in the actuation instrumentation systems for the reactor trip and emergency core cooling system are required to be calibrated monthly. From a review of the Grand Gulf, Unit 1, Technical Specifications and from discussions with the licensee's representatives, the staff found that the Rosemont trip units and the temperature switches associated with the isolation actuation instrumentation system were only required to be calibrated at 18-month intervals. By a September 12, 1983, letter from A. Schwencer to J. McGaughy, the staff requested that the licensee confirm that the method and frequency for calibrating and functionally testing the reactor protection system instrumentation is consistent with the assumption of the instrument channel set point methodology.

By an October 14, 1983, letter from L. F. Dale to H. R. Denton, the licensee stated that presently all of the Rosemont trip units in the isolation actuation system are being calibrated monthly and the temperature switches in the isolation actuation instrumentation system are being calibrated annually. The licensee also stated that changes would be proposed to review the Grand Gulf, Unit 1, Technical Specifications to require a monthly calibration of the Rosemont trip units and a yearly calibration of the temperature switches, consistent with the manufacturer's recommendations and with the current practice at Grand Gulf. The staff finds this acceptable. Addressing the overall issue of set point methodology, the licensee stated that he is participating with other owners of boiling water reactors (BWR) and the General Electric Company to develop a position statement on set point methodology.

The staff will confirm the acceptability of the set point methodology and confirm that the surveillance currently required supports the assumptions of the licensee's methodology in the position statement.

K. Agastat Relay Failures

During the performance of an 18-month surveillance test at Grand Gulf Unit 1, 12 (out of approximately 1,700) inoperable Agastat GP series relays were identified. These relay failures precluded the automatic operation of standby service water system valves, main steam isolation valves, and components in the control room ventilation system, combustible gas control system, reactor core isolation cooling system, residual heat removal system, and high-pressure core spray system. From the results of a test program conducted jointly by Mississippi Power and Light Company (the licensee), General Electric (the NSSS vendor) and Amerace

Corporation (the relay manufacturer), it was determined that the failures were end-of-service-life failures resulting from service aging of energized relays.

By letter dated October 13, 1983, from A. Schwencer (NRC) to J. P. McGaughy (MP&L), the NRC staff requested information regarding the use, maintenance, and surveillance testing of Agastat relays. By letters dated January 6, 1984, January 20, 1984, and March 7, 1984, from L. F. Dale (MP&L) to H. Denton (NRC) the licensee provided a discussion on the Agastat relay replacement program and ongoing surveillance program.

The licensee has completed a program of replacing the normally energized GP Series Agastat relays, manufactured before August 1977, used in safety-related systems. This program included both bench testing and in-place testing of the replacement relays. From the results of the service-life test program, the licensee determined that the normally deenergized pre-August 1977 Agastat GP Series relay and the normally energized Agastat GP Series relay manufactured after August 1977 are not subject to the accelerated aging and, therefore, need not be replaced at this time. The licensee, in coordination with GE and Amerace, will continue to evaluate the service life of the GP series relays to extend their service life (now estimated to be 4.5 years for the normally energized relays manufactured after August 1977 and 10 years for all relays operated in the normally deenergized state), or develop a program for their replacement before reaching the end of their calculated service life. The NRC staff finds this approach acceptable.

In response to a staff request regarding the adequacy of the current relay surveillance program, the licensee performed an analysis of the reactor protection system unavailability, core damage frequency, and public risk at Grand Gulf Unit 1 as a function of varying Agastat relay surveillance intervals. The analysis was based on work done for the Limerick Station Risk Assessment, the BWR/6 Standard Plant Probabilistic Risk Assessment (PRA), and the BWR/6 Standard Plant PRA Uncertainty Analysis. These models were modified to reflect the Grand Gulf design and surveillance testing program. The relay unavailability was evaluated considering both energized and de-energized relays, the relay failure rates, and the surveillance test intervals.

The surveillance test intervals at Grand Gulf were established based on the guidance contained in the BWR/6 Standard Technical Specifications. Channel functional tests are performed monthly and logic system functional tests are performed at 18-month intervals. A failure rate for the relays from the GE purchase part drawings of 1×10^{-6} failures per hour was compared to the actual plant-experienced failure rate. This comparison confirmed that the recently observed failures were within the predicted failure rate. Using these test intervals and failure rates, calculations were performed using reliability and fault tree methods to confirm the adequacy of the surveillance intervals. From these calculations, the licensee determined that the relay failures identified during the 18-month surveillance interval were within the expected failure limits, and that the surveillance test intervals are sufficient to detect relay failures before systems reliability degrades to an unacceptable level. Sensitivity studies were performed varying the surveillance test interval to determine the following: (1) the change in calculated system unavailability, (2) the change in the calculated core damage frequency, and (3) increased and decreased public risk. The results of these sensitivity calculations were provided as part of the licensee's submittal. Although the results show some sensitivity of systems availability as a result of varied surveillance intervals, overall core damage frequency and public risk remained relatively constant. For example, although the reactor trip system unavailability (per year) increases by an order of magnitude as the surveillance interval is varied between 1 and 3 months, the scram failure frequency, core damage frequency, and risk remain the same.

The NRC staff reviewed the calculations performed by the licensee to confirm that the observed failure rates are within the rates specified by GE. Based on this review, the staff confirmed that the experienced failures are within the expected failure rates. The staff also reviewed the methods used by the licensee to determine the acceptability of the current surveillance intervals for these failure rates. Based on this review, the staff found that test intervals and component failure rates are primarily considerations in the assessment of system reliability. The shorter the interval, the more likely it will be that a failure is found before a demand is placed on the component or system. Although the risk assessment models used by the licensee were developed for a slightly different design BWR, the system similarities provide a reasonable assurance that the surveillance intervals are adequate. Therefore, the staff finds that the current surveillance intervals for the Agastat GP Series relays acceptable.

The licensee is currently participating in the BWR Owners Group Technical Specification Improvement Program. The purpose of this program is to develop an analytical basis for allowable equipment maintenance down times and intervals between surveillance tests using reliability data, fault tree, and event tree models for each BWR product line. Adjustments to the surveillance intervals for the reactor protection system (Agastat relays) may be justified or required based on the results of this program.

In summary, because of the licensee's actions to institute a program for the replacement and surveillance testing of Agastat relays and the staff acceptance of such a program, it is concluded that Grand Gulf Unit 1 may continue to be operated before the completion of the BWR Owners Group Technical Specification Improvement Program without endangering the health and safety of the public.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.4 Fuel Handling System

NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," was developed as a result of Generic Task A-36, "Control of Heavy Loads Near Spent Fuel." Following the issuance of NUREG-0612, a generic letter dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with guidelines of NUREG-0612. The responses were to be made in two stages. The first response (Phase I, Section 5.1.1 of NUREG-0612) was to identify the load handling equipment within the scope of NUREG-0612 and to describe the associated general load handling operations such as safe load paths; procedures; operator training; special and general purpose lifting devices; the maintenance, testing, and repair of equipment; and the handling equipment specifications. The second response (Phase II) was intended to show that either single-failure-proof handling equipment was not needed or that single-failure-proof equipment had been provided. This supplement to the SER and the attached Technical Evaluation Report (TER) (see Appendix L of this report) constitutes the staff's evaluation of Phase I. An evaluation of Phase II will be addressed in a future evaluation.

The letter dated December 22, 1980, requested the licensee to review the provisions for handling and control of heavy loads (at the Grand Gulf facility in this case) to determine the extent to which the guidelines of NUREG-0612 are satisfied and to discuss and commit to mutually agreeable changes and modifications that would be required to fully satisfy these guidelines.

In Supplement 1 to the SER, the staff stated that the licensee had committed to implement the interim actions before the final implementation of NUREG-0612 guidelines and before the receipt of their license. The Grand Gulf licensee has subsequently completed the Phase I review. The changes necessary to implement compliance with Phase I should be in place by the first refueling outage.

The staff has reviewed the licensee's submittals and the staff's consultant TER and concurs with the TER findings and that the guidelines of NUREG-0612 Section 5.1.1 have been satisfied. Therefore, Phase I for Grand Gulf Units 1 and 2 is acceptable.

9.5 Fire Protection Systems

9.5.4 Specific Areas

9.5.4.1 Control Room

Section 7.4.1.4 of the FSAR describes the remote shutdown panel's design and capability. The present design objective of the remote shutdown panels (one panel for each division of redundant safe shutdown systems) is to achieve and maintain cold shutdown if an evacuation resulting from a fire disabling the control room should occur. The reactor core isolation cooling system, the safety/relief valves, and one division of the reactor heat removal (RHR) system can be controlled from one remote shutdown panel to achieve cold shutdown should a fire disable the control room. To ensure the availability of this remote shutdown panel in the event of a control room fire, License Condition 2.C.(30) requires that electrical isolation switches be installed between the control room and the Division I remote shutdown panel before startup after the first regularly scheduled refueling outage. Further, License Condition 2.C.(30) required that the design for the isolation switches be provided for staff review by January 1, 1984. By letter dated December 28, 1983, the licensee provided a description of the design modification for electrical isolation. The staff is currently reviewing this design submittal. By submitting their design before January 1, 1984, the licensee has complied with that part of License Condition 2.C.(30).

9.6 Other Auxiliary Systems

9.6.1 Communication Systems

9.6.1.2 Interplant Systems

Operating License Condition 2.C.(32), "Interplant Communication System (Section 9.6.1.2, SER, SSER #2)," requires that an evaluation of test results for the interplant communication system be provided no later than June 1, 1983. This date was established based on the projected startup schedule at the time of low-power licensing. The staff review has determined that a delay in the submittal of this report was justified (Section 9.6.1.2, SER, SSER #4) and required the licensee to submit a revised date before June 1, 1983. By letter dated May 31, 1983, the licensee proposed to amend the operating license to require submittal of this report no later than 90 days following completion of the testing, but no later than August 1, 1984. By letter dated June 27, 1984, the licensee proposed deleting the requirement to submit the report no later than August 1, 1984, because of the projected startup schedule. The staff has reviewed these submittals and finds them acceptable. Therefore, the license condition shall be modified to require the evaluation of test results be provided within 90 days after test completion.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure

13.1.1 Management and Technical Support

By letters dated May 24 and July 11, 1984, the licensee provided new charts of its corporate support organization (Figures 13.1 and 13.2). The significant changes are described below.

The Assistant Vice President, Nuclear Production, who had been responsible to the Senior Vice President, Nuclear, for plant operation and for technical support, is now the Vice President, Nuclear Support, responsible for all aspects of nuclear fuel, all offsite nuclear service and support, and for radiological and environmental areas including radiochemistry service and support areas.

The Vice President, Nuclear Operations, is responsible for assuring safe and reliable plant operations. The Plant Staff and Nuclear Licensing and Safety report to this position. The Director, Nuclear Licensing and Safety, is responsible for overall nuclear safety considerations and for all interface and communications with the NRC at the director level, providing increased and improved management resources devoted to safety and licensing. The Manager, Nuclear Licensing, is responsible for nuclear licensing activities previously handled by the Supervisor, Nuclear Licensing, in addition to emergency planning, commitment tracking, and nuclear regulatory legal interface. The Manager, Nuclear Safety and Compliance, is responsible for nuclear safety activities previously handled by the Supervisor, Nuclear Safety, in addition to regulatory compliance areas such as inspection and violation tracking and response and onsite/offsite commitment interface.

The plant organization is discussed in Section 13.1.2 of this SSER.

The Director, Quality Assurance, now reports directly to the Senior Vice President rather than to the Assistant Vice President.

A Director, Nuclear Engineering and Construction, who reports directly to the Senior Vice President, Nuclear, is responsible for station engineering, for outage planning and management, and for construction of Grand Gulf Unit 2. The principal engineering support groups are those shown in Figure 13.2. Two new groups have been added: Quality Engineering and Systems Engineering. The Principal Engineer, Quality, is responsible for Nuclear Plant Engineering (NPE) procedure development, quality reviews, internal NPE training programs and NPE interface with other MP&L Nuclear Production Department organizations. The Principal Engineer, Systems, is responsible for NPE project management of multi-discipline projects and for internal NPE contract administration.

A Manager, Nuclear Human Resources, is responsible for planning, forecasting, and budgeting in the human resources area and for overall nuclear employment policies, recruiting and training. He is also responsible for interfacing with the MP&L Personnel Department.

The NRC staff believes that the new organization is an improvement over that existing previously because of the reduced span of control required by senior management and because of the upgrading of the positions that report to the three executive positions. The NRC staff finds the new organization to be acceptable.

A new President/Chief Operating Officer was hired recently. He served 8 years in the U.S. Navy nuclear power program. Since 1969 he has been directly involved, in increasingly responsible positions, with the design, construction, and management of the two nuclear power plants owned by his employer, Arkansas Power & Light Company. This individual brings to his present position nuclear experience that had been lacking at the top levels of the licensee's management.

The present Senior Vice President, Nuclear, has 26 years of experience in the U.S. Navy in fossil-fueled and nuclear-fueled ships, including 2 years as commanding officer of a U.S. Navy submarine base, and 3 years as the senior executive of a nuclear applications business that provided radioisotope sources. Before his appointment to his present position in February 1983, he served as a member of the corporate safety review committees of three nuclear power stations, including Grand Gulf. The NRC staff concludes that the positions of President and Senior Vice President, Nuclear, have been significantly strengthened by these appointments.

License Condition 2.C.(36) required that the licensee provide an advisor to the Vice President, Nuclear, having substantial commercial reactor operating experience, for a period of at least 1 year following initial criticality. Because of the extended outage following initial criticality, this condition has been amended to require the presence of the advisor until the plant has operated for at least 6 months at power levels above 90% of full power.

By letter dated January 25, 1984, the licensee informed NRC that the advisor to the Vice President, Nuclear, since prior to initial criticality, resigned from the position, effective January 1, 1984, and has been replaced by another individual whose résumé was submitted with the letter. According to the résumé, this individual had graduated from the U.S. Naval Academy and served in the Navy for 8 years, 3 of which were in nuclear-powered submarine plants. He later worked for a power-generating public utility for 22 years. During 20 years of this later period working in nuclear power plants, the advisor held responsible BWR plant operating management positions for 9 years followed by about 6 years in progressively more responsible management positions directing the utility's nuclear power program. Based on its review of the résumé, the staff concludes that the new advisor to the Vice President, Nuclear (now Nuclear Operations), should be able to provide valuable assistance in the management of the Grand Gulf Nuclear Station during startup and initial power operation. The position of Vice President, Nuclear Operations, has not yet been filled; however, the Senior Vice President, Nuclear, is acting in that capacity.

In response to an NRC informal request for information, the licensee provided, in a letter dated January 20, 1984, information pertaining to the licensee's knowledge and use of Kuosheng Nuclear Station (KSNS) operating experience.

A technical information exchange agreement was executed between Middle South Energy, Inc. (MSEI), and Taiwan Power Company (TPC) on August 28, 1981, for an initial term of 5 years. The licensee has been appointed as MSEI's agent to exercise any rights that MSEI has under the agreement. Based on the agreement, both parties ensure a productive exchange of information on plans, ongoing efforts, and results of each party's work in the program areas regarding the nuclear power plant project and operational experience. This exchange of information has taken the form of technical reports, experimental data, correspondence, visits, and meetings and discussions held between technical experts of each party.

Several methods are used by the licensee to obtain technical information concerning Kuosheng operating history. These include: (1) the utilization of General Electric startup engineers who were part of the startup of Kuosheng, (2) contacts with Bechtel Power Corporation, the principal architect-engineer for Kuosheng, and (3) meetings held and visits made to each facility by representatives of MP&L and TPC.

During the development of preoperational and startup test procedures and performance of preoperational and startup tests, the licensee has had the benefit of several sources of Kuosheng startup experience. The licensee's startup organization received copies of Kuosheng startup test reports. These reports were reviewed for applicability to Grand Gulf and, if warranted, routed to the responsible system or test engineers. This helped to ensure that problems or significant events that occurred at Kuosheng are either avoided or have been properly prepared for at Grand Gulf. The licensee also utilizes some GE startup engineers who were part of the startup group for both Kuosheng units. These engineers have assisted in the development of test procedures and provided technical assistance to on-shift personnel during testing. In addition, significant events identified during startup of Kuosheng were transmitted through the GE engineering office in San Jose, California, and evaluated by Grand Gulf startup engineers for applicability to Grand Gulf.

Bechtel Power Corporation was able to provide the licensee with information regarding specific difficulties encountered during the startup program at Kuosheng. This information was reviewed to determine the potential for the occurrence of similar situations at Grand Gulf.

As a result, there have been numerous changes and enhancements to both startup test procedures and system operating instructions as a result of startup and operating experience gained from Kuosheng.

The NRC staff believes that the licensee's use of Kuosheng operating information will be helpful in achieving a smooth and efficient startup of Grand Gulf.

13.1.2 Operating Organization

By letter dated May 24, 1984, the licensee informed NRC that there have been significant changes made to the plant organization. The new organization is shown in Figure 13.3. The Grand Gulf General Manager reports to the Vice President, Nuclear Operations.

The functions of operations, maintenance, and support are now the individual responsibilities of three managers rather than by two managers as in the past. The new arrangement decreases the span of control of these three individuals, permitting them to concentrate on narrower areas of responsibility. In addition, a new position responsible for consolidated records management is being formed and the selected individual will report directly to the Manager, Plant Support. This employee (position not shown on the organization chart) will assume the duties of the Nuclear Records Administrator. Until this new position is finalized, the Nuclear Records Administrator retains responsibility for records management and is reporting on an interim basis to the Vice President, Nuclear Support. The NRC staff considers the new arrangement to be superior to the old and concludes that it is acceptable.

There have been changes in the personnel who fill the management positions in the plant organization. The Grand Gulf General Manager has been involved in commercial nuclear power plants since 1969. His earlier years were spent primarily in designing instrument and control systems. Later, as an instrument engineer, he participated directly in the startup of Browns Ferry Units 1 and 2. Before being employed at Grand Gulf in 1983, he served as Assistant Plant Superintendent at both Watts Bar and Sequoyah where he was responsible for areas of security, compliance, administration, safety, and maintenance. His résumé does not indicate that he had an operator's license; however, his Technical Assistant has over 20 years of nuclear plant operating experience, including 14 years in startup and testing of other BWR plants.

The Manager, Plant Support, was involved in procurement quality assurance for about 13 years. From 1979 to 1983, he was employed by the licensee as Nuclear Site Quality Assurance Manager at Grand Gulf.

The Manager, Plant Maintenance, was heavily involved, as test engineer in a shipyard, in the testing, maintenance, and repair of U.S. Navy nuclear-powered ships. In 1973, he was employed at Grand Gulf as Support Supervisor, providing technical direction and plant staff assistance in nuclear engineering, chemistry, radiation protection, and equipment performance testing. He served as Startup Manager for about 2 years and then served for another 2 years as Nuclear Support Manager responsible for training, administrative services, and, through his subordinate Technical Support Superintendent, reactor engineering, shift technical advisors (STAs), and engineering for licensing, maintenance, and other technical areas.

The Manager, Plant Operations, served for 8 years in the U.S. Navy nuclear power program and had experience in instrumentation and control systems aboard an operating submarine, in the training of reactor operators for the fleet, and in supervising the operations and maintenance of a submarine's mechanical and electrical systems. Following U.S. Navy service, he spent 8 years with the NRC as a reactor inspector, including 4 years as Senior Resident Inspector at a BWR during startup and operation. He later spent 2 years as Manager of Operations at a two-unit BWR plant in operation. He maintained an SRO license for that plant.

The Technical Assistant to the Manager, Plant Operations, has 11 years of operating BWR experience, including at least 1 year as an SRO-licensed shift foreman. Currently, the Technical Assistant to the Manager, Plant Operations, is acting as Manager, Plant Operations, because the Manager, Plant Operations, is currently unable to perform his duties.

The Operations Superintendent has been with Grand Gulf since 1975. He has served as an SRO-licensed shift supervisor and shift superintendent. He has three SRO-licensed Operations Assistants. Two of these assistants each have

4 years of "hot" experience on an operating BWR; the third spent 20 years in the U.S. Navy nuclear program, including shipboard operation, and has served as SRO-licensed shift supervisor and shift superintendent at Grand Gulf.

