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CHAPTER 18 RESPONSES TO TMI-RELATED REQUIREMENTS

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18.0 RESPONSES TO TMI RELATED REQUIREMENTS

18.1 RESPONSE TO REQUIREMENTS OF NUREG-0737

This section contains a response for each TMI-related requirement identified in NUREG-0737 and applicable to Grand Gulf Nuclear Station. For those items that have been superseded by other NUREGs, generic letters, or amendments to 10 CFR 50, the most recent requirements are addressed except for NUREG-0737, Supplement 1, which is discussed in Section 18.2.

18.1.1 Shift Technical Advisor (I.A.1.1)

REQUIREMENT

Each licensee shall provide an on-shift technical advisor to the Shift Manager. The Shift Technical Advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of ensuring safe operations of the plant, including the review and evaluation of operating experience.

RESPONSE

The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have a minimum of 12 months of nuclear power plant experience.

18.1.2 Shift Manager Administrative Duties (I.A.1.2)

REQUIREMENT

Review the administrative duties of the Shift Manager and delegate functions that detract from or are subordinate to the management responsibility for ensuring safe operation of the plant to other personnel not on duty in the control room.

RESPONSE

a. Shift Manager

Due to unit organizational changes in 1980, the position previously identified as Shift Supervisor now corresponds directly to the position of Shift Manager at GGNS. The Shift Manager is the GGNS General Manager, Plant Operations direct management representative and as such is responsible for the Command Function of the control room.

b. Control Room Supervisor

The Control Room Supervisor administratively supports the Shift Manager and if directed by the Shift Manager may be responsible for the actual operation of his assigned unit during his shift. Further discussion of the duties and responsibilities of the Control Room Supervisor is contained in subsection and 18.1.10.

The administrative duties of the Shift Manager are contained in plant administrative procedures and management standards. Administrative duties that detract from the Shift Manager's responsibility for ensuring the safe operation of the unit are delegated to others not assigned to control room duties.

18.1.3 Shift Manning (I.A.1.3)

REQUIREMENT

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

The administrative procedures shall also set forth a policy, the objective of which is to operate the plant with the required staff and develop working schedules such that use of overtime is avoided, to the extent practicable, for the plant staff who perform safety-related functions (e.g., Senior Reactor Operators, Reactor Operators, Health Physicists, Auxiliary Operators, I&C Technicians, and key maintenance personnel).

RESPONSE

The requirement to include shift manning in the plant procedures has been supplemented by requirements for minimum shift manning. These minimum requirements are established in 10 CFR 50.54(m). The requirement to limit overtime was also clarified by a revised NRC policy which was issued in Generic Letter 82-12. Both the GGNS Technical Specifications and Administrative Procedures include provisions which are in accordance with the NRC policy requirements. More detailed information about the overtime limitations and the minimum shift crew composition is provided in subsection 13.1.2.1 and the GGNS Technical Specifications.

18.1.4 Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications (I.A.2.1)

REQUIREMENT

Applicants for Senior Reactor Operator (SRO) license shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at specific plant) and no more than 2 years shall be academic or related technical training. After fuel loading, applicants shall have 1 year of experience as a licensed operator or equivalent. Applicants for either SRO or RO license shall have 3 months on-shift training.

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

Applicants must revise training and requalification programs to include training in heat transfer, fluid flow, thermodynamics, plant transients, and degraded core accident mitigation.

RESPONSE

Applicants for a SRO license at GGNS have at least 4 years of power plant experience. A maximum of 2 years of power plant experience requirement may be fulfilled by academic or related technical training on a one-for-one time basis. Each SRO candidate is required to have at least 2 years of responsible nuclear plant experience. Six months of this experience is required to be at GGNS, of which 3 months will be on-shift carrying out the duties of the Senior Reactor Operator while under the direct supervision of an SRO.

Additionally, personnel who hold a reactor operator license on GGNS will have held that license for a period of one year prior to being administered an SRO examination, except applicants who meet the requirements of NUREG-0737, Section I.A.2.1.

Each candidate is also required to satisfactorily complete the accredited Senior Licensed Operator Training Program.

The highest level of corporate management responsible for plant operations is the Vice President, Operations. He, or the General Manager, Plant Operations as permitted by 10CFR55, is responsible for certifying to the NRC that each license candidate is able to operate the plant safely and competently. This certification includes consideration of the training, the demonstrated ability and dependability, and the health and stability of each applicant.

The accredited Licensed Operator Training and Qualification Program at GGNS includes training in heat transfer, fluid flow, thermodynamics, plant transients, and degraded core accident mitigation.

18.1.5 Administration of Training Programs (I.A.2.3)

REQUIREMENT

Pending accreditation of training institutions, training instructors who teach systems, integrated response, transient, and simulator courses shall successfully complete a Senior Reactor Operator (SRO) examination prior to fuel loading, and instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedures, and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

RESPONSE

The GGNS Licensed Operator Training Program was accredited by the National Nuclear Accreditation Board (NNAB) as of April 1987 and is based on a System Approach to Training.

18.1.6 Revise Scope and Criteria for Licensing Examinations (I.A.3.1)

REQUIREMENTS

All Reactor Operator license applicants shall take a written examination with a new category dealing with the principles of heat transfer and fluid mechanics, a time limit of nine hours, and a passing grade of 80 percent overall and 70 percent in each category.

All Senior Reactor Operator license applicants shall take an operating test and a written examination with a new category dealing with the theory of fluids and thermodynamics, a time limit of seven hours, and a passing grade of 80 percent overall and 70 percent in each category.

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations.

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

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

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

RESPONSE

All Reactor Operator and Senior Reactor Operator applicants receive instruction in a Nuclear Power Plant Fundamentals Course which includes instruction in heat transfer, fluid flow, and thermodynamics. At the conclusion of this training course, all applicants are administered an NRC-style examination on which the passing criteria are the same as an NRC-administered examination.

Each applicant must then be examined by the NRC in order to become licensed. The criteria for passing these exams are scores of 70 percent in each category and 80 percent overall. All applicants for operator licenses are required to grant permission to the NRC to inform Grand Gulf Nuclear Station management of the results of their examination. Licensed individuals are given an examination administered by the Nuclear Training Department and must pass with scores of 70 percent in each category and 80 percent overall in order to be requalified.

The requalification programs at Grand Gulf Nuclear Station were accredited by the NNAB as of April 1987 and is based on a system approach to training.

18.1.7 Independent Safety Engineering Group (I.B.1.2)

REQUIREMENT

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent reviews and audits of plant activities, including maintenance, modifications, operational problems, and operational analysis, and shall aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. ISEG will then be in a position to advise utility management on the overall quality and safety of operations. ISEG need not perform detailed audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

RESPONSE

The Nuclear Safety Assurance Department performs the functions of an onsite independent safety engineering group (ISEG).

18.1.8 Guidance for the Evaluation and Development of Procedures for Transients and Accidents (I.C.1)

REQUIREMENT

Reanalysis of small break LOCAs, transients, accidents, and inadequate core cooling and preparation of guidelines for development of emergency procedures should be completed and submitted to the NRC for review. The NRC staff will review the analyses and guidelines and determine their acceptability, and will issue guidance to licensees on preparing emergency procedures from the guidelines.

RESPONSE

Mississippi Power & Light Company participated in the BWR Owners' Group program to develop emergency procedures guidelines for General Electric boiling water reactors.

In a letter dated June 30, 1980, Mr. R. H. Buchholz forwarded the GE Emergency Procedures Guidelines for the BWR 1-5 product lines to Mr. D. G. Eisenhut. In a letter dated October 21, 1980, Mr. Eisenhut informed the BWR Owners' Group that the guidelines were acceptable for trial implementation on six NTOL plants. These plants were either BWR-4 or BWR-5 product lines. MP&L (SERI) participated with the Owners' Group in extending the guidelines to address BWR-6/Mark III plants, and on January 31, 1981 in a letter from Mr. D. B. Walters to Mr. D. G. Eisenhut, these revised guidelines were transmitted to the NRC. On January 27, 1981, MP&L provided to the NRC by letter (AECM-81/044) the Grand Gulf Nuclear Station (GGNS) Emergency Procedures which were written based on the revised BWR Emergency Procedures Guidelines. The NRC has indicated these guidelines are acceptable for trial implementation at GGNS. Based on their review of the procedures and the implementation of the procedures, the NRC has concluded the guidelines have been adequately incorporated.

The long-term actions to address NUREG-0737, Action Plan I.C.1 have been incorporated into the NUREG-0737, Supplement 1 (Emergency Response Capability) requirements. These requirements are discussed in subsection 18.2.5.

18.1.9 Shift Relief and Turnover Procedures (I.C.2)

REQUIREMENT

Revise plant procedures for relief and turnover to require signed checklists and logs to assure that the operating staff (including auxiliary operators and maintenance personnel) possess adequate knowledge of critical plant parameter status, system status, system availability, system alignment, and systems (or components) that are in a degraded mode of operation permitted by the Technical Specifications.

A system shall be established to evaluate the effectiveness of the shift and relief turnover procedures (for example, periodic independent verification of system alignments).

RESPONSE

GGNS Administrative Procedure 02-S-01-4, Shift Relief and Turnover, requires the on-coming and off-going control room operators to exchange information of plant parameters, the availability and proper alignment of emergency core cooling systems in the control room, and a general walkdown of the control room boards. The off-going operator shall fill out a status checksheet prior to turnover. This status checksheet contains critical plant parameters and operability status of vital systems. The on-coming operator shall review the status checksheet. Both operators will sign the sheet. The sheet is then forwarded to the on-coming Control Room Supervisor and Shift Manager for review. Further, the Control Room supervisor and shift manager review the LCO Log.

Building or Area Operators use a Building Operator Logbook for their shift turnover. The off-going operator uses the logbook to inform the on-coming operator of the area status, including system/components degraded or inoperable, evolutions in progress, and any abnormal conditions.

GGNS Quality Programs audits implementation of relief and turnover procedures in accordance with the NRC accepted Grand Gulf Nuclear Station Quality Assurance Program Manual.

18.1.10 Control Room Supervisor Responsibilities (I.C.3)

REQUIREMENT

Revise plant procedures to ensure that duties, responsibilities, and authority of the Shift Supervisor and Control Room Operators are properly defined.

RESPONSE

Administrative Procedures define the responsibility and authority of the Control Room Supervisors and licensed operators.

18.1.11 Control Room Access (I.C.4)

REQUIREMENT

Revise plant procedures to limit access to the control room to those individuals responsible for the direct operation of the plant, technical advisors, specified NRC personnel, and to establish a clear line of authority, responsibility, and succession in the control room.

RESPONSE

Administrative Procedures limit access to the control room to those individuals responsible for operation of the plant, and others as deemed necessary. Additionally, the control area is to be kept clear except for on-duty Operations personnel, and access is not allowed without the permission of an on-shift licensed individual assigned to a Control Room position.

Administrative Procedures delineate the line of authority, responsibility, and succession inside and outside the control room in the following manner:

a. The General Manager, Plant Operations has the overall responsibility for operation of GGNS.

b. When the General Manager, Plant Operations is not available to supervise the safe and efficient operation of GGNS, this responsibility and authority is assumed by the following people in the order listed:

    1. Manager, Operations

    2. Manager, Maintenance

    3. Assistant Operations Manager, Shift

    4. Assistant Operations Manager, Support

    5. Shift Manager

    6. Control Room Supervisor

c. The Shift Manager shall retain his responsibility and authority, unless he is formally relieved of:

Operating responsibilities by a Licensed Senior Reactor Operator, who should be a management representative, at the direction of any of the following personnel, or by any of the following personnel should they be a Licensed Senior Reactor Operator:

1. Assistant Operations Manager, Support

2. Assistant Operations Manager, Shift

3. Manager, Maintenance

4. Manager, Operations

5. General Manager, Plant Operations

Emergency management responsibilities as described in the GGNS Emergency Plan.

d. The Control Room Supervisor shall retain his responsibility and authority under the direction of the Shift Manager, unless he is formally relieved by a Licensed Senior Reactor Operator, who should be a management representative, at the direction of the following personnel or by the following personnel should they hold a valid Senior Reactor Operator License:

1. Shift Manager

2. Assistant Operations Manager, Support

3. Assistant Operations Manager, Shift

4. Manager, Maintenance

5. Manager, Operations

6. General Manager, Plant Operations

e. The Shift Manager is, at all times, the General Manager, Plant Operations direct management representative for the conduct of operations and, as such, has the responsibility and authority to direct all activities and personnel at GGNS as required to:

1. Protect the health and safety of the public and the environment

2. Protect the health and safety of GGNS employees, contractors, or other personnel onsite

3. Prevent damage to GGNS equipment and structures

4. Protect the physical security of GGNS

5. Ensure compliance with the GGNS Operation License

f. The Control Room Supervisor administratively supports the Shift Manager to ensure the Command Function is not overburdened by administrative duties. The Shift Manager may direct the Control Room Supervisor to direct all activities and personnel during normal operations and emergencies as necessary to:

1. Protect the health and safety of the public and the environment

2. Protect the health and safety of employees, contractors, or other personnel

3. Prevent damage to equipment and structures

4. Ensure compliance with the operating license

g. The Shift Manager has the responsibility to maintain an overall “big picture” concept of the unit operations and not to become totally involved in any single plant operation during times of an emergency when multiple operations are required.

h. If the Shift Manager becomes incapacitated, the Unit 1 Control Room Supervisor will perform the functions of the Shift Manager until relieved.

