NUCLEAR REGULATORY COMMISSION

DOCKET NO. 50-416

MISSISSIPPI POWER AND LIGHT COMPANY, ET AL.

GRAND GULF NUCLEAR STATION, UNIT 1

RECEIPT OF PETITION FOR ACTION UNDER 10 CFR 2.206

Notice is hereby given that by petition dated March 29, 1984, the Jacksonians United For Liveable Energy Policies has asked that the Commission order the Mississippi Power and Light Company, et al. to show cause why the license for Grand Gulf Nuclear Station, Unit 1, should not be revoked and a stay of operation not be issued. The petitioner bases its request for relief on discrepancies discovered in technical specifications since the issuance of the license in 1982 and on problems associated with the capabilities of diesel generators used at the plant which were designed and manufactured by Transamerica Delaval, Incorporated. The petitioner also asks for modification of the license to remove management personnel responsible for problems at Grand Gulf and to ensure implementation and verification of corrective actions for identified deviations from NRC requirements. The petition is being treated under 10 CFR 2.206 and, accordingly, appropriate action will be taken on the petition within a reasonable time.

Copies of the petition are available for public inspection in the Commission's Public Document Room at 1717 H Street, N.W., Washington.

D.C. 20555 and in the local public document room for the Grand Gulf Nuclear Station at the Hinds Jr. College, George M. McLendon Library, Raymond, Mississippi 39154.

Dated at Bethesda, Maryland this day of May 1984.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by
H. R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

DL:LB #4	LA:DL:LB #4	5/11/84 OELD	DL:LB#4	AD:L:DL	DIR:DL
DHouston/pob	MDuncan		EAdensam	TNovak	DEisenhut
5/10/84	5/10/84		5/10/84	5/17/84	5/17/84

DD:NRR	DIR:NRR
EGCase	HRDenton
5/ /84	5/21/84

X55/21/84

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

APR 1 8 1984

Docket No. 50-416

Mr. J. P. McGaughy
Vice President, Nuclear Production
Mississippi Power & Light Company
P.O. Box 1640
Jackson, Mississippi 39205

Dear Mr. McGaughy:

Subject: Issuance of Order Restricting Conditions for Operation (Effective Immediately)

The Commission has issued the enclosed Order Restricting Conditions for Operation (Effective Immediately) related to the Grand Gulf Nuclear Plant, Unit 1, Facility Operating License No. NPF-13. Mississippi Power & Light Company (MP&L) shall not operate the plant unless such operation is in conformance with the revised Technical Specifications appended to the Order and MP&L, prior to entry into mode 2, certifies to the Regional Administrator, Region II, that MP&L's procedures have been modified and training conducted to reflect the revised Technical Specifications.

A copy of the Order has been filed with the Office of the Federal Register for publication.

Sincerely,

Elinor G. Adensam

Elinor G. Adensam, Chief
Licensing Branch No. 4
Division of Licensing

Enclosure:
Order

cc: See next page

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GRAND GULF

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President
Claiborne County Board of Supervisors
Port Gibson, Mississippi 39150

Office of the Governor
State of Mississippi
Jackson, Mississippi 39201

U.S. Environmental Protection Agency
Attn: EIS Coordinator
Region IV Office
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Atlanta, Georgia 30309

Dr. Alton B. Cobb
State Board of Health
P.O. Box 1700
Jackson, Mississippi 39205

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of MISSISSIPPI POWER & LIGHT COMPANY MIDDLE SOUTH ENERGY, INC., AND SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION (Grand Gulf Nuclear Station)	)))))))	Docket No. 50-416

ORDER RESTRICTING CONDITIONS FOR OPERATION
(EFFECTIVE IMMEDIATELY)

I.

Mississippi Power & Light Company (MP&L), Middle South Energy, Inc., and South Mississippi Electric Power Association (the licensees) are the holders of Facility Operating License No. NPF-13, which authorizes the operation of the Grand Gulf Nuclear Station, Unit 1 (the facility) at steady state reactor power levels not in excess of 191 megawatts thermal. The facility consists of a boiling water reactor (BWR/6) with a Mark III containment located in Claiborne County, Mississippi.

II.

On June 16, 1982, a low power license was issued for the Grand Gulf Nuclear Station, Unit 1. Inspections by Region II in regard to compliance of surveillance procedures with the Technical Specifications were performed from June 16, 1982, to October 8, 1982, and discrepancies in the surveillance procedures and Technical Specifications were identified. Based on these inspections, a Confirmation of Action (COA) letter was issued to restrict the next criticality (plant then in shutdown for other reasons) until the identified discrepancies were resolved. At the conclusion of this phase of MP&L's review,

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in late August 1983, another inspection was held to discuss the reasons for the discrepancies and to determine whether changes required for operation through the first fuel cycle had been submitted. The plant returned to criticality on September 25, 1983, and low power tests were conducted until November 8, 1983. The plant was shut down after testing and remained shutdown while undertaking an extensive licensed operator recertification program (another problem identified by Region II in early November 1983). During this shutdown, MP&L and the staff reviewed again the Technical Specifications as issued through Amendment No. 12 to the Operating License. Again, each review party found further problem areas, thus necessitating a complete, high quality review of the Technical Specifications by MP&L. A review program was initiated by MP&L on March 2, 1984, which involved approximately 150 personnel from MP&L, General Electric and Bechtel. From previous reviews and inspections and the program reviews, approximately 350 Technical Specification problem areas were identified.

III.

As a result of the above reviews and inspections, it was found that certain Technical Specifications are (1) inconsistent with the as-built plant and may thereby create unnecessary confusion to the plant operating staff or otherwise increase the risk of human error, and/or (2) inconsistent with the safety analyses associated with the basis for the plant design such that compliance with those Technical Specifications would permit operation under unanalyzed conditions with reduced margins of safety.

Consequently, the uncertainties raised by these inconsistencies require changes to the Technical Specifications to prevent the potential for undue risk to the public from operation of the facility up to power levels currently authorized. While all of the problems with the Technical Specifications will need to be resolved, operation at a power level of up to 5% does not require all such problems to be resolved at this time. A safety evaluation is attached as Attachment 1 which describes the changes required for 5% power operation and the reasons for each change. Therefore, I have determined that the public health, safety and interest require that, effective immediately, the licensees' current authorization under the license be restricted in accordance with this Order.

IV.

Accordingly, pursuant to sections 103, 161i, 161o, 182 and 186 of the Atomic Energy Act of 1954, as amended, and the Commission's regulations in 10 CFR Parts 2 and 50, it is hereby ordered, effective immediately, that:

> MP&L shall not operate the Grand Gulf plant under the terms of License No. NPF-13 unless such operation is in conformance with the revised Technical Specifications appended to this Order and MP&L, prior to entry into mode 2, certifies to the Regional Administrator, Region II, that MP&L's procedures have been modified and training conducted to reflect the revised Technical Specifications.

V.

Within 20 days of the date of this Order, the licensees may show cause why the actions described in Section IV should not have been ordered by filing a written answer under oath or affirmation that sets forth the matters of fact and law on which the licensees rely. As provided in 10 CFR 2.202(d), the licensees may answer by consenting to the Order set forth in Section IV of this Order to show cause. Alternatively, the licensees may request a hearing on this Order. Any request for a hearing on this Order or answer to the Order must be filed within 20 days of the date of this Order with the Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555. A copy of the request shall also be sent to the Executive Legal Director at the same address. A request for a hearing shall not stay the immediate effectiveness of Section IV of this Order.

If the licensees request a hearing on this Order, the Commission will issue an order designating the time and place of hearing. If a hearing is held, the issue to be considered at such a hearing shall be whether the Order should be sustained.

FOR THE NUCLEAR REGULATORY COMMISSION

HR Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Attachments:
(1) Safety Evaluation
(2) Revised Technical Specifications

Dated at Bethesda, Maryland
this 18th day of April 1984

SAFETY EVALUATION OF GRAND GULF UNIT 1
TECHNICAL SPECIFICATIONS
FOR LOW-POWER OPERATION

The staff has reviewed the Grand Gulf Technical Specifications (TS) to determine whether changes should be made to the TS for operation under the existing low-power (5%) license.

In the past 9 months, the licensee has been reviewing the Technical Specifications. In March 1984, the licensee initiated a comprehensive review of TS by comparing the TS with the Grand Gulf Final Safety Analysis Report (FSAR) requirements, the NRC staff's Safety Evaluation Report (SER) for Grand Gulf, the as-built design, and the staff's draft BWR/6 Standard Technical Specifications. As a result, the licensee has identified 357 problem areas which may result in requests for changes to the TS. Each area is assigned a problem sheet number which will be used to track the resolution of the problem either by obtaining a change to the TS or to otherwise resolve it. Based on its review, the licensee has requested TS changes for 23 problem areas; 14 were requested for restart and operation under the present low-power license, and 9 for power escalation tests. All of these were selected for resolution because these Technical Specifications were found by the licensee to be nonconservative with respect to the FSAR safety analyses and the SER.

The NRC staff and its consultant, Idaho National Engineering Laboratory (INEL), also reviewed the TS to determine any nonconservative specifications relative to the FSAR or SER. Most of the staff recommendations and comments regarding changes to the TS have been considered by Mississippi Power and Light (MP&L) and included in their identified 357 problem areas. For operation under the low-power license (5% power), the staff has not found any specifications that need to be changed in addition to the problem areas identified by MP&L. For operation above 5% power, the staff has identified several problem areas that will be resolved with the license in addition to those identified by the licensee. A safety evaluation for Technical Specification changes needed for power escalation above 5% power will be issued with the issuance of the full-power license amendment.

Table 1 lists the Technical Specification changes identified by the licensee as being needed prior to operation up to 5% power and above 5% power. Based on its review of these 23 nonconservative problem areas and related requests for Technical Specification changes identified by MP&L, the NRC staff finds that for 22 of the problem areas, the change will be in the direction of increased safety. However, the change requested for the standby gas treatment system (Problem Sheet No. 262) to allow bypassing of the radiation monitor during tests is not acceptable because it could result in unmonitored release of radioactive gaseous effluent. Therefore, the change identified by Problem Sheet No. 262 is not acceptabled based on the information provided in the request letter and will not be made in this Order.

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The staff's safety evaluation of each of the 23 problem areas is provided below. Attachment 2 provides the Grand Gulf Technical Specification page changes implemented by this Order.

The NRC staff concludes that, with the changes implemented by this Order, the Technical Specifications required for operation under the current license, which is limited to 5% power, is in accordance with the FSAR, SER, and applicable regulatory requirements.

Table 1

23 Technical Specification Changes Requested by MP&L

Problem Sheet No.	Item	Licensee Letter Date
001	Number of Automatic Depressurization System Valves	03/20/84
005	Reactor Water Cleanup System Isolation Instrumentation	03/20/84
015	Drywell and Containment Pressure Setpoints	04/07/84
016	Containment High Pressure Setpoints	04/07/84
021 & 139	Listing of Safety-Related Mechanical Snubbers	03/29/84 & 10/07/83
033	Containment Spray System Timer Setpoints	04/07/84
037	Calibration Frequency of Rosemont and Riley Instruments	12/14/83
038	Radiation Monitor Calibration Frequency	04/07/84
054	Containment Spray Actuation Instrumentation	03/29/84
076	Emergency Core Cooling System Response Times	Item 6, 09/09/83
078	Reactor Core Isolation Cooling System Initiation Instruments	10/11/83
103	Main Steam Flow Instrumentation	04/07/84
198	Radiation Monitor Instrumentation	03/29/84
213	Automatic Depressurization System Instrumentation	03/29/84
233	Containment Spray Flow Conditions	04/07/84
262	Standby Gas Treatment System Radioactivity Monitor	04/07/84
285	Chlorine Detector Calibration Frequency	03/29/84
292 & 293	Containment and Drywell Air Locks Test Pressure	04/07/84
306	Listing of Drywell Isolation Valves	04/07/84
308	Room Air Temperature Trip Setpoints	04/10/84
329	Accident Monitoring Instrumentation	04/10/84

Problem Sheet No. 001, Number of Automatic Depressurization System Valves

(1) Technical Specification

Section 3.5.1, ECCS - Operating, Limiting Condition for Operation (LCO), page 3/4 5-1; Bases 3/4.5.1 and 3/4.5.2, ECCS - Operating and Shutdown, pages B 3/4 5-1 and B 3/4 5-2.