The Technical Support Superintendent has been with Grand Gulf since 1978 in startup test supervisory positions. Before this, he was involved for 4 years in nuclear submarine overhaul at a shipyard. The Chemistry/Radiation Control Superintendent worked for 10 years in health physics and radiological controls at three other nuclear reactor plants.

Based on its review of the résumés of the plant manager and superintendent positions, the staff concludes that significant improvement in operating experience has been made at these levels.

There are now five shift superintendents and five shift supervisors. None of these has previous commercial BWR operating experience, but all but one have been at Grand Gulf for the past 4 years or more. All are SRO-licensed on Grand Gulf. Three of the shift superintendents and two of the shift supervisors have more than 6 years of nuclear experience with the U.S. Navy. Three of the ten hold baccalaureate degrees in engineering or physics.

By letter dated March 16, 1984, the licensee provided a tabulation of the education and operating experience of the STAs. All five have bachelor's degrees in engineering, applied science, or equivalent. None has hot operating experience on a commercial BWR other than Grand Gulf.

As required by the Grand Gulf operating license, MP&L has provided experienced advisors for each shift because the MP&L shift operators had little previous operating experience. By letter dated April 18, 1983, the licensee provided the résumés of the five advisors. Staff review of these résumés showed that all had served as licensed reactor operators and senior operators at large, operating, commercial BWR plants. Their individual total years of hot operating experience ranged from 6 to 14 years, including from 20 to 7 years as RO and from 4 to 8 years as SRO. All had participated in preoperational and startup testing of the plants on which they were licensed. None has an engineering degree.

The staff has reviewed the Grand Gulf plant staff résumés, including the shift advisors' résumés, and concludes that the Grand Gulf plant staff has acceptable qualifications for continued startup and full-power operation of the Grand Gulf plant. However, the staff's evaluation of the Chemistry/Radiation Control Superintendent reporting requirements will be provided in Section 16.4.1 of Supplement 6 to the SER.

13.2 Training Program

13.2.1 Training for Nonlicensed Plant Staff

In Supplement 2 to the SER, the NRC staff had found that the licensee's program for training nonlicensed personnel was acceptable. This finding was based on FSAR information available to the staff in February 1982.

By letter dated March 19, 1982, the licensee proposed to delete from the FSAR the duration of each subpart of the training program for the shift technical advisors. Such deletion is unacceptable because, as is noted in Standard Review Plan (SRP) Section 13.2.2, the duration of the course forms, in part, the bases for the NRC staff's findings that the licensee is technically qualified to operate the plant safely. Therefore, it is the NRC staff's position that the durations of the subparts of the training program shall be included in the FSAR.

13.3 Emergency Preparedness Evaluation

13.3.2 Evaluation of the Grand Gulf Emergency Plan

13.3.2.8 Emergency Facilities and Equipment

Emergency Response Facilities

On December 17, 1982, Generic Letter 82-33, enclosing Supplement 1 to NUREG-0737, was sent to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. In this letter, licensees of operating reactors and holders of construction permits were requested to furnish (pursuant to 10 CFR 50.54(f)) no later than April 15, 1983, a (1) proposed schedule for completing each of the basic requirements for the items identified in Supplement 1 to NUREG-0737 and (2) description of plans for phased implementation and integration of emergency response activities, including training.

The licensee responded to Generic Letter 82-33 by letter dated April 15, 1983. By letters dated August 22, 1983, and October 10, 1983, the licensee modified several dates as a result of negotiations with the staff. In these submittals, the licensee made commitments to complete the basic requirements. A license condition summarizing the licensee's schedule of commitments and the status of those commitments was developed by the staff on the basis of the Generic Letter and the information provided by the licensee.

The licensee's commitments include (1) the dates for providing required submittals to the NRC, (2) the dates for implementing certain requirements, and (3) a schedule for providing implementation dates for other requirements.

The NRC staff reviewed the April 15, 1983, letter from the licensee and entered into negotiations with the licensee regarding schedules for meeting the requirements of Supplement 1 to NUREG-0737. As a result of these negotiations, the licensee modified certain dates by letters dated August 22 and October 10, 1983. The NRC staff finds that the modified dates are reasonable, achievable dates for meeting the Commission requirements. The staff concludes that the schedule proposed by the licensee will provide timely upgrading of the licensee's emergency response capabilities.

The staff concludes that Operating License NPF-13 should include the following license condition:

2.C.(49) Emergency Response Facilities (Section 13.3.2.8, SSER #5)

MP&L shall implement the specific items below, in the manner described in MP&L letter (AECM-83/0232) dated April 15, 1983, as modified in MP&L letter (AECM-83/0486) dated August 22, 1983, no later than the following specified dates:

(a) Safety Parameter Display System (SPDS)

(1)	Submit a safety analysis and an implementation plan to the NRC	July 1985
(2)	SPDS fully operational and operators trained	Prior to startup following first refueling outage

(b) Detailed Control Room Design Review (DCRDR)

(1)	Submit a program plan to the NRC	December 1984
(2)	Submit a summary report to the NRC including a proposed schedule for implementation	July 1986

(c) Regulatory Guide 1.97 - Application to Emergency Response Facilities

(1)	Submit a report to the NRC describing how the requirements of Supplement 1 to NUREG-0737 have been or will be met	February 1985
(2)	Implement (installation or upgrade) requirements of RG 1.97 with the exception of flux monitoring, coolant level monitoring, and standby liquid control system (SLCS) flow monitoring.	Prior to startup following first refueling outage
(3)	Implement (installation or upgrade) requirements of RG 1.97 for flux monitoring, coolant level monitoring, and SLCS flow monitoring.	Prior to startup following second refueling outage

(d) Upgrade Emergency Operating Procedures (EOPs)

(1)	Submit a Procedures Generation Package to the NRC	April 1985
(2)	Implement the upgraded EOPs	Prior to startup following the first refueling outage

(e) Emergency Response Facilities

(1)	Technical Support Center (TSC) fully functional with exception of RG 1.97 implementation	Prior to startup following the first refueling outage

(2)	Operational Support Center (OSC) fully functional with exception of RG 1.97 implementation	Prior to startup following the first refueling outage
(3)	Emergency Operations Facility (EOF) fully functional with exception of RG 1.97 implementation	Prior to startup following the first refueling outage

13.3.3 Update of FEMA's Findings

In Section 13.3.3 of SSER 4, the staff provided the FEMA findings as documented in letters dated August 2 and December 17, 1982. Since then, FEMA has provided additional findings in a letter dated June 29, 1983 (see Appendix G of this report). This letter approves the State plans for Mississippi and Louisiana and the local plans for Grand Gulf subject to verification of the adequacy of the public alerting and notification system. In Section 13.3.2.5 of SSER 4, the NRC staff presented its evaluation of the design and operability of this system and found it to be acceptable.

13.4 Review and Audit

In Supplement 3 to the SER, the NRC staff noted that certain changes had taken place in the outside consultants who were members of the Safety Review Committee (SRC).

By letters dated July 15, 1982 and August 17, 1982, the licensee informed us that two former SRC consultant-members had discontinued their memberships and that two new consultant-members had been selected to fill these openings. In addition, a third consultant-member had been selected. One of the new members is a nuclear physicist who is instrumental in the development of nuclear manpower resources and training. The second new member was a staff member of the Atomic Energy Commission and, later, a Commissioner and Chairman. The third had been involved as an SRO and technical supervisor in the startup and operation of a large two-reactor PWR power plant and, later, for 5 years as the plant manager of a large BWR under construction.

Based on the résumés of the three new consultant members of the SRC, the NRC staff concludes that they will bring to the SRC valuable experience and expertise.

License Condition 2.C.(3) required the licensee to establish a subcommittee of the Corporate Safety Review Committee with duties to perform an independent verification of plant operating staff performance and other plant activities before exceeding 5% and 50% power and within 30 days following completion of the 100-hour warranty run. By letter dated November 18, 1983, the licensee submitted a copy of the report prepared to fulfill the review at 5% power. The NRC staff has reviewed this report and has made the following findings in the areas of shift staffing and shift advisors. By submitting this report, the NRC staff finds that the licensee has complied with that portion of Licensee Condition 2.C.(3) regarding assessment of performance before exceeding 5% power.

The Subcommittee reported on the readiness of operating personnel with respect to shift staffing. There are to be five shift crews, each of which will include two SROs, two ROs, three nonlicensed operators, two auxiliary operators, a shift clerk, an STA, and a shift advisor, all permanently assigned to a particular shift crew. Each shift has a radiation protection representative, and maintenance supervisors and craftsmen assigned from the electrical, mechanical, and instrumentation and controls sections. During the start-up period, a start-up engineering unit is present on each shift, consisting of one MP&L start-up test engineer and two General Electric engineers. The NRC staff concludes that such staffing, which goes well beyond regulatory requirements, is desirable.

The Subcommittee also reported on the use of the shift advisors. The shift superintendents and shift supervisors use the available BWR experience of the shift advisors by noting their cautions and suggestions and by asking for advice when they feel they need it. There is no indication that the shift superintendents and supervisors are becoming overly dependent on the shift advisors, or lack confidence in their own knowledge of the plant and procedures. The Special Subcommittee believes that the shift advisors are being utilized in a reasonable way thus far. The NRC staff believes that MP&L management is making use of the shift advisors as the staff had envisioned when it imposed the applicable license condition.

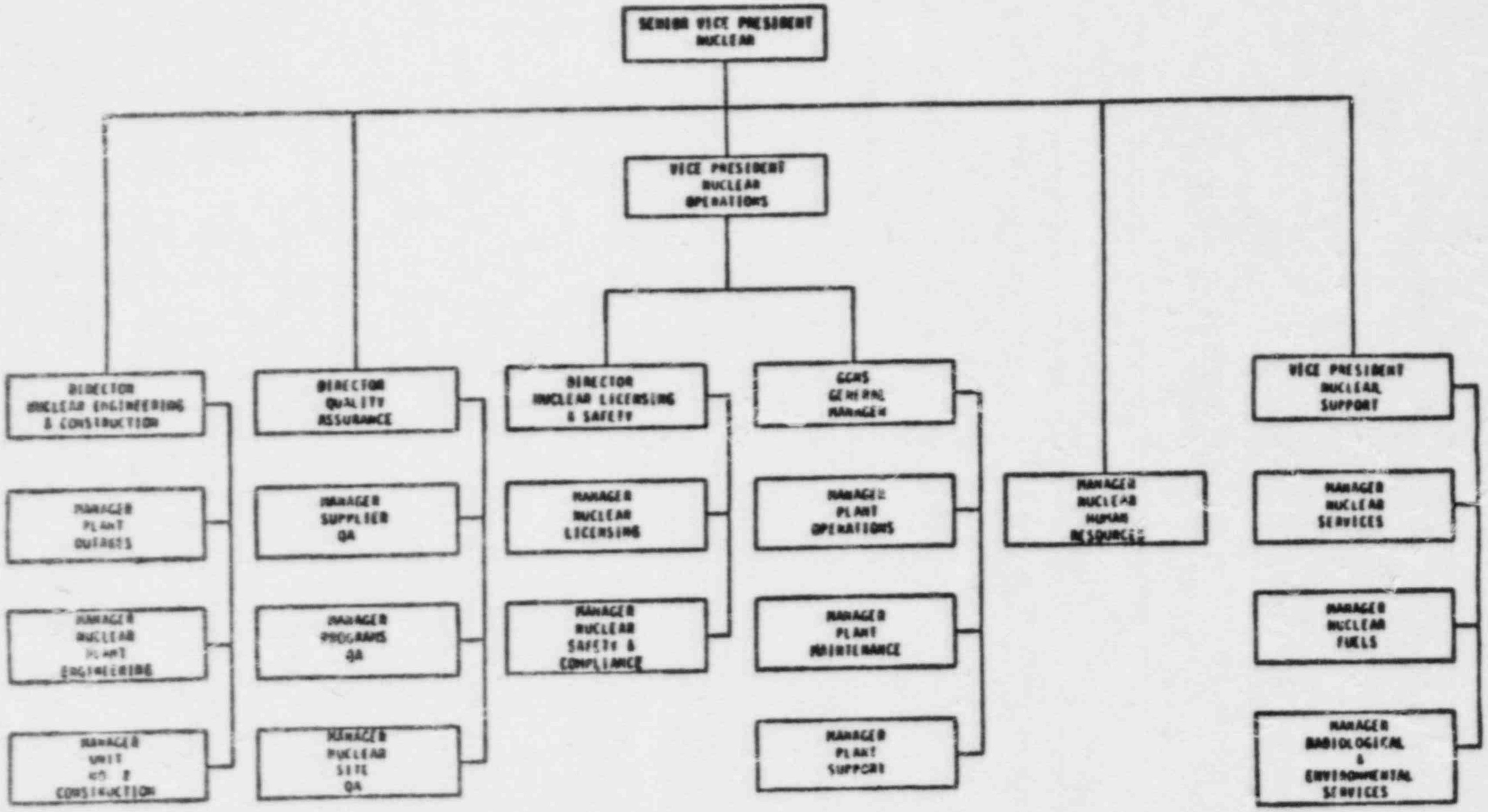

Figure 13.1 Offsite organization

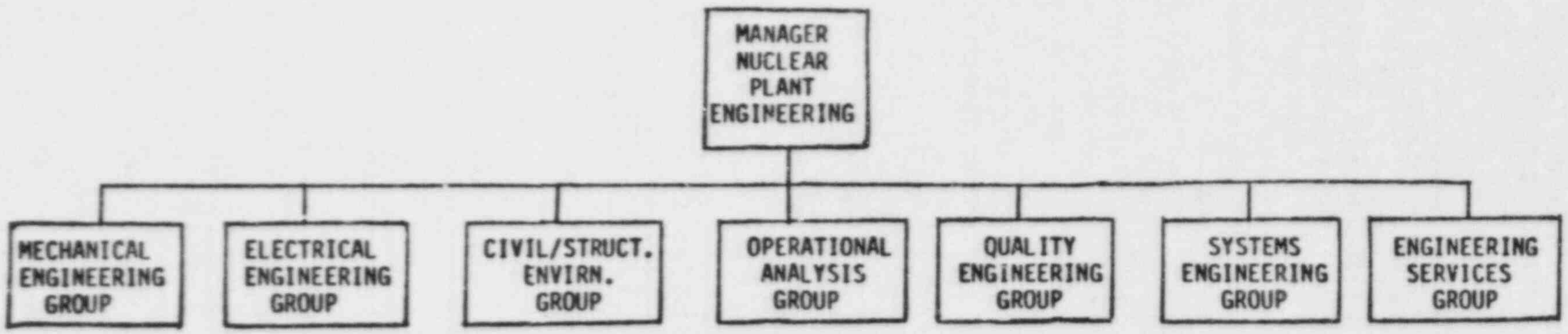

Figure 13.2 Grand Gulf Nuclear Plant Engineering Organization

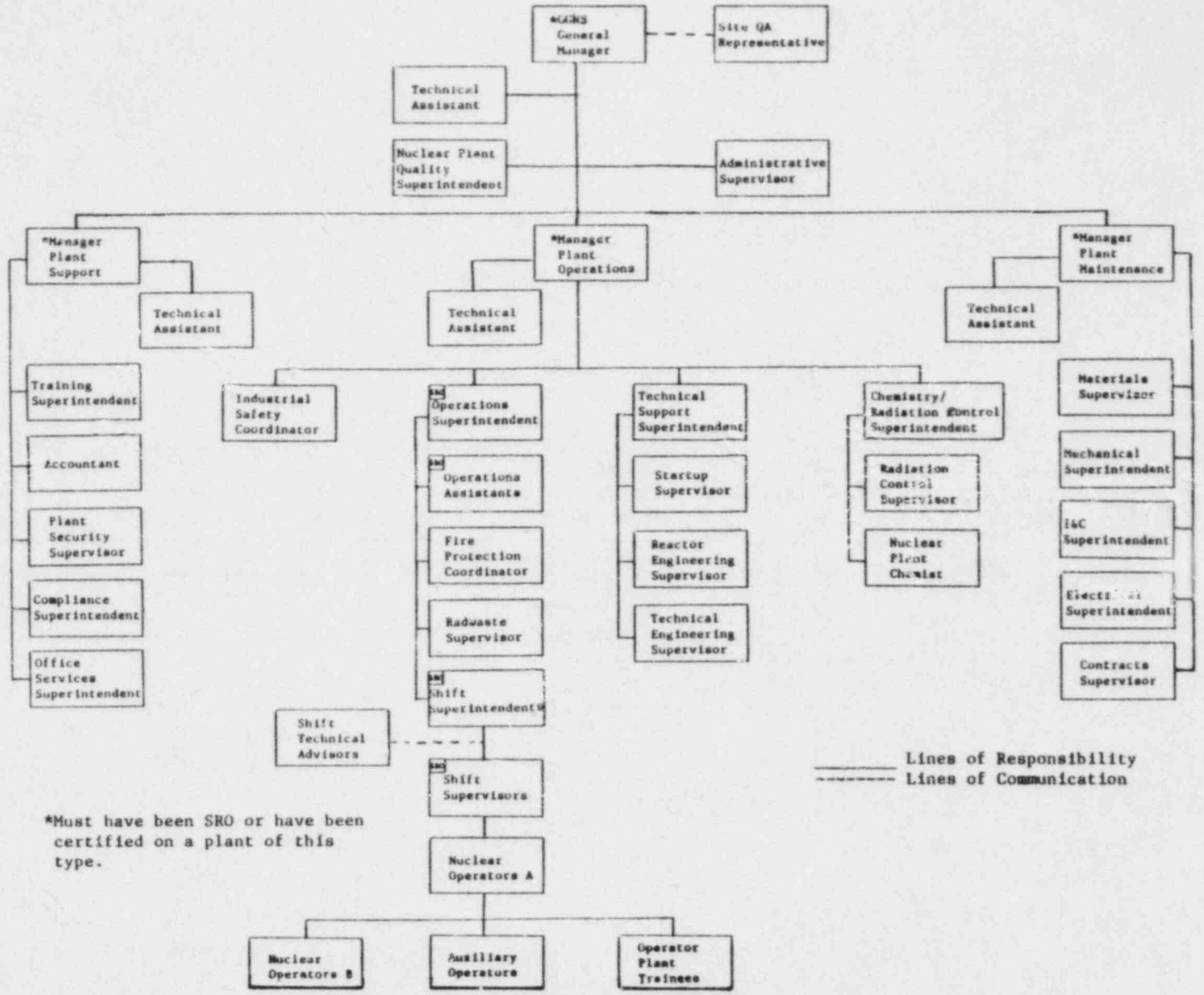

Figure 13.3 Unit organization

22 TMI-2 REQUIREMENTS

22.2 TMI Action Plan Requirements for Applicants for Operating License

I Operational Safety

I.D.1 Control Room Design Review

See Appendix E to this report.

II Siting and Design

II.B.3 Postaccident Sampling Capability

Introduction

In SSER 4, dated May 1983, the staff found that the licensee's postaccident sampling system (PASS) met nine of the eleven criteria for Item II.B.3 in NUREG-0737. The remaining two criteria that were not fully resolved are

(1) Core damage estimation procedure - The applicant's procedure was acceptable on an interim basis. Proposed License Condition 2.C.(44)(c)(i), discussed in SSER 4, would require submittal of a final procedure before startup following the first refueling outage.

(2) Data supporting the applicability of each selected analytical procedure or on-line instrument in a postaccident environment - Proposed License Conditions 2.C.(44)(c)(ii) and (c)(iii), discussed in SSER 4, covered this item.

Evaluation

By a letter dated August 25, 1983, the licensee provided additional information. To demonstrate applicability under postaccident conditions, the licensee has tested alternate backup grab sample procedures in a standard test matrix solution simulating postaccident chemistry conditions. The licensee has provided a summary of alternate PASS procedures along with ranges and accuracies in the standard test matrix solution. The staff finds the ranges and accuracies of these alternate procedures are within the staff's guidelines and, therefore, are acceptable.