18.1.12 Procedures for Feedback of Operating Experience to Plant Staff (I.C.5)

<u>REQUIREMENT</u>

Review administrative procedures to ensure that operating experience from within and outside the organization is continually provided to operators and other operational personnel and is incorporated in training programs.

RESPONSE

The Nuclear Safety Assurance Department is responsible for ensuring that operating experience information pertinent to plant operations is supplied to plant staff personnel and is incorporated into the training program in a timely manner.

GGNS procedures address review, handling and distribution of operating experience information and its incorporation into GGNS training programs.

18.1.13 Guidance on Procedures for Verifying Correct Performance of Operating Activities (I.C.6)

REQUIREMENT

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

RESPONSE

The Grand Gulf Nuclear Station Quality Assurance Program Manual, which has been accepted for use by the NRC, endorses with some clarification Regulatory Guide 1.33 Revision 2, February 1978, which in turn endorses ANSI 18.7-1976.

The Grand Gulf Nuclear Station Operations Manual establishes the procedures necessary to implement the requirements of Regulatory Guide 1.33 and ANSI 18.7-1976. Procedures have been written, approved, and implemented to verify correct performance of operating activities.

GGNS procedures take the following actions to address the clarification set out in I.C.6:

a. Only the Shift Manager or his direct designee(s), i.e., (qualified on-shift SROs) have the authority to release all permanently installed equipment or systems at GGNS for maintenance or surveillance testing; or return that equipment to service (excluding equipment in the administration building, warehouse, and equipment, tools, or machinery used only by other sections, such as the equipment used routinely by maintenance personnel in the hot maintenance shop). Granting of such permission shall be documented. When equipment or systems are ready to be returned to service, operations personnel shall place the equipment or systems in operation and verify and document its functional acceptability. In addition, the SRO is required to ensure all on-shift operations personnel are informed of any change in safety system status, i.e., (return to service, maintenance, surveillance testing).

b. Procedures require independent verification of activities related to protective tagging and temporary system alterations on safety-related equipment or systems.

c. Independent verification is required to ensure that safety-related equipment is properly returned to service if functional testing cannot be performed. In addition, procedures require functional testing, where applicable, to verify correct performance of activities.

18.1.14 Nuclear Steam Supply System Vendor Review of Procedures (I.C.7)

REQUIREMENT

Obtain nuclear steam supply system vendor review of power ascension and emergency operating procedures to further verify their adequacy.

RESPONSE

Procedures for both low power testing and power ascension testing were either written or reviewed by GE start-up test engineers. This work was performed onsite under the direction of the GE Site

Operations Manager. In addition, each of these procedures was reviewed by the GE Lead Engineer - Start-up, Test, Design, and Analysis (STD&A).

The GGNS Emergency Operating Procedures (EOPs) were revised based on comments resulting from the GE review of the procedures. This revision was submitted to the NRC in letter AECM-82/0299. Further revisions of the EOPs have been made based on NRC comments to incorporate human factors principles.

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

REQUIREMENT

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

RESPONSE

Mississippi Power and Light Company submitted to the NRC an early draft of the GGNS Emergency Operating Procedures (EOPs) which was based on the BWR Owner's Group Guidelines. The procedures were revised based on NRC comments. The NRC later observed the implementation of the procedures on the Perry Simulator (in March 1981) and in the GGNS control room (in June 1981). Additional changes to the procedures based on the observation of these exercises have been incorporated.

Future revision of the EOPs may be required based on the development of the BWR Owner's Group Emergency Procedures Guidelines or on staff positions developed to implement Task

Action Plan I.C.9, Long-Term Program for Upgrading of Procedures. As noted in subsection 18.1.8, NUREG-0737, Supplement 1 incorporates all long-term actions relative to procedure EOP development. A discussion of these long-term requirements is provided in subsection 18.2.5.

18.1.16 Control Room Design Review (I.D.1)

REQUIREMENT

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

RESPONSE

Mississippi Power & Light Company contracted the Essex Corporation to perform a human factors evaluation of the Grand Gulf control room. The results of that study and MP&L's plans for corrective action were submitted to the NRC in a letter from Mr. L. F. Dale to Mr. H. R. Denton dated December 29, 1980 (AECM-80/316). In addition, the NRC Human Factors Engineering Branch conducted a control room design review/audit. Several items which were not available during this review were subsequently evaluated by MP&L.

Resolution of the deficiencies identified during these reviews has been discussed with the NRC. Resolutions which have not yet been determined will be accomplished during the long-term program. The requirements for the long-term control room design review program are found in NUREG-0737, Supplement 1. These requirements are discussed in subsection 18.2.3.

18.1.17 Plant Safety Parameter Display Console (I.D.2)

REQUIREMENT

Install a safety parameter display system (SPDS) that will display a minimum set of parameters which define the safety status of the plant to operating personnel. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status.

RESPONSE

The requirements of this Action Plan (I.D.2) have been incorporated in NUREG-0737, Supplement 1. A discussion of the current requirements and long-term plans relative to the safety parameter display system is provided in subsection 18.2.2.

18.1.18 Training During Low-Power Testing (I.G.1)

REQUIREMENT

Define and commit to a special low-power testing program, approved by the NRC, to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and providing supplemental training.

RESPONSE

Mississippi Power & Light Company initially committed to performing a simulated station blackout test during the first refueling outage to address the NRC position on this Action Plan. In Generic Letter 83-24, the NRC acknowledged that plant equipment concerns could limit the practicality and value of such a test. MP&L implemented the alternate resolution to Action Plan I.G.1 described in the generic letter by 1) performing an evaluation of a postulated station blackout event at the Grand Gulf Nuclear Station (GGNS) (submitted in AECM-86/0042 dated April 3, 1986) and 2) completing alternate testing recommended in the "Boiling Water Reactor Owner's Group (BWROG) Evaluation of NUREG-0737 Requirement I.G.1, Training During Low Power Testing." The alternate testing conducted at GGNS to meet the I.G.1 requirement is described below.

The "RCIC Operation to Prove DC Separation" test was completed during component testing and during performance of the RCIC preoperational test and the integrated ECCS preoperational test. Separation of the DC system was proven by wiring checks and individual component operation rather than disconnecting all non-RCIC batteries. The "Integrated Containment Pressure Instrumentation Test" was not performed in conjunction with the containment integrated leak rate test, but rather each containment pressure instrument loop was tested individually. This testing was done by various combinations of overlapping tests for each drywell and containment pressure transmitter to prove that the sensing lines were not plugged, the transmitters would respond to pressure in the proper room, and the transmitters were calibrated.

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

REQUIREMENT

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of Appendix A to 10 CFR Part 50, “General Design Criteria.” The vent system shall be designed with sufficient redundancy to ensure a low probability of inadvertent or irreversible actuation.

RESPONSE

The requirement for reactor coolant system venting has now been incorporated into 10 CFR 50 (subsection 50.44.c.3.iii). GGNS has addressed this requirement as described below.

The primary method of venting the reactor pressure vessel (RPV) at Grand Gulf is through twenty (20) safety/relief valves located on the main steam lines between the RPV and the first main steam isolation valve within the drywell. These power-operated relief valves satisfy the intent of the NUREG-0737 requirement. Further information regarding the design, qualification, and power source of these valves is provided in Sections 5.1, 5.2, 7.3, and 8.3.

In addition to the power-operated relief valves, the reactor pressure vessel is equipped with two other means of high point venting. These are:

a. Normally closed head vent valves, operable from the control room, that discharge to the drywell equipment sump (see Figure 5.2-6).

b. A normally open reactor head vent valve which discharges to main steam line “A” (see Figure 5.2-6).

The operation of the safety/relief valves is governed by the Grand Gulf Operations Manual. These procedures provide instructions which enable the operator to maintain adequate core cooling. The instructions include the use of the above valves to depressurize the RPV.

No new accident analysis is required, because the result of a break in the safety/relief valve discharge line or the RPV vent line would be the same as a small steam line break. A complete steam line break is part of the plant's design basis, and smaller size breaks have been shown to be of lesser severity (see Section 6.2).

18.1.20 Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-Accident Operations (II.B.2)

REQUIREMENT

With the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50 percent of the core radioiodine, 100 percent of the core noble gas inventory, and 1 percent of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding-design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during post-accident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

RESPONSE

A radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials has been accomplished at Grand Gulf Nuclear Station. The results of that review, together with a description of the review, is presented in Section 12.6.

A review of the environmental qualification of equipment was performed based on the guidance provided in NUREG-0588. This review considered source terms resulting from the postulated release of radioactivity described in this Action Plan.

18.1.21 Post-Accident Sampling Capability (II.B.3)

REQUIREMENT

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain a sample (in less than 1 hour) under accident conditions without incurring a radiation exposure to any individual in excess of 3 or 18-3/4 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analyses within 3 hours of the time a decision is made to obtain a sample, and the chloride sample analysis within 24 hours).

<u>RESPONSE</u>

The capability to obtain and perform radioisotopic and chemical analyses of the reactor coolant and the containment atmosphere samples is provided by the Process Sampling System via the Post-Accident Sampling Station, which is described in subsections 7.7.1.11.4.2 and 9.3.2.2.4.

18.1.22 Training for Mitigating Core Damage (II.B.4)

REQUIREMENT

Licensees are required to develop a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged. They must then implement the training program.

RESPONSE

Personnel with responsibilities involving the mitigation of core damage are included in a training program. The depth of this training is varied for different personnel commensurate with their responsibilities following the accident. The operator-oriented training is the most extensive and is required of shift technical advisors and operations personnel. The training for operations management personnel that are not part of a shift operating crew, may be taught in a plant-specific training from other nuclear facilities.

Managers and technicians in instrumentation and controls, health physics, and chemistry receive training of narrower scope to effectively address their responsibilities.

18.1.23 Performance Testing of Boiling Water Reactor and Pressurized Water Reactor Relief and Safety Valves (II.D.1)

REQUIREMENT

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

RESPONSE

Mississippi Power & Light Company participated in the BWR Owners Group program to test the safety/relief valves. A description of the program was provided to the NRC on September 17, 1980, in a letter from D. B. Waters to R. N. Vollmer. One of the Grand Gulf Nuclear Station Dikkers valves was utilized in the program.

The results of the testing program are presented in General Electric Report NEDE-24988-P, “Analysis of Generic BWR Safety/ Relief Valve Operability Test Results.” MP&L (SERI) provided confirmation of the test results to Grand Gulf's plant-specific configuration in AECM-85/0099 dated March 29, 1985.

18.1.24 Direct Indication of Relief and Safety Valve Position (II.D.3)

REQUIREMENT

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve-position detection device or a reliable indication of flow in the discharge pipe.

RESPONSE

Grand Gulf Nuclear Station has a safety/relief valve position monitoring system consisting of pressure switches, sensor relays, annunciators, and indicating lights as necessary to monitor, annunciate, and indicate the open/closed condition of each safety/relief valve. Additional details may be found in subsections 7.3.1.1.1.4.11.2 and 7.3.1.1.1.4.12.14.

The safety/relief valve position monitoring system is designed to be safety grade. This equipment has been qualified to IEEE 323-1974, IEEE 344-1975, and NUREG-0588 in accordance with the Commission order of May 27, 1980 (CLI-80-21).

18.1.25 Dedicated Hydrogen Penetrations (II.E.4.1)

REQUIREMENT

Plants using external recombiners or purge systems for post accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

RESPONSE

Grand Gulf Nuclear Station has internal hydrogen recombiners which are located inside the containment in combination with a drywell purge system (see subsection 6.2.5). A backup filtered containment purge through a dedicated seismic Category I penetration is also provided. As internal systems located inside the containment, the only containment piping penetrations associated with the recombiners are the drywell and containment hydrogen analyzer sample and sample return lines. Each of these 3/4-inch lines has two remote manual motor-operated isolation valves. Since these are essential penetrations (see II.E.4.2), it is required that these valves remain open. The use of internal hydrogen recombiners makes this position not applicable to Grand Gulf.

A hydrogen ignition system (see subsection 6.2.5) is provided to ignite the hydrogen generated from a large metal-water reaction during a degraded core accident and to maintain the containment integrity.

Procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment will be reviewed and revised if necessary. The emergency procedures guideline for combustible gas control as developed by the BWR Owners Group along with the results of the GGNS hydrogen control study will be considered in this review.