(2) Change

Changed LCO to require "eight" operable ADS valves instead of "At least 7."

Changed Bases to indicate that the ADS controls "eight" selected valves instead of "seven," and that the safety analyses take credit for "seven" of these valves instead of "six."

(3) Reason for Change

Restore operating safety margins to those associated with initial conditions used in the safety analyses.

(4) Evaluation

The requested change would require that eight valves in the automatic depressurization system (ADS) be operable rather than the currently specified seven valves. The FSAR safety analyses are based on the use of eight valves for depressurization following an accident. In addition, the bases would be changed to allow operation with seven valves for 14 days if one valve is inoperable.

In a letter dated March 20, 1984, the licensee also provided the results of small-break loss-of-coolant-accident (LOCA) analyses that indicate that credit for only seven valves is needed to satisfy 10 CFR 50.46 acceptance criteria. The NRC staff has reviewed the results of the analyses and concludes that it is acceptable to allow one of the eight valves to be inoperable for up to 14 days. The LOCA analyses were performed using emergency core cooling system (ECCS) evaluation models which have been previously approved by the staff.

The changes are necessary and sufficient to correct deficiencies in the present specifications for ADS valves.

Problem Sheet No. 005, Reactor Water Cleanup System Isolation Instrumentation

(1) Technical Specification

Table 3.3.2-1, Isolation Actuation Instrumentation, page 3/4 3-12.

(2) Change

Changed to indicate "1" minimum operable channel per trip system, instead of "NA," for the standby liquid control system (SLCS) initiation of RWCU isolation function.

Changed applicable operational condition to "5" instead of "3," and added footnote "##" to require the SLCS initiation of RWCU isolation function to be operable in Operational Condition 5 only when control rods are withdrawn, but not if removed per Technical Specification 3.9.10.1 or 3.9.10.2.

Replaced present ACTION 27 for the SLCS initiation RWCU isolation function with new ACTION 30 on Table 3.3.2-1, which requires the affected SLCS pump to be declared inoperable whenever the associated SLCS initiation instrumentation is inoperable.

(3) Reason for Change

Reflect actual design of the SLCS initiation of RWCU isolation function which consists of 1 channel per trip system.

Provide clarity, completeness, and prevent unnecessary isolation of an unrelated system.

(4) Evaluation

The reactor water cleanup system is isolated automatically upon standby liquid control system initiation. Each of the two isolation trip systems receive signals from the SLCS. Each isolation trip systems' SLCS inputs are arranged in a one-out-of-one logic for isolation valve actuation. The "A" trip system initiates closure of valve G33-F004 and the "B" trip system initiates closure of valves G33-F001 and G33-F251.

In the issued version of the Grand Gulf Unit 1 Technical Specifications, the MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM column of Table 3.3.2-1 incorrectly includes NA for the SLCS initiation for RWCU isolation. If the RWCU is not isolated, some of the sodium pentaborate injected into the reactor to shut it down could be taken out of the reactor. Therefore, the effective Technical Specification is nonconservative with respect to system design and anticipated system performance. The licensee's proposed change corrects this deficiency in the Technical Specifications and is, therefore, necessary and sufficient.

Operational Condition 5 is the reactor refueling condition. The NRC staff finds this change to be necessary. It is acceptable in that maintenance on the SLCS would be performed in the refueling condition with all control rods inserted.

The staff has reviewed the requested change in the action statements for the operability requirements of the SLCS initiating instrumentation. The applicant has proposed a new ACTION statement that would declare the SLCS pump with the inoperable initiation instrumentation to be inoperable. The staff concludes that this Technical Specification change is acceptable because it is consistent with approved technical specification philosophy.

Problem Sheet No. 015, Drywell and Containment Pressure Setpoints

(1) Technical Specification

Tables 2.2.1-1, Reactor Protection System Instrumentation Setpoints, page 2-4; 3.3.2-2, Isolation Actuation Instrumentation Setpoints, pages 3/4 3-15, 3/4 3-16, 3/4 3-17a; 3.3.3-2, Emergency Core Cooling System Actuation Instrumentation Setpoints, page 3/4 3-28; and 3.3.8-2, Plant Systems Actuation Instrumentation Setpoints, page 3/4 3-99.

Bases 2.2.1, Reactor Protection System Instrumentation Setpoints, page B 2-8; 3/4.3.2, Isolation Actuation Instrumentation, page B 3/4 3-1; 3/4.3.3, Emergency Core Cooling System Actuation Instrumentation, page B 3/4 3-2; and 3/4.3.8, Plant Systems Actuation Instrumentation, page B 3/4 3-6.

(2) Change

Revised the drywell and containment pressure instrument setpoints and allowable values to account for the effect of worst case negative barometric pressure changes.

The Bases sections are supplemented to reflect that negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell and containment pressure-high.

(3) Reason for Change

Revise setpoints and allowable values because the drywell and containment pressure instrumentation do not automatically compensate for changes in barometric pressure, and which, if omitted, could contribute to delayed safety system initiation.

(4) Evaluation

For the Grand Gulf 1 design, both the drywell and containment pressure instrumentation provide trip signals that are necessary to ensure the capability to prevent or mitigate the consequences of postulated accidents. In addition, the drywell pressure instrumentation also provides trip signals required for achieving safe shutdown.

The licensee has stated that historical weather information for the plant locale indicates that the largest negative barometric deviation from standard pressure expected is 0.50 psi. The NRC staff has independently reviewed severe weather data including data for hurricanes and confirmed that 0.50 psi bounds expected pressure decreases. To ensure that the instrument trip setpoints set during normal weather conditions are not exceeded during storm conditions, the licensee has proposed to reduce the setpoints and allowable values by 0.50 psi.

The changes to the Bases sections identify which setpoints are affected by barometric pressure changes.

The changes to the drywell and containment pressure instrumentation setpoints and allowable values are necessary to bring limiting initial containment and drywell initial pressures into agreement with initial containment and drywell pressures assumed in FSAR safety analyses. An analysis is in progress to justify higher values; however, as an interim measure, the licensee has proposed these more conservative values.

The licensee has stated that the proposed changes are necessary and sufficient to bring the setpoints into agreement with FSAR safety analyses.

In response to a request from the NRC staff, the licensee is participating in a BWR Owners' Group effort to provide more detailed information on their setpoint methodology. The staff concludes that there is reasonable assurance, based on staff participation in meetings with the BWR Owners' Group working group on setpoint methodology, that the forthcoming more detailed information on setpoints and setpoint methodology being developed by this group will verify the acceptability of the proposed setpoints. In the interim, the staff finds that the change is in the conservative direction and is acceptable.

Problem Sheet No. 016, Containment High Pressure Setpoints

(1) Technical Specification

Table 3.3.8-2, Plant Systems Actuation Instrumentation Setpoints, page 3/4 3-99.

(2) Change

Containment high-pressure trip setpoint is changed to "7.84 psig" instead of "9 psig," and the corresponding allowable value is changed to "8.34 psig" instead of "9.2 psig."

(3) Reason for Change

Restore safety margins to those associated with the safety analyses.

(4) Evaluation

In response to a recommendation from the nuclear steam supply system (NSSS) vendor (General Electric), the licensee is proposing to revise the containment spray initiation instrumentation trip setpoint and allowable value. The licensee has stated that this change is necessary to correct an error by the NSSS vendor.

The licensee has stated that this change is necessary and sufficient to bring the Technical Specification trip setpoint and allowable value to values consistent with the assumptions of the safety analyses.

In response to a request from the NRC staff, the licensee is participating in a BWR Owners' Group effort to provide more detailed information on their setpoint methodology. The staff concludes that there is reasonable assurance, based on staff participation in meetings with the BWR Owners' Group working group on setpoint methodology, that the forthcoming more-detailed information on setpoints and setpoint methodology being developed by this group will verify the acceptability of the proposed setpoints. In the interim, the staff finds that the change is in the conservative direction and is acceptable.

Problem Sheet Nos. 021 and 139, Listing of Safety-Related Mechanical Snubbers

(1) Technical Specification

Table 3.7.4-2, Safety Related Mechanical Snubbers, page 3/4 7-16.

(2) Change

Changed the list of snubbers.

(3) Reason for Change

The snubber list changes are needed to make the list consistent with the as-built plant.

(4) Evaluation

Snubber operability is determined by an inspection defined in the surveillance requirements. A footnote to Table 3.7.4-2 allows the licensee to add snubbers to the list when they are found to be needed provided a revision to the table is included with the next license amendment request. The requirement in the footnote to include changes in the next license amendment allows the NRC staff to review the changes in a timely manner.

Technical Specification Section 3.7.4 requires that snubbers on systems required to be operable in operational condition 4 (cold shutdown with average reactor coolant temperature less than or equal to 200°F) and operational condition 5 (refueling) must themselves also be operable in operational conditions 4 and 5. Since the reactor is in operational condition 4, this Technical Specification change is necessary.

Problem Sheet No. 033, Containment Spray System Timer Setpoints

(1) Technical Specification

Table 3.3.8-2, Plant Systems Actuation Instrumentation Setpoints, page 3/4 3-99; and Bases 3/4.3.8, Plant Systems Actuation Instrumentation, page B 3/4 3-6.

(2) Change

Revised trip setpoints and allowable values in both containment spray system timers.

Revised Bases to refer to the analyzed minimum and maximum time delays between the initiation of the accident and containment spray initiation, which are 10 minutes and 13 minutes, respectively.

(3) Reason for Change

Restore margins assumed in safety analyses. Present timer settings permit analytical limits for containment spray initiation to be exceeded and possible delayed safety system initiation.

Avoid operation which could lead to unanalyzed conditions.

(4) Evaluation

The low-pressure coolant injection system and the containment spray system are subsystems of the residual heat removal (RHR) system. Two of three RHR trains automatically divert low-pressure coolant injection flow from the core to the containment spray provided certain conditions are sensed by the containment spray initiation logic. Timers are provided within this logic to ensure that injection flow is directed to the core for at least 10 minutes and that containment spray will be initiated no later than 13 minutes following a LOCA. These values were used in the safety analyses for core cooling and initiation of containment spray following a LOCA. In reviewing the setpoint calculations, the licensee determined that there is a nonconservative error in the setpoint resulting from a mistake in determining the total loop accuracy. In addition, the licensee discovered that the additional 90-second time delay in the initiation of Train B was not considered in the FSAR safety analyses. Accordingly, the licensee has proposed trip setpoints and allowable values to correct the deficiency in summing the instrument loop inaccuracy and to remove the time delay in Train B initiation. A footnote is proposed to be added to Table 3.3.8-2 to clarify the new trip setpoint for the System B timers. This footnote will specify that the present 90-second delay is to be set at a value not to exceed 10 seconds. A change to the bases has been proposed to address the upper and lower analytical time limits associated with containment spray initiation.

The licensee has stated that this change to the Technical Specifications is necessary and sufficient to correct the nonconservative errors in the setpoints and allowable values.

In response to a request from the NRC staff, the licensee is participating in a BWR Owners' Group effort to provide more detailed information on their setpoint methodology. The staff concludes that there is reasonable assurance, based on staff participation in meetings with the BWR Owners' Group working group on setpoint methodology, that the forthcoming more-detailed information on setpoints and setpoint methodology being developed by this group will verify the acceptability of the proposed setpoints. In the interim, the staff finds that the change is in the conservative direction and is acceptable.

Problem Sheet No. 037, Calibration Frequency of Rosemont ..d Riley Instruments

(1) Technical Specification

Table 4.3.2.1-1, Isolation Actuation Instrumentation Surveillance Requirements, pages 3/4 3-20 through 3/4 3-23a.

(2) Change

Changed to add footnote (c) requiring trip unit calibration at least once per 31 days to all Rosemont trip units.

Changed the channel calibration frequency for Riley temperature switches from 18 months to annual.

(3) Reason for Change

Ensure consistency within Technical Specifications for trip unit calibration frequency and thereby avoid operator confusion and minimize the potential for human error.