Conclusion

Based on its evaluation, the staff concludes that the postaccident sampling system now meets ten of the criteria of Item II.B.3 of NUREG-0737. The staff has found that suitable analytical procedures are applicable by demonstrating range and accuracy in the postaccident water chemistry conditions. Therefore, the staff finds that the licensee has complied with the following proposed license conditions discussed in SSER 4:

2.C.(44)(c)(ii) By August 15, 1983 (tentative), MP&L shall provide the alternative analytical chemistry procedures as discussed in Section II.B.3.3.

2.C.(44)(c)(iii) By May 25, 1984 (tentative), MP&L shall provide a summary of suitably verified analytical chemistry procedures as discussed in Section II.B.3.3.

License Condition

The staff concludes that License Condition 2.C.(44)(c) of Operating License NPF-13 should be revised to reflect the remaining proposed license condition discussed in SSER 4 this further evaluation and should read as follows:

2.C.(44)(c) Post Accident Sampling (II.B.3, SER, SSER #1, SSER #4, SSER #5)

For the procedure for relating radionuclide gaseous and ionic species to estimate core damage, MP&L shall incorporate the additional requirements as discussed in Section II.B.3.1 of SSER #4 before startup following the first refueling outage.

II.B.7 Analysis of Hydrogen Control (and)
II.B.8 Rulemaking Proceedings on Degraded-Core Accidents

Introduction

As previously reported in SSER 2, June 1982, the staff requested that the licensee propose a program to improve the hydrogen control capability for the Grand Gulf Nuclear Station to the extent that the plant may safely accommodate the consequences of a postulated degraded-core accident with concomitant, large hydrogen releases. This includes the release of hydrogen generated from a metal-water reaction involving up to 75% of the active cladding.

The staff also reported in SSER 2 that the licensee had selected a hydrogen igniter system for installation similar to that installed in operating ice-condenser plants.

In SSER 3, the staff reported the results of an interim evaluation of the efficacy of the Grand Gulf hydrogen ignition system (HIS). At that time, the staff concluded that the interim evaluation provided sufficient basis for finding the ignition system acceptable for an interim period of approximately 1 year from the date a full-power license was issued. The staff also reported in SSER 3 that continuing research, conducted by both the industry and the NRC into issues relevant to Mark III hydrogen control by deliberate ignition, was expected to form the bases for a final evaluation.

After SSER 3 was issued, certain ongoing research conducted by the Boiling Water Reactor (BWR) Hydrogen Control Owners Group (HCOG), as well as additional investigation of issues by the staff, recently has resulted in the development of additional information that is sufficiently important to warrant discussion in this supplement to the SER. This additional information revises the previous descriptions of the thermal environment against which essential equipment was evaluated. In one instance new test data suggest more severe thermal conditions may exist in the wetwell than previously considered; the other issue involves the calculation of thermal conditions for the drywell that are more severe than previously considered. Because of the state of this preliminary research, this report should be viewed as an interim evaluation, and a final evaluation of the Grand Gulf igniter system will be prepared once the research work now in process is completed and before the first refueling of Grand Gulf Unit 1 is completed.

Wetwell Thermal Environment

In SSER 3, the staff reported that the licensee, through HCOG, was developing a test program that would investigate hydrogen combustion above the suppression pool. Since that time, a test program has been developed, with close interaction between the HCOG and the staff, to ensure satisfactory resolution of the technical concerns. Furthermore, certain phases of preliminary testing have been completed.

Among the reasons for investigating hydrogen combustion above a suppression pool is that, as noted in SSER 3, the analysis of equipment survivability was predicated on the assumptions and methodology implicit in the analytical model, namely the CLASIX code. Under certain circumstances, equipment could be exposed to conditions more severe than those considered in the model. (These more severe conditions would result from continuous burning of hydrogen as it is released from the surface of the pool, which would result in a locally severe thermal environment.) The licensee had considered this matter and concluded that the essential equipment would survive. Although in its interim evaluation, the staff agreed with the licensee, the staff recommended that this finding be verified either experimentally or analytically. For that reason, the BWR HCOG initiated its hydrogen control research program.

One of the first elements of the HCOG program was the 1/20th-scale Mark III hydrogen-combustion-visualization program. The initial objective of this program was to provide a visual record of hydrogen combustion behavior in a 360-degree model of a Mark III containment. The test facility was designed to simulate the wetwell and upper containment regions of the Mark III containment. This included the volume below the HCU floor (wetwell), the annular volume above the HCU floor, and the upper containment. There were no provisions to model the interaction of flow with the drywell region of the containment. There was no simulation of the containment spray system. Hydrogen was admitted through quenchers and/or vents into the suppression pool and ignited by a number of igniters placed around the facility. Because the facility was constructed of pyrex and had minimal structural strength (design pressure of 5 psig), the test vessel was vented to relieve pressure whenever internal pressures exceeded 0.1 psig. The staff believes deficiencies in the test facility may have produced results that would be inaccurate when applied to actual plant conditions and, therefore, it would be inappropriate to develop regulatory positions on the bases of these data. The objective of the program was to qualitatively assess the effects of variations in several parameters including (1) hydrogen release rate, (2) wetwell blockages and heat sinks, (3) sparger versus vent release, (4) number and location of spargers, and (5) igniter location. Furthermore, it was anticipated that the results of the 1/20-scale tests would provide valuable information to aid in the design of a 1/4-scale facility if it were determined that tests on a larger scale facility were necessary. A total of 41 tests were conducted. After the 1/20-scale test program was developed and the shakedown testing conducted, instrumentation was added to assess the thermal environment.

The 1/20-scale test program results demonstrated a number of important facets of hydrogen combustion phenomena in a Mark III containment. When hydrogen injection flow rates of 0.4 lb/sec or greater were used, continuous burning of hydrogen in the form of a steady diffusion flame occurred above the suppression pool. Combustion was initiated by the igniters and rapidly propagated downward to the pool surface. Steady diffusion flames anchored at the surface of the suppression pool were established almost immediately above the submerged spargers that released hydrogen. This phenomena, designated as primary burning, is accompanied by horizontal air flow above the pool. Primary burning was seen to intensify as the hydrogen injection flow rate was increased, as evidenced by taller flames and higher temperatures. From a circumferential viewpoint, burning was more intense at the site of two adjacent spargers. As burning continued and the bulk containment atmoshere oxygen concentration decreased, the flames appeared to weaken, grow taller, and move upward wherein they became anchored on the simulated HCU floor grating. This phenomena, characterized by the upward movement of the diffusion flame and anchoring at a high elevation, was designated as secondary burning. As mentioned previously, horizontal air flow above the pool surface allowed the diffusion burning to continue by providing a source of oxygen. Another pattern of circulation that emerged from the testing was the creation of chimneys, which provided for flow to and from the region of burning (wetwell) and exchanged flow with the upper containment. The location of hot (up) chimneys and cold (down) chimneys also was seen to vary with changes in the blockages above the pool. Most of the instrumentation used to measure temperature and heat flux was located in the most intense hot chimney.

Test measurements produced peak gas temperatures in the range of 560°F to 700°F (with one measurement at 836°F) for a hydrogen release rate of 0.8 lb/sec for the location just below the HCU floor. Increasing the hydrogen release rate to 1.0 lb/sec and 2.0 lb/sec increased the measured peak gas temperature by approximately 200F° and 450F°, respectively. Peak gas temperatures, measured at an elevation approximately 8 ft above the HCU floor, ranged between 200°F to 530°F at a hydrogen release rate of 0.8 lb/sec. The temperatures were strongly dependent on the amount of blockage, which was varied, at the HCU floor elevation directly below the thermocouple.

The majority of tests were conducted with the hydrogen being released through 9 spargers to represent a stuck-open relief valve and the opening of 8 automatic depressurization system (ADS) valves. When all the hydrogen was released through a single sparger the peak gas temperature increased approximately 400F° Available data showed that the measured gas temperatures and heat fluxes are strongly affected by the hydrogen flow rate and the number of release locations. It should be noted that because of the limits of the test facility, all tests were conducted with a constant hydrogen injection rate throughout the test.

Because the 1/20th-scale test program showed that there would be persistent diffusion flames with high local temperatures, the licensee has undertaken an extensive effort to better define the conditions that may prevail during a degraded core accident. This research into wetwell combustion phenomena can be classified into three major areas:

(1) revised analysis of the degraded core accident sequence progression with modified hydrogen and steam releases

(2) assessment of the thermal environment in the 1/20-scale tests and evaluation of equipment survivability

(3) 1/4-scale hydrogen combustion tests to better simulate the range of combustion behavior in a Mark III containment

The licensee contends that the high temperatures and heat fluxes seen in the 1/20-scale tests are produced primarily as a result of overly conservative hydrogen release rates. In this regard, the licensee is continuing to pursue revised analyses of degraded core accidents with the MARCH code and the BWR HEATUP code sponsored by the Industry Degraded Core (IDCOR) group. The HEATUP code was developed to calculate the temperature history of the reactor core and the rate of hydrogen production resulting from the metal-water reaction during a condition of inadequate coolant makeup. Important models in the code describe heat transfer, void fraction as a function of position and primary system inventory, and the metal-water reaction. More discussion of the code and the staff's preliminary review is provided later in this section.

The HEATUP code analyses predict a strong interaction between hydrogen release rates and the total metal-water reaction for accident sequences that do not proceed to core melt. That is, for accident sequences involving large hydrogen release rates (on the order of 1 lb/sec and higher) only a relatively small total metal-water reaction can be achieved (i.e., on the order of 20%) before significant core melting and presumably core slump would occur. This primarily is due to the fact that the zirconium-steam reaction is exothermic and, therefore, results in significant heating of the core. To produce a 75% metal-water reaction, which is required by the proposed rule on hydrogen control for degraded core accidents, and to still maintain a relatively intact and, therefore, coolable core geometry, it is necessary that hydrogen generation rates be held to less than approximately 0.2 lb/sec. This point is especially significant because it has been demonstrated that persistent diffusion flames will not exist at these hydrogen release rates; therefore, for these sequences, severe local environments will not challenge equipment survivability. A more detailed discussion of hydrogen releases is provided later in this supplement.

To better define the hydrogen release in a degraded core condition, the licensee is analyzing equipment survivability assuming diffusion flame burning of hydrogen. Although these calculations are still considered preliminary, they demonstrate the severity of the thermal environment if large hydrogen release rates are postulated to occur for a long time. In his analyses, the licensee has considered the temperature response of three selected items (an igniter assembly transformer, a pressure transmitter, and a solenoid) representative of impacted essential equipment. The igniter transformer was considered to be the limiting component in the igniter assembly and was evaluated for survivability because the igniters are located immediately below the HCU floor. The pressure transmitters, representative of reactor pressure vessel water level, are located on instrument racks that are mounted on the grating sections of the HCU floor. Air-operated isolation valves, also located beneath the HCU floor, have several components--a junction box, limit switches, filters, and a solenoid valve. Because of the exposure of the solenoid valve it was evaluated as the limiting component for the air-operated isolation valves.

The thermal environment to which essential equipment might be subjected as a result of diffusion flame burning of hydrogen was evaluated on the basis of the best available data as obtained from the 1/20-scale test program. Because the 1/20-scale test facility did not model the containment spray system, the test data were interpreted in such a manner as to account for the bulk atmosphere cooling effect of the sprays. No credit was taken for the direct cooling of essential equipment by the spray water. Figures 22.1 and 22.2 present the results of selected preliminary analyses performed by the licensee assuming hydrogen release rates of 0.4 lb/sec and 0.8 lb/sec.

For an assumed constant hydrogen release rate of 0.8 lb/sec, the solenoid was estimated to reach its qualification temperature of 330°F in approximately 10 min. Under the same conditions the pressure transmitter was estimated to reach its qualification temperature of 303°F in approximately 8 min.

For an assumed constant hydrogen release rate of 0.4 lb/sec, the solenoid was estimated to reach its qualification temperature in approximately 15 min. Calculations for the pressure transmitter indicate that the qualification temperature would be reached in approximately 26 min.

As discussed in more detail in the next section, it is the licensee's position that because of the limitations inherent in the physical process, degraded core accidents are not likely to result in a sustained hydrogen release rate of 0.4 lb/sec for more than approximately 8 min. For a hydrogen release rate of 0.8 lb/sec, the time interval would be smaller. Thus, on the basis of equipment analyses demonstrating the capability of equipment to withstand hydrogen diffusion flames for 15 to 26 min, the licensee states that essential equipment in the wetwell region would survive in the degraded core accident environment and perform its intended function.

The staff has considered the analyses provided by the licensee to evaluate equipment survivability and has found that there is uncertainty regarding the methodology for determining applicable heat fluxes as well as uncertainty in interpreting the benefits of containment sprays. Therefore, the staff will require that further temperature response analyses be performed by the licensee.

In addition to evaluating the thermal response of equipment, the licensee has reviewed the original list of essential equipment as identified in SSER 3. As a result of this review, the licensee has deleted three items previously identified as essential equipment--hydrogen analyzer tubing, MSIV limit switches, and drywell pressure instrumentation. The rationale for deleting MSIV limit switches and drywell pressure instrumentation is that they will have performed their function before the time in the accident sequence when severe environmental conditions may be encountered. In the case of the hydrogen analyzer tubing, it was determined that the tubing was not a component sensitive to the environment because it is qualified to a temperature of approximately 1,000°F. The staff has considered this matter and finds the deletion of these three items to be acceptable on the bases proposed by the licensee.

The third major element of the applicant's hydrogen research program is the 1/4-scale hydrogen-combustion test program sponsored by the BWR HCOG. The 1/4-scale test facility will be used to perform tests for studying the behavior of the flames produced by the release of hydrogen through a pool of water at the bottom of the containment. The test enclosure, which is designed to operate at pressures of up to 40 psig, consists of an outside tank, 31.5 ft in diameter by 49.4 ft high, containing a smaller tank, 20 ft in diameter by 23 ft high. The space between the two tanks is the test volume; it contains floors and other large blockages simulating the obstructions that exist in the actual containment. Provisions are made for heating the water at the bottom of the test vessel and for modeling the sprays of the containment. Hydrogen can be introduced through a series of vent holes in the wall of the inner tank or through spargers mounted in the suppression pool. The test program calls for instrumentation to measure temperatures (gases and solid), heat fluxes (total and radiative), species concentrations (H_2, O_2, H_2O), velocities, flame location, total pressure, and flow rates of fuel and water. A computerized data acquisition system will be used to collect data at rates that are sufficient to resolve the transients produced by possible volumetric burns in the test enclosure. Provisions also will be made to obtain a visual record of the combustion in the test chamber.

On the basis of its preliminary review, the staff concludes that the 1/4-scale test program proposed by the licensee can provide sufficient information to resolve questions regarding the conditions leading to and the consequences resulting from hydrogen combustion in the wetwell and containment. Specifically, the staff believes that the proposed program can provide firm bases for evaluation of equipment survivability in the wetwell and containment regions of the Grand Gulf Nuclear Station.

Hydrogen Generation

This section discusses the generation rates and quantities of hydrogen associated with degraded core accidents that should be considered at this stage of the review.

A number of event sequences were evaluated during the review of hydrogen releases accompanying severe accidents. The selection of the event sequences to be considered at this time is based on the following general guidelines:

(1) The event sequences must be physically achievable in that all major inputs and outputs of energy and materials should be accounted for.

(2) The event sequences should represent a significant fraction of the degraded core accident risk as indicated in probabilistic risk assessment (PRA) studies.

(3) The production of hydrogen equivalent to the oxidation of up to 75% of the active cladding should be included.

(4) Event sequences in which essentially the entire core is reduced to a rubble bed or is melted need not be considered. The effects of recovery of cooling before this point should be included in assessing the efficacy of the distributed ignition system.

A review of the energy inputs and outputs in a typical core uncovery accident shows that there is a rather limited range of accident situations in which the above guidelines can be met. For example, consider an isolation accident with loss of all injection. The core would eventually boil dry and melt if the event sequence were unmitigated. At about $4x10^3$ sec, the major energy source, the decay heat, would amount to about 41 MW in what would be the dry upper half of a partially covered core. This is the time at which hydrogen production typically accelerates to a high rate. The oxidation energy associated with the production of 0.4 lb of hydrogen per second, the rate at which a diffusion flame would be sustained, would add another 27 MW to the heat being generated in the upper half of the core. Offsetting these amounts are the radiation heat losses, estimated at less than 10 MW, and the potential enthalpy of superheating the steam in the upper half of the core, which is not over 16 MW. The energy inputs exceed the outputs by at least 40 MW, most of which must be absorbed in the upper half of the core. The heat capacity of the upper half of the core is such that its temperature will rise at a rate of about 50 K/min with this heat input. Of course higher sustained hydrogen generation rates would correspond to greater energy imbalance and rapid core melt. If that portion of the event sequence starting from the time when hydrogen generation accelerates rapidly (dry upper core at 1,800°K) is considered, it is apparent that only 7 or 8 min will elapse before the entire upper half of the core has reached 2,173°K, the temperature of molten Zircaloy. The latter temperature is suggested by the licensee as a criterion for major core disruption. The bases for this view are that (1) with the cladding melted, some of the UO_2 fuel would form an alloy with the cladding, (2) there would be no firm envelope to restrain the fuel pellets, and (3) requenching would tend to embrittle and shatter the cladding. The licensee further asserts that events more severe than described above need not be considered at this time.

The staff is not in full accord with the 2,173°K figure as a criterion of core disruption, because it seems to unduly minimize the window of accidents short of core melt that needs to be considered. However, with such a substantial rate of oxidation going on, the rate of core temperature rise is so great that any other reasonable criterion of core disruption would soon be met. For example, the entire upper half of the core would reach the temperature of molten UO_2 (3,113°K) in only an additional 19 min. No reasonable approximation of the original upper core geometry could be expected to be maintained beyond this point. The rate of hydrogen production based on detailed analysis is found to vary with time as described later in this section. If the hydrogen generation rate were contrived at a constant value of 0.4 lb/sec, only 640 lbs of hydrogen (equivalent to a reaction of approximately 19% of the active cladding) would be formed in this case before major core disruption.

It is clear, therefore, that if 75% of the active cladding is to be oxidized (2,500 lbs of hydrogen produced) without totally destroying the original core geometry, it must be done at an extremely slow rate such that the heat of oxidation can be dissipated. For this situation the rate of hydrogen production would be well under 0.2 lb/sec.

However, it is also clear that the above combination of guidelines may not lead to the single most restrictive bounding case. It is necessary, therefore, to consider scenarios that lead to lesser total amounts of hydrogen produced, though at higher rates, in order to understand the limitations (if any) associated with the distributed ignition system.

The licensee has developed detailed calculations of a variety of such sequences, with hydrogen generation obtained from the HEATUP code. The HEATUP code has not been released for public comment and use. It was, therefore, described to the staff and its consultants in sufficient detail to form a preliminary evaluation of its scope and usefulness. Although there has not been time for a detailed study of the actual coding of the program, the initial conclusion reached by the staff has been that the HEATUP code is state-of-the-art in its principles, comparable and in some ways superior to other codes now in use to predict hydrogen production.

The staff's survey of scenarios likely to require consideration showed that transients accompanied by failure of injection should be given the closest attention. This is not only because of their relatively significant expected frequency of 10^{-4} per reactor year, but also because the schedule of hydrogen evolution is similar to that of other less frequent but possibly important accident groups, such as small break loss-of-coolant accidents (LOCAs) and anticipated transients without scram (ATWS).

The transient event sequences of primary concern include a broad family of accidents initiated possibly by a loss of offsite power, coupled with loss of high-pressure injection and failure to depressurize (TQUX). Alternatively, the system may become depressurized but the feedwater and high- and low-pressure injection may all fail (TQUV). In either case, whole families of variations may arise if there is rapid or slow depressurization, restricted at some phase of the accident. These groups of accidents will be designated TQUX, TQUV.