18.1.26 Containment Isolation Dependability (II.E.4.2)

REQUIREMENT

a. Containment isolation system designs shall comply with the recommendations of Standard Review Plan Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

b. All plant personnel shall give careful consideration to the definition of essential and nonessential systems; identify each system determined to be essential; identify each system determined to be nonessential; describe the basis for selection of each essential system; modify their containment isolation designs accordingly; and report the results of the reevaluation to the NRC.

c. All nonessential systems shall be automatically isolated by the containment isolation signal.

d. The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

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

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

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

RESPONSE

a. Grand Gulf Nuclear Station complies with this requirement as stated in subsection 7.3.1.1.2.

b. A reevaluation of all systems penetrating the primary containment has been accomplished. The results of the reevaluation are listed in Table 18.1-1. A new classification called “beneficial” has been added for nonessential systems that are not required for accident mitigation, but are desirable for plant operation (see also Table 6.2-44).

c. All nonessential power-operated isolation valves are automatically closed upon receipt of a containment isolation signal. There are some locked closed manual valves and blind flanges in nonessential systems.

d. A letter from Mr. Robert L. Tedesco to Mr. J. P. McGaughy, dated December 12, 1980, required MP&L to prepare a response to IE Bulletin 80-06 dealing with ESF reset logic and provided additional guidance for evaluating reset logic. The response has been provided in letters from Mr. L. F. Dale to the NRC's Mr. H. R. Denton, dated February 20, 1981(AECM-81/078), June 1, 1981 (AECM-81/154), December 7, 1981 (AECM-81/449), and April 16, 1982(AECM-82/129). AECM-82/129 verifies that required ESF reset modifications have been completed.

e. The containment isolation analytical set point pressure for Mark I, II, and III containments is approximately 2 psig (drywell pressure). In the GGNS Technical Specifications and the TRM, the trip set point is a value less than the analytical value. Under normal operating conditions, fluctuations in the atmospheric barometric pressure as well as heat inputs from such sources as pumps are expected to result in drywell pressure increases of approximately 1 psig. Consequently, the Technical Specification and Appendix 16B trip set point at a value less than 2 psig provides a 1 psig margin above the expected normal operating pressure. A 1 psig margin to isolation has proved on earlier operating plants to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, such a low value (particularly in view of the small drywell volume of the Mark III containment) provides a very sensitive and positive means of detecting and protecting against breaks and leaks in the reactor coolant system. In view of the guidelines set forth in the clarification to position 5 which suggest a maximum of 1 psig differential between the maximum expected normal operating pressure and the instrument setpoint, no change of the setpoint is necessary for the Grand Gulf containment.

f. The containment purge system is designed to meet the objectives of BTP CSB 6-4 and the Staff Interim Position of October 23, 1979. Information on the purge system design and analysis is provided in subsections 9.4.7 and

6.2.4.3.3. Valve qualification has demonstrated the low volume containment purge system valves can close under a 3 psi differential pressure and the drywell and high volume containment purge system valves can close against pressures developed in the drywell within 5 seconds following a LOCA.

GGNS will provide an evaluation of the need to use the containment purge mode of the containment cooling system based on operating experience obtained during the first fuel cycle related to airborne activity level (ALARA), overall containment air quality, and personnel access to containment.

g. A high radiation signal actuates an alarm and automatically initiates isolation of the containment and drywell.

18.1.27 Additional Accident-Monitoring Instrumentation

18.1.27.1 Noble Gas Effluent Monitor (II.F.1.1)

REQUIREMENT

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

a. Noble gas effluent monitors with an upper range capacity of 10 Ci/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

b. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (as low as reasonably achievable (ALARA) concentrations) to a maximum of 10 Ci/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

RESPONSE

Grand Gulf Nuclear Station provides for continuous monitoring of high level, post-accident releases of radioactive noble gases, both during and following an accident, via the Containment

Ventilation Monitoring System described in subsection 11.5.2.2.4, the Offgas and Radwaste Building Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.6, the Fuel Handling Area Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.7, the Turbine Building Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.8, the Standby Gas Treatment A and B Exhaust Ventilation Radioactivity Monitoring Systems described in subsection 11.5.2.2.9. Additional information concerning the above systems' detector types, detector locations, detector ranges, and radionuclides detected is presented in Tables 11.5-1 and 18.1-3.

18.1.27.2 Sampling and Analysis of Plant Effluents (II.F.1.2)

REQUIREMENT

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by absorption on charcoal or other media, followed by onsite laboratory analysis.

RESPONSE

Grand Gulf Nuclear Station provides for continuous sampling of plant gaseous effluent for post-accident releases of radioactive iodines and particulates via the Containment Ventilation Monitoring System described in subsection 11.5.2.2.4, the Offgas and Radwaste Building Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.6, the Fuel Handling Area Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.7, the Turbine Building Ventilation Radioactivity Monitoring System described in subsection 11.5.2.2.8, and the Standby Gas Treatment A and B Exhaust Ventilation Radioactivity Monitoring Systems described in subsection 11.5.2.2.9. Additional information concerning the above systems' detector types, detector locations, detector ranges, and radionuclides detected is present in Tables 11.5-1 and 18.1-3.

18.1.27.3 Containment High-Range Radiation Monitor (II.F.1.3)

REQUIREMENT

In-containment radiation level monitors with a maximum range of 10 R/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

RESPONSE

Grand Gulf Nuclear Station provides for in-containment, high range, radiation monitoring in both the containment and drywell areas via the In-Containment Area Radiation Monitoring System described in subsections 7.5.1.2.3.6 and 12.3.4.3.

18.1.27.4 Containment Pressure Monitor (II.F.1.4)

REQUIREMENT

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

RESPONSE

Grand Gulf Nuclear Station provides for continuous measurement and indication of containment and drywell pressure by using two wide-range and two narrow-range containment pressure transmitters and two wide-range drywell pressure transmitters that are continuously recorded and displayed in the control room. Further discussion is provided in subsection 7.5.1.2.3.1.

18.1.27.5 Containment Water Level Monitor (II.F.1.5)

REQUIREMENT

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow-range instrument shall be provided for PWRs and shall cover the range from the bottom to the top of the containment sump. A wide-range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000-gallon capacity. For BWRs, a wide-range instrument shall be provided and shall cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

RESPONSE

Grand Gulf Nuclear Station continuously monitors suppression pool level with two wide-range and two narrow-range level signals that are recorded in the control room. The wide-range water level indicators monitor the suppression pool level from the centerline of the ECCS suction lines to above the top of the weir wall. This range provides adequate information to the operator to assess the status of this water supply to ECC systems. Further discussion is provided in subsection 7.5.1.2.3.3.

18.1.27.6 Containment Hydrogen Monitor (II.F.1.6)

REQUIREMENT

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10 percent hydrogen concentration under both positive and negative ambient pressure.

RESPONSE

Grand Gulf Nuclear Station provides for continuous recording of hydrogen concentration in the containment and drywell atmospheres in the range of 0 to 10 percent hydrogen concentration under both positive and negative ambient pressure. Further discussion is provided in subsection 7.5.1.2.8.3.

18.1.28 Instrumentation for Detection of Inadequate Core Cooling (II.F.2)

REQUIREMENT

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

RESPONSE

The NRC has reviewed the BWROG report "Review of the BWR Reactor Vessel Water Level Measurement System." Generic letter 84-23 provides the NRC position on level instrumentation which is based on this report. Physical improvements are needed to increase the reliability and accuracy of the instrumentation and reduce the burden on the operator. These improvements may be categorized:

a. Those which reduce high drywell temperature induced indication errors

b. The use of analog level transmitters, unless operating experience confirms the high reliability of mechanical level equipment.

The GGNS response to this position was provided by letter dated December 6, 1984 (AECM-84/0521). This letter provides justification for the GGNS position that no changes are required.

18.1.29 Office of Inspection and Enforcement Bulletins

18.1.29.1 Safety-Related Valve Position (II.K.1.5)

REQUIREMENT

Review all valve positions, positioning requirements, positive controls, and related test and maintenance procedures to ensure proper ESF functioning.

RESPONSE

A response to the above requirement was forwarded to the NRC in letter AECM-80/26, dated March 19, 1980, which responded to IE Bulletin 79-08. Below is the response (amended, 2002) to this particular item.

A review of the emergency core cooling systems (ECCS) indicated that the system valves' positions are suitably controlled by the following means:

a. Automatic actuation of power-operated valves within the system is provided to isolate the boundary/bypass paths and to align the system for proper operation. Main control room valve position indication is provided for these valves. The handswitches in the control room for these valves are spring return to the auto position to allow the valve to operate automatically if required.

b. Manual valves within the main flow path are provided with locking provisions to ensure correct valve positions. Manual valves which are not accessible during power operation (i.e., located in drywell) are also provided with main control room position indicating lights.

c. Manual valves on branch piping to the main flow piping are provided with locking provisions if incorrect valve position could affect system safety function. Exceptions are the piping high point vents, low point drains, and test connection valves which are verified procedurally to be aligned properly for operation.

For the condensate storage tank piping to the suction of the HPCS and RCIC pumps, the manual isolation valve adjacent to the storage tank is verified procedurally for proper alignment.

For all other safety-related systems other than ECCS, the power-operated valves have been equipped with handswitches having the spring return feature and have been equipped with position indication in the control room. The manual valves in these systems are verified procedurally for proper alignment. These manual valves are not equipped with position indication in the control room.

All system P&IDs have been reviewed to verify that the valves are positioned correctly for proper operation of the safety-related system.

The protective tagging procedures require the use of miniature tags on control panels where required to avoid obscuring any active indicators on the panels.

The position of each manually operated valve is identified in a valve lineup sheet. Valve line-up checks are conducted as required by Technical Specifications to verify system flow paths.

For safety-related systems/components, this valve lineup has independent verifications. Where appropriate, valves are locked in their designated position to prevent inadvertent repositioning.

If valve positions are to be changed for surveillance purposes, the surveillance procedure has steps requiring return to normal valve lineup prior to completion. Start and completion of surveillance procedures are logged in the control room logbook.

When maintenance is performed on a safety-related system which requires valves to be repositioned, administrative procedures require:

a. The approval of the Shift Manager or designee prior to performing maintenance to allow the Shift Manager or designee to verify redundant flow paths, etc. prior to authorizing maintenance

b. The maintenance work documents to specify post-maintenance functional checks or operability tests to verify system return to normal following maintenance activities

When possible, a functional test or Surveillance Operability Test will be performed as required following maintenance on any safety-related system. When such tests are not possible, a complete valve and electrical lineup is performed within the tagged boundary and a partial functional test is performed, where possible, to provide assurance that systems are in fact functional after maintenance.

System lineup changes other than those covered by step-by-step procedures are logged, and abnormal lineups are covered during shift turnover.

During periodic tours, operators and supervisory personnel conduct spot checks of fluid system and electrical line-ups.

18.1.29.2 Safety Related System Operability Status Assurance (II.K.1.10)

<u>REQUIREMENT</u>

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to ensure that operability status is known.

<u>RESPONSE</u>

A response to the above requirement was forwarded to the NRC in letter AECM-83/0225, dated June 23, 1983, which responded to IE Bulletin 79-08. Below is the response to this particular item.

An Administrative Section procedure which provides guidelines for release of permanent plant equipment specifies that redundant safety-related systems must be verified to be operable if required prior to the intentional removal of any safety-related system from service. The procedure also specifies that the Shift Manager or designee must notify other operations personnel of the status of plant systems and that control room operators are aware of all safety-related systems which are removed from service. Further discussion of the program and associated responsibilities pertaining to releasing of plant equipment is provided in subsections 13.1.2.3 and 18.1.13.

18.1.29.3 Proper Functioning of Heat Removal Systems (II.K.1.22)

REQUIREMENT

Describe the automatic and manual actions necessary for proper functioning of the auxiliary heat removal systems that are used when the main feedwater system is not operable.

RESPONSE

A response to the above requirement was forwarded to the NRC in letter AECM-80/26, dated March 19, 1980, which responded to IE Bulletin 79-08. Additional information pertaining to the above requirement is provided below.

Following a loss of feedwater and reactor scram, a low reactor water level signal (level 2) will automatically initiate the HPCS and RCIC systems into the reactor coolant make-up injection mode. The HPCS and RCIC systems will continue to inject water into the vessel until a high water level signal (level 8) automatically trips the RCIC system and closes the HPCS injection valve. Unless a high reactor water level signal (level 8) exists, HPCS will continue until manually stopped.

Both the RCIC and HPCS systems will automatically reinitiate on a low water level signal (level 2) following a high water level trip (level 8).

The following actions occur during an automatic initiation of RCIC and HPCS:

a. Automatic Operation of RCIC

   The RCIC system will start automatically upon receipt of a low water level initiation signal (level 2). Upon receipt of this initiation signal, the following events occur:

1. The steam supply valve opens.

2. Condensate drain pot valves close when the supply valve leaves its full closed position.

3. SSW system starts.

4. Room cooler fan starts.

5. Pump discharge injection valve opens.

6. Gland seal air compressor starts.

7. Lube oil cooling water supply valve opens.

8. Test line valves close.

9. CST suction valve opens.

10. The turbine control system brings the turbine up to speed as soon as the steam supply valve leaves its full closed position. Pump discharge flow develops as soon as the pump discharge pressure is sufficient to open the check valve between the pump and the reactor vessel. As pump discharge and steam inlet pressure change with a variable reactor pressure range, the control signal will be sent to the turbine to maintain constant steady state pump flow.

11. When pump discharge pressure reaches a predetermined pressure, the minimum flow valve opens until system flow reaches a predetermined flow; then it will close.

Upon occurrence of a low water level in the condensate storage tank or a high water level in the suppression pool, the RCIC pump suction will transfer from the CST (CST suction valve closes) to the suppression pool (suppression pool suction valve opens).

b. Automatic Initiation of HPCS

The HPCS system will start automatically upon receipt of a low water level initiation signal (level 2). Upon receipt of this initiation signal, the following events occur:

1. HPCS pump starts.

2. HPCS injection valve opens.

3. HPCS minimum flow valve opens as discharge pressure increases and closes as flow increases.

4. CST and suppression pool test return and bypass valves close (if open).

5. CST suction valve opens.

6. HPCS diesel generator starts.

7. HPCS service water pump starts.

8. HPCS service water return valve opens.

9. HPCS room cooler fan starts.

Upon occurrence of a low water level in the condensate storage tank or a high water level in the suppression pool, the HPCS pump suction will transfer from the CST (CST suction valve closes) to the suppression pool (suppression pool suction valve opens).