Restore design margin by changing to manufacturer's recommended calibration frequency.

(4) Evaluation

Footnote (c) which states "Calibrate trip unit at least once per 31 days" is applied to certain Rosemont trip units associated with the isolation actuation instrumentation channels delineated in Table 4.3.2.1-1 of the Technical Specifications. By letter dated September 9, 1983, from A. Schwencer (NRC) to J. P. McGaughy (MP&L), the NRC staff requested that the licensee provide the rationale for calibrating certain Rosemont trip units at 18-month intervals and other Rosemont trip units at 31-day intervals. In response to the staff's request, by letter dated October 14, 1983, from L. F. Dale (MP&L) to H. Denton (NRC), the licensee stated that the Rosemont trip unit for each channel delineated in Table 4.3.2.1-1 (isolation actuation instrumentation) was being calibrated monthly, and changes would be proposed to the Technical Specifications to require this surveillance frequency on all Rosemont trip units.

Through its review of the isolation actuation instrumentation surveillance requirements, the licensee determined another case where the surveillance testing interval for Riley temperature switches required by the Technical Specifications was greater than that recommended by the manufacturer. Temperature-monitoring instrument channels are currently being calibrated yearly to satisfy manufacturer's recommendations. To resolve this deficiency, Technical Specification requirements for the temperature-monitoring instruments are being changed to be consistent with the component manufacturer's recommendations.

On the basis of its review, the staff finds that the Technical Specification changes are necessary to provide surveillance requirements consistent with the manufacturers' recommendations. Therefore, the staff finds the Technical Specification changes acceptable.

Problem Sheet No. 038, Radiation Monitor Calibration Frequency

(1) Technical Specification

Tables 4.3.2.1-1, Isolation Actuation Instrumentation Surveillance Requirements, page 3/4 3-20; 4.3.7.1-1, Radiation Monitoring Instrumentation Surveillance Requirements, page 3/4 3-59; 4.3.7.5-1, Accident Monitoring Instrumentation Surveillance Requirements, page 3/4 3-72; and 4.3.7.12-1, Radioactive Gaseous Effluent Monitoring Instrumentation Surveillance Requirements, page 3/4 3-92.

(2) Change

Changed the channel calibration frequency for accessible and continuous radiation monitors from 18 months to 12 months.

(3) Reason for Change

Recommended by vendor and stated in FSAR.

(4) Evaluation

From a review of the FSAR and the Technical Specifications, the licensee has found a discrepancy between the commitments contained in the FSAR and the requirements of the Technical Specifications. The FSAR states that continuous radiation monitoring instruments that are accessible during normal operation and airborne radiation monitors will be calibrated annually based on the vendor's recommendations.

The staff finds these changes are necessary to provide surveillance requirements consistent with vendor's recommendations, and are therefore acceptable.

Problem Sheet No. 054, Containment Spray Actuation Instrumentation

(1) Technical Specification

Section 3.3.8, Plant Systems Actuation Instrumentation; Table 3.3.8-1, Plant Systems Actuation Instrumentation, pages 3/4 3-96 through 3/4 3-98a.

(2) Change

Revised to require that, with nonconservative setpoints, the channel is declared inoperable and action is taken as required by Table 3.3.8-1.

Revised to require that with inoperable channels, the action required by Table 3.3.8-1 is to be taken.

Revised to transfer existing requirements to Table 3.3.8-1.

Revised to require two operable drywell pressure-high and reactor vessel water level (level 1) channels for each containment spray trip system. Also revised to indicate the Action Statement corresponding to each of the actuation instruments.

(3) Reason for Change

Reflect actual system design and avoid operation with conditions leading to unanalyzed events. (Existing Technical Specification permits the timers, if inoperable, to be placed in a tripped condition that could lead to premature LPCI flow diversion to the containment spray header.)

Reflect actual system design (presently indicates there are two, rather than one, trip systems per containment spray system) which, if uncorrected, could confuse operators and contribute to potential for human error.

Revise to implement Action Statements 3.3.8.a, 3.3.8.b, and 3.3.8.c in a consistent manner so as to avoid operator confusion and minimize potential for human error.

(4) Evaluation

Coolant flow for the containment spray system is provided by the residual heat removal pumps, which also provide flow for low-pressure coolant injection for the first 10 minutes following a LOCA. The design includes two containment spray trains (A and B). Each containment spray train is initiated by its associated instrument trip system. Each trip system consists of the following channels:

(1) two drywell pressure-high
(2) two containment pressure-high
(3) two reactor vessel water level-low (level 1)
(4) one 10-minute timer (system B has an additional timer to provide a delay of up to 90 seconds after the system A trip)

Upon sensing a LOCA condition via the drywell pressure-high and/or vessel water level-low instrumentation, the spray actuation instrumentation starts its timers. If at the end of the timer cycle (10 minutes) a containment high-pressure signal exists, the low-pressure coolant injection train A flow will be automatically diverted from coolant injection into the core to the containment spray function. Simultaneously, at the end of its timers' cycles, low-pressure coolant injection system B flow to the core will be automatically diverted to containment spray provided a containment high-pressure condition is sensed. To meet FSAR analyses of a LOCA, the coolant flow to the core must continue for at least 10 minutes and spray flow must begin prior to 13 minutes after the LOCA.

In order to ensure the operability of the containment spray function given a single failure, the minimum number of required operable channels is proposed to be changed from one per trip system to two per trip system for the drywell pressure-high and the reactor vessel low-level 1 instruments.

Changes to the Action Statements in Technical Specification 3.3.8 are required to be consistent with the system design. In the issued version of the Technical Specifications, Action Statements a and b.1 incorrectly require that inoperable timers be placed in the tripped condition. Placing a timer in the tripped condition could result in premature diversion of low-pressure coolant injection flow to the containment sprays. The correct action is to declare the associated trip system inoperable when a timer is inoperable and then take the action required by Technical Specification 3.6.3.2.

In the issued version of the Grand Gulf Technical Specifications, Action Statement 2.b indicated that there are two, rather than one, trip system for each spray system. Corrections to indicate the installed number of trip systems are proposed, and appear in Action 130b on Table 3.3.8-1. Other changes are proposed to reformat the required actions when instrument channels are determined to be inoperable.

Based on its review, the staff finds that the proposed changes improve system reliability and provide a sufficiently conservative set of requirements should one or more channels become inoperable. These changes are in accordance with the regulatory guidelines of the Standard Technical Specifications for General Electric Boiling Water Reactors and are necessary to correct a deficiency in the Grand Gulf Technical Specifications.

Problem Sheet No. 076, Emergency Core Cooling System Response Times

(1) Technical Specification

Table 3.3.3-3, Emergency Core Cooling System Response Times (Seconds), page 3/4 3-30.

(2) Change

Revised to change response time of LPCI pumps for the injection mode of RHR system to "$\leq$40" seconds.

(3) Reason for Change

Restore margin to that assumed in safety analyses. If uncorrected, could permit operation leading to unanalyzed events. (Existing pump response time of 45 seconds for pumps A and B is inconsistent with the response time of 40 seconds used in safety analysis providing basis for plant design.)

(4) Evaluation

The change requires a faster response of the low-pressure coolant injection (LPCI) system following receipt of an emergency core cooling system (ECCS) actuation signal. The response time of less than or equal to 40 seconds is consistent with the analyses assumptions used for ECCS evaluation in Section 6.3 of the Grand Gulf Final Safety Analysis Report (FSAR).

The change is necessary to make the Technical Specifications consistent with accident analyses, and is acceptable.

Problem Sheet No. 078, Reactor Core Isolation Cooling System Initiation

(1) Technical Specification

Table 3.3.5-1, Reactor Core Isolation Cooling System Actuation Instrumentation, pages 3/4 3-45 and 3/4 3-46.

(2) Change

Minimum OPERABLE channels per trip system for Reactor Vessel Water Level-Low, Level 2 is changed from "2" to "4." Present ACTION 50 is changed to reflect only one trip system rather than two.

(3) Reason for Change

Reflect actual system design and provide a conservative set of requirements should one or more channels become inoperable.

(4) Evaluation

The reactor core isolation cooling system initiates on low reactor water level. The initiation logic is arranged as one trip system with four water level signals feeding a one-out-of-two-twice logic. The present requirement of 2 minimum OPERABLE channels per trip system would not result in RCIC initiation unless the correct 2 channels are operable. To assure that RCIC initiation is available given a single failure, the minimum OPERABLE channels per trip system should be revised from 2 to 4 channels. In addition, the proposed change to ACTION 50 is needed. The proposed ACTION statement addresses the one trip system design of the Grand Gulf RCIC system and replaces an ACTION statement intended for a 2-trip system design.

On the basis of its review, the staff finds that the changes enhance system reliability and provide a sufficiently conservative set of requirements should one or more channels become inoperable. These changes are in accordance with the regulatory guidelines of the Standard Technical Specifications for General Electric Boiling Water Reactors and are necessary to correct a deficiency in the Grand Gulf Technical Specifications.

Problem Sheet No. 103, Main Steam Flow Instrumentation

(1) Technical Specification

Table 3.3.2-1, Isolation Actuation Instrumentation, pages 3/4 3-10, 3/4 3-14a.

(2) Change

The number of main steam line flow channels required to be operable in each trip system is revised from "2" to "8," and note (g) is deleted.

(3) Reason for Change

Reflect actual plant trip logic design and provide Technical Specification requirements consistent with the single-failure criteria assumed in safety analyses.

(4) Evaluation

For the Grand Gulf design, one of the signals that initiates main steam line (MSL) isolation is high steam line flow. Sixteen main steam line flow instrument channels are arranged into two trip systems, each trip system containing two channels per steam line for a total of eight channels per trip system. To assure initiation of MSL isolation, postulating a single failure in the instrumentation system, all eight MSL flow channels in each trip system should be operable. Therefore, the licensee has proposed to revise the minimum channels operable requirements of the Technical Specifications from two per trip system to eight per trip system. With the change from 2 to 8 channels per trip, footnote g is not required.

Based on its review, the staff finds that the changes improve system reliability and provide a sufficiently conservative set of requirements should one or more channels become inoperable. These changes are in accordance with the regulatory guidelines of the Standard Technical Specifications for General Electric Boiling Water Reactors and are necessary to correct a deficiency in the Grand Gulf Technical Specifications.

Problem Sheet No. 198, Radiation Monitor Instrumentation

(1) Technical Specification

Table 3.3.7.1-1, Radiation Monitoring Instrumentation, pages 3/4 3-56 and 3/4 3-58.

(2) Change

Changed required minimum operable channels from 3 to 2 per trip system for items 7, 8, and 9 of the table.

Added note (h) to item 6 of Table.

Revised action statements 74 and 75 to reflect trip system logic.

(3) Reason for Change

Reflect plant design and safety analysis, thereby restoring safety margin assumed in the analysis.

Clarify system design and thereby avoid possible operator confusion and minimize the potential for human error.

Reflect plant design better and provide consistency within the Technical Specifications.

(4) Evaluation

The containment and drywell exhaust radiation monitoring subsystem, the fuel-handling area ventilation exhaust radiation monitoring subsystem, the fuel-handling area pool sump exhaust radiation monitoring subsystem and the control room ventilation radiation monitoring subsystem, each include four monitors, with each monitor assigned to a subsystem actuation channel. The channels are grouped in pairs and each pair makes a trip system. Both channels in one trip system are required to trip for the associated alarm/isolation function to occur. The effective Technical Specifications require three monitor channels to be operable in each subsystem. Such requirements do not assure actuation for the two-out-of-two logic configuration when a single failure is postulated in one of the three required instrument channels. Accordingly, to provide Technical Specification requirements which are consistent with the plant design, the licensee has proposed to revise the MINIMUM CHANNELS OPERABLE column of Table 3.3.7.1-1 from 3 to 2 per trip system. To provide ACTION statement requirements consistent with the design, the licensee has proposed to insert the phrase "in a trip system" between the words "monitors" and "inoperable" in ACTION 74 and ACTION 75. In addition, the licensee has proposed to add note "h" to item 6, the control room ventilation radiation monitoring subsystem. This note describes the logic for system initiation and does not change the requirements of the Technical Specifications.