In the TQUV (rapidly depressurized) group with no injection, decay heat and depressurization will boil away the water inventory to the point of the start of core uncovery in about 2,000 sec (subsequent hydrogen production is not highly sensitive to the time of core uncovery). About 1 hour into the accident, the water level will be down to about 1/4 of the core height (from the bottom). As the rate of steaming decreases because of reduced water level, the upper ends of the fuel elements will overheat and the temperature will become high enough so that the cladding will react with steam.

$Zr + 2H_2O \text{------->} ZrO_2 + 2H_2$

91 kg Zr-------->4 kg H_2 + 598 MW sec

In several detailed calculations of these depressurized unmitigated sequences, the hydrogen production was steam limited. Some 30-35% of the active cladding (equivalent) was oxidized yielding 1,000-1,100 lbs hydrogen, generated over approximately 50 min.

During the peak hydrogen production period of 13 min, hydrogen generation averaged 0.53 lb/sec (0.64 lb peak). During the remainder of the time, the hydrogen generation rate was less than 0.4 lb per sec. This sequence led to considerable core disruption as defined by the licensee's criterion.

The licensee has calculated variations on this scenario (1) to determine what injection would be necessary and when it would have to be started in order to prevent severe core damage and (2) to determine the corresponding amounts and schedule of hydrogen production.

Without injection, the time of the maximum hydrogen generation rate was determined to be about 4,000 sec in the rapidly depressurized case, or about

10,000 sec in the pressurized case. The amount of injection required to quench the reaction depends on the length of time in advance of maximum H_2 generation time that injection is restarted, but if this time interval is 10 min or more, relatively low injection rates (300 gpm) will turn the reaction around (quench). Thus, any depressurized TQUV in which a low injection rate (such as control rod drive water) or a high-pressure injection is recovered prior to 3,400 sec would be quenchable without core disruption. If depressurized slowly or not at all, the time for recovery of high-pressure injection is extended even further. If injection is not restarted before maximum H_2 generation time, it is unlikely that major core disruption can be averted. If no injection at all takes place, the sequence quickly leads to core melt well before 75% of cladding can react.

If any full flow injection device (>300 gpm) is recovered within 3,400 sec, the core is quenchable without extensive hydrogen production. Thus, only a restricted range of partial injection, i.e., less than about 100 gpm and started before 3,400 sec, leads to extensive hydrogen production (75% active cladding), whereas many injection devices with individual capacity of up to 9,000 gpm are normally available. The sequences that are limited to the low flow rates are only a small fraction of the total of recoverable and nonrecoverable TQUX and TQUV sequences. Pumps that may provide makeup water at Grand Gulf and their approximate capacities are listed in Table 22.1.

Once core geometry changes, the currently available HEATUP or MARCH codes are not applicable. Uncertainties associated with core relocation, clad relocation, and H_2 generation become very large.

Although the staff is confident that the extended production of hydrogen is very unlikely to aggravate the TQUV and TQUX types of scenarios, there are enough uncertainties in various aspects of the sequence that research on these matters should be continued. There are studies being made to extend the calculations of hydrogen production to cases involving relocated fuel and cladding. These should be continued to supplement the results from the present HEATUP or MARCH code.

The staff concludes that a substantial range of accident sequences, meeting the guidelines chosen earlier, would result either in rates of hydrogen generation too low to support diffusion burns (<0.4 lb/sec) or would be slightly above 0.4 lb/sec for only a short time (about 15 minutes). The oxidation of 75% of the active cladding without core disruption involves slow rates of ($\leq$0.2 lb/sec) hydrogen production. Extended periods of hydrogen generation that are greater than 0.4 lb/sec without violating energy bounds require unusual combinations of circumstances that have a low probability of occurrence. Sequences with hydrogen generation substantially greater than 0.4 lb/sec for protracted periods appear to lead quite rapidly to core melt.

Drywell Environment

As a result of the staff's continuing review of the CLASIX code and the containment analyses performed by the licensee in support of the igniter system, the staff has identified a concern that is relevant to analyses of the drywell atmosphere temperature transient for the drywell pipe break sequence. As part of the staff's interim evaluation of the igniter system, discussed in Supplement 3 to the SER, the staff cited confirmatory containment analyses performed by the Sandia National Laboratory using the HECTR code. The staff also noted that the HECTR code at that time did not contain a model for the drywell region of the containment. After the SER was issued, the staff sought confirmation of the calculated drywell atmosphere transient response predicted by the licensee using the CLASIX-3 code. The staff used the CONTEMPT-LT28 code to estimate the drywell transient and thus confirm the licensee's analyses. Because the CONTEMPT-LT28 is not designed for long-term Mark III containment analyses and does not contain provisions for hydrogen-combustion modeling, a number of simplifying approximations were made to model the problem. The results of the staff's CONTEMPT analyses indicated significantly higher drywell atmosphere temperatures than those predicted by the licensee, i.e., on the order of 100°F. These differences in temperature occurred before the onset of hydrogen combustion was predicted to occur in the drywell. Because the CONTEMPT-LT28 model is an approximation of the Mark III drywell configuration and because the code does not contain provisions for burning, the calculations were terminated before onset of the complex interactions between the drywell and containment and before the onset of hydrogen combustion. The CONTEMPT-LT28 calculations, therefore, predicted high drywell atmosphere temperatures (on the order of 400°F) as a result of the high temperature steam and hydrogen releases directly into the drywell. High temperatures were predicted basically for the same reasons as they are predicted for main steam line breaks, normally considered as design-basis accidents.

The reason for CLASIX-3 predicting lower temperatures for the postulated drywell pipe accident was that the code models overpredicted convective heat transfer in a superheated atmosphere with a high steam concentration. This resulted in a nonconservative underestimate of the containment atmosphere temperature. It should be noted that the CLASIX-3 models were primarily developed to predict conservatively high pressures associated with hydrogen combustion and not necessarily high preburn temperatures. The staff informed the licensee of this matter, and the CLASIX-3 models have recently been modified to more appropriately account for structural heat transfer in the drywell environment.

Using the modified CLASIX-3 code, the licensee has reanalyzed the consequences of a postulated pipe break in the drywell. Preliminary analyses were performed to assess the effects of two phenomena that may occur in the drywell. The first phenomenon, diffusion burning of hydrogen, may occur as a result of oxygen being introduced to the drywell through the purge compressors or vacuum breakers. The other possible phenomenon is the occurrence of volumetric burns encompassing the entire drywell region as assumed in the original CLASIX-3 analysis. The results of the preliminary analyses indicate a bulk atmosphere temperature of approximately 350°F for the case assuming that continuous burning of hydrogen resulting from the operation of one purge compressor. For the case that assumes discrete volumetric burns and operation of two purge compressors, preliminary analyses indicate a drywell temperature of approximately 400°F with spikes reaching 1,200°F. The analyses of the postulated drywell pipe break accident are considered preliminary since the licensee is currently revising the calculation to better reflect the actual sequence of events. The original drywell pipe break analyses simply used the same hydrogen and steam releases that were generated from MARCH analyses of the stuck-open relief valve scenario. This was done as an expedient and was justified by the fact that a small pipe break scenario (S_2E) based on a break flow area associated with a 2-in. pipe would be bounded by the release associated with a stuck-open relief valve with a flow area (0.163 ft³) equivalent to a 5.5-in.-diameter line. Other modifications to be made in future analyses include a more accurate determination of the flow split between the drywell and suppression pool once the ADS valves are opened.

The staff will report on these future drywell pipe break calculations in a later supplement to the SER. In addition to the revised calculations, the staff has requested that the licensee evaluate the effects of diffusion burning of hydrogen in the drywell on equipment survivability for equipment located in the drywell. The staff will report on the results of that evaluation at a later date.

License Conditions

To ensure timely resolution of the issues that have not been completely resolved, the staff proposes the following revision to License Condition 2.C.44(d) requiring the performance of additional analysis and testing. This additional research effort should be sufficient to allow the Commission to confirm the adequacy of an installed igniter system before startup following the first refueling outage. Specifically, the research effort shall include the following:

(1) A containment sensitivity analysis shall be performed to determine the adequacy of the hydrogen control system for a spectrum of degraded core accidents including the determination of accident sequences for which equipment survivability is ensured.

(2) Research shall be conducted to investigate the conditions leading to and consequences resulting from hydrogen combustion in the wetwell and containment. Testing shall be performed in a larger scale facility such as the 1/4-scale test facility proposed by MP&L.

(3) Research shall be conducted to investigate the conditions leading to hydrogen combustion in the drywell.

(4) Confirmatory tests shall be performed on thermal response of selected equipment exposed to hydrogen burns.

Furthermore, the staff proposes an additional license condition requiring the licensee, during the interim period of operation, to perform studies of options for enhancing equipment survivability. The options to be examined in such studies should include thermal shielding, additional cooling, and relocation of essential equipment.

Conclusions

As a result of recently completed research and the ongoing investigation of hydrogen control in a degraded core accident, some substantive new information has been developed. The control of large quantities of hydrogen associated with the postulated degraded core accidents has consequences in terms of raising the containment atmosphere pressure and temperature. The recent developments may bear on the staff's prior conclusions regarding the containment atmosphere thermal environment. However, there is nothing to suggest that the previous pressure analyses are not conservative; rather, the occurrence of diffusion burning by gradually and continuously releasing the energy of combustion serves to reduce the pressure consequences of hydrogen combustion. However, diffusion burning of hydrogen may create severe local environments that challenge essential equipment.

The licensee, in his initial assessment of the efficacy of the igniter system, used a very conservative hydrogen release profile based on MARCH code calculations and extrapolation of high hydrogen release rates until a total metal-water reaction of 75% of the active cladding was achieved. This approach was an expedient to assessing the consequences of hydrogen combustion during degraded core accidents. However, this conservative approach of utilizing unrealistically large hydrogen release rates for a long duration, was shown to produce a similarly unrealistic severe local thermal environment. As a result, the licensee has chosen to adopt a revised approach based on more realistic, yet conservative, hydrogen release histories.

The staff believes that the mission of reducing the risks associated with large hydrogen releases may best be served by continuing to require utilities to provide protection for accidents involving the release of hydrogen corresponding to a fuel cladding reaction of up to 75%. The staff, however, contemplates no binding requirement on the rate at which the hydrogen shall be assumed to be released. Therefore, utilities may use hydrogen release rates that are representative of physical processes, including those that may limit the release rates, for accident sequences that could generate 75% metal-water reaction and still be terminated short of a core meltdown.

The licensee has provided analyses, based on data taken from small scale testing to demonstrate survivability of equipment in the wetwell region. The staff finds these analyses to be insufficient; therefore, confirmation with larger scale testing is required. The staff concludes that the licensee should continue the investigation of hydrogen combustion through testing in a larger facility, such as the proposed 1/4-scale test facility.

Furthermore, the staff finds that it would be prudent to require the licensee to perform additional studies of the feasibility of options that may be taken to improve the capability of essential equipment to survive the effects of hydrogen burning. These options include relocation of equipment away from locally severe thermal conditions, provisions for thermal protection of equipment, and the provision for additional cooling mechanisms (e.g., drywell sprays).

It is the staff's judgment, subject to adoption of the license conditions detailed above, that the igniter system can be shown to be effective in controlling hydrogen releases from the more likely degraded core accident scenarios with acceptable consequences. The staff will continue to review this matter and will report its findings in a future supplement to the SER.

II.K.3 Final Recommendations of Bulletins and Orders Task Force

II.K.3.28 Verify Qualification of ADS Accumulators

The staff has requested by letter dated August 11, 1983, from A. Schwencer (NRC) to J. P. McGaughy, Jr. (MP&L) additional information regarding Item II.K.3.28. The review of the licensee's response to this request will be reported in a future supplement to the SER. Before this issue can be resolved, the staff requires the following licensing conditions.

2.C.(44)(k) ADS Accumulators

Prior to startup following the first refueling outage, MP&L shall perform an integrated leak test on the ADS air system, perform sampling to establish instrument air quality, provide instrumentation to monitor ADS air receiver pressure, establish suitable surveillance procedures for the ADS air system and provide proposed changes to the Technical Specifications associated with the surveillance procedures.

The licensee has completed the following actions regarding the ADS:

(1) conducted a leakage reduction program
(2) performed an integrated leak test
(3) installed a mechanical pressure gauge to monitor the integrity of the accumulators

The licensee has committed to verify daily the availability of the ADS accumulators. The staff finds these actions and commitments acceptable pending final resolution of Item II.K.3.28.

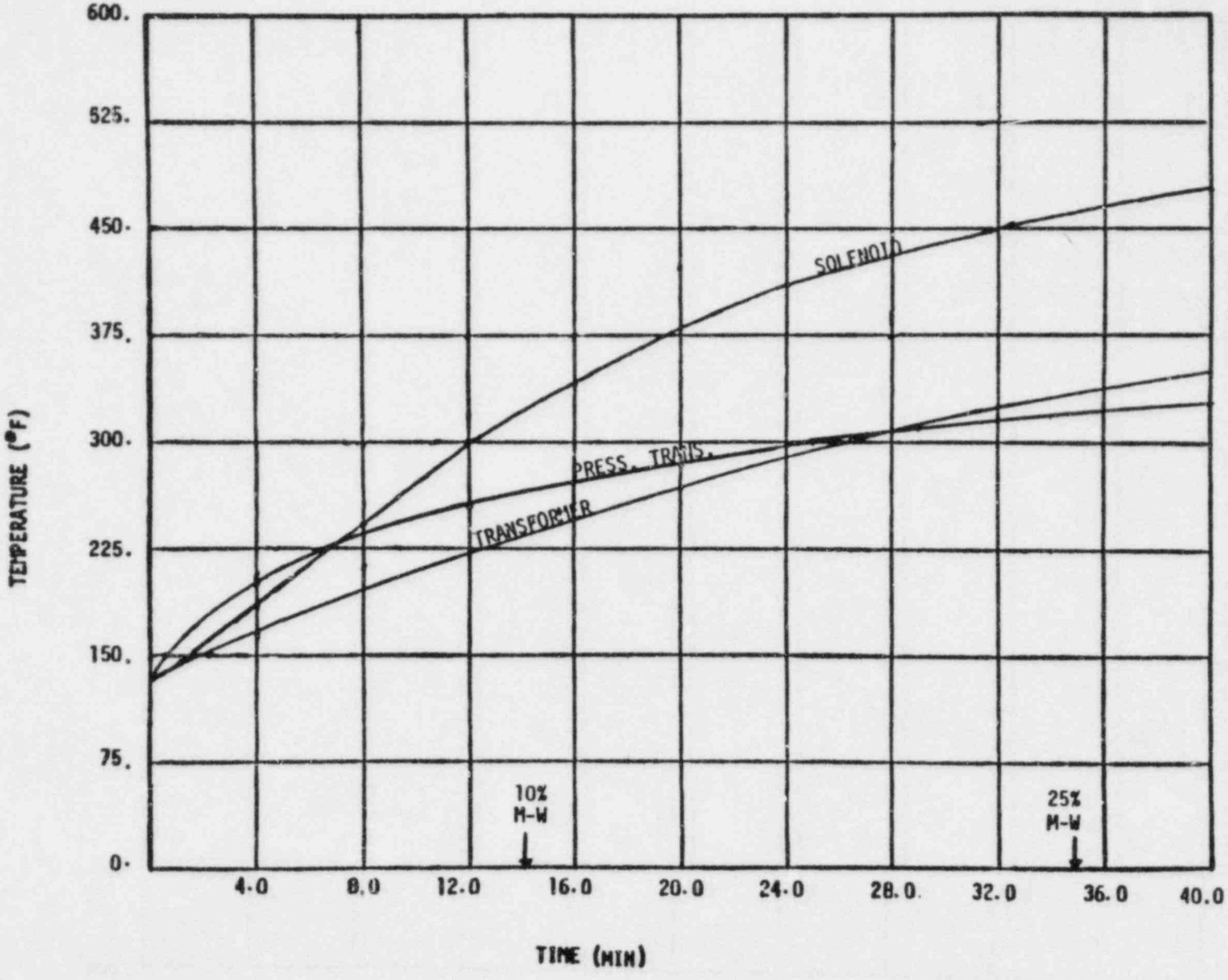

Figure 22.1 Calculated equipment temperatures where $\dot{M}_{H_2}$ = 24 lb/min (0.4 lb/sec)

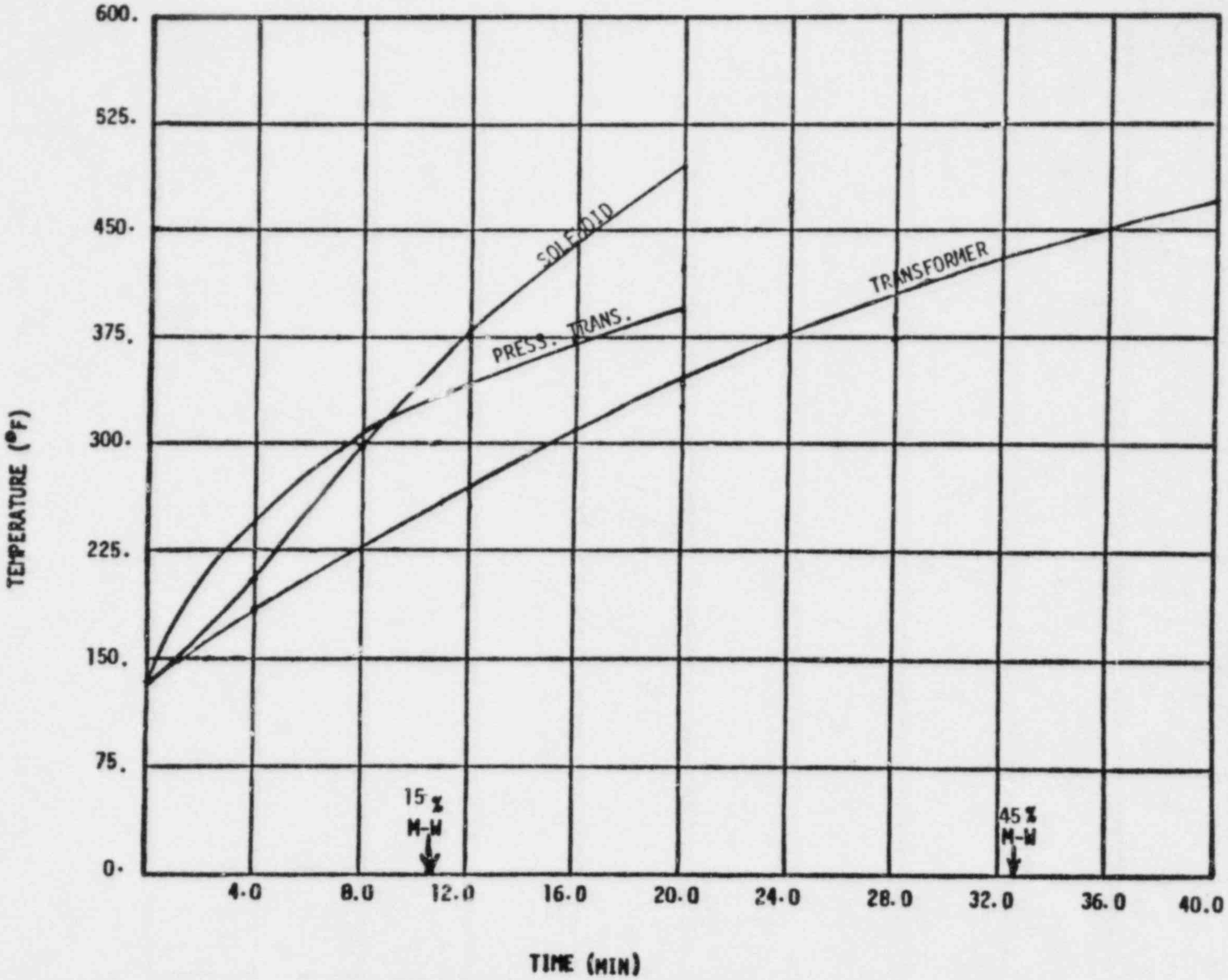

Figure 22.2 Calculated equipment temperatures where $\dot{M}_{H_2}$ = 48 lb/min (0.8 lb/sec)

APPENDIX A

CONTINUATION OF CHRONOLOGY

June 13, 1983	SER Supplement No. 4 to licensee.
June 16, 1983	Letter from licensee regarding additional information on Hydrogen Control Owners Group Program.
June 17, 1983	Submittal from licensee of Amendment No. 56 to the FSAR.
June 17, 1983	Letter from licensee regarding Baxter Wilson plant selected for backup emergency operations facility.
June 21, 1983	Letter to licensee regarding list of proposed Technical Specification changes.
June 23, 1983	Letter from licensee regarding clarification capabilities of hydrogen ignition systems.
June 29, 1983	Letter to licensee regarding Generic Letter 83-24.
June 29, 1983	Letter from licensee regarding changes to Technical Specifications.
June 30, 1983	Letter from licensee forwarding annual financial report for 1982.
July 1, 1983	Letter to licensee transmitting Amendment No. 7 to Operating License NPF-13.
July 5, 1983	Letter to licensee regarding Generic Letter 83-26.
July 5, 1983	Letter to licensee regarding Revision 7 to the Physical Security Plan.
July 6, 1983	Letter to licensee regarding Generic Letter 83-27.
July 8, 1983	Letter to licensee regarding Generic Letter 83-28.
July 8, 1983	Letter from licensee regarding changes to the Technical Specifications.
July 11, 1983	Letter from licensee regarding changes to the Technical Specifications.
July 14, 1983	Letter from licensee regarding automatic containment isolation signal.