The operator can manually initiate the HPCS and RCIC systems from the control room before the level 2 automatic initiation level is reached. The operator has the option of manual control after automatic initiation and can maintain reactor water level by throttling system flow rates.

For the loss of feedwater transient, the RCIC and HPCS systems are used to automatically provide the required make-up flow. No manual operations are required.

With MSIVs closed, reactor pressure may rise to the setpoint of the safety/relief valves, resulting in mechanical actuation to reduce reactor pressure.

The operation of the safety/relief valves and the RCIC and HPCS systems will cause the suppression pool to eventually heat up. As the average temperature of the suppression pool rises, the operator will initiate the RHR suppression pool cooling mode.

A summary of the operator actions is given below:

a. Start the associated RHR standby service water pump.

b. Establish SSW flow through the associated heat exchanger by opening the RHR heat exchanger SSW inlet and outlet valves.

c. Start the associated RHR pump.

d. Close the associated RHR heat exchanger bypass valve.

e. Adjust system flow by opening RHR test return valve.

f. Verify minimum flow valve to suppression pool closes when flow exceeds a predetermined value.

g. Verify that the associated heat exchanger pressure controller is in the manual position and is set to maintain the air-operated steam pressure reducing valve closed.

h. Energize the associated solenoids for steam pressure reduction and condensate discharge permissive by switching both hand switches to the “ON” position.

i. Gradually open the associated steam supply valve ahead of the steam pressure control valve.

j. Gradually open the associated air-operated steam line pressure reducing valve and increase pressure to the required value.

k. Verify that associated heat exchanger steam pressure and both the inlet and outlet temperature are increasing.

l. When the associated heat exchanger pressure reaches the required value, switch the RHR heat exchanger pressure control to automatic.

m. As steam pressure increases, slowly adjust the liquid level in the heat exchanger by regulating the level controller to obtain the appropriate operating level.

n. When the associated heat exchanger pressure reaches the predetermined stable pressure, adjust heat load on the heat exchanger by adjusting water level to obtain optimum differential temperature for the SSW flow to the heat exchanger.

o. Verify that the RCIC turbine is operating.

p. Verify that heat exchanger outlet temperature and condensate water quality have reached their acceptable limits.

q. Open associated heat exchanger flow valve to RCIC.

r. Close associated heat exchanger flow valve to suppression pool.

s. Monitor RHR heat exchanger level and pressure for stable operation.

The RHR steam condensing mode is now in service transferring reactor vessel heat to the atmosphere via the standby service water system.

Removal of reactor vessel heat may also be achieved by remote manual actuation of any of the 20 safety/relief valves which discharge to the suppression pool. If reactor pressure reduction and heat removal are required through safety/relief valve operation, the RHR suppression pool cooling mode would also be used to maintain suppression pool temperature.

18.1.29.4 Reactor Vessel Level Instrumentation (II.K.1.23)

<u>REQUIREMENT</u>

Describe all uses and types of reactor vessel level indications for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status.

<u>RESPONSE</u>

A response to the above requirements was forwarded to the NRC in letter AECM-80/26, dated March 19, 1980, which responded to IE Bulletin 79-08. Below is the response to this particular item.

Reactor vessel water level is continuously monitored by 7 indicators or recorders for normal, transient, and accident conditions. Those monitors used to provide automatic safety equipment initiation are arranged in a redundant array with two instruments in each of two or more independent electronic divisions. Thus, adequate information is provided to automatically initiate safety actions and provide the operator with assurance of the vessel water level at all times. A more detailed description of water level instrumentation used in BWR/6 plants and applicable to GGNS is provided in NEDO-24708A.

These water level measurement devices have operated in BWR plants for many years. Tests of BWR water level instrumentation under simulated steam and water line breaks have been conducted showing satisfactory performance. For additional information, see subsection 7.3.1.2(8)(e).

The range of reactor vessel water level from below the top of the active fuel area up to the top of the vessel is covered by a combination of narrow- and wide-range instruments. Level is indicated and/or recorded in the control room.

A separate set of narrow-range level instrumentation on separate condensing chambers provides reactor level control via the reactor feedwater system. This set also indicates or records in the control room (three level indicators and one level recorder).

The safety-related systems or functions served by safety-related reactor water level instrumentation are:

Reactor Core Isolation Cooling System (RCIC)
High Pressure Core Spray System (HPCS)
Low Pressure Core Spray System (LPCS)
Residual Heat Removal/Low Pressure Injection (RHR/LPCI)
Automatic Depressurization System (ADS)
Containment and Reactor Vessel Isolation Control System (CRVICS)
Standby Service Water System (SSW)

All systems automatically initiate on low reactor water level. In addition, the RCIC and HPCS systems shut down on high reactor water level. The RCIC and HPCS systems automatically restart if low reactor level is reached again.

Additional instrumentation which the operator can use to determine changes in reactor coolant inventory or other abnormal conditions are:

Drywell High Pressure
Containment High Radioactivity Levels
Suppression Pool High Temperature
Safety Relief Valve (SRV) Discharge High Temperature
High/Low Feedwater Flow Rates

High/Low Main Steam Flow
High Containment, Steam Tunnel, and Equipment Area Temperatures
High Differential Flow-Reactor Water Cleanup System
Abnormal Reactor Pressure
High Suppression Pool Water Level
High Drywell and Containment Sump Fill and Pumpout Rate
Valve Steam Leakoff High Temperatures
Low RCIC Steam Supply Pressure
High RCIC Steam Supply Flow
Low Main Steam Line Pressure

An example of the use of this additional information by the operator is as follows: Drywell high pressure is an indirect indication of coolant loss. Coincident high suppression pool temperature further verifies a loss of reactor coolant. High SRV discharge temperature would pinpoint loss of coolant via an open valve.

Other instrumentation that can signal abnormal plant status but does not necessarily indicate loss of coolant are:

High Neutron Flux
High Process Monitor Radiation Levels
Main Turbine Status Instrumentation
Abnormal Reactor Recirculation Flow
High Electrical Current (Amperes) to Recirc Pump Motors

Operators are instructed in use of other available information to initiate safety systems as a continuing part of their training.

18.1.30 Final Recommendations of Bulletins and Orders Task Force

18.1.30.1 Report Safety and Relief Valve Failures Promptly and Report Challenges Annually (II.K.3.3)

REQUIREMENT

Ensure that any PORV or safety valve that fails to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

RESPONSE

Safety relief valve failures will be reported as applicable in accordance with the requirements of 10 CFR 50.72 and 10 CFR 50.73. Challenges to the safety/relief valves will be reported as applicable in accordance with the requirements of 10 CFR 50.73. Challenges to the safety/relief valves are no longer required to be documented in the annual report per Operating License Amendment No. 167.

18.1.30.2 Separation of High Pressure Coolant Injection and Reactor Core Isolation Cooling System Initiation Levels -Analysis and Implementation (II.K.3.13)

REQUIREMENT

Currently, the reactor core isolation cooling (RCIC) system and the high pressure coolant injection (HPCI) system both initiate on the same low water level signal, and both isolate on the same high water level signal. The HPCI system will restart on low water level, but the RCIC system will not. The RCIC system is a low flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the initiation logic of the RCIC system should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff, and changes should be implemented if justified by the analyses.

RESPONSE

As a generic item, the possible separation of initiation levels for RCIC and HPCS was studied by General Electric for the BWR

Owners Group. The results of this study were forwarded to the NRC by a letter dated December 24, 1980 from D. B. Waters to D. G. Eisenhut. The study concluded the following:

a. For rapid level changes associated with accident scenarios and severe transients, HPCS and RCIC initiation would be essentially simultaneous in that possible separation distances could not preclude HPCS challenges.

b. For slow level changes due to small leaks or slow transients, adequate time exists for manual initiation of RCIC by the reactor operator prior to HPCS auto-initiation.

c. No significant reductions in thermal cycles is achievable by separating the set points nor is a reduction in cycles necessary.

Mississippi Power & Light (SERI) has endorsed the conclusions of this study and has taken the position that the proposed separation of RCIC and HPCS initiation is unnecessary for safety considerations.

Modification of the initiation logic for automatic restart of the RCIC system on low water level has been incorporated into the Grand Gulf design. FSAR subsection 7.4.1.1 reflects this modification.

18.1.30.3 Modify Break Detection Logic to Prevent Spurious Isolation of High Pressure Coolant Injection and Reactor Core Isolation Cooling (II.K.3.15)

REQUIREMENT

The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe break detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation.

RESPONSE

The BWR Owners' Group has evaluated this issue and has recommended the addition of a time delay to the HPCI/RCIC break detection circuitry. Where required, Mississippi Power & Light Company (SERI) has incorporated this time delay into Grand Gulf steam line break detection circuitry. FSAR subsection 7.6.1.4 reflects this new design.

18.1.30.4 Reduction of Challenges and Failures of Relief Valves Feasibility Study and System Modification (II.K.3.16)

REQUIREMENT

The record of relief valve failures to close for all boiling water reactors (BWRs) in the past 3 years of plant operation is approximately 30 in 73 reactor-years (0.41 failures per reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small-break loss-of-coolant accident (LOCA). The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

a. Additional anticipatory scram on loss of feedwater

b. Revised relief valve actuation set points

c. Increased emergency core cooling (ECC) flow

d. Lower operating pressures

e. Earlier initiation of ECC systems

f. Heat removal through emergency condensers

g. Offset valve set points to open fewer valves per challenge

h. Installation of additional relief valves with a block or isolation valve feature to eliminate opening of the safety/relief valves (SRVs), consistent with the ASME Code

i. Increasing the high steam line flow setpoint for main steam line isolation valve (MSIV) closure

j. Lowering the pressure setpoint for MSIV closure

k. Reducing the testing frequency of the MSIVs

l. More-stringent valve leakage criteria

m. Early removal of leaking valves

An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order or magnitude).

RESPONSE

Mississippi Power & Light Company (SERI) participated in a BWR Owners' Group evaluation of possible ways to reduce challenges to safety/relief valves. The results of that evaluation were forwarded to the NRC in a letter from D. W. Waters to D. G. Eisenhut dated March 31, 1981. It is SERI's position that further modifications to the Grand Gulf Nuclear Station would not significantly reduce the frequency of SRV events.

18.1.30.5 Report on Outages of Emergency Core Cooling systems Licensee Permit and Proposed Technical Specification Changes (II.K.3.17)

REQUIREMENT

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

RESPONSE

System Energy Resources, Inc. is a participant in the INPO Nuclear Plant Reliability Data System (NPRDS) program in which ECCS outage information is reported. Also, SERI complies with the reporting requirements of 10 CFR 50.73 whereby significant problems with ECC systems are reported to the NRC. These actions satisfy the requirement as documented in an NRC letter dated June 27, 1985.

18.1.30.6 Modification of Automatic Depressurization System Logic-Feasibility for Increased Diversity for Some Event Sequences (II.K.3.18)

REQUIREMENT

The automatic depressurization system (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor vessel water level provided no high pressure coolant injection (HPCI) or high pressure coolant system (HPCS) flow exists and a low pressure emergency core cooling (ECC) system is running. This logic would complement, not replace, the existing ADS actuation logic.

RESPONSE

MP&L (SERI) participated in a BWR Owner's Group study to modify ADS actuation logic. The results of this study were submitted to the NRC on October 29, 1982 in letter BWROG-8260. Eight alternatives, including retaining the current design, were considered.

In a letter dated December 14, 1982, Mississippi Power & Light (SERI) submitted its evaluation of the BWROG report and chose to implement Option 4 of the study. This option includes the addition of a timer that bypasses the existing high drywell pressure trip logic if RPV water level is low for a sustained period of time, plus the addition of a manual inhibit switch.

These logic modifications were accomplished by installing a bypass timer that is activated on low RPV water level (Level 1). When the timer runs out, the high drywell pressure trip is bypassed and the ADS is initiated on low water level signal, provided other system prerequisites for ADS actuation are met. Starting the bypass timer at low RPV water level (Level 1) allows the operator adequate time to recover the water level manually, yet still ensures automatic depressurization in time to prevent excessive fuel heatup, even under the worst-case conditions. In addition to the bypass timer, a manual inhibit switch for the automatic depressurization system was installed. This modification allows certain operator actions specified in the Emergency Procedure Guidelines to be performed more reliably.

Principally, automatic initiation of the ADS following boron injection or while restoring RPV water level manually could be prevented.

NUREG-0737, Item II.K.3.18, states "The Automatic Depressurization System (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling." MP&L (SERI) concluded that implementation of the Option 4 modifications and of the Emergency Procedure Guidelines will ensure adequate core cooling in even the worst-case conditions.