On the basis of its review, the staff finds that the changes enhance system reliability and provide a sufficiently conservative set of requirements should one or more channels become inoperable. These changes are in accordance with the regulatory guidelines of the Standard Technical Specifications for General Electric Boiling Water Reactors and are necessary to correct a deficiency in the Grand Gulf Technical Specifications.

Problem Sheet No. 213, Automatic Depressurization System Instrumentation

(1) Technical Specification

Table 3.3.3-1, Emergency Core Cooling System Actuation Instrumentation, pages 3/4 3-25 and 3/4 3-27.

(2) Change

Changed the minimum operable channels for the ADS trip system manual initiation function from 1 per valve to to 2 per system.

Changed Action Statement 32 so that with less than the required minimum operable channels per trip function, the associated ADS trip system was declared inoperable instead of the associated ADS valve.

(3) Reason for Change

Place limiting conditions for operation and surveillance requirements on systems level ADS initiation circuits.

(4) Evaluation

The automatic depressurization system (ADS) consists of eight safety/relief valves and associated actuation instrumentation. The actuation instrumentation consists of two trip systems, either of which will actuate all eight ADS valves. Each ADS trip system includes two manual hand switches. Operation of both hand switches will produce an ADS trip system actuation signal. Table 3.3.3-1 of the effective Technical Specifications requires 1 per valve as the minimum operable channels for manual initiation. The 1 per valve refers to the hand switches used to actuate individual safety/relief valves, and not to the two hand switches per trip system used to actuate the ADS trip system. Accordingly, to provide Technical Specification requirements consistent with the design configuration for ADS initiation, the licensee has proposed to revise the "minimum operable channels per trip function" column of Table 3.3.3-1 from 1 per valve to 2 per system, and to replace the word "valve" in ACTION 32 with "trip system."

On the basis of its review, the staff finds that the change makes the Technical Specification consistent with the as-built ADS by placing limiting conditions for operation and surveillance requirements on the system level ADS manual initiation circuits. Therefore, the staff finds that the change is necessary and acceptable.

Problem Sheet No. 233, Containment Spray Flow Conditions

(1) Technical Specification

Section 4.5.1.b, Emergency Core Cooling Systems, Surveillance Requirements, page 3/4 5-4.

(2) Change

Revised to increase total developed head values for the emergency core cooling system pumps as follows:

	New Head (psid)	Previous Head (psid)
LPCS pump	$\geq$290	$\geq$261
LPCI pumps A, B, & C	$\geq$125	$\geq$89
HPCS pump	$\geq$445	$\geq$182

Revised to add "Flow and total developed head values for surveillance testing include system losses to ensure design requirements are met."

(3) Reason for Change

Reflect system design (injection) requirements. (Inservice testing of pumps to existing Specification 4.0.5 is not conservative relative to system requirements.)

Provide information for Specification 4.5.1.b to avoid personnel confusion and minimize potential for human error.

(4) Evaluation

The effective Technical Specification requires a developed head for each emergency core cooling system (ECCS) pump based on manufacturer's data. This does not include pressure losses in the system piping that occur in the as-built plant configuration. For consistency with FSAR analyses assumptions, the specification is revised to include the effect of these system losses.

The staff has compared the proposed specification with the flow-versus-head assumptions used in the emergency core cooling system analyses. The specification requires a reasonably higher developed head at the pump than assumed at the vessel in the LOCA analyses. This indicates that system losses and ECCS injection requirements have been accounted for in the proposed specification.

The staff therefore finds the change is necessary to correct a deficiency in the Technical Specifications, and is acceptable.

Problem Sheet No. 262, Standby Gas Treatment System Radioactivity Monitor

(1) Technical Specification

Tables 3.3.7.12-1, Radioactive Gaseous Effluent Monitoring Instrumentation, pages 3/4 3-90, 3/4 3-91; 4.3.7.12-1, Radioactive Gaseous Effluent Monitoring Instrumentation Surveillance Requirements, page 3/4 3-94; and 4.11.2.1.2-1, Radioactive Gaseous Waste Sampling and Analysis Program, page 3/4 11-9.

(2) Change

Added the standby gas treatment system to the Technical Specification tables for radioactive gaseous effluent monitoring.

Added the standby gas treatment system to Technical Specification Table 4.11.2.1.2-1 to provide for inclusion of measureable SGTS exhaust contributions in the dose rate calculations, if the SGTS has been run.

(3) Reason for Change

Reflect plant design and ensure consistency with the intent of 10 CFR 50 Appendix A, Criterion 64.

(4) Evaluation

The purpose of the standby gas treatment system (SGTS) radiation monitors is to measure radioactive gaseous effluent releases to the environment during and following a design-basis accident (DBA) and these radiation monitors are included in Table 4.3.7.5-1, Accident Monitoring Instrumentation. The current design meets General Design Criterion (GDC) 64 of 10 CFR 50 without changing Technical Specifications as requested. Furthermore, the radiation monitors in Table 4.11.2.1.2-1 are for the gaseous effluent monitors for normal plant operation, including anticipated operational occurrences.

The requested change could allow SGTS operation for surveillance demonstration testing without radiation monitors in service as long as grab samples are taken at least every 8 hours and analyzed for gross activity within 24 hours. A radiation monitor should be operable whenever the SGTS is in a testing mode. Testing should not start unless the respective radiation monitors are operable, and should be terminated in the event of failure of a radiation monitor. Therefore, the staff finds this request unacceptable, and this change is not included in this Order.

Problem Sheet No. 285, Chlorine Detector Calibration Frequency

(1) Technical Specification

Section 4.3.7.8, Chlorine Detection System, Surveillance Requirements, page 3/4 3-75.

(2) Change

Changed the channel calibration frequency of the chlorine detection system from 18 months to 6 months.

(3) Reason for Change

Ensure the safety margin of the design committed to in the FSAR.

(4) Evaluation

The licensee has proposed a chlorine detection instrument channel calibration frequency once per 6 months instead of once per 18 months as in the effective Technical Specifications. Regulatory Guide 1.95, Rev. 1, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release," January 1977, recommends a calibration frequency of once per 6 months.

The staff finds that the change provides for surveillance requirements that are consistent with manufacturer's recommendations and regulatory guidelines. Therefore, the staff finds that the change is necessary and acceptable.

Problem Sheet No. 292 and 293, Containment and Drywell Air Locks Test Pressure

(1) Technical Specification

Sections 4.6.1.3, Containment Air Locks, Surveillance Requirements, and 4.6.2.3, Drywell Air Locks, Surveillance Requirements, pages 3/4 6-6 and 3/4 6-16.

(2) Change

Revised to require verification that the seal air flask pressure for the containment and drywell air locks is greater than or equal to "90" psig rather than "60" psig.

Changed to include the 30-day leakage criteria in the minimum required seal air flask pressure for the drywell air lock door inflatable seal system.

(3) Reason for Change

Restore margin needed for actual air lock system design. (Existing allowable seal air flask pressure is not conservative since it did provide for a 30-day leakage criteria after loss of air supply.)

Reflect system design requirements and safety analysis by ensuring drywell air lock inflatable seal integrity for 30 days upon loss of seal air supply.

(4) Evaluation

The basis for the change is that the current Technical Specification 4.6.1.3.d.2/4.6.2.3.d.2 requires verifying seal air flask pressure to be greater than or equal to 60 psig. Technical Specification 4.6.1.3.d.3/4.6.2.3.d.3, however, requires verifying that the system pressure does not decay more than 2 psig from 90 psig within 48 hours. Based on this allowable pressure decay rate, the air flask pressure should be changed from 60 psig to 90 psig. This will ensure that the minimum inflatable seal pressure of 60 psig will be maintained for at least 30 days assuming no active air supply. The staff finds the change to the Technical Specifications necessary and acceptable.

Problem Sheet No. 306, Listing of Drywell Isolation Valves

(1) Technical Specification

Table 3.6.4-1, "Containment and Drywell Isolation Valves," page 3/4 6-41.

(2) Change

Added 5 valves to the Technical Specification Table for "Containment and Drywell Isolation Valves."

(3) Reason for Change

Reflect plant design and thereby prevent possible operator error.

(4) Evaluation

Four check valves in the combustible gas control system are to be added to Table 3.6.4-1. In addition, a normally locked closed refueling pool drain system valve is to be added.

Two of these check valves, E61-F002A and B, are located on the drywell purge compressor lines (one per line). The remaining check valves, E61-F004A and B, are located on the post-LOCA drywell vacuum breaker line. In light of the fact that there are no inboard isolation valves provided for these lines, these check valves perform isolation functions as backups to the outboard isolation valves presently existing in those lines. Inclusion of these check valves in Table 3.6.4-1 because of their backup isolation functions is, therefore, considered by the licensee to be appropriate.

A normally locked closed drain valve, G41-F265, is also added to the table. This valve is an upper containment pool drain system valve that is only opened during a refueling outage. Because this valve is on a line that penetrates the drywell, inclusion of this valve in the table is considered by the licensee to be appropriate.

The changes correct the Technical Specifications to reflect the plant design configuration and are, therefore, acceptable.

Problem Sheet No. 308, Room Air Temperature Trip Setpoints

(1) Technical Specification

Table 3.3.2-2, Isolation Actuation Instrumentation Setpoints, pages 3/4 3-16, 3/4 3-17, 3/4 3-17a.

(2) Change

Decreased the trip setpoints and allowable values for the temperature-high functions for RWCU, RCIC, and RHR system leakage detection instrumentation.

(3) Reason for Change

Reflect plant design to ensure proper leakage detection, thereby ensuring safety margins.

(4) Evaluation

The licensee has reviewed the calculations used to establish trip setpoints and allowable values for the temperature sensing instrument channels that provide input to the leak detection isolation features. From this review, the licensee has determined that the values are too high to ensure prompt isolation. Using the current Technical Specification values may result in delayed detection or in some cases no detection of a 25 gpm leak.

In response to a request from the NRC staff, the licensee is participating in a BWR Owners' Group effort to provide more detailed information on their setpoint methodology. The staff concludes that there is reasonable assurance, based on staff participation in meetings with the BWR Owners' Group working group on setpoint methodology, that the forthcoming more-detailed information on setpoints and setpoint methodology being developed by this group will verify the acceptability of the proposed setpoints. In the interim, the staff finds that the proposed change is in the conservative direction and is acceptable.

Problem Sheet No. 329, Accident Monitoring Instrumentation

(1) Technical Specification

Table 3.3.7.5-1, Accident Monitoring Instrumentation, page 3/4 3-70.

(2) Change

Transferred and increased the operational conditions applicable to each accident monitoring instrument from Table 3.3.7.5-1.

Changed titles of Items 13 through 18 to indicate the specific monitor type.

For item 2, changed from Action Statement 80 to new Action Statement 82.

(3) Reason for Change

Reflect plant design requirements thereby ensuring safety margins.

Avoid possible operator error.

Reflect plant design thereby ensuring proper operator action.

(4) Evaluation

The present applicability is for operational conditions 1 and 2 for all instrumentation. The change extends applicability to other conditions (3, 4 and 5) on an instrument specific basis, as a result of licensee's review based on FSAR Appendix 15A, entitled "Plant Nuclear Safety Operational Analysis." Because the change expands the applicability of the current specification, it is considered conservative and, therefore, acceptable.

ATTACHMENT 2 TO ORDER LIMITING OPERATION
FACILITY OPERATING LICENSE NO. NPF-13
DOCKET NO. 50-416

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised pages are identified by date of Order and contain a vertical line indicating the area of change. The corresponding reverse pages are also provided to maintain document completeness.