July 15, 1983	Summary of June 29 meeting in Bethesda, MD, regarding Mark III BWR Owners Group.
July 18, 1983	Meeting with BWR Hydrogen Control Owners Group to discuss large-scale hydrogen generation in Mark III BWRs, requirements of hydrogen control, and capability of distributive ignition system.
July 19, 1983	Letter from licensee regarding Technical Specifications.
July 20, 1983	Letter from licensee regarding SER Section 6.2.8.
July 21, 1983	Letter to licensee regarding Generic Letter 83-30.
July 21, 1983	Letter from licensee regarding revision to Chapter 14 of the FSAR.
July 22, 1983	Letter to licensee regarding Mark III Hydrogen Control Owners Group.
July 27, 1983	Letter to licensee regarding intergranular stress corrosion cracking in recirculation system.
August 1, 1983	Letter to licensee regarding results of control room envelope leak tightness test.
August 3, 1983	Letter to licensee regarding Technical Specification changes.
August 8, 1983	Letter to licensee regarding Operating License Condition 2.C.(30).
August 9, 1983	Letter from licensee regarding Technical Specification changes.
August 11, 1983	Letter to licensee regarding TMI Action Plan Item II.K.3.28.
August 13, 1983	Letter from licensee regarding hydrogen control.
August 15, 1983	Letter from licensee regarding NUREG-0737 Technical Specifications status per Generic Letter 83-02.
August 17, 1983	Letter from licensee regarding intergranular stress corrosion cracking.
August 18, 1983	Letter from licensee regarding revised control room inleakage dose assessment.
August 19, 1983	Letter to licensee regarding isolation of instrument air line.
August 22, 1983	Letter from licensee regarding emergency response capability.

August 23, 1983	Letter from licensee regarding balance-of-plant vibration monitoring program.
August 23, 1983	Letter from licensee regarding hydrogen control.
August 23, 1983	Letter from licensee regarding control room inleakage.
August 25, 1983	Letter from licensee regarding relief from ASME Code Section XI requirements for preservice inspection of nozzle.
August 25, 1983	Letter from licensee regarding Operating License Condition 2.C.(12)(c)(i)(iii).
August 25, 1983	Letter from licensee regarding SER Supplement 4, Section 22.2, Item II.B.3.
August 26, 1983	Letter from licensee regarding quality assurance audit.
August 26, 1983	Letter from licensee regarding Revision 0 to pump and valve inservice inspection program.
August 26, 1983	Letter from licensee regarding extended restart delays.
August 29, 1983	Letter to licensee regarding action on State of Michigan Municipal Energy Agency request for enforcement action against utility regarding violation of antitrust license conditions.
September 2, 1983	Letter to licensee regarding paid public notice about application for amendment to Operating License NPF-13.
September 6, 1983	Letter from licensee regarding Generic Letter 83-28.
September 9, 1983	Letter from licensee regarding inservice inspection of pump and valves.
September 9, 1983	Letter from licensee regarding proposed changes to the Technical Specifications.
September 12, 1983	Letter from licensee regarding proposed schedules to complete Technical Specifications.
September 12, 1983	Letter from licensee regarding hydrostatic leakage rate testing.
September 12, 1983	Letter to licensee regarding changing Technical Specifications.
September 13, 1983	Letter from licensee regarding high-pressure core spray injection functions of drywell pressure-high and manual initiation.

September 13, 1983	Summary of July 28 meeting in Bethesda, MD, regarding BWR hydrogen control systems.
September 13, 1983	Letter to licensee regarding Notice of Consideration of issuance of amendment to Operating License NPF-13.
September 15, 1983	Letter to licensee forwarding Amendment No. 9 to Operating License NPF-13.
September 15, 1983	Summary of August 23, 1983, meeting regarding HEATUP computer code and calculation of hydrogen generation rates.
September 20, 1983	Letter from licensee regarding pneumatic testing.
September 23, 1983	Letter to licensee regarding pneumatic testing.
September 23, 1983	Letter to licensee regarding startup test program.
September 23, 1983	Letter to licensee transmitting Amendment No. 10 to Operating License NPF-13.
September 23, 1983	Letter to licensee transmitting Amendment No. 11 to Operating License NPF-13.
September 28, 1983	Letter from licensee regarding safety-related mechanical snubbers.
September 30, 1983	Letter from licensee regarding extended outage.
September 30, 1983	Summary of September 23, 1983, meeting regarding Agastat relay failures.
October 4, 1983	Letter from licensee regarding isolation of instrument air systems.
October 7, 1983	Letter from licensee regarding installation of mechanical pressure gauge on automatic depressurization systems air makeup line.
October 10, 1983	Letter from licensee regarding instrumentation.
October 13, 1983	Letter to licensee regarding inoperable Agastat relays.
October 14, 1983	Letter from licensee regarding containment structural integrity test.
October 14, 1983	Letter from licensee regarding SER Confirmatory Item 1.10(4).
October 14, 1983	Letter from licensee regarding fuel assembly liftoff.
October 14, 1983	Letter from licensee regarding number of operable channel requirements for isolation actuation instrumentation.

October 17, 1983	Letter from licensee regarding evaluation of adequacy of hydrogen control systems.
October 19, 1983	Letter to licensee regarding Generic Letter 83-28.
October 19, 1983	Letter from licensee regarding applicability of Shoreham diesel generator crankshaft failure to Grand Gulf Nuclear Station.
October 24, 1983	Letter from licensee regarding automatic dispatch system (ADS) accumulators and air system.
October 24, 1983	Letter from licensee regarding drywell personnel air lock 10 CFR 21 report.
October 26, 1983	Letter from licensee regarding revisions to FSAR Appendix 13A.
October 26, 1983	Letter from licensee regarding diesel generator reliability report.
October 26, 1983	Letter from licensee regarding adequacy of its personnel to operate Grand Gulf Nuclear Station.
October 31, 1983	Letter to licensee requesting additional information about Transamerica Delaval, Inc. (TDI), diesel generators.
October 31, 1983	Generic Letter 83-38 to licensee regarding NUREG-0965.
November 1, 1983	Generic Letter 83-36 to licensee requesting review of Technical Specifications to determine consistency with guidance in NUREG-0737.
November 2, 1983	Generic Letter 83-35 to licensee regarding clarification of TMI Action Plan Item II.K.3.31.
November 4, 1983	Letter from licensee forwarding response to Generic Letter 83-28 regarding generic implications of Salem ATWS events providing status of conformance with NRC positions, plans, and schedules for needed improvements.
November 7, 1983	Letter from licensee forwarding résumés of advisors to plant operations staff supplying BWR operating experience.
November 15, 1983	Letter from licensee forwarding partial response to request for additional information about Transamerica Delaval, Inc., diesel generators supplied to facility.
November 18, 1983	Letter from licensee forwarding "Grand Gulf Nuclear Station Unit 1 5% Power Operational Readiness Review," per License Condition 2.C.(3).

December 2, 1983	Generic Letter 83-32 to licensee concerning NRC recommendations on operator action for reactor trip and anticipated transients without scram.
December 8, 1983	Generic Letter 83-39 to licensee about voluntary survey of licensed operators.
December 12, 1983	Letter to licensee forwarding questionnaire on staffing for Unit 1.
December 14, 1983	Letter from licensee forwarding application to amend License NPF-13, revising Technical Specification to increase surveillance requirements for Rosemont trip units and Riley temperature switches listed in Table 4.3.2.1-1.
December 15, 1983	Letter from licensee forwarding definitions for "channel," "trip system" and "trip fuction" as generic definitions, and instrumentation in Technical Specification Table 3.3.2-1 regarding isolation actuation instrumentation, per September 12, 1983, commitment.
December 16, 1983	Generic Letter 83-41 to licensee regarding fast cold starts of diesel generators.
December 19, 1983	Generic Letter 83-42 to licensee regarding clarification to Generic Letter 81-07 about response to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."
December 19, 1983	Generic Letter 83-43 to licensee regarding reporting requirements of 10 CFR 50.72, 10 CFR 50.73, and Standard Technical Specifications.
December 19, 1983	Letter from licensee responding to informal survey on profile of plant staff.
December 19, 1983	Letter from licensee forwarding justification for proposed changes to Technical Specification on main steamline isolation, condenser vacuum low.
December 20, 1983	Letter from licensee considering initial justification for delayed pneumatic testing to be still valid.
December 22, 1983	Letter from licensee forwarding Amendment 57 to FSAR updating as-built conditions, providing results of systems testing, and rendering Final Safety Analysis Report consistent with Safety Evaluation Report.
December 23, 1983	Letter from licensee discussing organization of Transamerica Delaval, Inc. Diesel Generator Owners Group detailed at December 21, 1983 meeting in Atlanta, GA, and requesting meeting during week of January 16, 1984.
December 27, 1983	Letter to licensee forwarding list of NRC questions about Delaval diesel generators.

December 28, 1983	Letter from licensee forwarding description of modification required by License Condition 2.C.(30) regarding remote shutdown panel, in response to NRC FSAR Question 13.18(4).
December 28, 1983	Letter from licensee documenting results of Bourns potentiometer retest, per November 14, 1983, commitment.
December 29, 1983	Letter to licensee requesting that the enclosed T. M. Novak request for additional information of December 27, 1983, about Transamerica Delaval, Inc. emergency diesel generators be answered specifically.
January 5, 1983	Generic Letter 84-01 to licensee about NRC use of terms "important to safety" and "safety-related."
January 6, 1984	Generic Letter 84-02 to licensee about notice of meeting on facility staffing.
January 6, 1984	Letter from licensee forwarding response to December 12, 1983, request for information about plant staffing and experience.
January 6, 1984	Letter from licensee forwarding proprietary affidavit and figures referenced in utility's January 6, 1984, response to NRC questions about Agastat relays.
January 6, 1984	Letter from licensee forwarding response to NRC's October 13, 1983, request for additional information about Agastat relays.
January 6, 1984	Letter from licensee endorsing safety review committee on operational readiness review for 5% power.
January 11, 1984	Letter from licensee forwarding modifications to FSAR Chapter 14 on startup test program.
January 13, 1984	Generic Letter 84-03 to licensee regarding availability of NUREG-0933, "Prioritization of Generic Safety Issues."
January 16, 1984	Letter from licensee responding to Generic Letter 83-40 on operation licensing exams.
January 18, 1984	Letter from licensee forwarding responses to NRC's December 29, 1983, request for additional information on Transamerica Delaval, Inc., diesel generators employed at facilities.
January 20, 1984	Letter from licensee submitting additional information on Agastat relays per January 6, 1984, letter.

January 20, 1984	Letter from licensee submitting information about knowledge and use of Taiwan Power Company's Kuosheng Nuclear Station's operating experience, in response to NRC informal request.
January 23, 1984	Letter from licensee forwarding first of several submittals intended to demonstrate justification for control room envelope in leakage higher than originally assumed in FSAR.
January 30, 1984	Letter to licensee requesting review of enclosed vital area barrier locations to determine whether upgrading is required.
February 2, 1984	Letter from licensee forwarding additional information in support of control room leakage following design-basis-accident issue on elimination of postaccident 0-2 minute unfiltered containment release from dose model.
February 2, 1984	Letter from licensee forwarding description of implementation of listed NUREG-0737 items per Generic Letter 83-36.
February 2, 1984	Letter to licensee discussing elements of Transamerica Delaval, Inc. (TDI) Diesel Generator Owners Group program to qualify TDI generators.
February 3, 1984	Letter to licensee acknowledging receipt of January 11, 1984, letter about proposed revisions to startup test program.
February 6, 1984	Letter from licensee forwarding "Physical Modelling of Containment Concentrations at Control Room - Grand Gulf Nuclear Station," conducted in support of higher control room inleakage values.
February 6, 1984	Letter from licensee requesting exemption from 10 CFR 50.71(e) which requires updated FSAR to be submitted within 24 months of operating license.
February 9, 1984	Letter from licensee forwarding "Degraded Core Accident Hydrogen Control Program," quarterly status report for quarter ending September 30, 1983, in response to request in Supplement 4 to the SER (NUREG-0831).
February 9, 1984	Letter to licensee advising that NRC will not review emergency plans to delete privacy or proprietary information unless specifically requested by licensee, per Generic Letter 81-27 of July 9, 1981.
February 9, 1984	Letter from licensee advising that containment, liner, and penetrations are capable of withstanding 5 psid negative internal pressure from hydrogen combustion.

February 13, 1984	Letter to licensee forwarding request for additional information on ultimate capacity for containment under external or negative pressure.
February 14, 1984	Letter to licensee forwarding "Control of Heavy Loads at Nuclear Power Plants - Grand Gulf Nuclear Station Unit 1, (Phase II)," draft technical evaluation report.
February 15, 1984	Letter from licensee requesting that due date for balance of information on isolation actuation instrumentation, per utility's letters of September 12, 1983, and December 15, 1983, be extended until March 16, 1984.
February 17, 1984	Letter from licensee requesting extension for submittal of analysis of reliability of the emergency core cooling system for Agastat relay test intervals until March 2, 1984.
February 20, 1984	Letter from licensee forwarding "Comprehensive Report on Standby Diesel Generators--Significant Activities to Enhance and Verify Reliability."
February 20, 1984	Letter from licensee forwarding information on shift advisors, including job description.
February 21, 1984	Letter to licensee forwarding Amendment 12 to License NPF-13 and safety evaluation.
February 21, 1984	Letter from licensee forwarding new problem sheets, problem sheets with supporting documents, and uncontrolled Technical Specifications with punchlist numbers on tops of pages where inconsistencies are identified.
February 22, 1984	Letter from licensee forwarding quarterly report for last quarter 1983, "Degraded Core Accident Hydrogen Control Program."
February 22, 1984	Letter from licensee advising that liner, penetrations and containment structure are evaluated at 5 psid and found capable of withstanding differential pressure without compromise of containment pressure boundary.
February 24, 1984	Letter to licensee discussing deficiencies discovered in Transamerica Delaval, Inc., emergency diesel generators.
February 24, 1984	Letter to licensee requesting review of amended Technical Specifications and certification that Technical Specifications reflect plant FSAR and SER analyses.
February 26, 1984	Letter from licensee confirming discussions and commitments made in February 21, 1984, meeting with NRC.
February 27, 1984	Letter from Transamerica Delaval, Inc., Owners Group forwarding "Investigation of Types AF and AE Piston Skirts."

February 27, 1984	Summary of February 16, 1984, meeting with Transamerica Delavel, Inc., Owners Group in Wading River, NY, about program plan to establish reliability of diesel generators.
February 28, 1984	Letter from Transamerica Delaval, Inc., Owners Group forwarding task descriptions of 16 known problems with Transamerica Delaval, Inc., emergency diesel generators.
February 28, 1984	Letter to Transamerica Delaval, Inc., Owners Group forwarding request for additional information about Transamerica Delaval diesel generators.
March 1, 1984	Letter to licensee summarizing January 26, 1984, meeting in Bethesda, MD.
March 2, 1984	Letter from Long Island Lighting Co. forwarding "Grand Gulf Component Tracking System," "Shoreham Component Tracking Systems," and "Transamerican Delaval, Inc. Diesel Generators Owners Group Program Plan."
March 2, 1984	ASLB issues First Order Following Prehearing Conference (Modifying Briefing Schedule).
March 6, 1984	Summary of February 21, 1984, meeting with licensee in Bethesda, MD, on details of proposed onsite/offsite electrical power reliability program for Tansamerica Delaval, Inc., diesel generators.
March 7, 1984	Letter from licensee forwarding results of analysis performed showing relationship between reliability of emergency core cooling system and Agastat relay test intervals. Analysis is withheld (ref. 10 CFR §2.790).
March 7, 1984	Letter from licensee cncerning ECCS reliability analysis for Agastat relay test intervals.
March 8, 1984	Letter from licensee concerning operating shift experience levels.
March 8, 1984	Letter from licensee forwarding requested information on experience levels of utility operating shift personnel and expressing support of position taken by Industry Working Group on Operating Shift experience on February 24, 1984.
March 8, 1984	Letter from licensee submitting interim response to February 24, 1984, letter requesting certification of Technical Specifications and FSAR.
March 9, 1984	Letter from licensee endorsing S.H. Hobbs' February 1984 letter (HGN-015) to H.R. Denton in response to NRC's December 8, 1983 request for additional information about Hydrogen Control Owners Group (HCOG) test program. Questions to be answered by HCOG and utility, respectively, are listed.

March 9, 1984	Meeting with licensee in Bethesda, MD, to review program for Technical Specifications review. (Summary issued March 21, 1984.)
March 9, 1984	Letter from licensee concerning the hydrogen control test program.
March 13, 1984	Letter from licensee concerning confirmation of Longergan safety/relief valve qualificaiton and operability testing of reclassified valves.
March 13, 1984	Letter from Transamerica Delaval, Inc., Owners Group forwarding "Transamerica Delaval, Inc. Diesel Generator Rocker Arm Capscrew Stress Analysis Report."
March 14, 1984	Generic Letter 84-07 to licensee regarding procedural guidance for pipe replacement at BWRs.
March 16, 1984	Letter from licensee concerning compliance with 10 CFR 61 regarding classification and waste form requirements.
March 16, 1984	Letter from licensee requesting delay in submittal of inservice inspection program plan.
March 16, 1984	Letter from licensee forwarding updated information on operating shift experience to supersede previous submittal.
March 18, 1984	Letter from licensee concerning Technical Specifications review program.
March 19, 1984	Letter to Transamerica Delaval, Inc. (TDI) Owners Group forwarding request for additional information about TDI diesel generators.
March 19, 1984	Letter from licensee requesting additional information on Technical Specifications bases.
March 19, 1984	Letter to licensee requesting additional information on Technical Specifications addressing core thermal power at high pressure and high flow.
March 20, 1984	Letter to licensee forwarding application for amendment to License NPF-13, changing Technical Specifications on requirements for operability of automatic depressurization system valve.
March 20, 1984	Summary of March 14, 1934, meeting with utility on Technical Specification change review.
March 21, 1984	Summary of March 9, 1984, meeting with utility, Bechtel, and General Electric in Bethesda, MD, about Technical Specification review program.