18.1.30.7 Restart of Core Spray and Low Pressure, Coolant Injection Systems (II.K.3.21)

REQUIREMENT

The core spray and low pressure, coolant injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to ensure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

RESPONSE

The BWR Owner's Group has evaluated this issue (BWROG-80-12, December 29, 1980) and has recommended a modification to the HPCS logic. This modification will allow automatic restart of HPCS on a reactor water low level 2 initiation signal, independent of drywell pressure conditions. Mississippi Power & Light Company (SERI) incorporated this modification into the Grand Gulf HPCS logic. FSAR subsection 7.3.1.1.1.3 reflects this design modification.

18.1.30.8 Automatic Switchover of Reactor Core Isolation Cooling System Suction - Verify Procedures and Modify Design (II.K.3.22)

REQUIREMENT

The reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

RESPONSE

The RCIC system design at Grand Gulf Nuclear Station incorporates the automatic RCIC suction transfer from the condensate storage tank (CST) to the suppression pool upon a CST low level signal or a suppression pool high level signal. Further discussion of the RCIC system is included in subsection 5.4.6.

18.1.30.9 Confirm Adequacy of Space Cooling for High-Pressure Coolant Injection and Reactor Core Isolation Cooling Systems (II.K.3.24)

REQUIREMENT

Long-term operation of the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) system may require space cooling to maintain the pump room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of alternating current power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite alternating current power to their support systems, including coolers, for at least 2 hours.

RESPONSE

Grand Gulf Nuclear Station utilizes safety-related pump rooms cooled by unit coolers and support systems designed to withstand the consequences of a complete loss of offsite ac power. Loss of offsite ac power results in power being supplied from the engineered safety features bus. Refer to subsection 9.4.5 for a further discussion of safety-related ventilation and cooling systems.

18.1.30.10 Effect of Loss of Alternating Current Power on Pump Seals (II.K.3.25)

REQUIREMENT

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

RESPONSE

Mississippi Power & Light Company (SERI) participated in a BWR Owner's Group evaluation of the effect of loss of alternating current power on recirculation pump seals and has determined that no change in design is necessary as described below.

The reactor recirculation pumps at Grand Gulf are provided with a mechanical shaft seal assembly. Two seals are built into a cartridge to facilitate replacement. Each individual seal in the cartridge is designed to withstand pump design pressure so that one seal can adequately limit leakage in the event the other seal fails. The pump shaft passes through a breakdown bushing in the pump casing to reduce leakage to less than 70 gpm in the event of a gross failure of both shaft seals.

During normal operation, the two sets of seals share the work load of the assembly. The sealing surfaces form two cavities in which pressure is measured and transmitted to the Operator Control Console in the control room. Pressure in the first cavity normally reads about 1050 psig, slightly above reactor pressures, and pressure in the second cavity is normally about 525 psig. Seal purge flow may be provided into the first seal cavity from the control rod drive (CRD) system. When seal purge has not been secured, the CRD flow provides cool, reactor grade water to minimize seal wear and prolong seal life. Seal purging flow goes from the first cavity through a breakdown pressure orifice into the second cavity. Flow from the second cavity drains into the drywell equipment drain sump. The CRD system is capable of providing 3-5 gpm to the first seal cavity. Approximately 1 gpm goes through the seal cartridge, and the remainder flows around the pump shaft and bushing into the impeller cavity. When seal purge has been secured, flow enters the seal cartridge from the impeller cavity around the pump shaft and bushing. Alarms are provided on the seal purge flow lines and seal leakoff lines to indicate seal failure. The combination of seal pressure, seal flow, and leakoff alarms permits the operator to analyze seal failures.

The recirculation pump seal cavity requires forced cooling due to the heat of both the reactor water and friction generated by the sealing surfaces. Cooling is provided by the component cooling water (CCW) system. CCW flows in a cooling jacket surrounding the seal assembly. Temperature elements in the pump seal cavity monitor seal water temperature. Temperatures are recorded in the control room, and high temperature alarms are provided in the Operator Control Console.

Three CCW pumps are provided, and CCW pump B is powered from a Class 1E ESF power supply. In the event of loss of offsite power, the emergency diesel generators power the ESF bus feeding CCW pump B. Within 30 seconds of loss of offsite power, the automatic load shedding and sequencing system repowers CCW pump B. With the loss of offsite power, the plant service water (PSW) system is no longer able to provide cooling to the CCW heat exchangers, and the standby service water (SSW) system automatically assumes the cooling function. (If a LOCA is also present, transfer of the SSW to the CCW heat exchangers is prevented).

As a result of our review of containment isolation design (see subsection 18.1.26, Containment Isolation Dependability), the CCW supply and return lines through the containment have been designated “beneficial” and do not receive an automatic isolation signal so that CCW flow may continue to the recirculation pumps on loss of offsite power and/or LOCA events.

In summary, the recirculation pump seal coolers at Grand Gulf are provided with a reliable source of cooling water which can continue to operate following loss of offsite power. In addition, the seals are provided with diverse instruments and alarms which alert the operator to seal failure. Should a gross seal failure take place, the operator can simply close the suction and discharge valves on the affected pump and stop the leak. Thus, we believe this combination of design features eliminates the possibility of any adverse safety effects resulting from loss of seal cooling due to loss of offsite power, and therefore, no modifications are required.

18.1.30.11 Provide Common Reference Level for Vessel Level Instrumentation (II.K.3.27)

REQUIREMENT

Different reference points of various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points.

RESPONSE

Mississippi Power & Light provided a final response to this item in a letter dated September 10, 1981. In order to satisfy the requirements of a common reactor vessel level reference point for all reactor vessel level loops, Mississippi Power & Light made the necessary modifications to reference the fuel zone instrument from the bottom of the reactor vessel steam dryer skirt (referenced to instrument zero, 533 vessel inches).

Scales for the fuel zone instrument indicator and recorder reflect a range from -20 to -320 inches. The top of active fuel is marked on the scale at -167 inches.

Also, System Energy Resources, Inc. plans to incorporate a common water level reference (to instrument zero) on the safety parameter display system (see subsection 18.2.2).

18.1.30.12 Verify Qualification of Accumulators on Automatic Depressurization System Valves (II.K.3.28)

REQUIREMENT

Safety analysis reports claim that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that the emergency core cooling (ECC) systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

RESPONSE

Mississippi Power & Light Company (SERI) provided information concerning the automatic depressurization system (ADS) accumulators and related air systems in an October 24, 1983 submittal and a January 30, 1985 submittal. The information that was provided is summarized in the following paragraphs.

The ADS valves and their accumulators, receivers, and associated components are a part of the nuclear boiler system which is safety related. Normal pneumatic supply to the receivers is from the plant instrument air system with pressure being increased to ADS service requirements by either of two full capacity booster compressors. Two instrument air compressors (unit 1 and 2) are available, either of which is capable of supplying all Unit 1 instrument air requirements. The instrument air system, including the booster compressors, is not a safety-related system except for penetrations to the auxiliary building, containment and drywell, isolation valves, piping between isolation valves, and piping from the containment isolation valve to the ADS air receiver tanks.

Each ADS valve is provided with two accumulators to ensure operability following a loss of instrument air. Short-term makeup to the accumulators is provided by four air receivers. Two air receivers supply the accumulators associated with the four ADS valves on steam lines A and C. These receivers also supply the accumulator for the low-low set valve (non-ADS valve). The two remaining receivers supply the accumulators for the four ADS valves on steam lines B and D. The ADS accumulators and receivers ensure a post-accident pneumatic supply is available to the ADS valves for a period of time sufficient to re-establish the operability of the instrument air system or connect a temporary air supply for long-term makeup. The system capability for post-LOCA operation is discussed in subsection 5.2.2.4.

Long-term post-accident makeup to the ADS system will be provided by restoring the operability of the instrument air system, recognizing that either of two service air compressors or the Unit 2 instrument air compressor can be used to back up the Unit 1 instrument air compressor. A 1E divisional source powers the Unit 1 instrument air compressor which is initially shed, but can be restored. Also, in the event of a loss of offsite power, all of the station air compressors can be cooled by the standby service water system.

In the unlikely event that instrument air cannot be restored, a temporary air supply will be connected into the safety-related portion of the instrument air supply outside containment. This would involve connecting nitrogen bottles to the test connection located between Q1P53-F003 and the penetration (see Figure 9.3-1).

18.1.30.13 Revised Small-Break Loss-of-Coolant Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K (II.K.3.30)

REQUIREMENT

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

RESPONSE

General Electric Company has submitted a final response to Item II.K.3.30 in a letter from R. H. Bucholz to D. G. Eisenhut, dated June 26, 1981. Based on GE test results and sensitivity studies, the existing GE small-break LOCA model already satisfies the concerns of Item II.K.3.30.

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

REQUIREMENT

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

RESPONSE

Based on the General Electric response to Item II.K.3.30 that the existing GE small-break LOCA model satisfies the concerns, the existing small-break LOCA analysis included in Section 6.3 provides a satisfactory plant-specific analysis as required by Item II.K.3.31.

18.1.30.15 Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure (II.K.3.44)

REQUIREMENT

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result from a stuck-open relief valve should be included in this category.

RESPONSE

Mississippi Power & Light (SERI) participated in the BWR Owner's Group generic evaluation of Item II.K.3.44 which addressed the issue of adequate core cooling for transients with a single failure. The results of this evaluation were submitted to the NRC in a letter dated December 29, 1980 from Mr. D. B. Waters, Owner's Group Chairman, to Mr. D. G. Eisenhut. The evaluation stated that the worst case transient-with-single-failure combination for BWR/6 plants is the loss of feedwater event with failure of the high pressure core spray system. A stuck open relief valve was also considered in addition to the high pressure core spray failure. The results of these studies indicated that the core remains covered during the whole course of the transient either due to reactor core isolation cooling system operation or automatic or manual depressurization permitting low pressure inventory makeup. The operator action assumed in the analysis is manual depressurization of the vessel to permit low pressure injection. In a letter dated November 19, 1981, Mississippi Power & Light (SERI) stated that the BWR Owner's Group generic analysis assumptions and initial conditions had been reviewed and determined to be representative for the Grand Gulf Nuclear Station.

18.1.30.16 Evaluation of Depressurization with Other Than Automatic Depressurization System (II.K.3.45)

REQUIREMENT

Analyses to support depressurization modes other than full actuation of the automatic depressurization system (ADS) [e.g., early blowdown with one or two safety relief valves (SRVs)] should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

RESPONSE

Mississippi Power & Light Company (SERI) participated in the BWR Owners' Group generic evaluation of Item II.K.3.45 which addressed the issue of alternate modes of depressurization other than full actuation of the ADS. The results of this evaluation, which apply to Grand Gulf, were submitted to the NRC in a letter from Mr. D. B. Waters, Owners' Group Chairman, to Mr. D. G. Eisenhut, dated December 29, 1980.

18.1.30.17 Michelson's Concerns (II.K.3.46)

REQUIREMENT

General Electric should provide a response to the Michelson concerns as they relate to boiling water reactors.

RESPONSE

The General Electric Company responded to the questions posed by Mr. Michelson in the letter from R. Buchholz to D. Ross dated February 21, 1980. This response is also applicable to the Grand Gulf Nuclear Station (GGNS). Further responses related to this issue were provided by Mississippi Power & Light (SERI) in letters dated September 10, 1981 and December 6, 1984. These responses are summarized below.

The GGNS (BWR/6) design, which has four independent vessel level sensing lines, has been shown to be less vulnerable to a failure of this type. Analyses of various scenarios for this concern have been conducted for both GGNS and the BWR/6 design as part of the BWR Owners Group efforts. As a result of the GGNS evaluation, it was shown that GGNS can withstand any reactor vessel level reference line break, coupled with an additional worst single failure in a protective channel not dependent on the failed sensing line, without compromising safety. A similar analysis was conducted for the BWR Owners Group as discussed in SLI-8211. The results of this analysis also supported the positive results performed for GGNS. MP&L, (SERI) therefore, concluded that the BWR/6 RPV water level monitoring design and logic preclude this from being a safety concern for GGNS.

18.1.31 Emergency Preparedness - Short-Term (III.A.1.1)

REQUIREMENT

Comply with Appendix E, "Emergency Facilities," to 10 CFR Part 50, Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants;" and for the offsite plans, meet essential elements of NUREG-75/111 or have a favorable finding from FEMA.

RESPONSE

Mississippi Power & Light Company (SERI) submitted Revision 1 of the Grand Gulf Nuclear Station Emergency Response Plan by letter AECM-81/83, dated May 14, 1981. This response satisfies the requirements of this item.

18.1.32 Upgrade Emergency Support Facilities (III.A.1.2)

This item has been superseded by NUREG-0737, Supplement 1. See subsection 18.2.6.

18.1.33 Improving Licensee Emergency Preparedness - Long Term (III.A.2)

REQUIREMENT

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement are delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

RESPONSE

Mississippi Power & Light Company (SERI) submitted Revision 1 of the Grand Gulf Nuclear Station Radiological Emergency Response Plan by letter AECM-81/83 dated May 14, 1981. This response included elements of NUREG-0654, Revision 1, Appendix 2.

Additionally, letter AECM-81/103 of April 10, 1981 provided information concerning the meteorological requirements of NUREG-0654 and Regulatory Guide 1.23, "Meteorological Measurements Programs in Support of Nuclear Power Plants." Current requirements related to meteorological monitoring are provided in NUREG-0737, Supplement 1. See subsection 18.2.4.