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ATTACHMENT 2 (Con't)

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2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-High		
1) Flow Biased	≤ 0.66 W+48%, with a maximum of	≤ 0.66 W+51%, with a maximum of
2) High Flow Clamped	≤ 111.0% of RATED THERMAL POWER	≤ 113.0% of RATED THERMAL POWER
c. Neutron Flux-High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1064.7 psig	≤ 1079.7 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 11.4 inches above instrument zero*	≥ 10.8 inches above instrument zero*
5. Reactor Vessel Water Level-High, Level 8	≤ 53.5 inches above instrument zero*	≤ 54.1 inches above instrument zero*
6. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
7. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
8. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
9. Scram Discharge Volume Water Level - High	≤ 60% of full scale	≤ 63% of full scale
10. Turbine Stop Valve - Closure	≥ 40 psig**	≥ 37 psig
11. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 44.3 psig**	≥ 42 psig
12. Reactor Mode Switch Shutdown Position	NA	NA
13. Manual Scram	NA	NA

*See Bases Figure B 3/4 3-1.

**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% neutron flux trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux-High 118% setpoint; i.e, for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Flow Biased Simulated Thermal Power-High setpoint, a time constant of 6 ± 1 seconds is introduced into the flow biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow biased setpoint as shown in Table 2.2.1-1.

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown. The flow referenced trip setpoint must be adjusted by the specified formula in Specification 3.2.2 in order to maintain these margins when MFLPD is $\geq$ to FRTP.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve closure trip is bypassed. For a turbine trip under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Reactor Vessel Water Level-High

A reactor scram from high reactor water level, approximately two feet above normal operating level, is intended to offset the addition of reactivity effect associated with the introduction of a significant amount of relatively cold feedwater. An excess of feedwater entering the vessel would be detected by the level increase in a timely manner. This scram feature is only effective when the reactor mode switch is in the Run position because at THERMAL POWER levels below 10% to 15% of RATED THERMAL POWER, the approximate range of power level for changing to the Run position, the safety margins are more than adequate without a reactor scram.

6. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIV's are closed automatically from measured parameters such as high steam flow, high steam line radiation, low reactor water level, high steam tunnel temperature and low steam line pressure. The MSIV's closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

7. Main Steam Line Radiation-High

The main steam line radiation detectors are provided to detect a gross failure of the fuel cladding. When the high radiation is detected, a trip is initiated to reduce the continued failure of fuel cladding. At the same time the main steam line isolation valves are closed to limit the release of fission products. The trip setting is high enough above background radiation levels to prevent spurious trips yet low enough to promptly detect gross failures in the fuel cladding.

8. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant. The trip setting was selected as low as possible without causing spurious trips. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable.

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.2-1.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.2.1-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months, where N is the total number of redundant channels in a specific isolation trip system.

*With a design providing only one channel per trip system, an inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.2-1 for that Trip Function shall be taken.

**If more channels are inoperable in one trip system than in the other, place the trip system with more inoperable channels in the tripped condition, except when this would cause the Trip Function to occur.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level-Low Low, Level 2	6A, 7, 8, 10(c)(d)	2	1, 2, 3 and #	20
b. Reactor Vessel Water Level-Low Low Level 2 (ECCS - Division 3)	6B	4	1, 2, 3 and #	29
c. Reactor Vessel Water Level-Low Low Low, Level 1 (ECCS - Division 1 and Division 2)	5(n)	2	1, 2, 3 and #	29
d. Drywell Pressure - High	6A, 7(c)(d)	2	1, 2, 3	20
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	5(n)	2	1, 2, 3	29
f. Drywell Pressure-High (ECCS - Division 3)	6B	4	1, 2, 3	29
g. Containment and Drywell Ventilation Exhaust Radiation - High High	7	2(e)	1, 2, 3 and *	21
h. Manual Initiation	6A, 7, 8, 10(c)(d)	2	1, 2, 3 and *#	22
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level-Low Low Low, Level 1	1	2	1, 2, 3	20
b. Main Steam Line Radiation - High	1, 10(f)	2	1, 2, 3	23
c. Main Steam Line Pressure - Low	1	2	1	24
d. Main Steam Line Flow - High	1	8	1, 2, 3	23
e. Condenser Vacuum - Low	1	2	1, 2,** 3**	23

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
2. MAIN STEAM LINE ISOLATION (Continued)				
f. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp.- High	1	2	1, 2, 3	23
h. Manual Initiation	1, 10	2	1, 2, 3	22
3. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level-Low Low, Level 2	N.A.(c)(d)(h)	2	1, 2, 3, and #	25
b. Drywell Pressure - High	N.A.(c)(d)(h)	2	1, 2, 3	25
c. Fuel Handling Area Ventilation Exhaust Radiation - High High	N.A.(j)	2	1, 2, 3, and *	25
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	N.A.(j)	2	1, 2, 3, and *	25
e. Manual Initiation	N.A.(c)(d)(f)(h) N.A.(c)(d)(f)(h)	2 2	1, 2, 3 *	26 25
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Δ Flow - High	8	1	1, 2, 3	27
b. Δ Flow Timer	8	1	1, 2, 3	27
c. Equipment Area Temperature - High	8	1/room	1, 2, 3	27
d. Equipment Area Δ Temp. - High	8	1/room	1, 2, 3	27
e. Reactor Vessel Water Level - Low Low, Level 2	8	2	1, 2, 3	27

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)				
f. Main Steam Line Tunnel Ambient Temperature - High	8	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	8	1	1, 2, 3	27
h. SLCS Initiation	$8^{(i)}$	1	1, 2, 5##	30
i. Manual Initiation	8	2	1, 2, 3	26
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Flow - High	4	1	1, 2, 3	27
b. RCIC Steam Supply Pressure - Low	4, $9^{(m)}$	1	1, 2, 3	27
c. RCIC Turbine Exhaust Diaphragm Pressure - High	4	2	1, 2, 3	27
d. RCIC Equipment Room Ambient Temperature - High	4	1	1, 2, 3	27
e. RCIC Equipment Room Δ Temp. - High	4	1	1, 2, 3	27
f. Main Steam Line Tunnel Ambient Temperature - High	4	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	4	1	1, 2, 3	27
h. Main Steam Line Tunnel Temperature Timer	4	1	1, 2, 3	27

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

ACTION

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 21 - Close the affected system isolation valve(s) within one hour or:
  a. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
  b. In Operational Condition *, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary containment and operations with a potential for draining the reactor vessel.

ACTION 22 - Restore the manual initiation function to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 23 - Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 24 - Be in at least STARTUP within 6 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 26 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable.

ACTION 27 - Close the affected system isolation valves within one hour and declare the affected system inoperable.

ACTION 28 - Lock the affected system isolation valves closed within one hour and declare the affected system inoperable.

ACTION 29 - Close the affected system isolation valves within one hour and declare the affected system or component inoperable or:
  a. In OPERATIONAL CONDITION 1, 2 or 3 be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
  b. In OPERATIONAL CONDITION # suspend CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

ACTION 30 - Declare the affected SLCS pump inoperable.

NOTES

* When handling irradiated fuel in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

** The low condenser vacuum MSIV closure may be manually bypassed during reactor SHUTDOWN or for reactor STARTUP when condenser vacuum is below the trip setpoint to allow opening of the MSIVs. The manual bypass shall be removed when condenser vacuum exceeds the trip setpoint.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

\## With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(a) See Specification 3.6.4, Table 3.6.4-1 for valves in each valve group.

(b) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
i. RHR Equipment Room Ambient Temperature - High	4	1/room	1, 2, 3	27
j. RHR Equipment Room Δ Temp. - High	4	1/room	1, 2, 3	27
k. RHR/RCIC Steam Line Flow - High	4	1	1, 2, 3	27
l. Manual Initiation	4(k)	1	1, 2, 3	26
m. Drywell Pressure-High (ECCS-Division 1 and Division 2)	9(m)	1	1, 2, 3	27
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	3	1/room	1, 2, 3	28
b. RHR Equipment Room Δ Temp. - High	3	1/room	1, 2, 3	28
c. Reactor Vessel Water Level - Low, Level 3	3	2	1, 2, 3	28
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	3(l)	2	1, 2, 3	28
e. Drywell Pressure - High	3(l)	2	1, 2, 3	28
f. Manual Initiation	3	2	1, 2, 3	26

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

NOTES (Continued)

(c) Also actuates the standby gas treatment system.
(d) Also actuates the control room emergency filtration system in the isolation mode of operation.
(e) Two upscale-Hi Hi, one upscale-Hi Hi and one downscale, or two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated containment and drywell isolation valves.
(f) Also trips and isolates the mechanical vacuum pumps.
(g) Deleted.
(h) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.
(i) Closes only RWCU system isolation valves G33-F001, G33-F004, and G33-F251.
(j) Actuates the Standby Gas Treatment System and isolates Auxiliary Building penetration of the ventilation systems within the Auxiliary Building.
(k) Closes only RCIC outboard valves. A concurrent RCIC initiation signal is required for isolation to occur.
(l) Valves E12-F037A and E12-F037B are closed by high drywell pressure. All other Group 3 valves are closed by high reactor pressure.
(m) Valve Group 9 requires concurrent drywell high pressure and RCIC Steam Supply Pressure-Low signals to isolate.
(n) Valves E12-F042A and E12-F042B are closed by Containment Spray System initiation signals.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches *	≥ -43.8 inches
b. Reactor Vessel Water Level-Low Low, Level 2 (ECCS - Division 3)	≥ -41.6 inches*	≥ -43.8 inches
c. Reactor Vessel Water Level-Low Low Low, Level 1 (ECCS Division 1 and Division 2)	≥ -150.3 inches*	≥ -152.5 inches
d. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	≤ 1.39 psig	≤ 1.44 psig
f. Drywell Pressure-High (ECCS - Division 3)	≤ 1.39 psig	≤ 1.44 psig
g. Containment and Drywell Ventilation Exhaust Radiation - High High	≤ 2.0 mr/hr**	≤ 4.0 mr/hr**
h. Manual Initiation	NA	NA
2. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
c. Main Steam Line Pressure - Low	≥ 849 psig	≥ 837 psig
d. Main Steam Line Flow - High	≤ 169 psid	≤ 176.5 psid
e. Condenser Vacuum - Low	≥ 9 inches Hg. Vacuum	≥ 8.7 inches Hg. Vacuum
f. Main Steam Line Tunnel Temperature - High	≤ 185°F**	≤ 191°F**

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
2. MAIN STEAM LINE ISOLATION (Continued)		
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. Manual Initiation	NA	NA
3. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
b. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
c. Fuel Handling Area Ventilation Exhaust Radition - High High	≤ 2.0 mR/hr**	≤ 4.0 mR/hr**
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	≤ 18 mR/hr**	≤ 35 mR/hr**
e. Manual Initiation	NA	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. Δ Flow - High	≤ 79 gpm	≤ 89** gpm
b. Δ Flow Timer	≤ 45 seconds	≤ 57 seconds
c. Equipment Area Temperature - High		
1. RWCU Hx Room	≤ 120°F	≤ 126°F
2. RWCU Pump Rooms	≤ 170°F	≤ 176°F
3. RWCU Valve Nest Room	≤ 135°F	≤ 141°F
4. RWCU Demin. Rooms	≤ 139°F	≤ 145°F
5. RWCU Rec. Tank Room	≤ 139°F	≤ 145°F
6. RWCU Demin. Valve Room	≤ 135°F	≤ 141°F
d. Equipment Area Δ Temp. - High		
1. RWCU Hx Room	≤ 65°F	≤ 66°F
2. RWCU Pump Rooms	≤ 115°F	≤ 118°F
3. RWCU Valve Nest Room	≤ 70°F	≤ 73°F
4. RWCU Demin. Rooms	≤ 70°F	≤ 73°F
5. RWCU Rec. Tank Room	≤ 70°F	≤ 73°F
6. RWCU Demin. Valve Room	≤ 71°F	≤ 74°F

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)		
e. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
f. Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. SLCS Initiation	NA	NA
i. Manual Initiation	NA	NA
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Flow - High	≤ 363" H_2O	≤ 371" H_2O
b. RCIC Steam Supply Pressure - Low	≥ 60 psig	≥ 53 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d. RCIC Equipment Room Ambient Temperature - High	≤ 185°F**	≤ 191°F**
e. RCIC Equipment Room Δ Temp. - High	≤ 125°F**	≤ 128°F**
f. Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. Main Steam Line Tunnel Temperature Timer	≤ 30 minutes	≤ 30 minutes
i. RHR Equipment Room Ambient Temperature - High	≤ 165°F**	≤ 171°F**
j. RHR Equipment Room Δ Temperature - High	≤ 99°F**	≤ 102°F**
k. RHR/RCIC Steam Line Flow - High	≤ 145" H_2O	≤ 160" H_2O

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION (Continued)		
l. Manual Initiation	NA	NA
m. Drywell Pressure-High (ECCS Division 1 and Division 2)	$\leq$ 1.39 psig	$\leq$ 1.44 psig
6. RHR SYSTEM ISOLATION		
a. RHR Equipment Room Ambient Temperature - High	$\leq$ 165°F**	$\leq$ 171°F**
b. RHR Equipment Room Δ Temperature - High	$\leq$ 99°F**	$\leq$ 102°F**
c. Reactor Vessel Water Level - Low, Level 3	$\geq$ 11.4 inches*	$\geq$ 10.8 inches
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	$\leq$ 135 psig	$\leq$ 150 psig
e. Drywell Pressure - High	$\leq$ 1.23 psig	$\leq$ 1.43 psig
f. Manual Initiation	NA	NA

* See Bases Figure B 3/4 3-1.

** Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Flow - High	$\leq 13^{(a)}$###
b. RCIC Steam Supply Pressure - Low	$\leq 13^{(a)}$
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA
d. RCIC Equipment Room Ambient Temperature - High	NA
e. RCIC Equipment Room Δ Temp. - High	NA
f. Main Steam Line Tunnel Ambient Temp. - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. Main Steam Line Tunnel Temperature Timer	NA
i. RHR Equipment Room Ambient Temperature - High	NA
j. RHR Equipment Room Δ Temp. - High	NA
k. RHR/RCIC Steam Line Flow - High	NA
l. Manual Initiation	NA
m. Drywell Pressure - High (ECCS Division 1 and Division 2)	$\leq 13^{(a)}$
6. RHR SYSTEM ISOLATION	
a. RHR Equipment Room Ambient Temperature - High	NA
b. RHR Equipment Room Δ Temp. - High	NA
c. Reactor Vessel Water Level - Low, Level 3	$\leq 13^{(a)}$
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA
e. Drywell Pressure - High	NA
f. Manual Initiation	NA

(a) The isolation system instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME. Isolation system instrumentation response time specified includes the delay for diesel generator starting assumed in the accident analysis.

(b) Radiation detectors are exempt from response time testing. Response time shall be measured from detector output or the input of the first electronic component in the channel.

*Isolation system instrumentation response time for MSIVs only. No diesel generator delays assumed.

**Isolation system instrumentation response time for associated valves except MSIVs.

#Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to isolation time shown in Tables 3.6.4-1 and 3.6.5.2-1 for valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

###Without 13 second time delay.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	$R^{(c)}$	1, 2, 3 and #
b. Reactor Vessel Water Level- Low Low, Level 2 (ECCS - Division 3)	S	M	$R^{(c)}$	1, 2, 3 and #
c. Reactor Vessel Water Level- Low Low Low, Level 1 (ECCS - Division 1 and Division 2)	S	M	$R^{(c)}$	1, 2, 3 and #
d. Drywell Pressure - High	S	M	$R^{(c)}$	1, 2, 3
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	S	M	$R^{(c)}$	1, 2, 3
f. Drywell Pressure-High (ECCS - Division 3)	S	M	$R^{(c)}$	1, 2, 3
g. Containment and Drywell Ventilation Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
h. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3 and *#
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	$R^{(c)}$	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	S	M	$R^{(c)}$	1
d. Main Steam Line Flow - High	S	M	$R^{(c)}$	1, 2, 3
e. Condenser Vacuum - Low	S	M	$R^{(c)}$	1, 2**, 3**

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
2. MAIN STEAM LINE ISOLATION (Continued)				
f. Main Steam Line Tunnel Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3
h. Manual Initiation	NA	M(a)	NA	1, 2, 3
3. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R(c)	1, 2, 3 and #
b. Drywell Pressure - High	S	M	R(c)	1, 2, 3
c. Fuel Handling Area Ventilation Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
e. Manual Initiation	NA	M(a)	NA	1, 2, 3 and *
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Δ Flow - High	S	M	R	1, 2, 3
b. Δ Flow Timer	NA	M	Q	1, 2, 3
c. Equipment Area Temperature - High	S	M	A	1, 2, 3
d. Equipment Area Ventilation Δ Temp. - High	S	M	A	1, 2, 3
e. Reactor Vessel Water Level - Low Low, Level 2	S	M	R(c)	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)				
f. Main Steam Line Tunnel Ambient Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3
h. SLCS Initiation	NA	M(b)	NA	1, 2, 5##
i. Manual Initiation	NA	M(a)	NA	1, 2, 3
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Flow - High	S	M	R(c)	1, 2, 3
b. RCIC Steam Supply Pressure - Low	S	M	R(c)	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	S	M	R(c)	1, 2, 3
d. RCIC Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
e. RCIC Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
f. Main Steam Line Tunnel Ambient Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION (Continued)				
h. Main Steam Line Tunnel Temperature Timer	NA	M	Q	1, 2, 3
i. RHR Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
j. RHR Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
k. RHR/RCIC Steam Line Flow - High	S	M	R(c)	1, 2, 3
l. Manual Initiation	NA	M(a)	NA	1, 2, 3
m. Drywell Pressure-High (ECCS Division 1 and Division 2)	S	M	R(c)	1, 2, 3
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
b. RHR Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3	S	M	R(c)	1, 2, 3
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	S	M	R(c)	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
6. RHR SYSTEM ISOLATION (Continued)				
e. Drywell Pressure - High	S	M	R(c)	1, 2, 3
f. Manual Initiation	NA	M(a)	NA	1, 2, 3

*When handling irradiated fuel in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

**The low condenser vacuum MSIV closure may be the manually bypassed during reactor SHUTDOWN or for reactor STARTUP when condenser vacuum is below the trip setpoint to allow opening of the MSIVs. The manual bypass shall be removed when condenser vacuum exceeds the trip setpoint.

#During CORE ALTERATION and operations with a potential for draining the reactor vessel.

##With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days as part of circuitry required to be tested for automatic system isolation.

(b) Each train or logic channel shall be tested at least every other 31 days.

(c) Calibrate trip unit at least once per 31 days.

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[a]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
A. DIVISION I TRIP SYSTEM			
1. RHR-A (LPCI MODE) & LPCS SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. LPCI Pump A Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system	1, 2, 3, 4*, 5*	32
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCS Pump Discharge Pressure-High (Permissive)	2	1, 2, 3	31
f. LPCI Pump A Discharge Pressure-High (Permissive)	2	1, 2, 3	31
g. Manual Initiation	2/system	1, 2, 3	32
B. DIVISION 2 TRIP SYSTEM			
1. RHR B & C (LPCI MODE)			
a. Reactor Vessel Water Level - Low, Low Low, Level 1	2[b]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. LPCI Pump B Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system	1, 2, 3, 4*, 5*	32
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCI Pump B and C Discharge Pressure - High (Permissive)	2/pump	1, 2, 3	31
f. Manual Initiation	2/system	1, 2, 3	32

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
C. DIVISION 3 TRIP SYSTEM			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Level 2	4[(b)]	1, 2, 3, 4*, 5*	33
b. Drywell Pressure - High##	4[(b)]	1, 2, 3	33
c. Reactor Vessel Water Level-High, Level 8	2[(c)]	1, 2, 3, 4*, 5*	31
d. Condensate Storage Tank Level-Low	2[(d)]	1, 2, 3, 4*, 5*	34
e. Suppression Pool Water Level-High	2[(d)]	1, 2, 3, 4*, 5*	34
f. Manual Initiation##	1/system	1, 2, 3, 4*, 5*	32
D. LOSS OF POWER			
1. Division 1 and 2			
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	4	1, 2, 3, 4**, 5**	30
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	4	1, 2, 3, 4**, 5**	30
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	4	1, 2, 3, 4**, 5**	30
2. Division 3			
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	4	1, 2, 3, 4**, 5**	30

(a) A channel may be placed in an inoperable status for up to 2 hours during periods of required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.
(b) Also actuates the associated division diesel generator.
(c) Provides signal to close HPCS pump discharge valve only.
(d) Provides signal to HPCS pump suction valves only.
(e) One out-of-two taken.
* Applicable when the system is required to be OPERABLE per Specification 3.5.2 or 3.5.3.
** Required when ESF equipment is required to be OPERABLE.
\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.
\#\# Prior to STARTUP following the first refueling outage, the injection function of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the reactor pressure less than 600 psig.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within one hour* or declare the associated system(s) inoperable.

b. With more than one channel inoperable, declare the associated system(s) inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ADS trip system or ECCS inoperable.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the associated ADS trip system or ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one trip system, place that trip system in the tripped condition within one hour* or declare the HPCS system inoperable.

b. For both trip systems, declare the HPCS system inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour* or declare the HPCS system inoperable.

---

*The provisions of Specification 3.0.4 are not applicable.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
A. DIVISION 1 TRIP SYSTEM		
1. RHR-A (LPCI MODE) AND LPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. LPCI Pump A Start Time Delay Relay	$\leq$ 5 seconds	$\leq$ 5.25 seconds
d. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. ADS Timer	$\leq$ 105 seconds	$\leq$ 117 seconds
d. Reactor Vessel Water Level-Low, Level 3	$\geq$ 11.4 inches*	$\geq$ 10.8 inches
e. LPCS Pump Discharge Pressure-High	145 psig, increasing	125-165 psig, increasing
f. LPCI Pump A Discharge Pressure-High	125 psig, increasing	115-135 psig, increasing
g. Manual Initiation	NA	NA
B. DIVISION 2 TRIP SYSTEM		
1. RHR B AND C (LPCI MODE)		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. LPCI Pump B Start Time Delay Relay	$\leq$ 5 seconds	$\leq$ 5.25 seconds
d. Manual Initiation	NA	NA
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. ADS Timer	$\leq$ 105 seconds	$\leq$ 117 seconds
d. Reactor Vessel Water Level-Low, Level 3	$\geq$ 11.4 inches*	$\geq$ 10.8 inches
e. LPCI Pump B and C Discharge Pressure-High	125 psig, increasing	115 psig, increasing
f. Manual Initiation	NA	NA
C. DIVISION 3 TRIP SYSTEM		
1. HPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	$\geq$-41.6 inches*	$\geq$-43.8 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. Reactor Vessel Water Level - High, Level 8	$\leq$ 53.5 inches*	$\leq$ 55.7 inches
d. Condensate Storage Tank Level - Low	$\geq$ 0 inches	$\geq$ -3 inches
e. Suppression Pool Water Level - High	$\leq$ 5.9 inches	$\leq$ 6.5 inches
f. Manual Initiation	NA	NA

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
D. LOSS OF POWER		
1. Division 1 and 2		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 2912 volts	2912 +0, -291 volts
	2. 120 volt Basis 83.2 volts	83.2 +0, -8.3 volts
	3. Time Delay 0.5 seconds	0.5 +0.5, -0.1 seconds
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	1. 4.16 kV Basis 3328 volts	3328 +0, -167 volts
	2. 120 volt Basis 95.1 volts	95.1 +0, -4.8 volts
	3. Time delay 0.5 seconds	0.5 +0.5, -0.1 seconds
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	1. 4.16 kV Basis 3744 volts	3744 +93.6, -0 volts
	2. 120 volt Basis 107 volts	107 +2.7, -0 volts
	3. Time Delay 9.0 seconds	9.0 ± 0.5 seconds
2. Division 3		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 3045 volts	3045 ± 61 volts
	2. 120 volt Basis 87 volts	87 ± 1.7 volts
	3. Time Delay 2.3 seconds	2.3 + 0.2, -0.3 seconds

*See Bases Figure B 3/4 3-1.

#These are inverse time delay voltage relays or instantaneous voltage relays with a time delay. The voltages shown are the maximum that will not result in a trip. Lower voltage conditions will result in decreased trip times.