March 22, 1984	Meeting with licensee to review program for processing Technical Specifications change requests. (Summary issued April 20, 1984.)
March 23, 1984	Letter to Transamerica Delaval, Inc. (TDI) Owners Group forwarding Stone and Webster report, "Emergency Diesel Generator Air Start Valve Capscrew Dimension and Stress Analysis."
March 23, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group requesting meeting on April 18, 1984, to discuss short-term and long-term corrective actions and investigations on TDI.
March 23, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding additional information on TDI emergency diesel generators.
March 24, 1984	Generic Letter 83-16 to licensee regarding transmittal of NUREG-0977 relative to ATWS events at Salem Generating Station, Unit 1.
March 24, 1984	Letter to licensee forwarding additional guidance for use in reporting offsite doses to public for 1982.
March 28, 1984	Meeting with licensee in Bethesda, MD, to review program for processing Technical Specifications changes requests. (Summary issued April 20, 1984.)
March 29, 1984	Letter from licensee submitting application for amendment to License NPF-13.
March 30, 1984	Letter from Transamerica Delaval, Inc., Owners Group forwarding report, "Emergency Diesel Generator Cylinder Head Stud Stress Analysis."
March 30, 1984	Letter from licensee forwarding payment for March 29, 1984, proposed license amendment.
March 30, 1984	Letter from licensee concerning shift advisers.
April 1, 1984	Generic Letter 83-16A to licensee regarding transmittal of NUREG-0977 relative to ATWS events at Salem Generating Station, Unit 1.
April 2, 1984	Generic Letter 84-05 to licensee regarding change to NUREG-1021, "Operator Licensing Examiner Standards."
April 4, 1984	Board Notification 84-72 to licensee regarding Transamerica Delaval, Inc. (TDI) Owners Group/NRC meeting transcript and additional TDI Owners Group information.

April 4, 1984	Meeting with licensee in Bethesda, MD, to discuss results of NRR staff review of licensee's Technical Specifications review program. (Summary issued May 8, 1984.)
April 4, 1984	Generic Letter 84-08 to licensee regarding interim procedures for NRC management of plant-specific backfitting.
April 4, 1984	Letter from licensee forwarding response to request for additional information on hydrogen control regarding 1/4-scale Mark III test facility and hydrogen combustion test program.
April 4, 1984	Board Notification 83-44 to licensee regarding testimony reaffirming NRC Position re Unresolved Safety Issue A-17, "System Interaction in Nuclear Power Plants."
April 5, 1984	Meeting with licensee in Bethesda, MD, to review program for processing Technical Specifications change requests. (Summary issued May 17, 1984.)
April 5, 1984	Meeting with licensee in Bethesda, MD, to discuss the reliability of onsite power.
April 7, 1984	Letter from licensee forwarding application to amend license surveillance procedure review and miscellaneous Technical Specifications regarding responsibility for auditing station.
April 8, 1984	Generic Letter 83-17 to licensee regarding integrity of requalification exams for renewal of reactor operator and Senior Reactor Operator licenses.
April 9, 1984	Letter from licensee concerning Technical Specifications review program.
April 9, 1984	Letter from licensee certifying that Technical Specifications accurately reflect the plant, the FSAR as amended, supporting documents, and the SER analyses, in all material respects. It also certifies that the as-built plant conforms to the significant and substantive safety requirements and licensing criteria of the FSAR as amended and supporting documents.
April 9, 1984	Letter from Transamerica Delaval, Inc. Owners Group submitting transcript from March 22, 1984, meeting correlated with NRC's February 26, 1984, letter requesting additional information on Types AF and AE piston.
April 10, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding parametric information from TDI.

April 10, 1984	Summary of March 22, 1984 meeting with Transamerica Delaval, Inc. (TDI) and TDI Diesel Generator Owners Group about Types AF and AE piston skirts, design review of connecting rod-bearing shells, and rocker arm capscrew stress analysis.
April 10, 1984	Letter from licensee forwarding Technical Specification problem sheet, Item 818, regarding FSAR sections on secondary containment isolation.
April 11, 1984	Meeting with licensee in Bethesda, MD, to discuss program for processing Technical Specifications change requests. (Summary issued May 17, 1984).
April 11, 1984	Letter to licensee concerning major unresolved issues relating to Transamerica Delaval, Inc., diesel generators.
April 11, 1984	Letter to licensee forwarding comments on reports, "Design Review of Connecting Rod Bearing Shells for TDI Enterprise Engines" and "Emergency Diesel Generator Rocker Arm Capscrew Stress Analysis."
April 12, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding fatigue data for nodular cast iron used in piston skirt evaluation.
April 13, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding reports, "Supplement to Emergency Diesel Generator Air Start Valve Capscrew Dimension and Stress Analysis" and "Supplement to Emergency Diesel Generator Cylinder Head Stud Stress Analysis."
April 13, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding calculations for rocker arm capscrew stress analysis and cylinder head stud evaluation.
April 13, 1984	Meeting with licensee to discuss the Transamerica Delaval, Inc., diesel generators.
April 13, 1984	Letter from licensee concerning vital area barriers.
April 13, 1984	Letter from licensee concerning masonry wa' s and HPCS diesel generator temperature.
April 13, 1984	Letter from licensee concerning changes to technical support and operational support centers.
April 14, 1984	Letter from licensee concerning negotiations with DOE regarding disposal of high level waste or spent fuel.
April 15, 1984	Summary of April 1983, meeting with licensee to discuss plant operations enhancement program and anticipated schedule for next criticality.

April 15, 1984	Letter from licensee forwarding "Report on Integration and Scheduling of Supplement 1 to NUREG-0737."
April 16, 1984	Letter from licensee concerning third-party review of Technical Specifications review program.
April 16, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding report, "Emergency Diesel Generator Engine Driven Jacket Water Pump Design Review."
April 17, 1984	Letter from licensee requesting withdrawal of proposed changes to Technical Specifications which were asked for in August 9, 1983, letter.
April 18, 1984	Meeting with licensee to discuss the Transamerica Delaval, Inc. diesel generators.
April 18, 1984	Letter from licensee providing supplemental information concerning Transamerica Delaval, Inc., diesel generators.
April 18, 1984	Letter from licensee concerning organization and qualifications of management and staff.
April 18, 1984	Letter from licensee concerning diesel generator and gas turbine reliability.
April 18, 1984	Letter to licensee issuing Order Restricting Conditions for Operation. MP&L shall not operate the plant unless such operation is in conformance with the revised Technical Specifications appended to the order and MP&L, prior to entry into mode 2, certifies to the Region II Administrator that MP&L's procedures have been modified and training has been conducted to reflect the revised Technical Specifications.
April 19, 1984	Letter from Transamerica Delaval, Inc. forwarding report, "Design Review of Push Rods for TDI Generators."
April 19, 1984	Generic Letter 84-11 to licensee regarding inspections of BWR stainless steel piping.
April 19, 1984	Letter from licensee documenting completion of the Technical Specifications Review Program and presenting the final Program Completion Report.
April 19, 1984	Generic Letter 83-18 to licensee regarding NRC staff review of BWR Owners Group Control Room Survey Program.
April 20, 1984	Meeting with licensee in Bethesda, MD, to discuss program for processing Technical Specifications change requests. (Summary issued May 25, 1984.)
April 20, 1984	Letter from licensee concerning update report on Transamerica Delaval, Inc. standby diesel generators.

April 20, 1984	Letter to licensee advising about review of Technical Specifications to verify proper derivation from analysis and evalation included in FSAR.
April 23, 1984	ASLB issued Second Order Following Prehearing Conference (Admitting Intervenor and Ruling on Contentions).
April 24, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding proposed agendum for May 2, 1984, meeting at NRC.
April 24, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding Stone and Webster's report, "Emergency Diesel Generator Engine and Auxiliary Module Wiring and Termination Qualification to IEEE-383-1974."
April 24, 1984	Letter from licensee advising of change in counsel to N.S. Reynolds of Bishop, Liberman, Cook, Purcell and Reynolds.
April 25, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report, "Supplement to Emergency Diesel Generator Rocker Arm Capscrew Stress Analysis."
April 25, 1984	Letter to licensee forwarding (1) evaluation of Transamerica Delaval, Inc. diesel generator reliability for power operation and (2) W.S. Laity's letters of March 30, and April 17, 1984, about standby diesel generators.
April 25, 1984	Letter to licensee forwarding list of additional concerns.
April 26, 1984	Generic Letter 84-10 to licensee concerning administration of operating tests before initial criticality (10 CFR 55.25).
April 26, 1984	Letter from licensee responding to informal request for additional information about trip setpoints for radiation monitors and allowable value for high pressure coolant system and reactor core isolation cooling suction shift on high suppression pool level.
April 26, 1984	Letter from licensee forwarding Nuclear Mutual Limited certificate of insurance showing evidence of nuclear property insurance in effect at facility.
April 26, 1984	Letter from Long Island Lighting Co. forwarding Stone and Webster's report, "Emergency Diesel Generator and Auxiliary Module Wiring and Termination Qualification to IEEE-383-1974."
April 26, 1984	Letter from licensee responding to informal request for additional information on ICSB concerns.

April 27, 1984	Meeting with licensee in Bethesda, MD, to review program for processing Technical Specifications change requests. (Summary issued May 25, 1984.)
April 27, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding TDI's diesel generator report, "Design Review of Connecting Rods of TDI Inline DSR-48 Emergency Diesel Generators."
April 27, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding TDI's engine instruction manual.
April 27, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report, "Design Review of Engine Base and Bearing Caps for TDI Diesel Engine."
April 27, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding report, "Emergency Diesel Generator Fuel Oil Injection Tubing."
April 27, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding current engine inspection schedule.
April 30, 1984	Generic Letter 84-12 to licensee concerning compliance with 10 CFR 61 and implementation of Radiological Effluent Technical Specifications (RETS) and attendant Process Control Program (PCP).
April 30, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding interim reports on remaining Phase I components, turbochargers, cylinder heads, and cylinder blocks/cylinder liners.
April 30, 1984	Letter from licensee providing additional information which confirms methodology, nominal values, and uncertainties in Technical Specifications bases.
April 30, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group listing all correspondence from TDI Owners Group to NRC since February 28, 1984.
April 30, 1984	Letter from Long Island Lighting Co. forwarding (1) W.J. Museler's April 27, 1984 letter and (2) report, "Design Review of Connecting Rods of TDI Inline DSR-48 Emergency Diesel Generators."
May 1, 1984	Letter from licensee forwarding utility advisor's evaluation team report on shift advisor program.
May 1. 1984	Letter from licensee acknowledging receipt of April 18, 1984, order restricting conditions of operation and responding to that order.

May 1, 1984	Letter from licensee forwarding outstanding Technical Specification problem sheets.
May 2, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding (1) Calculations 11600.60-245.1-M3 concerning air start valve capscrew and dimensional and stress analysis, (2) unnumbered calculation on jacket water pump, and (3) sketches of intake and exhaust tappet valve system.
May 2, 1984	Generic Letter 83-19 to licensee regarding new procedures for providing public notice concerning issuance of amendments to OLs.
May 2, 1984	Letter from licensee forwarding final report for Kuosheng Nuclear Power Station entitled, "Safety Relief Valve Discharge Test."
May 3, 1984	Generic Letter 84-13 to licensee about Technical Specifications for snubbers.
May 3, 1984	Letter from licensee confirming May 3, 1984 conversation between M.D. Houston and J.C. Cesare on Generic Letter 84-11 concerning inspection of BWR stainless steel piping.
May 4, 1984	Letter to licensee forwarding request for additional information on February 26, 1984, submittal on onsite/offsite power reliability.
May 6, 1984	Letter from licensee forwarding additional information supporting licensee's conclusion that little technical justification exists for disassembly of Transamerica Delaval, Inc. diesel generator before first refueling outage.
May 6, 1984	Letter from licensee providing additional information which supports utility's conclusions about justification for requirement to perform confirmatory disassembly inspection of Transamerica Delaval, Inc. diesel generator before first refueling outage.
May 7, 1984	Letter to Transamerica Delaval, Inc. (TDI) Owners Group forwarding preliminary comments on TDI Owners Group reports.
May 8, 1984	Generic Letter 84-09 to licensee about recombiner capability requirements of 10 CFR 50.44(c)(3)(ii).
May 8, 1984	Letter from licensee forwarding definitions of channel, trip system, and trip function for remaining instrumentation in Technical Specification Section 3/4.3, incorporating secondary containment isolation and correcting December 13, 1983, submittal about terminology.

May 8, 1984	Letter from licensee forwarding revision 29 to Technical Specification problem sheets.
May 8, 1984	Summary of April 4, 1984, meeting with licensee in Bethesda, MD, about results in NRR comparison of Technical Specifications with FSAR and SER, and results of licensee's comprehensive review program.
May 8, 1984	Letter to licensee forwarding request for additional information about September 9, 1983, proposed changes to Technical Specifications.
May 9, 1984	Letter to licensee discussing NRC review and processing of Technical Specification changes for full-power license amendment.
May 9, 1984	Generic Letter 83-20 to licensee regarding integrated scheduling for implementation of plant modifications.
May 10, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding Revision 0 to report, "Project Interface Document Between Duke Power Co. TDI Diesel Generator Owners Technical Program Consultants and NRC."
May 11, 1984	Letter from licensee forwarding Relief Request 00012 from ASME Code, Section XI, requirements for preservice inspection of Class I valve internal surfaces, per 10 CFR 50.55a(g)(5)(iv).
May 11, 1984	Generic Letter 84-14 to licensee regarding replacement and requalification training program.
May 11, 1984	Letter from licensee concerning pipe supports subject to 10-year inservice inspection plan to comply with ASME Code.
May 11, 1984	Generic Letter 83-21 to licensee regarding clarification of access to control procedures for law enforcement visits.
May 14, 1984	Letter from licensee concerning diesel generator reliability issues.
May 14, 1984	Letter from licensee concerning interim reliability/risk assessment on ac power supply systems.
May 14, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report, "Design Review of Elliott Model 90G Turbocharger Used on TDI DSR-48 and DSRV-16 Emergency Diesel Generator Sets."
May 14, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report, "Evaluation of Cylinder Heads of TDI Series R-4 Diesel Engines."

May 15, 1984	Letter to Philadelphia Electric Co. forwarding NRC's report on setpoint methodology for General Electric-supplied protection system instrumentation.
May 16, 1984	Summary of April 26, 1984, meeting with licensee on means for resolution of Technical Specification problems.
May 17, 1984	Summary of April 11, 1984, meeting with licensee and Bechtel in Bethesda, MD, about enclosed Technical Specifications.
May 17, 1984	Summary of April 5, 1984, meeting with licensee in Bethesda, MD, about Technical Specification.
May 17, 1984	Letter from Transamerica Delaval, Inc. Owners Group forwarding cover letter transmitting report on investigation of Types AF and AE piston skirts.
May 17, 1984	Letter from Long Island Lighting Co. advising that Transamerica Delaval, Inc. Owners Group letter of May 16, 1984 and report, "Evalation of Emergency Diesel Generator Crankshafts at Shoreham and Grand Gulf Nuclear Power Stations" has been issued.
May 18, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report on design review of connecting rods for TDI DSRV-4 series diesel generator.
May 18, 1984	Meeting with licensee in Bethesda, MD, to discuss onsite/offsite power supply reliability.
May 18, 1984	Letter from licensee forwarding Amendment No. 58 to FSAR.
May 19, 1984	Letter to licensee concerning review of spare parts for use in ASME Code pumps.
May 20, 1984	Letter from licensee concerning qualification status and compliance with 10 CFR 50.49 environmental qualification of electrical equipment important to safety.
May 22, 1984	Letter to licensee forwarding order requiring diesel generator inspection.
May 22, 1984	Letter from licensee concerning re-serialization of preservice relief request.
May 23, 1984	Letter from licensee forwarding quarterly status report, "Degraded Core Accident Hydrogen Control Program."
May 23, 1984	Letter to licensee concerning NRC position regarding use of manually entered codes and anti passback features for control of access to vital areas.

May 24, 1984	Letter from licensee concerning review of proposed changes to Technical Specifications.
May 24, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding report, "Design Review of Connecting Rods for TDI DSRV-4 Series Diesel Generators."
May 24, 1984	Letter from licensee forwarding application for amendment to License NPF-13.
May 25, 1984	Letter from licensee responding to May 8, 1984, request for additional information on proposed changes to Technical Specifications on minimum suppression pool water level.
May 25, 1984	Summary of April 20, 1984, meeting with licensee in Bethesda, MD, about review of Technical Specifications.
May 25, 1984	Summary of April 27, 1984, meeting with licensee in Bethesda, MD, about Technical Specification review.
May 25, 1984	Letter from licensee responding to request for additional information on proposed changes to the Technical Specifications.
May 25, 1984	Letter from licensee concerning submittal date for GDC 17 exemption request.
May 25, 1984	Letter from licensee forwarding report, "Summary of Environmental Protection Program Respecting Construction of Grand Gulf Nuclear Station for Six Months Ending April 30, 1984."
May 30, 1984	Letter from licensee withdrawing several proposed Technical Specifications changes.
May 30, 1984	Letter from licensee acknowleding receipt of Commission's order of May 22, 1984, about inspection and testing of standby diesel generators.
May 31, 1984	Letter from licensee advising that all Category I post-accident instrumentation identified in letters of July 15 and November 29, 1982, be included in current Technical Specifications.
May 31, 1984	Letter from licensee submitting commitment to evaluate design of certain seismic monitoring instruments.
June 1, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding two proprietary oversize drawings in response to Battelle Northwest Laboratory's request.
June 3, 1984	Letter from licensee responding to Generic Letter 84-11 pertaining to inspections of BWR stainless steel piping for intergranular stress corrosion cracking.

June 3, 1984	Meeting with BWR Hydrogen Control Owners Group to discuss hydrogen control program and emergency procedure guidelines.
June 4, 1984	Letter from licensee concerning Technical Specifications Review Program.
June 4, 1984	Letter from licensee concerning application for partial, temporary exemption to 10 CFR 50, Appendix A, Criterion 17.
June 4-5, 1984	Meeting with licensee at site to discuss the inspection of Transamerica Delaval, Inc., diesel generators.
June 5, 1984	Letter from Transamerica Delaval, Inc. (TDI) Owners Group forwarding supplement to report, "Emergency Diesel Generator Auxiliary Module Control Wiring and Termination Qualfication Review for TDI Diesel Generators."
June 5, 1984	Letter from licensee providing supplemental information on the Technical Specifications review.
June 8, 1984	Letter from licensee concerning completion and results of General Electric's overview review of Technical Specifications Program.

APPENDIX C

NUCLEAR REGULATORY COMMISSION (NRC) UNRESOLVED SAFETY ISSUES

A-39 Safety Relief Valve Hydrodynamic Loads

Safety relief valves (SRVs) inplant tests with cross quencher devices were performed during August 1981 at the Kuosheng Power Plant in Taiwan, the first operating BWR 6/Mark III plant in the world. The NRC staff participated in this technical activity and reported preliminary conclusions in Supplement 1 to the Grand Gulf SER.

By License Condition 2.C.(45), the licensee is required to perform an augmented SRV test program at Grand Gulf during the first cycle of operation and to provide the final report on the Kuosheng SRV tests when it becomes available. By letter dated May 2, 1983, the licensee submitted the Final Test Report on SRV testing at Kuosheng. By this action, the licensee has complied with that part of License Condition 2.C.(45).

APPENDIX E

CONTROL ROOM REVIEW

In SSER 4, dated May 1983, the staff concluded that License Condition 2.C.(44)(a) should be revised as follows: Before startup following the first refueling outage, MP&L shall be able to maintain a maximum-effective-temperature condition of 85°F in the remote shutdown panel (RSP) for at least 8 hours.

Because the condition deals with a maximum temperature and the ventilation system is using outside ambient air, it is necessary that the demonstration be conducted under hot-weather conditions. The environmental report indicates a temperature range from 2°F to 101°F and 66 days per year of temperatures over 90°F. Therefore, it is the staff's position that the demonstration should be conducted under outside ambient temperature conditions of at least 95°F.

Accordingly, the staff concludes License Condition 2.C.(44)(a) should be revised as follows: Before startup following the first refueling outage, MP&L shall demonstrate the ability to maintain a maximum-effective-temperature condition of 85°F in the remote shutdown panel (RSP) for at least 8 hours with an ambient outdoor temperature of at least 95°F.

APPENDIX F

NRC REVIEW TEAM

Mr. M. Dean Houston is the NRC Project Manager for this project. Mr. Houston may be contacted at the U.S. Nuclear Regulatory Commission on 301/492-8358.