18.1.34 Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized Water Reactors and Boiling Water Reactors (III.D.1.1)

REQUIREMENT

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

a. Immediate leak reduction

   1. Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   2. Measure actual leakage rates with system in operation and report them to the NRC.

b. Continuing Leak Reduction -- Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

RESPONSE

Specific procedures for implementing a leakage reduction program at Grand Gulf Nuclear Station have been developed and implemented. The following is a summary of the leak reduction program for systems outside containment that could contain highly radioactive fluids during an accident.

The Leak Reduction Program is primarily dependent upon visual inspection of system components during periods of time when the system is in operation or otherwise pressurized. Leakage will be identified by one of the following methods.

Water Leakage

Water leakage will be detected by direct observation where practical. When ALARA or other considerations dictate, leakage will be collected. Observable leakage past vent and drain valves will be reduced to as low as practical levels. Valve packing leakage will be minimized.

Steam Leakage

Steam leakage from the RCIC system will be detected by direct observation or be identified by having an iodine and particulate airborne radioactivity sample taken while the system is operating. Abnormal activity will require further investigation. The method of leak detection by having an iodine and particulate airborne radioactivity sample cannot be used prior to power operations.

Gas Leakage

Gas leakage will be detected by local leak rate testing, pneumatic pressure testing, normal running condition of system or any other acceptable means of detecting gas leakage. Any detected leakage will be reduced to as low as practical levels. Gaseous systems to be tested include the Hydrogen Analyzers and associated piping in the Combustible Gas System.

Each identified system will be checked for leakage as part of the appropriate surveillance or inspection procedures. Initial leak test results were established and reported to the NRC (Reference AECM-89/0007).

The following systems are included, to the extent indicated, in the program.

a. Reactor Core Isolation Cooling System

   Entire system outside containment containing steam or water except drain line to main condenser.

b. Residual Heat Removal System

   Entire System outside containment containing steam or water except line to Liquid Radwaste System and some headers that are isolated by manual valves.

c. High Pressure Core Spray System

Entire system outside containment.

d. Low Pressure Core Spray System

Entire system outside containment.

e. Combustible Gas Control System

Hydrogen analyzers only.

f. Suppression Pool Make-Up System

Suppression Pool Level detection portion of the system.

g. Feedwater Leakage Control System

Entire system.

h. Post-Accident Sampling System

Entire system.

Systems containing radioactive materials which are excluded from the program follow with the justification for exclusion.

a. MSIV Leakage Control System

This system draws leakage from the main steam lines between the MSIVs and the outboard shut-off valve and exhaust into the auxiliary building so that the leakage will be processed by the Standby Gas Treatment System (SGTS). The MSIV Leakage Control System operates at a negative pressure; hence leakage would be into the system and of no concern.

b. Standby Gas Treatment System

The SGTS collects and processes post-LOCA containment leakage. Leakage out of the SGTS is into regions served by the system and would not increase the radioactivity levels existing in the auxiliary building during post-LOCA operation.

c. Reactor Water Cleanup (RWCU) System

The system is not required to function during or immediately following an accident and is isolated from post-accident fluids. Possible system usage would be under controlled conditions such that the system could be prepared for such usage in the long-term post-accident situation.

d. Suppression Pool Cleanup System

   See justification for c.

e. Off-Gas System

   See justification for c.

f. Liquid and Solid Radwaste System

   See justification for c.

18.1.35 Improved In-Plant Iodine Instrumentation Under Accident Conditions (III.D.3.3)

REQUIREMENT

a. Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

b. Each applicant for a fuel loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

RESPONSE

In-plant iodine monitoring at Grand Gulf Nuclear Station is accomplished by use of continuous air monitors and portable low volume samplers with subsequent laboratory analysis of filter media. A further discussion of in-plant iodine monitoring under accident conditions is contained in subsection 12.5.2.2.5. Procedures for counting and analysis are in place. Also, health physics technicians have been trained to collect and analyze samples for radioiodine for both routine and emergency conditions.

18.1.36 Control Room Habitability Requirements (III.D.3.4)

REQUIREMENT

In accordance with Task Action Plan item III.D.3.4 and control room habitability, licensees shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (Criterion 19, "Control Room," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50).

RESPONSE

The control room design at Grand Gulf Nuclear Station meets the habitability requirements of GDC 19 of 10 CFR 50 Appendix A and the guidelines of Regulatory Guides 1.78 and 1.95. Section 6.4 provides a complete description of the control room HVAC system layout and functional design that provides for protection of the control room from radioactive and toxic gases.

Additional information required for the control room habitability evaluation:

a. Control Room Mode of Operations: see descriptions of the modes of operation for the control room HVAC systems in subsections 6.4.2 and 9.4.1.

b. Control Room Characteristics:

    1. Control room air volume: see subsection 6.4.2.2.

    2. Control room emergency zone: see subsection 6.4.2.1.

    3. Control room ventilation system schematic with normal and emergency air flow rates: see Figure 6.5-1.

    4. Infiltration leakage rate: See subsection 6.4.2.3 and Tables 6.4-1 and 15.6-13.

    5. HEPA filter and charcoal adsorber efficiencies: see subsection 6.5.1.4.1 and Table 15.6-13.

6. Closest distance between containment and air intake: approximately 43 feet; however, this is not unobstructed distance, as the containment is completely enclosed by a secondary containment consisting of the auxiliary building and enclosure building (see Figure 1.2-4).

7. Layout of control room, air intakes, containment building, and chlorine or other chemical storage facility with dimensions: see Figure 2.2-5 and Table 2.2-6.

8. Control room shielding, including radiation streaming from penetrations, doors, ducts, stairways, etc.: see subsection 6.4.2.5 and Tables 15.6-12, 15.6-13, and 15.6-14.

9. Automatic isolation capability - damper closing time, damper leakage, and area: butterfly valves with leakage requirements as specified by MSS-SP-67 for Type 1 valves are utilized as automatic isolation dampers for the control room HVAC systems; see Table 18.1-2 for a summary of the characteristics of these dampers.

10. Toxic gas: see subsections 6.4.1.1e, 6.4.2.2, 6.4.4.2, 7.3.1.1.10, 9.4.1.1.1e, 9.4.1.3, and 9.4.1.5.

11. Self-contained breathing apparatus availability: see subsection 6.4.2.6.

12. Bottled air supply: see subsection 6.4.2.6.

13. Emergency food and potable water supply: supplies for five persons for 5 days.

14. Control room personnel capacity: see subsection 6.4.1.1.

15. Potassium iodide drug supply: a sufficient supply of 130 mg tablets is maintained.

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
4	Fuel Pool Cooling & Cleanup Transfer Tube	Nonessential	No (Locked Closed)	N/A
5	Nuclear Boiler - Main Steam Lines	Essential	Yes	Penetration is within the reactor coolant pressure boundary but is not required to be open for mitigation of accidents.
6	Nuclear Boiler - Main Steam Lines	Essential	Yes	Same as 5, above.
7	Nuclear Boiler - Main Steam Lines	Essential	Yes	Same as 5, above.
8	Nuclear Boiler - Main Steam Lines	Essential	Yes	Same as 5, above.
9	Nuclear Boiler - Feedwater Inlet	Essential	Reverse flow for check valves; remote - manual for motor-operated shutoff valve.	Same as 5, above. Also, feedwater inlet is a potential source of make-up to the reactor vessel if available.
10	Nuclear Boiler - Feedwater Inlet	Essential	Reverse flow for check valves; remote - manual for motor-operated shutoff valve.	Same as 9, above.
11	RHR Pump - "A" Suction	Essential	No	Emergency Core Cooling
12	RHR Pump - "B" Suction	Essential	No	Same as 11, above.

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
13	RHR Pump - "C" Suction	Essential	No	Same as 11, above.
14	RHR Reactor Shutdown Cooling Suction	Essential	Yes	Same as 5, above.
17	Steam Supply to RHR and RCIC Turbine	Essential	Yes	Same as 5, above.
19	Nuclear Boiler - Main Steam Drains	Essential	Yes	Same as 5, above.
20	RHR Heat Exchanger "A" to LPCI	Essential	No Cooling System (ECCS)	Emergency Core
21	RHR Heat Exchanger "B" to LPCI	Essential	No Cooling System	Emergency Core
22	RHR Pump "C" to LPCI	Essential	No Cooling System	Emergency Core
23	RHR - "A" Pump Test and Minimum Flow Line to Suppression Pool	Essential	No	ECCS - Suppression Pool Cooling Return Line
24	RHR - "C" Pump Test and Minimum Flow Line to Suppression Pool minimum flow line	Essential	Yes for 14" connection; No for 4" pump	Test line only for ECCS pump.
25	HPCS Pump Suction	Essential	No	Emergency Core Cooling System
26	HPCS Pump Discharge	Essential	No	Emergency Core Cooling System

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
27	HPCS Test Line	Essential connection; No for 4" pump minimum flow line	Yes for 12" ECCS Pump	Test line only for
28	RCIC Pump Suction	Essential	No	RCIC provides make-up to RPV in the event of loss of all ac power.
29	RCIC Turbine Exhaust	Essential	Yes	Same as 28, above.
30	LPCS Pump Suction	Essential	No	Emergency Core Cooling System
31	LPCS Pump Discharge	Essential	No	Emergency Core Cooling System
32	LPCS Test Line	Essential	Yes for 14" connection; No for 4" pump minimum flow line	Test line only for ECCS pump.
33	CRD Pump Discharge	Beneficial	No (Remote - manual only)	CRD provides potential source of high pressure make-up to reactor pressure vessel. instrumentation is provided to monitor functional integrity of piping inside containment. Line can be isolated by the operator from control room based on status of CRD system.
34	Containment Purge and Ventilation Air Supply	Nonessential	Yes	N/A
35	Containment Purge and Ventilation Air Exhaust	Nonessential	Yes	N/A

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
36	Drywell Chilled Water Return	Nonessential	Yes	Drywell chilled water provides coolant through these penetrations for drywell coolers. These coolers are not required to mitigate the consequences of accidents but are helpful in maintaining temperature during and after transients. Class 1E instrumentation is provided to monitor functional integrity of piping inside the containment (and drywell). This line can be isolated by the plant operator from the control room based on the status of the drywell chilled water system. After automatic isolation, this line can be unisolated, if required, by the plant operator from the control room
37	Drywell Chilled Water Supply	Nonessential	Yes	Same as 36, above.
38	Plant Chilled Water Supply	Nonessential	Yes	N/A
39	Plant Chilled Water Return	Nonessential	Yes	N/A
40	Integrated Leak Rate Test Connection	Nonessential	No (blank flange)	N/A
41	Service Air Supply	Nonessential	Yes	N/A

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
42	Instrument Air Supply	Nonessential	Yes	Instrument air provides operating air to the drywell cooler discharge dampers which fail closed on loss of air. These drywell coolers are not required to mitigate the consequences of accidents, but are helpful in maintaining drywell temperatures during and after transients. Instrumentation is provided to monitor functional integrity inside the containment. In addition, a Class 1E pressure switch on the containment isolation valve causes the valve to close on low air pressure, which may be indicative of loss of system integrity. Furthermore, the set point of the pressure switch is higher than the containment design pressure; therefore, any leakage would be into containment rather than out of containment. This line inside containment can be isolated manually by the operator in the control room or automatically upon receiving an isolation signal. After automatic isolation, this line can be reopened, if required for drywell cooling operation, by the plant operator from the control room. The containment and drywell isolation valves of this line will re-close if the isolation signal returns. This is the same logic presently used for drywell chilled water supply and return isolation valves, penetrations 36 and 37, for drywell coolers.

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
43	RWCU to Main Condenser	Nonessential	Yes	N/A
44	Component Cooling Water Supply	Beneficial	No	CCW provides cooling water to recirc pump seal coolers.
45	Component Cooling Water Return	Beneficial	No	CCW provides cooling water to recirc pump seal coolers.
46	RCIC Pump Minimum Flow Bypass	Essential	No	RCIC provides make-up to RPV in the event of loss of all ac power.
47	Post-Accident Sample	Beneficial	No (Locked closed)	Allows for post-accident sampling of the reactor recirc system.
48	RHR Heat Exchanger "B" Relief Valve Vent Header to Suppression Pool	Essential	No	This normally closed line is of the Emergency Core Cooling System which allows venting of non-condensible gases from the heat exchanger.
49	RWCU Backwash Transfer Pump to Spent Resin Tank	Nonessential	Yes	N/A
50	Drywell & Containment Equipment Drain Sump Pump Discharge	Nonessential	Yes	N/A
51	Drywell & Containment Floor Drain Sump Pump Discharge	Nonessential	Yes	N/A
54	To & From Refueling Water Storage Tank - Upper Containment Pool	Nonessential	No (Locked closed manual valves)	N/A

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
56	Condensate Supply to Containment	Nonessential	Yes	N/A
57	To Upper Containment Pool from Fuel Pool Cooling & Cleanup System	Nonessential	Yes	N/A
58	From Upper Containment Pool to Fuel Pool Drain Tank	Nonessential	Yes	N/A
60	Auxiliary Building Drains Pumpback to Suppression Pool	Nonessential	Yes	N/A
65	Combustible Gas Control Containment Purge (Outside Air Supply)	Nonessential	Yes	N/A
66	From Purge Radiation Air Detection System to Containment Exhaust Charcoal Filter Train	Nonessential	Yes	N/A
67	RHR Pump "B" Test Line to Suppression Pool	Essential	No	ECCS - Suppression pool cooling return line.
69	Refueling Water Transfer Pump Suction	Nonessential	Yes	N/A
70	Instrument Air Supply to ADS Receivers	Nonessential	Yes	N/A
71A	LPCS Relief Valve Vent Header to Suppression Pool	Essential	No (Relief valve discharge line)	ECCS piping over pressure protection discharge to suppression pool.