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES (SECONDS)

1.	LOW PRESSURE CORE SPRAY SYSTEM	$\leq$ 40
2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM PUMPS A, B AND C	$\leq$ 40
3.	AUTOMATIC DEPRESSURIZATION SYSTEM	NA
4.	HIGH PRESSURE CORE SPRAY SYSTEM	$\leq$ 27
5.	LOSS OF POWER	NA

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

FUNCTIONAL UNITS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]	ACTION
a. Reactor Vessel Water Level - Low Low, Level 2	4	50
b. Reactor Vessel Water Level - High, Level 8	2[b]	51
c. Condensate Storage Tank Water Level - Low	2[c]	52
d. Suppression Pool Water Level - High	2[c]	52
e. Manual Initiation	1/system[d]	53

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(b) One trip system with two-out-of-two logic.

(c) One trip system with one-out-of-two logic.

(d) One trip system with one channel.

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM

ACTUATION INSTRUMENTATION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) or that trip system in the tripped condition within one hour or declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the minimum OPERABLE channels per Trip System requirement, declare the RCIC system inoperable.

ACTION 52 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within one hour or declare the RCIC system inoperable.

ACTION 53 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the RCIC system inoperable.

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-I shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the conditions and at the frequencies shown in Table 4.3.7.1-1.

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. Component Cooling Water Radiation Monitor	1	At all times	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
2. Standby Service Water System Radiation Monitor	1/heat exchanger train	1, 2, 3, and*	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
3. Offgas Pre-treatment Radiation Monitor	1	1, 2	$\leq 5 \times 10^3$ mR/hr/NA	1 to 10^6 mR/hr	70
4. Offgas Post-treatment Radiation Monitor	2[(a)]	1, 2	$\leq 1 \times 10^5$ cpm (Hi), $\leq 1.0 \times 10^6$ cpm (Hi Hi Hi)	10 to 10^6 cpm	71
5. Carbon Bed Vault Radiation Monitor	1	1, 2	$\leq$ 2 x full power background/NA	1 to 10^6 mR/hr	72
6. Control Room Ventilation Radiation Monitor	2/trip system[(h)]	1,2,3,5 and**	$\leq$4 mR/hr/ $\leq$5 mR/hr#	10^{-2} to 10^2 mR/hr	73
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	2/trip system[(h)]	At all times	$\leq$2.0 mR/hr/ $\leq$4 mR/hr[(b)]#	10^{-2} to 10^2 mR/hr	74
8. Fuel Handling Area Ventilation Exhaust Radiation Monitor	2/trip system[(h)]	1,2,3,5 and**	$\leq$ 2mR/hr/ $\leq$4 mR/hr[(d)]#	10^{-2} to 10^2 mR/hr	75
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	2/trip system[(h)]	(c)	$\leq$ 18 mR/hr/ $\leq$35 mR/hr[(d)]#	10^{-2} to 10^2 mR/hr	75

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
10. Area Monitors					
a. Fuel Handling Area Monitors					
1) New Fuel Storage Vault	1	(e)	$\le$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
2) Spent Fuel Storage Pool	1	(f)	$\le$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
3) Dryer Storage Area		(g)	$\le$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
b. Control Room Radiation Monitor	1	At all times	$\le$0.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72

* With RHR heat exchangers in operation.

** When irradiated fuel is being handled in the primary or secondary containment.

\# Initial setpoint. Final Setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to Commission within 90 days after test completion.

(a) Trips system with 2 channels upscale-Hi Hi Hi, or one channel upscale Hi Hi Hi and one channel downscale or 2 channels downscale.

(b) Isolates containment/drywell purge penetrations.

(c) With irradiated fuel in spent fuel storage pool.

(d) Also isolates the Auxiliary Building and Fuel Handling Area Ventilation Systems.

(e) With fuel in the new fuel storage vault.

(f) With fuel in the spent fuel storage pool.

(g) With fuel in the dryer storage area.

(h) Two upscale Hi Hi, one upscale Hi Hi and one downscale, or two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated isolation values.

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 70 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 71 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With both of the required monitors inoperable, be in at least HOT SHUTDOWN within 12 hours.

ACTION 72- With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 73 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour; restore the inoperable channel to OPERABLE status within 7 days, or, within the next 6 hours, initiate and maintain operation of at least one control room emergency filtration system in the isolation mode of operation.

b. With both of the required monitors in a trip system inoperable, initiate and maintain operation of at least one control room emergency filtration system in the isolation mode of operation within one hour.

ACTION 74 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors in a trip system inoperable, isolate the containment and drywell purge and vent penetrations within 12 hours.

ACTION 75 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors in a trip system inoperable, initiate and maintain operation of at least one standby gas treatment subsystem within 12 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Component Cooling Water Radiation Monitor	S	M	A	At all times
2. Standby Service Water System Radiation Monitor	S	M	A	1, 2, 3, and*
3. Offgas Pre-treatment Radiation Monitor	S	M	A	1, 2
4. Offgas Post-treatment Radiation Monitor	S	M	A	1, 2
5. Carbon Bed Vault Radiation Monitor	S	M	A	1, 2
6. Control Room Ventilation Radiation Monitor	S	M(a)	A	1, 2, 3, 5 and**
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	S	M	A	At all times
8. Fuel Handling Area Ventilation Radiation Monitor	S	M	A	1, 2, 3, 5 and**
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	S	M	A	(b)
10. Area Monitors				
a. Fuel Handling Area Monitors				
1) New Fuel Storage Vault	S	M	R	(c)
2) Spent Fuel Storage Pool	S	M	R	(d)
3) Dryer Storage Area	S	M	R	(e)
b. Control Room Radiation Monitor	S	M	R	At all times

* With RHR heat exchangers in operation.

** When irradiated fuel is being handled in the primary or secondary containment.

(a) The CHANNEL FUNCTIONAL TEST shall demonstrate that control room annunciation occurs if any of the following conditions exist.
   1. Instrument indicates measured levels above the alarm/trip setpoint.
   2. Circuit failure.
   3. Instrument indicates a downscale failure.
   4. Instrument controls not in Operate mode.

(b) With irradiated fuel in the spent fuel storage pool.

(c) With fuel in the new fuel storage vault.

(d) With fuel in the spent fuel storage pool.

(e) With fuel in the dryer storage area.

SEISMIC MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.2 The seismic monitoring instrumentation shown in Table 3.3.7.2-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required seismic monitoring instruments inoperable for more than 30 days, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrument(s) to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.2.1 Each of the above required seismic monitoring instruments shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.2-1.

4.3.7.2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01 g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. In lieu of any other report required by Specification 6.9.1, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.5-1.

TABLE 3.3.7.5-1
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	APPLICABLE OPERATIONAL CONDITIONS	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	ACTION
1. Reactor Vessel Pressure	1, 2, 3	2	1	80
2. Reactor Vessel Water Level	1, 2, 3, 4, 5	2	1	82
3. Suppression Pool Water Level	1, 2, 3	2	1	80
4. Suppression Pool Water Temperature	1, 2, 3	6, 1/sector	6, 1/sector	80
5. Drywell/Containment Differential Pressure	1, 2, 3	2	1	80
6. Drywell Pressure	1, 2, 3	2	1	80
7. Drywell and Control Rod Drive Cavity Temperature	1, 2, 3	2 (each)	1 (each)	80
8. Containment Hydrogen Concentration Analyzer and Monitor	1, 2, 3	2	1	80
9. Drywell Hydrogen Concentration Analyzer and Monitor	1, 2, 3	2	1	80
10. Containment Pressure (wide and narrow range)	1, 2, 3	2 (each)	1 (each)	80
11. Containment Air Temperature	1, 2, 3	2	1	80
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	1, 2, 3	1/valve	1/valve	80
13. Containment/Drywell Area Radiation Monitors	1, 2, 3, 4, 5	2#	1#	81
14. Containment Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
15. Off-gas and Radwaste Bldg. Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
16. Fuel Handling Area Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
17. Turbine Bldg. Ventilation Exhaust Radiation Monitor	1, 2, 3	1	1	81
18. Standby Gas Treatment System A & B Exhaust Radiation Monitors	*	1/each	1/each	81

#Each for containment and drywell.
*When its associated train of the standby gas treatment system is required operable (Ref. 3.6.6.3).

TABLE 3.3.7.5-1 (Continued)
ACCIDENT MONITORING INSTRUMENTATION

ACTION STATEMENTS

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and be in COLD SHUTDOWN within the next 24 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and be in COLD SHUTDOWN within the next 24 hours.

ACTION 81 -

With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable channel(s) to OPERABLE status within 72 hours, or:

a. Initiate the preplanned alternate method of monitoring the appropriate parameter(s), and

b. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 82 - For OPERATIONAL CONDITIONS 1, 2, 3

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and be in COLD SHUTDOWN within the next 24 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and be in COLD SHUTDOWN within the next 24 hours.

For OPERATIONAL CONDITIONS 4, 5

With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable channel(s) to OPERABLE status within 72 hours, or initiate the preplanned alternate method of monitoring the appropriate parameter(s).

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Pool Water Level	M	R
4. Suppression Pool Water Temperature	M	R
5. Drywell/Containment Differential Pressure	M	R
6. Drywell Pressure	M	R
7. Drywell and Control Rod Cavity Temperature	M	R
8. Containment Hydrogen Concentration Analyzer and Monitor	NA	M*
9. Drywell Hydrogen Concentration Analyzer and Monitor	NA	M*
10. Containment Pressure	M	R
11. Containment Air Temperature	M	R
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	M	R
13. Containment/Drywell Area Radiation Monitors	M	R**
14. Containment Ventilation Exhaust Radiation Monitor	M	A
15. Off-gas and Radwaste Bldg. Ventilation Exhaust Radiation Monitor	M	A
16. Fuel Handling Area Ventilation Exhaust Radiation Monitor	M	A
17. Turbine Bldg. Ventilation Exhaust Radiation Monitor	M	A
18. Standby Gas Treatment System A & B Exhaust Radiation Monitors	M	A

*Using sample gas containing:

a. One volume percent hydrogen, remainder nitrogen.

b. Four volume percent hydrogen, remainder nitrogen.

**The CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10R/hr and a one point calibration check of the detector below 10R/hr with an installed or portable gamma source.

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8 Two independent chlorine detection systems shall be OPERABLE with their trip setpoints adjusted to actuate at a chlorine concentration of less than or equal to 5 ppm.

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detection system inoperable, restore the inoperable detection system to OPERABLE status within 7 days, or within the next 6 hours, initiate and maintain operation of at least one control room emergency filtration system subsystem in the isolation mode of operation.

b. With both chlorine detection systems inoperable, within one hour initiate and maintain operation of at least one control room emergency filtration system subsystem in the isolation mode of operation.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.8 Each of the above required chlorine detection systems shall be demonstrated OPERABLE by performance of a CHANNEL CHECK at least once per 12 hours, a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION at least once per 6 months.

TABLE 4.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. RADWASTE BUILDING VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*
2. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N.A.	Q(4)	M	**
3. CONTAINMENT VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor Providing Alarm	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Effluent System Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*

TABLE 4.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4. TURBINE BLDG. VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*
5. FUEL HANDLING AREA VENTILATION MONTORING SYSTEM					
a. Noble Gas Activity Monitor	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W.	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*

TABLE 4.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
6. OFFGAS PRE-TREATMENT MONITOR					
a. Noble Gas Activity Monitor	D	M#	A(3)##	Q(2)	***
7. OFFGAS POST-TREATMENT MONITOR					
a. Noble Gas Activity Monitor Providing Alarm and Automatic Termination of Release	D	M	A(3)##	Q(1)	**

3/4.3.8 PLANT SYSTEMS ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.8 The plant systems actuation instrumentation channels shown in Table 3.3.8-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.8-2.

APPLICABILITY: As shown in Table 3.3.8-1.

ACTION:

a. With a plant system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.8-2, declare the channel inoperable and take the ACTION required by Table 3.3.8-1.

b. With one or more plant systems actuation instrument channels inoperable, take the ACTION required by Table 3.3.8-1.