The principal NRC staff reviewers for this project are

Name	Title	Branch
D. Terao	Mechanical Engineer	Mechanical Engineering
M. Hum	Sr. Materials Engineer	Materials Engineering
K. Parczewski	Sr. Chemical Engineer	Chemical Engineering
F. Witt	Sr. Chemical Engineer	Chemical Engineering
R. Wright	Materials Engineer	Equipment Qualification
H. Garg	Sr. Electrical Engineer	Equipment Qualification
C. Tinkler	Sr. Containment Systems Engineer	Containment Systems
R. Giardina	Reactor Systems Engineer - Mechanical	Power Systems
M. Tokar	Reactor Engineer	Core Performance
R. Eckenrode	Human Factors Engineer	Human Factors Engineering
D. Perrotti	Emergency Preparedness Analyst	Emergency Preparedness Licensing Branch
C. P. Tan	Senior Structural Engineer	Structural Engineering
G. Bagchi	Section Leader	Equipment Qualifications
M. Virgilio	Senior Reactor Engineer	Instrumentation and Control Systems
J. Read	Senior Physical Scientist	Accident Evaluation
A. Notafransesco	Containment Systems Engineer	Containment Systems
J. Kudrick	Section Leader	Containment Systems
F. Clemenson	Senior Auxiliary Systems Engineer	Auxiliary Systems

The following consultants to the staff participated in this review:

Brookhaven National Laboratory
Exxon Nuclear Idaho Company, Inc.
Idaho Nuclear Engineering Laboratory

APPENDIX G

FEDERAL EMERGENCY MANAGEMENT AGENCY REPORTS

Federal Emergency Management Agency

Washington, D.C. 20472

JUN 2 9 1983

Mr. William J. Dircks
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Dircks:

In accordance with the proposed Federal Emergency Management Agency (FEMA) Rule, 44 CFR 350, the States of Mississippi and Louisiana submitted their State plans and supporting local plans related to the Grand Gulf Nuclear Power Station to the Directors of FEMA Regions IV and VI, for their review and approval. The Regional Directors forwarded findings on their respective State and local plans to me pursuant to Section 350.11 of the proposed rule. Each Director's original submission included a critique of the Grand Gulf exercise conducted on November 4 and 5, 1981, and a report of the public meetings held on October 27, 1981, at the Tensas Parish Courthouse, St. Joseph, Louisiana, and on November 3, 1981, in the Addison Junior High School, Port Gibson, Mississippi, to explain the site-specific aspects of the State and local plans. The results of the most recent exercise conducted on January 26, 1983, have also been considered as part of this finding.

Based on an overall evaluation, I find and determine that, subject to the condition stated below, the plans and preparedness for offsite protection near the Grand Gulf Nuclear Power Station are adequate to protect the health and safety of the public and that there is reasonable assurance that appropriate protective measures can and will be taken offsite in the event of a radiological emergency. The condition for the above approval is that the adequacy of the public alerting and notification system, which is now in operation, must be verified as called for in Appendix 3 of NUREG-0654/FEMA-REP-1, Rev. 1.

Accordingly, I approve the State plans for Mississippi and Louisiana and the local plans relevant to the Grand Gulf Nuclear Power Station subject to the aforementioned condition.

Sincerely,

for Richard W. Krimm

Dave McLoughlin
Deputy Associate Director
State and Local Programs
and Support

APPENDIX L

EVALUATION OF CONTROL OF HEAVY LOADS
PHASE I

EGG-HS-6185

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
GRAND GULF NUCLEAR STATION UNITS 1 AND 2
(Final--Phase I)

Docket No. 50/416 and 50/417

Author

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Principal Technical Investigator

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Published March 1983

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

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U.S. Nuclear Regulatory Commission
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FIN No. A6457

ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants either operating or under construction submit a response of compliance with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This final report is a result of EG&G's review of the responses submitted for the Grand Gulf Nuclear Station Units 1 and 2 to the requirements of Section 5.1.1 of NUREG-0612 (Phase I). Sections 5.1.2, 5.1.4, 5.1.5, and 5.1.6 (Phase II) will be covered in a separate report.

EXECUTIVE SUMMARY

The Grand Gulf Nuclear Station Units 1 and 2 now totally complies with the guidelines of NUREG-0612 as a result of cooperation between the staffs of NRC, EG&G, TERA Corporation, and the applicant.

CONTENTS

TABLES

TECHNICAL EVALUATION REPORT

FOR

GRAND GULF NUCLEAR STATION UNITS 1 AND 2

1. INTRODUCTION

1.1 Purpose of Review

This technical evaluation report (TER) documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at Mississippi Power & Light Company's Grand Gulf Nuclear Station Units 1 and 2. This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants,"[1] Section 5.1.1. This constitutes Phase I of a two-phase evaluation. Phase II assesses conformance to Sections 5.1.2, 5.1.4, 5.1.5, and 5.1.6 of NUREG-0612 and will be documented in a separate report.

1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to ensure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978,[2] to all power reactor licensees, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective (achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.6) is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single failure-proof crane), or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in-depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to ensure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter[3] to Mississippi Power & Light Company, the Applicant for Grand Gulf Nuclear Station Units 1 and 2 requesting that the Applicant review provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. On November 23, 1981, Mississippi Power & Light Company provided the initial response[4] to this request followed by a revision [5] dated February 25, 1982. Based on this information, a preliminary draft of this report was prepared and discussed with the applicant. Additional information was provided by the applicant in References [6,7]. The current (final) draft of this report was prepared from information contained in all these submittals.

2. EVALUATION AND RECOMMENDATIONS

2.1 Overview

The following sections summarize Mississippi Power & Light Company's review of heavy load handling at Grand Gulf Nuclear Station Units 1 and 2 accompanied by EG&G's evaluation, conclusions, and recommendations to the Applicant for bringing the facilities more completely into compliance with the intent of NUREG-0612. The Applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 1140 pounds.

2.2 Heavy Load Overhead Handling Systems

This section reviews the Applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the aforementioned list.

2.2.1 Scope

Report the results of the Applicant's review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal.

2.2.1.1 Summary of Applicant Evaluation on Overhead Handling Systems

The Applicant's review of overhead handling systems identified the cranes and hoists shown in Table 2.1 as those which handle heavy loads in the vicinity of irradiated fuel or safe shutdown equipment.

In Table 2.2, the Applicant has identified other cranes that have been excluded from satisfying the criteria of the general guidelines of NUREG-0612. These various overhead handling devices were reviewed by the Applicant to the criteria of NUREG-0612 and were excluded based on sufficient physical separation from any load-impact point that could damage any system or component required for plant shutdown or decay heat removal. Some of the devices have been excluded because the Applicant has indicated that the heavy load of approximately 1140 pounds for this facility would not be exceeded.

2.2.1.2 EG&G Evaluation, Conclusions, and Recommendations for Overhead Handling Systems

The Applicant's response indicates that each overhead handling device at the Grand Gulf Nuclear Station Units 1 and 2 is listed in Tables 2.1 and 2.2. Figures 1 through 7 of Reference 4 show the locations of all the overhead handling systems in the plant and their proximity to safety-related components. EG&G concludes that the Applicant's list of cranes and hoists in the aforementioned tables is complete and satisfies the requirements of NUREG-0612.

TABLE 2.1 OVERHEAD HANDLING DEVICES IN VICINITY OF SAFE SHUTDOWN EQUIPMENT GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Handling System	Capacity (tons)	Location
Containment Polar Crane/Auxiliary Hoist	125/35	Containment
Spent-Fuel Cask Crane	150	Auxiliary Building
New Fuel Bridge Crane	5	Auxiliary Building
Monorail for LPCS & RHR "C" Hatches	10	Auxiliary Building (elevation 139 ft)

TABLE 2.2 OVERHEAD HANDLING DEVICES EXCLUDED FROM FURTHER CONCERN
GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Handling System	Capacity (tons)	Location
Component Cooling Water Pump Monorail	2	Auxiliary Bldg. 93 ft
Floor Drain Transfer Pumps Monorail	3	Auxiliary Bldg. 93 ft
Control Rod Drive Pump Monorails (2)	5	Auxiliary Bldg. 93 ft
Control Building Hot Machine Shop Monorail	15	Control Bldg. 93 ft
Control Rod Drive Removal Hoist	10	Containment 93 ft
HPCS Hatch/Equipment Monorail	25	Auxiliary Bldg. 113 ft
RCIC Hatch Monorails	5	Auxiliary Bldg. 113 ft
Chilled Water Pump Monorail	2	Auxiliary Bldg. 134 ft
RHR "A" Hatch & Equipment Monorail	10	Auxiliary Bldg. 139 ft
RHR "B" Hatch & Equipment Monorail	10	Auxiliary Bldg. 139 ft
Main Steam Tunnel Crane	12	Auxiliary Bldg. 139 ft
Railroad Bay Monorail	5	Auxiliary Bldg. 139 ft
Fuel Pool Cooling & Cleanup Pump Monorails (2)	5	Auxiliary Bldg. 166 ft
Control Rod Drive Repair Room Monorail	1/2	Auxiliary Bldg. 166 ft
Spent-Fuel Cask Hatch Monorail	10	Auxiliary Bldg. 166 ft
Containment Cooler Monorail	2	Containment 166 ft
Valve-Handling Crane	12	Containment 166 ft
Spent-Fuel Pool Cooling Heat Exchanger Monorail	7-1/2	Auxiliary Bldg. 185 ft
Jib Crane	1/2	Containment and Auxiliary Bldg. 208 ft
Diesel Generator Cranes (2)	6	Diesel Generator Bldg.
Standby Service Water Pump House Monorails (2)	12	Standby Service Water Pump Houses

The Applicant performed a review of the various overhead handling devices to the criteria of NUREG-0612 by a physical inspection of the plant and by studying plant layout drawings. For those devices which were excluded, the Applicant has provided justification that indicates sufficient physical separation exists between components necessary for safe shutdown or decay heat removal and load-impact points. The Applicant also included electrical cabling, valves, and instrumentation tubing effects in their assessment. EG&G concludes that the Applicant has met the requirements of NUREG-0612 concerning exclusion of overhead handling systems.

2.2.1.3 Summary on Heavy Load Overhead Handling Systems

The Grand Gulf Nuclear Station Units 1 and 2 complies with the criteria of NUREG-0612 on Heavy Load Overhead Handling Systems.

2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612, Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- Guideline 1--Safe Load Paths
- Guideline 2--Load-Handling Procedures

- Guideline 3--Crane Operator Training
- Guideline 4--Special Lifting Devices
- Guideline 5--Lifting Devices (not specially designed)
- Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- Guideline 7--Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee.

2.3.1.1 Summary of Applicant's Evaluation of Safe Load Paths

Due to the many different load-handling situations for the cranes of Table 2.1, the Applicant has determined that safe load paths are neither required nor prudent for every situation and would unnecessarily restrict plant operations and maintenance activities. To address this problem, the Applicant has identified possible load-handling situations and has assigned a safety class designation to each category. Table 2.3 lists the Load Safety Classes and Safe Load Path and/or Procedural Actions required. Each of the heavy loads listed in Tables 2.4, 2.5, 2.6, and 2.7 has been assigned one or more safety classes. For each of the heavy loads listed, the safe load path and/or procedural requirements corresponding to the assigned safety classes have been added to the appropriate plant procedures. The Applicant's actions taken to address each of these loads were summarized for each of the handling systems of Table 2.1.

In that summary, the Applicant has addressed safe load paths, drawings, minimum lift heights, procedural restrictions, technical specification changes, markings in the area where the load is to be handled, supervision of heavy lifts, and deviations that require prior approval of Operations Superintendent.

2.3.1.2 EG&G Evaluations, Conclusions, and Recommendations on Safe Load Paths

EG&G has reviewed the Applicant's handling of Guideline 1 and finds that the Applicant has met the criteria for safe load paths.

The four cranes listed in Table 2.1 cannot have safe load paths defined because their loads must be carried over irradiated fuel or safe shutdown equipment. For these cases, the Applicant has defined load safety classes, Table 2.3, and the actions required for handling heavy loads. The heavy load paths will be

TABLE 2.3 LOAD SAFETY CLASSES AND SAFE LOAD PATH ACTIONS
GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Heavy Load[a]-Handling Situation	Safe Load Path/ Procedural Actions Required
Safety Class 1. Load must be carried directly over (i.e., there are no intervening structures such as floors) spent fuel, the reactor vessel, or safe shutdown equipment.	1. Procedurally limit time and height load is carried over the area of concern.
Safety Class 2. Load could be carried directly over spent fuel, the reactor vessel, or safe shutdown equipment, i.e., load can be handled during the time when spent fuel or the reactor vessel is exposed or safe shutdown equipment is required to be operable and there are no physical means (such as interlocks or mechanical stops) available to restrict load movement over these objects.	2. Procedurally define an area over which loads shall not be carried so that if load is dropped, it will not result in damage to spent fuel or operable safe shutdown equipment or compromise reactor vessel integrity.
Safety Class 3. Load can be carried over spent fuel or safe shutdown equipment, but the fuel or equipment is not directly exposed to the load drop, i.e., intervening structures such as floors provide some protection.	3. See 3A and 3B.
Safety Class 3A. Preliminary evaluation indicates that intervening structures will protect spent fuel or safe shutdown equipment.	3A. No load travel path is required at this time. General precautions limiting load travel height is prudent.
Safety Class 3B. Preliminary evaluation cannot conclusively demonstrate that intervening structures will protect fuel or safe shutdown equipment.	3B. Define safe load paths that follow, to the extent practical, structural floor members. Limit load travel height to minimum height practical.

TABLE 2.3 (CONTINUED)

Heavy Load[a]-Handline Situation	Safe Load Path/ Procedural Actions Required
Safety Class 4. Load cannot be carried over spent fuel or over safe shutdown equipment when such equipment is required to be operable, i.e., design or operational limitations prohibit movement.	4. No safe load path required.

a. A heavy load is defined as a load that is greater than the weight of a channeled fuel assembly and its associated handling tool.

TABLE 2.4. POLAR CRANE HEAVY LOADS[a] - GRAND GULF NUCLEAR STATION UNITS 1 AND 2

	Load	Safety Class	Approximate Weight (tons)	Applicable Lift Procedures[i]	Lifting Equipment
1.	Reactor Pressure Vessel Head (RPV)	1/3B	117	07-S-14-184[b]	Head Strongback Carousel
2.	Steam Dryer	1/2/3B	40	--[g]	Dryer & Separator Strongback
3.	Shroud Head/ Steam Separator	1/3B	68	07-S-14-186[c]	Dryer & Separator Strongback
4.	Drywell Head	1/3B	61.5	07-S-14-182[e]	Drywell Head Lifting Frame
5.	Portable Refueling Shield	2/3A	12	07-S-14-187[d]	Shackles & Slings
6.	RPV Head Insulation with Support Structure	1/3A	10.5	--[h]	Drywell Head Lifting Frame
7.	Reactor Well/Steam Dryer Storage Area Gate	2/3A	3.5	07-S-14-189[f]	Shackles & Slings
8.	Upper Containment Fuel Pool/Transfer Pool Gate	2/3A	3.5	07-S-14-189[f]	Shackles & Slings
9.	Load Block	2/3B	5.6 (M) 1 (Aux.)	--[i]	N/A
10.	RWCU Regenerative HX Hatches (2)	2/3B	15	--[i]	Shackles & Slings
11.	RWCU Non-Regenerative HX Hatches (3)	2/3B	15-17	--[i]	Shackles & Slings

TABLE 2.4 (CONTINUED)

Load	Safety Class	Approximate Weight (tons)	Applicable Lift Procedures[i]	Lifting Equipment
12. RWCU Filter Demineralizer Hatches (2)	2/3B	20	--[i]	Shackles & Slings

a. A heavy load is defined as a weight exceeding the weight of a channeled fuel assembly and its associated handling tool (approximately 1140 lb).

b. General Maintenance Instruction, 07-S-14-184, "Installation and Removal of Reactor Vessel Head, Safety Related."

c. General Maintenance Instruction, 07-S-14-186, "Installation and Removal of the Reactor Moisture Separator, Non-Safety Related."

d. General Maintenance Instruction, 07-S-14-187, "Installation and Removal of the Portable Refueling Shield (Cattle Chute), Non-Safety Related."

e. General Maintenance Instruction, 07-S-14-182, "Installation and Removal of the Drywell Head, Non-Safety Related."

f. General Maintenance Instruction, 07-S-14-189, "Installation and Removal of the Fuel Pool and Canal Gates, Non-Safety Related."

g. A Maintenance instruction for the installation and removal of the steam dryer has not yet been prepared. When an instruction is prepared, it will include the necessary detail, precautions, etc., to adequately address the requirements of NUREG-0612.

h. As with the steam dryer (addressed above), no maintenance instruction for the installation and removal of the Reactor Vessel Insulation Assembly has yet been prepared. The same condition for procedure development and content apply as for the steam dryer (g, above).

i. The Maintenance Instruction for Polar Crane Operation in general is applicable to all loads. In addition, it governs the lifts of all loads listed in this table that do not have special lift procedures designated.

TABLE 2.5 SPENT-FUEL CASK CRANE HEAVY LOADS
GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Load	Safety Class	Approx. Weight (tons)	Applicable Lift Procedures	Lifting Equipment
1. Spent-Fuel Cask	N/A	125	--[a]	Dual Load Path Cask Lifting System
2. Recirculating Pump Motor	N/A	30	--[a]	Slings and Shackles
3. HPCS Pump Motor	N/A	18	--[a]	Slings and Shackles

a. Detailed lift procedures have not yet been developed for the Spent Fuel Cask Crane. Such procedures will be developed, but are not required to meet the guidelines of NUREG 0612 for this "single failure proof" handling system.

TABLE 2.6 NEW FUEL BRIDGE CRANE HEAVY LOADS
GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Load	Safety Class	Approx. Weight (tons)	Applicable Operating Procedures	Lifting Equipment
1. New Fuel Shipping Containers	2	1.5	--[a]	Slings and Shackles
2. Fuel Pool & Clean-up Filter Demin-eralization Hatch (2)	2	3	--[a]	Slings and Shackles
3. Spent-Fuel Canal Gate	2	3.5	--[a]	Slings and Shackles

a. The Maintenance Instruction for New Fuel Bridge Crane Operation is applicable to all lifts.

TABLE 2.7 LPCS AND RHR PUMP "C" EQUIPMENT AND HATCH HOIST HEAVY LOADS GRAND GULF NUCLEAR STATION UNITS 1 AND 2

Load	Safety Class	Approx. Weight (lb)	Applicable Procedures	Lifting Equipment
1. Hatch Cover (2)	2	9,000	--[a]	Slings and Shackles
2. RHR Pump	2	16,000	--[a]	Slings and Shackles
3. RHR Motor	2	7,600	--[a]	Slings and Shackles
4. LPCS Pump	2	20,000	--[a]	Slings and Shackles
5. LPCS Motor	2	17,000	--[a]	Slings and Shackles
6. LPCS Lower Shell	2	17,000	--[a]	Slings and Shackles

a. Proposed Maintenance Instruction for the LPCS/RHR "C" Hatch Hoist is applicable to all lifts.

defined in procedures and shown on drawings. The cranes will be match marked for proper alignment during heavy load lifts. In addition, supervision will be provided during heavy load lifts to enforce procedural requirements.

For deviations from defined load paths, the Applicant will require approval of the Operations Superintendent. In Reference [6], the Applicant clarified their response and indicated that plant procedures were approved by the Plant Safety Review Committee and those procedures required the Operations Superintendent to approve deviations from safe load paths.

In Reference [7], the Applicant stated that all procedures required by Guideline 1 of NUREG-0612 were developed and available for audit.

2.3.1.3 Summary on Safe Load Paths

Grand Gulf Nuclear Station Units 1 and 2 fully comply with the criteria of Guideline 1, "Safe Load Paths".