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
71B	RHR "C" Relief Valve and Post-Accident Sample Return to Suppression Pool	Essential/ Beneficial	No (Relief valve discharge line and locked closed MOV)	Same as 71A, above, and is also necessary for post-accident sampling return to suppression pool.
73	RHR Shutdown Vent Header to Suppression Pool	Nonessential	No (Relief valve discharge line)	This portion of the RHR system is not required for mitigation of accidents.However, relief valves provide reliable isolation of the containment.
75	RCIC Turbine Exhaust Vacuum Breaker	Essential	Yes (On high dry-well pressure or RCIC line break only)	Provides vacuum breaker operation to prevent induction of water into turbine exhaust piping once turbine is shut down.
76B	RHR Shutdown Suction Relief Valve Discharge	Nonessential	No (Relief valve discharge line)	Same as 73, above.
77	RHR Heat Exchanger "A" Relief Valve Vent Header to Suppression Pool	Essential	No	Same as 48, above.
81	Post-Accident Sample	Beneficial	No (Locked closed)	This line should be available to allow the post-accident sampling from the recirc system jet pump lines.
82	Integrated Leak Rate Test Connection	Nonessential	No (Blind Flange)	N/A
83	RWCU Line from Regen. Heat Exchanger to Feedwater	Nonessential	Yes	N/A
84	Chemical Waste Sump Pump Discharge	Nonessential	Yes	N/A

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
85	Suppression Pool Cleanup Return	Nonessential	Yes	N/A
86	Demineralized Water Supply to Containment	Nonessential	Yes	N/A
87	RWCU Pump Discharge	Nonessential	Yes	N/A
88	RWCU Pump Discharge	Nonessential	Yes	N/A
89	Standby Service Water Supply "A"	Essential	No	Provides essential cooling water to safety-related equipment located inside containment.
90	Standby Service Water Return "A"	Essential	No	Same as 89, above.
91	Standby Service Water Return "B"	Essential	No	Same as 89, above.
92	Standby Service Water Supply "B"	Essential	No	Same as 89, above.
101C, 101F, 102D, 103D, 104D	Drywell & Containment Pressure Instruments	Essential	No	Monitor pressure inside containment and drywell during normal, transient, and accident conditions.
106A, 106B, 106D, 106E, 107A, 107B, 107D, 107E	Drywell & Containment Hydrogen Analyzer Sample & Return Lines	Essential	No	Monitor hydrogen concentration in the drywell and in the containment during normal, transient, and accident conditions.
109A, 109B	Drywell Fission Product Monitor Sample & Return Post Accident Sample Return	Beneficial	Yes	Allow monitoring of airborne fission products in the drywell atmosphere during all normal, transient, and accident conditions.

TABLE 18.1-1: TMI CONTAINMENT ISOLATION EVALUATION (CONTINUED)

Containment Penetration Number	System Name	Classification	Automatic Isolation (see Table 6.2-44 for details)	Discussion (as necessary)
109D	Containment Pressure Instrument & Post-Accident Sampling	Beneficial	Yes	Allows monitoring of containment pressure during normal, transient, and accident conditions; also allows for post-accident sampling of the containment atmosphere.
110A, 110C, 110F	Integrated Leak Rate Test Instrumentation	Nonessential	No (Blind flange)	N/A
113, 114, 115, 116, 117, 118, 119, 120	Suppression Pool Level Instruments	Essential	No	Allow monitoring of suppression pool level during all normal, transient, and accident conditions.

TABLE 18.1-2: CONTROL ROOM ISOLATION DAMPER CHARACTERISTICS

Equipment No.	Size	Leakage*	Closing Time*
QSZ51F001	24"	0	4 Sec.
QSZ51F002	24"	0	4 Sec.
QSZ51F003	18"	0	4 Sec.
QSZ51F004	18"	0	4 Sec.
QSZ51F010	18"	0	4 Sec.
QSZ51F011	18"	0	4 Sec.

* Leakage and valve maximum closing time criteria as required by MSS-SP-67 have been verified for the above listed valves by manufacturer's shop testing.

TABLE 18.1-3: TMI ITEM II.F.1 - NOBLE GAS EFFLUENT MONITORS

Release Points Monitor	Range μCi/cc	Indicator Location	Recorder Location	Alarm Location	Sensitivity	Power Source	Vendor's Model Number
Containment Bldg.	10^{-7} to 10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	40 CPM/mR /hr (Note 1)	Non-1E MCC	Eberline Sping-4 with AXM-1
Radwaste Bldg.	10^{-7} to 10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	40 CPM/mR /hr (Note 1)	Non-1E MCC	Eberline Sping-4 with AXM-1
Turbine Bldg.	10^{-7} to 10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	40 CPM/mR /hr (Note 1)	Non-1E MCC	Eberline Sping-4 with AXM-1
Fuel Handling	10^{-7} to 10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	40 CPM/mR /hr (Note 1)	Non-1E MCC	Eberline Sping-4 with AXM-1
SGTS A	10^{-7} to 10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	40 CPM/mR /hr (Note 1)	1E MCC (Note 2)	Eberline Sping-4 with AXM-1
SGTS B	5.8×10^{-8} to 9.9×10^{5}	Computer System Any Plant Data System (PDS) terminal	Computer System Any Plant Data System (PDS) terminal	Control Room & Locally	Note 4	1E MCC (Note 2)	Canberra CAM200PIG FF-DB CAM100GA-G

NOTES: (1) Medium range noble gas detector for AXM-1 is 1900 cpm/mR/hr. All others (Sping-4 and AXM-1) are 40 cpm/mR/hr.

(2) The power distribution panel for the SGTS effluent monitors is fed from the Class 1E ac distribution system. The panel is connected to the Class 1E system by means of two series Class 1E circuit breakers to provide isolation. This allows for continued SGTS operation following a loss of offsite power.

(3) Calibration as per the TRM.

(4) <u>Background sensitivity (Cs-137) for particulate channel (MD455V6 in MAP35C)</u>

From side (radial): 130 cpm/(mR/hr)

Through end (axial): 244 cpm/(mR/hr)

<u>Background sensitivity (Cs-137) for Iodine channel (MD455V6 in MA35C)</u>

From side (radial): 180 cpm/(mR/hr)

Through end (axial): 400 cpm/(mR/hr)

<u>Background sensitivity (Co-60) for normal range noble gas channel</u>

Any direction: 24 cpm/(mR/hr)

<u>Background sensitivity (Cs-137) for high range noble gas channel (approximate values)</u>

Bare detector sensitivity = 8.92E+5 cpm/(mR/hr)

Using attenuation/buildup the response inside the shield ≈ 80 cpm/(mR/hr)

Chapter 18 content, in its entirety, is HISTORICAL INFORMATION

18.2 RESPONSE TO NUREG-0737 SUPPLEMENT 1/GENERIC LETTER 82-33(EMERGENCY RESPONSE CAPABILITY)

The following information addresses the requirements and actions for implementing Generic Letter 82-33 entitled Supplement 1 to NUREG-0737, Requirements for Emergency Response Capability.

18.2.1 Emergency Response Capability (ERC) Integration

REQUIREMENT

Generic Letter 82-33 required that each operating reactor license provide the schedule for completing each of the basic requirements of NUREG-0737, Supplement 1, by April 15, 1983. In addition, a description of the plan for phased implementation and integrations of emergency response capability should be provided. These plans will be reviewed as part of the NRC evaluation and the NRC will take action necessary to ensure that such requirements and commitments are enforced.

RESPONSE

On April 15, 1983, a detailed ERC integration plan and schedule was submitted to the NRC in response to Generic Letter 82-33. The GGNS ERC integration specifically discussed the background activities performed in the proposed activities and the integration of all ERC initiatives including the safety parameter display system, the detailed control room design review, the emergency procedure upgrade process, Regulatory Guide 1.97 compliance, emergency response facility implementation, and ERC training.

The GGNS schedule was negotiated with the NRC as documented in MP&L letters dated August 22nd and October 10, 1983. The negotiated schedule is now reflected in Operating License Condition 2.C.(36) for ensuring compliance with these scheduled commitments.

The GGNS integration process is maintained by the GGNS NUREG-0737 Supplement 1, Emergency Response Capability Integrated Project Plan and the GGNS ERC Integrated Schedule.

18.2.2 Safety Parameter Display System

REQUIREMENT

Implement a safety parameter display system (SPDS) which includes the following:

a. The SPDS should provide a concise display of critical plant variables to the control room operators to aid them in rapidly and reliably determining the safety status of the plant. Although the SPDS will be operated during normal operations as well as during abnormal conditions, the principal purpose and function of the SPDS is to aid control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. This can be particularly important during anticipated transients and the initial phase of an accident.

b. Each operating reactor shall be provided with a safety parameter display system that is located convenient to the control room operators. This system will continuously display information from which the plant safety status can be readily and reliably assessed by control room personnel who are responsible for the avoidance of degraded and damaged core events.

c. The control room instrumentation required (see General Design Criteria 13 and 19 of Appendix A to 10 CFR 50) provides the operators with the information necessary for safe reactor operation under normal, transient, and accident conditions. The SPDS is used in addition to the basic components and serves to aid and augment these components. Thus, requirements applicable to control room instrumentation are not needed for this augmentation (e.g., GDC 2, 3, 4 in Appendix A; 10 CFR Part 100; single-failure requirements). The SPDS need not meet requirements of the single-failure criteria and it need not be qualified to meet Class 1E requirements. The SPDS shall be suitably isolated from electrical or electronic interference with equipment and sensors that are in use for safety systems. The SPDS need not be seismically qualified and additional seismically qualified indication is not required for the sole purpose of being a backup for

SPDS. Procedures which describe the timely and correct safety status assessment when the SPDS is and is not available will be developed by the licensee in parallel with the SPDS. Furthermore, operators should be trained to respond to accident conditions both with and without the SPDS available.

d. There is a wide range of useful information that can be provided by various systems. This information is reflected in such staff documents as NUREG-0696, NUREG-0835, and Regulatory Guide 1.97. Prompt implementation of an SPDS can provide an important contribution to plant safety. The selection of specific information that should be provided for a particular plant shall be based on engineering judgment of individual plant licensees, taking into account the importance of prompt implementation.

e. The SPDS display shall be designed to incorporate accepted human factors principles so that the displayed information can be readily perceived and comprehended by SPDS users.

f. The minimum information to be provided shall be sufficient to provide information to plant operators about:

    1. Reactivity control

    2. Reactor core cooling and heat removal from the primary system

    3. Reactor coolant system integrity

    4. Radioactivity control

    5. Containment conditions

    The specific parameters to be displayed shall be determined by the licensee.

g. Submit a written safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which include symptoms of severe accidents and include the specific implementation plan for SPDS.

RESPONSE

A program was implemented which assures that SPDS meets the above requirements. The GGNS SPDS safety analysis and implementation plan was completed and submitted to the NRC on July 31, 1985 via AECM-85/0219 in compliance with Operating License Condition 2.C.(36). Revision 1 to the SPDS safety analysis was submitted to the NRC on April 1, 1988 via AECM-88/0059. The following discussion provides a general description of the GGNS SPDS.

DESIGN BASIS

Various NRC documents have been published concerning SPDS implementation such as NUREG-0737, NUREG-0696, NUREG-0835, and others. Generic Letter 82-33 entitled "Supplement 1 to NUREG 0737 - Requirements for Emergency Response Capability" established specific requirements and became the NRC criteria to meet Emergency Response Capability requirements. All previous documents were used as guidance. The SPDS was implemented at GGNS in compliance with section 4.1 of the Generic Letter.

The Emergency Procedures (EP's) at GGNS were developed from the generic BWR Owner's Group Emergency Procedure Guidelines, and the GGNS SPDS was designed to provide support to the operators in executing the EP's. Parameter selection and display organization as well as access method were determined by consideration of use of the flow-charted EP's. All five "critical safety functions" specified in NUREG-0737 Supplement 1 are met by monitoring entry conditions for and providing data to assist in execution of these plant EP's.

HARDWARE

The SPDS has a design availability of greater than 99%. This goal is met through redundancy in instrument inputs, data acquisition hardware, data distribution hardware, and highly reliable computer network and display workstation hardware. Electrical power for the computer system is from battery-backed/diesel-backed un-interruptible power supplies. Data source switching is automatic and totally transparent to the SPDS operator.

A dedicated color CRT in the Control Room provides access to plant safety status information.

SIGNAL ISOLATION

The GGNS SPDS is not a class 1E system. Wherever it is connected to a class 1E component, suitable isolation is accomplished by use of fiber optic cabling for data transmission and appropriate breaker/fuse protection for power supplies.

OPERATOR USE

Critical Safety Function parameter information needed to assess plant safety status is continuously displayed on SPDS with no operator action required for access. Parameter identifications and values are grouped by specific plant emergency procedures as an aid in assessing whether abnormal condition warrant corrective actions to avoid a degraded core. Safety status indicators are color coded and an audible alert is provided whenever a transition from a safe condition is detected.

ALGORITHMS

Several types of data validation algorithms are used in the GGNS SPDS. For points with only two inputs, "TWO ELEMENT ANALYSIS" is performed. This is where point quality and relative agreement are considered and the best result in displayed, with appropriate quality. For most points with three or more inputs, a state-of-the-art analysis called "PARITY SPACE VECTOR ANALYSIS" (PSVA) is used. This is an advanced mathematical treatment which is fairly immune from effects such as multiple point failure, common mode failure, and single "point sticking" phenomena.

18.2.3 Detailed Control Room Design Review

REQUIREMENT

Implement a detailed control room design review (DCRDR) program which includes:

a. The objective of the review is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (from NUREG-0660, Item I.D.1). As a complement to improvements of plant operating staff capabilities which will result from implementation of the SPDS and from upgraded emergency operating procedures, this review will identify any modifications of control room configurations that would contribute to a significant reduction of risk and enhancement in the safety of operation. Decisions to modify the control room would include consideration of long-term risk reduction and any potential temporary decline in safety after modifications resulting from the need to relearn maintenance and operating procedures. This should be carefully reviewed by persons competent in human factors engineering and risk analysis.

b. The review will be conducted to identify human engineering discrepancies. The review shall consist of:

   1. The establishment of a qualified multidisciplinary review team and a review program incorporating accepted human engineering principles.

   2. The use of function and task analysis (that had been used as the basis for developing emergency operating procedures technical guidelines and plant specific emergency operating procedures) to identify control room operator tasks and information and control requirements during emergency operations. This analysis has multiple purposes and should also serve as the basis for developing training and staffing needs and verifying SPDS parameters.

   3. A comparison of the display and control requirements with a control room inventory to identify missing displays and controls.

   4. A control room survey to identify deviations from accepted human factors principles. This survey will include, among other things, an assessment of the control room layout, the usefulness of audible and visual alarm systems, the information recording and recall capability, and the control room environment.

c. The assessment of which human engineering discrepancies are significant and should be corrected, including the selection of design improvements that will correct those discrepancies. Improvements that can be accomplished with an enhancement program (paint-tape-label) shall be done promptly.

d. The verification that each selected design improvement will provide the necessary correction and can be introduced in the control room without creating any unacceptable human engineering discrepancies because of significant contribution to increased risk, unreviewed safety questions, or situations in which a temporary reduction in safety could occur. Improvements that are introduced will be coordinated with changes resulting from other improvement programs such as SPDS, operator training, new instrumentation (Regulatory Guide 1.97, Rev. 2), and upgraded emergency operating procedures.

e. The submittal of a program plan within 2 months of the start of the control room review that describes how the items above will be accomplished.

f. The submittal of a summary report of the completed review outlining proposed control room changes, including their proposed schedules for implementation. The report will also provide a summary justification for human engineering discrepancies with safety significance to be left uncorrected or partially corrected.

RESPONSE

Entergy Operations is implementing a DCRDR program which will fully respond to the above requirements. Various items from the Preliminary Design Assessment (completed per item I.D.1 of NUREG-0737, see FSAR section 18.1.16) which were referred to in the DCRDR were included in the program. The GGNS DCRDR Program Plan was submitted to the NRC in December 1984, in compliance with Operating License NPF-29, Condition 2.C.(36). The program review and assessment phases were completed and a summary report thereof submitted to the NRC on July 31, 1986, in compliance with Operating License NPF-29, Condition 2.C.(36). This summary report defined the program which was actually used for the review, the review findings (i.e., Human Engineering Discrepancies) and assessment of those findings, proposed resolution of the findings and a schedule for resolution, implementation or justification for no action as appropriate.

18.2.4 Regulatory Guide 1.97 - Application to Emergency Response Facilities

REQUIREMENT

Implement a program to apply Regulatory Guide 1.97 to the Emergency Response Facilities as described below:

a. Functional Statement

Regulatory Guide 1.97 provides data on required instrumentation to assist control room operators in preventing and mitigating the consequences of reactor accidents.

b. Control Room

Provide measurements and indication of type A, B, C, D, and E variables listed in Regulatory Guide 1.97 (Rev. 2). Individual licensees may take exceptions based on plant-specific design features. BWR incore thermocouples and continuous offsite dose monitors are not required pending their further development and consideration as requirements. It is acceptable to rely on currently installed equipment if it will measure over the range indicated in Regulatory Guide 1.97 (Rev. 2), even if the equipment is presently not environmentally qualified. Eventually, all the equipment required to monitor the course of an accident would be environmentally qualified in accordance with the pending commission rule on environmental qualification.

Provide reliable indication of the meteorological variables (wind direction, wind speed, and atmospheric stability) specified in Regulatory Guide 1.97 (Rev. 2) for site meteorology. No changes in existing meteorological monitoring systems are necessary if they have historically provided reliable indication of these variables that are representative of meteorological conditions in the vicinity (up to about 10 miles) of the plant site. Information on meteorological conditions for the region in which the site is located shall be available via communication with the National Weather Service. These requirements supersede the clarification of NUREG-0737, Item III.A.2.2 (FSAR subsection 18.1.33).

c. Technical Support Center (TSC)

The Type A, B, C, D, and E variables that are essential for performance of TSC functions shall be available in the TSC.

BWR incore thermocouples and continuous offset dose monitors are not required pending their further development and consideration as requirements.

The indicators and associated circuitry shall be of reliable design but need not meet Class 1E, single-failure or seismic qualification requirements.

d. Emergency Operations Facility (EOF)

Those primary indicators needed to monitor containment conditions and releases of radioactivity from the plant shall be available in the EOF.

The EOF data indications and associated circuitry shall be of reliable design but need not meet Class 1E, single-failure or seismic qualification requirements.

e. Submit a report describing how GGNS meets these requirements. The submittal should include documentation which may be in the form of a table that includes the following information for each Type A, B, C, D, and E variable shown in Regulatory Guide 1.97 (Rev. 2).

1. Instrument range
2. Environmental qualification (as stipulated in guide or state criteria)
3. Seismic qualification (as stipulated in guide or state criteria)
4. Quality assurance (as stipulated in guide or state criteria)
5. Redundancy and sensor(s) location(s)
6. Power supply (e.g. Class 1E, non-Class 1E, battery backed)
7. Location of display (e.g., control room board, SPDS, chemical laboratory)
8. Schedule (schedule for installation or upgrade)

Deviations from the guidance in Regulatory Guide 1.97 (Rev. 2) should be explicitly shown, and supporting justification or alternatives should be presented.

RESPONSE

Mississippi Power & Light submitted the GGNS position report on Regulatory Guide 1.97 (RG 1.97) on February 28, 1985 (AECM-85/059) in compliance with Operating License Conditions 2.C.(36). This report fulfills the requirements of NUREG-0737, Supplement 1, Section 6.2. The Type A, B, C, D, and E variables were addressed showing instrument range, environmental qualification, seismic qualification, quality assurance, redundancy, power supply, control room display, and schedule for implementation as discussed in the GGNS positions. Deviations, considered appropriate for GGNS, were discussed and supporting justification or alternatives were provided in Attachment 3 of the Position Report. In addition, see FSAR Chapter 3, Appendix 3A and FSAR Section 7.5 for additional clarifications of Regulatory Guide 1.97, Rev. 2 compliance.

The measurement and indication of RG 1.97 variables per NUREG-0737 Supplement 1, section 6.1.b, for display in the control room were discussed in Attachment 1 to the Position Report.

As required by NUREG-0737, Supplement 1, Sections 6.1.c, 6.1.d, 8.2.1.h, and 8.4.1.g, types A, B, C, D, and E variables necessary for TSC and EOF functions will be provided primarily by the use of the GGNS emergency response facility information system/ safety parameter display system (ERFIS/SPDS) as identified in MP&L letter from J. P. McGaughy to H. R. Denton dated April 15, 1983. The GGNS ERFIS/SPDS computer-based system, containing the SPDS safety parameters for monitoring post-accident status, is provided in the TSC and EOF. The SPDS display basis and parameter set have been developed and are described in the SPDS Functional Specification.

Human factors considerations of Section 5.1.d to NUREG-0737, Supplement 1, for existing RG 1.97 instrumentation were evaluated during the GGNS DCRDR review phase. Future modifications will be evaluated against the results established by the DCRDR summary results.

The NRC reviewed the GGNS Reg. Guide 1.97 Position Report submittal (AECM-85/0059) and provided an Interim Safety Evaluation Report (MAEC-85/0409) which identified the GGNS Reg. Guide 1.97 instrumentation for which deviations were not adequately justified.

MP&L provided a response to the NRC's Interim Safety Evaluation Report on February 14, 1986 (AECM-86/0030).

The NRC reviewed MP&L's response to the Interim Safety Evaluation Report and provided Safety Evaluation Report (MAEC-87/0013) concerning the submittal of the request for additional information. The NRC concluded that GGNS either conforms to, or has adequately justified deviations from Reg. Guide 1.97 for each of the post accident monitoring variables except neutron flux. The NRC further concluded that GGNS's commitment regarding implementation of fully qualified neutron flux monitoring instrumentation is acceptable and that, interim operation with existing flux instrumentation is acceptable.

18.2.5 Upgrade Emergency Operating Procedures

REQUIREMENT

Implement a program to upgrade existing Emergency Operating Procedures (EOPs) which includes:

a. Use human factored, function oriented, Emergency Operating Procedures to improve human reliability and the ability to mitigate the consequences of a broad range of initiating events and subsequent multiple failures or operator errors, without the need to diagnose specific events.

b. Reanalyze transients and accidents and prepare Technical Guidelines, in accordance with NUREG-0737, Item I.C.1. These analyses will identify operator tasks, and information and control needs. The analyses also serve as the basis for integrating upgraded EOPs and the control room design review and verifying the SPDS design.

c. information and control needs. The analyses also serve as the basis for integrating upgraded EOPs and the control room design review and verifying the SPDS design.

d. Upgrade EOPs to be consistent with Technical Guidelines and an appropriate procedure Writer's Guide.

e. Provide appropriate training of operating personnel on the use of upgraded EOPs prior to implementation of the EOPs.

f. Implement upgraded EOPs.

g. Submit to the NRC the Technical Guidelines for review.

h. Submit to the NRC a Procedures Generation Package at least 3 months prior to the date of the start of formal operator training on the upgraded procedures. The Procedures Generation Package shall include:

    1. Plant-Specific Technical Guidelines - A description of the planned method for developing the plant specific EOPs from the generic guidelines, including plant specific information

    2. Writer's Guide - The specific methods to be used in preparing the upgraded EOPs based on the Technical Guidelines

    3. Validation Plan - A description of the program for validation of the EOPs

    4. Training Plan - A brief description of the training program for the upgraded EOPs.

RESPONSE

MP&L implemented an EOP Upgrade Program which responded to the above requirements. The GGNS Procedures Generation Package was submitted to the NRC on April 11, 1985, (AECM-85/0110) in compliance with Operating License NPF-29, Condition 2.C.(36). A revised addition to the Procedures Generation Package was submitted on July 15, 1986, (AECM-86/0208) to define small changes in the EOP Upgrade Program since the original submittal.

The present symptom based Flowchart Emergency Operating Procedures were developed according to the GGNS1 Procedure Generation Package (PGP). The procedures were developed from Rev. 4 of the BWROG Emergency Procedure Guidelines (EPG). A Plant Specific Technical Guideline (PSTG) was developed for GGNS1 using plant specific data. The Flowchart Emergency Operating Procedures were developed from the PSTG in accordance with the PGP Writers Guide.

Development of a symptom based hydrogen control procedure was omitted in this program due to lack of an NRC approved guideline. A hydrogen control procedure will be developed upon NRC approval of a hydrogen control guideline.

The Emergency Operating Procedures were validated by utilizing the procedures in scenarios developed from a task analysis of the BWROG EPGs and the GGNS1 PSTG.

A Training program was implemented to train the operators on intent and use of the new Flowchart Emergency Operating Procedures prior to their implementation. The GGNS Upgrade EOPs were implemented prior to startup following the first refueling outage in compliance with Operating License NPF-29, Condition 2.C (36).

18.2.6 Emergency Response Facilities

REQUIREMENT

The Technical Support Center (TSC), Emergency Operations Facility (EOF), and the Operations Support Center (OSC) will be designed, constructed, staffed, and operated in a manner that will effectively support emergency response facility activities in accordance with the NUREG-0737, Supplement 1.

RESPONSE

Descriptions of the GGNS Emergency Response Facilities were provided in several MP&L (SERI) letters to the NRC including AECM-81/25 (April 8, 1981), AECM-81/52 (February 12, 1981), AECM-82/112 (April 27, 1982), AECM-83/222 (April 13, 1983), AECM-83/232 (April 15, 1983), and AECM-83/347 (June 17, 1983). These letters describe design details of the facilities which meet the guidelines of NUREG-0737, Supplement 1. A general description of each facility is provided in the GGNS Emergency Plan (FSAR Section 13.3). In accordance with Operating License Condition 2.C.(36), these facilities were fully operational with the exception of Regulatory Guide 1.97 implementation prior to start-up from the first refueling outage as described in MAEC-86/0410 (December 20, 1986).