2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over orin proximity to irradiated fuel or safe shutdown equipment. As a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment, inspections, and acceptance criteria required before movement of load, the steps and proper sequence to be followed in handling the load, defining the safe load path, and other special precautions.

2.3.2.1 Summary of Applicant's Evaluation on Load-Handling Procedures

The Applicant is developing procedures for the heavy loads handled by each crane (see Tables 2.4, 2.5, 2.6, and 2.7) and will contain the following information:

(1) Identification of required equipment

(2) Inspections and acceptance criteria required before movement of load

(3) The steps and proper sequence to be followed in handling the load

(4) Defining the safe load path

(5) Any other special precautions.

2.3.2.2 EG&G Evaluations, Conclusions, and Recommendations on Load-Handling Procedures

With the Applicant preparing the necessary load-handling procedures, EG&G considers the criteria of Guideline 2 will be accomplished. Further, Reference [7] states that procedures required by Guideline 2 of NUREG-0612 have been developed and are available for audit.

2.3.2.3 Summary on Load-Handling Procedures

Grand Gulf Nuclear Station Units 1 and 2 fully comply with the criteria of Guideline 2, "Load-Handling Procedures".

2.3.3 Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]

Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, "Overhead and Gantry Cranes."[5]

2.3.3.1 Summary of Applicant's Evaluation of Crane Operator Training

The Applicant has developed a new procedure for the qualification and training of overhead crane operators and meets the provisions of ANSI B30.2-1976, Chapter 2-3. The procedures include training, examination, experience, and physical requirements for crane operators as well as precautions and instructions to ensure proper conduct of crane operation. In addition, required crane operator training includes instruction in crane operator conduct, such as proper hand signals, testing of controls, limit devices, attaching the load, and moving the load. The Applicant has taken no exceptions to this guideline.

With regard to the LPCS/RHR "C" Hatch Monorail/Hoist System, the provisions of ANSI B 30.2-1976 are not directly applicable. However, the Applicant has included appropriate requirements in plant procedures regarding the control and use of hoists. These procedures require that hoist operators be trained in hoist operation and certified as hoist operators by the Maintenance Superintendent.

2.3.3.2 EG&G Evaluation, Conclusions, and Recommendations on Crane Operator Training

The Applicant has met the criteria of this guideline for training, qualification, and conduct as specified by Chapter 2-3 of ANSI B30.2-1976.

2.3.3.3 Summary on Crane Operator Training

The Grand Gulf Nuclear Station Units 1 and 2 fully comply with the criteria of Guideline 3, "Crane Operator Training".

2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, "Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials."[6] This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in

Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) of the load and of the intervening components of the special handling device.

2.3.4.1 Summary of Applicant's Evaluation on Special Lifting Devices

In Reference [4], the Applicant has identified three special lifting devices that are used to handle heavy loads in the containment. These special lifting devices are:

(1) Head Strongback Carousel
(2) Dryer/Separator Strongback
(3) Drywell Head Lifting Frame (Strongback).

The Applicant provided a description of each of the devices and the plant function or operations in which those devices are used. The Applicant evaluated the devices against ANSI N14.6-1978 and provided detailed comparison to Sections 3.2 and 5 of the standard. The Applicant could not apply the remaining sections in retrospect. The Applicant has indicated that sound engineering practices were placed on the fabricator and inspector by the designer for the purpose of assuring that the designer intent was accomplished. On that basis, the Applicant considers that there is reasonable assurance that the intent of the standard was accomplished in the design, fabrication, inspection, and testing of these devices.

The Applicant considered Sections 1.0, 2.0, 3.4, 3.5, and 3.6 of ANSI N14.6-1978 as not pertinent to load-handling reliability of the devices and, therefore, did not address them.

Section 6 of ANSI N14.6-1978 concerning critical loads was not considered because a determination of critical loads requires an analysis of the consequences of various load-drop scenarios and is not required until the final report to the NRC.

In their review of Section 3.2, ANSI N14.6-1978, the Applicant addressed stress-design factors and fracture toughness of materials utilized to fabricate devices.

The Head Strongback Carousel and Dryer/Separator Strongback were designed with stress-design factors consistent with ANSI N14.6, Section 3.2. The Drywell Head Lifting Frame was designed to AISC criteria which resulted in lower design factors being realized than required by ANSI N14.6. However, the Applicant considers that based on conservative load criteria used in the design, the resulting design factors are consistent with those generally required for safety-related items.

In Reference [7], the Applicant reviewed their crane speeds, used the CMAA-70 guidelines for loads and determined that for the maximum hoisting speed of 5 feet per minute, dynamic load increases would be on the order of 2.5% which is negligible. This substantiated a concern on whether dynamic loads should be considered in stress-design factors.

For Fracture Toughness considerations, the materials utilized to fabricate the load-bearing components in the lifting devices were evaluated in terms of their fracture-toughness properties. All materials have been determined to possess adequate resistance to brittle fracture with the possible exception of A-53 utilized for the vertical supports and bracing in the RV Head Strongback. Therefore, to ensure that brittle failure of these load-bearing components is remote, the Applicant shall perform periodic inspections of these components. The Applicant considers these actions appropriate to ensure that brittle failure of these load-bearing components is extremely remote.

From a review of Section 5, ANSI N14.6-1978, the Applicant will establish a program for inspection, testing, and maintenance of the devices that meets the provisions of ANSI N14.6-1978 with the following four exceptions:

(1) The Applicant does not consider an inspection of three months or less necessary. Between usages, these devices are stored in a specific location under controlled environment and are not subjected to any other usage except the dedicated usage. The Applicant has revised their procedures to inspect these devices prior to each usage or a thorough test and inspection annually. Based on these factors, the Applicant has demonstrated equivalency to Section 5.3.7.

(2) In Section 5.3.3, special lifting devices should be load tested to 150% of maximum load following any incident in which any load-bearing component may have been subjected to stresses substantially in excess of those for which it was qualified by

previous testing or following an incident that may have caused permanent distortion of load-bearing parts. The Applicant considers dimensional examinations for deformation and nondestructive examinations for defects to determine whether the device is still acceptable for use rather than subject the device to 150% load testing. If defects or deformation are detected, the device will be repaired or modified and then tested to 150% load followed by examination for defects or deformation. The Applicant considers this action an equivalent alternative to Section 5.3.3.

(3) The lifting devices were subjected to 125% proof load test rather than the 150% load test required by Section 5.2.1. Following the proof tests, all load-bearing welds were subjected to NDE. The Applicant considers the potential for overloading these devices is extremely remote because the devices are dedicated to one or two specific loads throughout their service life. In addition, the devices will receive thorough periodic examinations and, if damaged or repaired, will be subjected to a 150% load test before being returned to service. For these reasons, the Applicant considers the 125% initial proof test as adequate.

(4) Several components of the lifting devices will be subjected to NDE and dimensional inspections on intervals longer than those required by Section 5.3.1(2) as those components require disassembly or removal of paint. The Applicant will inspect those ponents on a five-year interval because they are difficult and time-consuming inspections that are not judged to be justified for a shorter interval based on their very limited and dedicated usage.

Reference [6] forwarded the Applicant's response to the initial draft report prepared by EG&G under contract to NRC. On September 1, 1982, a telephone conference call was held between staff members of EG&G, NRC, TERA Corporation, and the Applicant to discuss the responses. As a result of agreements reached during that conference call, certain changes were made and are reflected below.

One of the concerns with Section 3.1.1 of ANSI N14.6-1978 was the placing of limitations on the use of the special lifting devices. Also, there was concern about the quality assurance measures in effect per Section 3.1.2 of ANSI N14.6-1978.

The Applicant amended their response concerning the Drywell Head Strongback to include the Quality Assurance Programs used in the design and fabrication of the special lifting device. In addition, the Dryer Separator Strongbacks and Reactor Head Strongback Carousel quality assurance programs were specified.

The Applicant addressed the concern of misuse of the devices by stating that procedures will be modified to exclude loads except for those intended for the special lifting devices.

2.3.4.2 EG&G Evaluation, Conclusion, and Recommendations on Special Lifting Devices

As a result of References [4,5], EG&G did not concur with the Applicant's evaluation of Sections 3.1, 3.3, 4.1, 4.2, and 4.3 as difficult to apply in retrospect. Good engineering practice is not an acceptable substitute for design specifications, stress analysis, design considerations, fabrication and welding, inspection, and fabrication considerations. The Applicant's designer must have a stress analysis on the lifting devices or they could be used to lift any load desired in the facility.

Sections 1.0, 2.0, 3.4, 3.5, and 3.6 are also pertinent to the special lifting devices and should be addressed in the Applicant's report.

EG&G recommends the Applicant address each item in ANSI N14.6-1978 and provide the necessary documentation to indicate that the special lifting devices can be safely used for handling heavy loads.

EG&G feels that lifts conducted with the devices identified by the Applicant have a high probability of qualifying as critical loads under the definition found in Section 2, especially considering the phrase "uncontrolled movement." The lifts identified in Tables 2.4, 2.5, 2.6, and 2.7 will be conducted when the plant is shut down, thus reducing the number of systems required for unit safety, but greatly increasing the possibility of breaching containment in the event of inadvertent heavy load drop. In addition, it should be pointed out that Section 2.1 of NUREG-0612 specifies the allowable off-site radioactive release applicable to heavy loads as 25% of the guide- line exposures outlined in 10 CFR Part 100. For the lifts considered in this guideline, the definition of "critical load" in ANSI N14.6 should be so amended.

In Guideline 4 of NUREG-0612, the stress-design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. The Applicant's evaluation of the lifting devices failed to include this change in stress-design factors.

In the Applicant's evaluation of fracture toughness properties of materials utilized in fabrication of load-bearing components in each of the lifting devices, it is not clear to EG&G how periodic inspections can be performed to detect pending brittle failure. The Applicant should furnish the procedures describing the techniques that will be employed to ensure that brittle failure does not occur.

EG&G concurs with the Applicant's plan to inspect the special lifting devices prior to each usage and supplement that program with a thorough testing and nondestructive examination performed annually. Based on the controlled storage of the lifting devices, their dedicated single usage and the complete inspection schedule, the Applicant has demonstrated compliance with this section of ANSI N14.6.

EG&G agrees with the Applicant's actions on Section 5.3.3 where inspections and examinations are performed prior to a 150% load test if the device has been deformed. The special lifting devices should be load tested to 150% even though repairs or modifications may not have been required.

EG&G agrees with the Applicant's assessment of the 125% proof load test and their exception to performing a 150% load test as required by Section 5.2.1 of ANSI N14.6. When the device is to be used, the Applicant will have to perform a 150% load test to comply with ANSI N14.6. Therefore, the initial 125% proof load test would not be required for those devices already tested. New devices should be proof tested as recommended by ANSI N14.6-1978.

EG&G did not concur with the Applicant's plan to inspect the components of the lifting devices on five-year intervals, contrary to the requirements of Section 5.3.1(2) of ANSI N14.6-1978. The Applicant should reevaluate the criteria of ANSI N14.6 and develop a plan based on usage level and time intervals. Inconvenience is not an adequate substitution for the safe handling of heavy loads at nuclear power plants.

After receipt of Reference [6] and the subsequent conference call on September 1, 1982, EG&G comments were resolved by a point-to-point comparison to ANSI N14.6-1978. The Applicant then addressed the remaining concerns in Reference [7]. Consequently, EG&G considers that the Applicant has met the criteria of Guideline 4 of NUREG-0612.

2.3.4.3 Summary on Special Lifting Devices

The Grand Gulf Nuclear Station Units 1 and 2 now fully comply with the criteria of Guideline 4, "Special Lifting Devices".

2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, "Slings".[7] However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the "static load" which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used.

2.3.5.1 Summary of Applicant's Evaluation on Lifting Devices (Not Specially Designed)

In Reference [6], the Applicant addressed slings to ANSI B30.9 criteria. From the conference call of September 1, 1982, and Reference [7], the Applicant has stated that load-handling procedures will require use of ANSI B30.9 and NUREG-0612 5.1.1(5) criteria for sling selection and rigging techniques.

In addition, the Applicant also will require sling selection, use, and marking based on the sum of both maximum static and dynamic loads.

2.3.5.2 EG&G Evaluation, Conclusion, and Recommendations on Lifting Devices (Not Specially Designed)

EG&G has reviewed the Applicant's submittal of Reference [7] and considers that the Applicant now meets the criteria of Guideline 5 and ANSI B30.9.

2.3.5.3 Summary on Lifting Devices (Not Specially Designed)

The Grand Gulf Nuclear Station Units 1 and 2 now fully comply with the criteria of Guideline 5, "Slings".

2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, "Overhead and Gantry Cranes," with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency (e.g., the polar crane inside a PWR containment may be used only every 12 to 18 months during refueling operations, and is generally not accessible during power operation). ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use).

2.3.6.1 Summary of Applicant's Evaluation on Cranes (Inspection, Testing, and Maintenance)

In Reference [4,5], the Applicant has reviewed the maintenance procedures and instructions of the cranes in Table 2.1 and amended them as required to meet the criteria of Chapter 2-2 of ANSI B30.2-1976. No exceptions were taken to ANSI B30.2. The LPCS/RHR "C" Hatch Monorail/ Hoist System is not directly applicable to ANSI B30.2; however, activities of this system are covered by procedures prepared following guidelines of ANSI B30.16-1973, Section 16-2.2.

2.3.6.2 EG&G Evaluation, Conclusion, and Recommendations on Cranes (Inspection, Testing, and Maintenance)

From a review of Reference [4,5] by EG&G and subsequent submittals, the Applicant meets the criteria of NUREG-0612 for inspection, testing, and maintenance of their cranes. The Applicant should have the maintenance procedures and instructions available for possible NRC review.

2.3.6.3 Summary on Cranes (Inspection, Testing, and Maintenance)

Grand Gulf Nuclear Station Units 1 and 2 fully comply with the criteria of Guideline 6, "Cranes (Inspection, Testing, and Maintenance)."

2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, "Overhead and Gantry Cranes," and of CMAA-70, "Specifications for Electric Overhead Traveling Cranes."[8] An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied.

2.3.7.1 Summary of Applicant's Evaluation of Crane Design

The overhead cranes of Table 2.1 were compared to the 1975 revision CMAA-70 and to the additional safety requirements of ANSI B30.2-1976, Section 2-1 by the Applicant. A similar comparison for the Spent-Fuel Cask crane was not performed as this crane has been designed to "Single Failure-Proof Criteria" and that comparison can be found in the FSAR, Appendix 3A.

Based on these comparisons, the Applicant found that the Polar Crane and the New Fuel Bridge Crane comply with the guidelines of CMAA-70-1975 and ANSI B30.2-1976, except for one minor exception in regard to welding. ANSI B30.2-1976 requires welding to AWS D1.1 as modified by AWS D14.1. The Applicant's review indicated no significant differences between AWS D1.1 and D14.1 that would affect load-handling reliability except for requirements on storage of low hydrogen welding rods. The Applicant communicated with the crane manufacturer and found that their shop practices provided for control of low-hydrogen rods even though AWS D1.1 was not used. Therefore, the welding requirements in effect were equivalent to the requirements of ANSI B30.2.

The LPCS and RHR "C" Hatch Monorail/Hoist System are not directly applicable to CMAA-70 and ANSI B30.2-1976;however, the design did meet applicable industry stan- dards. ANSI B30.16, "Overhead Hoists-1973," and Hoist Manufacturers Institute Standard HMI 100-74, "Standard Specification for Electric Wire Rope Hoists," are the industry standards that apply to these hoists. The Applicant compared the design of their hoists to the criteria in these standards and found that they meet or exceed the requirements of ANSI B30.16 and HMI 100-74. In addition, the Applicant also discussed design with the hoist manufacturer and obtained their input. Therefore, the Applicant considers that the design of LPCS/RHR "C" Monorail System satisfies the intent of NUREG-0612, Section 5.1.1(7).

In Reference [7], the Applicant made a more emphatic statement in that all information concerning specifications of cranes conforms to Guideline 7 of NUREG 0612 and are available for audit.

2.3.7.2 EG&G Evaluation, Conclusions, and Recommendations on Crane Design

The Applicant has demonstrated equivalency of actual design requirements where compliance with CMAA-70 and ANSI B30.2-1976 were not met. EG&G considers the Applicant has met Guideline 7, Crane Design for the Containment Polar Crane and New Fuel Bridge Crane. In addition, EG&G also concurs with the Applicant's assessment of the LPCS/RHR "C" Monorail System to this guideline. The Spent-Fuel Cask Crane was designed to

"Single Failure-Proof Criteria" of Regulatory Guide 1.104 and no further action by Applicant is required.

2.3.7.3 Summary on Crane Design

Grand Gulf Nuclear Station Units 1 and 2 fully comply with the criteria of Guideline 7, "Crane Design".

3. CONCLUDING SUMMARY

3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the Applicant as being subject to the provisions of NUREG-0612 is complete (see Section 2.2). In Section 2.2.1.2, the Applicant fulfilled the requirements of NUREG-0612 concerning exclusion of various overhead handling systems.

3.2 Guideline Recommendations

Compliance with all of the NRC guidelines for heavy-load handling (Section 2.3) are now satisfied at the Grand Gulf Nuclear Station Units 1 and 2.

3.3 Interim Protection

Compliance with the seven guidelines of NUREG-0612 Section 5.1 has been assured before the plant operation date; therefore, interim protection need not be implemented.

TABLE 3.1 GRAND GULF NUCLEAR STATION UNIT 1 AND 2 COMPLIANCE MATRIX

Equipment Designation	Heavy Loads	Weight or Capacity (tons)	Guideline 1 Safe Load Paths	Guideline 2 Procedures	Guideline 3 Crane Operator Training	Guideline 4 Special Lifting Devices	Guideline 5 Slings	Guideline 6 Crane - Test and Inspection	Guideline 7 Crane Design
Polar Crane	C	125/35	C	C	C	C	C	C	C
Spent-Fuel Cask Crane	C	150	C	C	C	C	C	C	C
New Fuel Bridge Crane	C	5	C	C	C	C	C	C	C
Monorail for LPCS & RHR "C" Hatches	NA	10	--	--	--	--	--	--	--

C = Applicant action fully complies with NUREG-0612 Guideline, subject to review by NRC staff.

4. REFERENCES

1. U.S. Nuclear Regulatory Commission, Regulatory Guide, NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

2. V. Stello, Jr. (NRC), Letter to all Applicant's, Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel, dated May 17, 1978.

3. U.S. Nuclear Regulatory Commission, Letter to Mississippi Power & Light Company, Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel, dated December 22, 1980.

4. L. F. Dale, Mississippi Power & Light Company, Letter to D. G. Eisenhut (NRC), Subject: Response to Staff Position, Interim Actions for Control of Heavy Loads, dated November 23, 1981.

5. L. F. Dale, Mississippi Power & Light Company, Letter to D. G. Eisenhut (NRC), Subject: Revision to Response to Staff Position, Interim Actions for Control of Heavy Loads, dated February 25, 1982.

6. L. F. Dale, Mississippi Power & Light Company, Letter to H. R. Denton (NRC), Subject: Response to EG&G Comments on Six-Month Heavy Load Report, dated August 6, 1982.

7. L. F. Dale, Mississippi Power & Light Company, Letter to H. R. Denton (NRC), Subject: Amended Response to EG&G Comments on Six-Month Heavy Load Report, Nine-Month Report Load Drop Analysis, dated November 19, 1982.

8. American National Standards Institute, ANSI B30.2-1976, "Overhead and Gantry Cranes."

9. American National Standards Institute, ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials."

10. American National Standards Institute, ANSI B30.9-1971, "Slings."

11. Crane Manufacturers Association of America, Inc., CMAA-70, "Specifications for Electric Overhead Traveling Cranes."

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16. ABSTRACT (200 words or less)

Supplement 5 to the Safety Evaluation Report for Mississippi Power & Light Company, et al, joint application for licenses to operate the Grand Gulf Nuclear Station, Units 1 and 2, located on the east bank of the Mississippi River near Port Gibson in Claiborne County, Mississippi, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status on the resolution of those issues chat require further evaluation before authorizing operation of Unit 1 above 5% of rated power.

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