SURVEILLANCE REQUIREMENTS

4.3.8.1 Each plant system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.8.1-1.

4.3.8.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

TABLE 3.3.8-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CONTAINMENT SPRAY SYSTEM			
a. Drywell Pressure-High	2	1, 2, 3	130
b. Containment Pressure-High	1	1, 2, 3	131
c. Reactor Vessel Water Level-Low Low Low, Level 1	2	1, 2, 3	130
d. Timers			
1) System A	1	1, 2, 3	131
2) System B	1	1, 2, 3	131
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM			
a. Reactor Vessel Water Level-High, Level 8	3	1	132

TABLE 3.3.8-1 (Continued)

PLANT SYSTEMS ACTUATION INSTRUMENTATION

ACTION

ACTION 130 - a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, place the inoperable channel in the tripped condition within one hour; otherwise, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

b. With the number of OPERABLE channels two less than required by the Minimum OPERABLE channels per Trip System requirement, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

ACTION 131 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the channels to OPERABLE status within one hour; otherwise, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

ACTION 132 - For the feedwater system/main turbine trip system:

a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or be in at least STARTUP within the next 6 hours.

b. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels per Trip System requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

TABLE 3.3.8-2

PLANT SYSTEMS ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CONTAINMENT SPRAY SYSTEM		
a. Drywell Pressure-High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
b. Containment Pressure-High	$\leq$ 7.84 psig	$\leq$ 8.34 psig
c. Reactor Vessel Water Level-Low Low Low, Level 1	$\geq$ - 150.3 inches	$\geq$ - 152.5 inches
d. Timers		
1) System A	10.85 $\pm$ 0.10 minutes	10.26 - 0.00, + 1.18 minutes
2) System B	10.85 $\pm$ 0.10 minutes**	10.26 - 0.00, + 1.18 minutes
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM		
a. Reactor Vessel Water Level-High, Level 8	$\leq$ 53.5 inches*	$\leq$ 55.7 inches

*See Bases Figure B 3/4 3-1.

**Setpoint for System B is the sum of E12-K093B plus E12-K116. E12-K116 is not to exceed 10.00 seconds.

TABLE 4.3.8.1-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. CONTAINMENT SPRAY SYSTEM				
a. Drywell Pressure-High	S	M	R	1, 2, 3
b. Containment Pressure-High	S	M	R	1, 2, 3
c. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3
d. Timers	NA	M	Q	1, 2, 3
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM				
a. Reactor Vessel Water Level-High, Level 8	S	M	R	1

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 ECCS divisions 1, 2 and 3 shall be OPERABLE with:

a. ECCS division 1 consisting of:

1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.
2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.
3. Eight OPERABLE ADS valves.

b. ECCS division 2 consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.
2. Eight OPERABLE ADS valves.

c. ECCS division 3 consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* # and 3*.

ACTION:

a. For ECCS division 1, provided that ECCS divisions 2 and 3 are OPERABLE:

1. With the LPCS system inoperable, restore the inoperable LPCS system to OPERABLE status within 7 days.
2. With LPCI subsystem "A" inoperable, restore the inoperable LPCI subsystem "A" to OPERABLE status within 7 days.
3. With the LPCS system inoperable and LPCI subsystem "A" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCS system to OPERABLE status within 72 hours.
4. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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*The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.

#See Special Test Exception 3.10.5.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. For ECCS division 2, provided that ECCS divisions 1 and 3 are OPERABLE:

1. With either LPCI subsystem "B" or "C" inoperable, restore the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 7 days.

2. With both LPCI subsystems "B" and "C" inoperable, restore at least the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*.

c. For ECCS division 3, provided that ECCS divisions 1 and 2 and the RCIC system are OPERABLE:

1. With ECCS division 3 inoperable, restore the inoperable division to OPERABLE status within 14 days.

2. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE:

1. With LPCI subsystem "A" and either LPCI subsystem "B" or "C" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

2. With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*.

*Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

e. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE and divisions 1 and 2 are otherwise OPERABLE:

1. With one of the above required ADS valves inoperable, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to $\leq$ 135 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to $\leq$ 135 psig within the next 24 hours.

f. With an ECCS discharge line "keep filled" pressure alarm instrumentation channel inoperable, perform Surveillance Requirement 4.5.1.a.1 at least once per 24 hours.

g. With an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to OPERABLE status with 72 hours or determine ECCS header delta P locally at least once per 12 hours; otherwise declare the associated ECCS inoperable.

h. In the event an ECCS system is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the useage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

*Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

SURVEILLANCE REQUIREMENTS

4.5.1 ECCS division 1, 2 and 3 shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI and HPCS systems:

1. Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

2. Performance of a CHANNEL FUNCTIONAL TEST of the:

   a) Discharge line "keep filled" pressure alarm instrumentation, and

   b) Header delta P instrumentation.

3. Verifing that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. Verifing that, when tested pursuant to Specification 4.0.5, each:

1. LPCS pump develops a flow of at least 7115 gpm with a total developed head of greater than or equal to 290 psid.

2. LPCI pump develops a flow of at least 7450 gpm with a total developed head of greater than or equal to 125 psid.

3. HPCS pump develops a flow of at least 7115 gpm with a total developed head of greater than or equal to 445 psid.

c. For the LPCS, LPCI and HPCS systems, at least once per 18 months:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

2. Performing a CHANNEL CALIBRATION of the:

   a) Discharge line "keep filled" pressure alarm instrumentation and verifying the:

      1) High pressure setpoint of the:

         (a) LPCS system to be 580 + 20, - 0 psig.

         (b) LPCI subsystems to be 480 + 20, - 0 psig.

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 2 scf per hour at P_a, 11.5 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock ~~door~~ closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. The provisions of Specification 3.0.4 are not applicable.

b. With the containment air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one containment air lock door inflatable seal system seal pressure instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the associated inflatable seal pressure to be $\geq$ 60 psig at least once per 12 hours.

*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours after each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 2 scf per hour when the gap between the door seals is pressurized to Pa, 11.5 psig.

b. By conducting an overall air lock leakage test at P_a, 11.5 psig, and verifying that the overall air lock leakage rate is within its limit:

   1. At least once per 6 months#, and

   2. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.*

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

d. By verifying each airlock door inflatable seal system OPERABLE by:

   1. Demonstrating each of the two inflatable seal pressure instrumentation channels per airlock door OPERABLE by performance of a:

      a) CHANNEL FUNCTIONAL TEST at least once per 31 days, and

      b) CHANNEL CALIBRATION at least once per 18 months,

      with a low pressure setpoint of $\geq$ 60 psig.

   2. At least once per 7 days, verifying seal air flask pressure to be greater than or equal to 90 psig.

   3. At least once per 18 months, conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 2 psig from 90 psig within 48 hours.

#The provisions of Specification 4.0.2 are not applicable.

*Exemption to Appendix J of 10 CFR 50.

DRYWELL AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.2.3 Each drywell air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the drywell, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 2 scf per hour at P_a, 11.5 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one drywell air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. The provisions of Specification 3.0.4 are not applicable.

b. With the drywell air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one drywell air lock door inflatable seal system seal pressure instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the associated inflatable seal pressure to be $\geq$ 60 psig at least once per 12 hours.

*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.2.3 Each drywell air lock shall be demonstrated OPERABLE:

a. Within 8 hours after each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 2 scf per hour when the gap between the door seals is pressurized to P_a, 11.5 psig.

b. At least once per 6 months by conducting an overall air lock leakage test at P_a, 11.5 psig and by verifying that the overall air lock leakage rate is within its limit.#

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

d. By verifying each airlock door inflatable seal system OPERABLE by:

1. Demonstrating each of the two inflatable seal pressure instrumentation channels per airlock door OPERABLE by performance of a:

   a) CHANNEL FUNCTIONAL TEST at least once per 31 days, and

   b) CHANNEL CALIBRATION at least once per 18 months,

   with a low pressure setpoint of $\geq$ 60 psig.

2. At least once per 7 days verifying seal air flask pressure to be greater than or equal to 90 psig.

3. At least once per 18 months, conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 2 psig from 90 psig within 48 hours.

#The provisions of Specification 4.0.2 are not applicable.

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
b. Drywell		
LPCI "A"	E12-F041A	313(I)
LPCI "B"	E12-F041B	314(I)
LPCI "B"	E12-F236	314(O)
CRD to Recirc. Pump A Seals	B33-F013A	326(I)
CRD to Recirc. Pump A Seals	B33-F017A	326(O)
Instrument Air	P53-F008	335(I)
Standby Liquid Control	C41-F007	328(I)
Standby Liquid Control	C41-F006	328(O)
Cont. Cooling Water Supply	P42-F115	329(I)
Plant Service Water Supply	P44-F075	332(I)
Condensate Flush Conn.	B33-F204	333(I)
Condensate Flush Conn.	B33-F205	333(O)
Combustible Gas Control	E61-F002A	339(O)
Combustible Gas Control	E61-F002B	338(O)
Combustible Gas Control	E61-F004A	340(O)
Combustible Gas Control	E61-F004B	340(O)
Upper Containment Pool Drain	G41-F265	342(O)
CRD to Recirc. Pump B Seals	B33-F013B	346(I)
CRD to Recirc. Pump B Seals	B33-F017B	346(O)
Service Air	P52-F196	363(I)
Cont. Leak Rate Test Inst.	M61-F021	438A(I)
Cont. Leak Rate Sys.	M61-F020	438A(O)
BLIND FLANGES		
Cont. Leak Rate Sys.	NA	40(I)(O)
Cont. Leak Rate Sys.	NA	82(I)(O)
Containment Leak Rate System	NA	343(I)(O)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
4. Test Connections(g)		
a. Containment		
Main Steam T/C	B21-F025A	5(0)
Main Steam T/C	B21-F025B	6(0)
Main Steam T/C	B21-F025C	7(0)
Main Steam T/C	B21-F025D	8(0)
Feedwater T/C	B21-F030A	9(0)(f)
Feedwater T/C	B21-F063A	9(0)(f)
Feedwater T/C	B21-F063B	10(0)(f)
Feedwater T/C	B21-F030B	10(0)(f)
RHR Shutdown Cool. Suction T/C	E12-F002	14(0)(c)
RCIC Steam Line T/C	E51-F072	17(0)
RHR to Head Spray T/C	E12-F342	18(0)(c)
RHR to Head Spray T/C	E12-F061	18(0)(c)
LPCI "C" T/C	E12-F056C	22(0)(c)
RHR "A" Pump Test Line T/C	E12-F322	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F336	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F349	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F303	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F310	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F348	23(0)(c)
RHR"C" Pump Test Line T/C	E12-F311	24(0)(c)
RHR"C" Pump Test Line T/C	E12-F304	24(0)(c)
HPCS Discharge T/C	E22-F021	26(0)(c)
HPCS Test Line T/C	E22-F303	27(0)(c)
HPCS Test Line T/C	E22-F304	27(0)(c)
RCIC Turbine Exhaust T/C	E51-F258	29(0)(c)
RCIC Turbine Exhaust T/C	E51-F257	29(0)(c)
LPCS T/C	E21-F013	31(0)(c)
LPCS Test Line T/C	E21-F222	32(0)(c)
LPCS Test Line T/C	E21-F221	32(0)(c)

TABLE 3.7.4-1 (Continued)

SAFETY RELATED HYDRAULIC SNUBBERS*

SNUBBER NO.	AREA	ELEVATION
MAIN STEAM SYSTEM		
Q1B21G006S102A	11	155
Q1B21G006S103A	11	150
Q1B21G006S104A	11	150
Q1B21G006S105A	11	150
Q1B21G006S101B	11	156
Q1B21G006S102B	11	156
Q1B21G006S103B	11	149
Q1B21G006S104B	11	150
Q1B21G006S105B	11	150
Q1B21G006S106B	11	150
Q1B21G006S107B	11	150
Q1B21G006S108B	11	150
Q1B21G006S101C	11	156
Q1B21G006S102C	11	156
Q1B21G006S103C	11	149
Q1B21G006S104C	11	150
Q1B21G006S105C	11	150
Q1B21G006S106C	11	150
Q1B21G006S107C	11	150
Q1B21G006S108C	11	150
Q1B21G006S102D	11	155
Q1B21G006S103D	11	150
Q1B21G006S104D	11	150
Q1B21G006S105D	11	150

TABLE 3.7.4-2

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

a. RECIRCULATION SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1B33G023R01(2)	11	117
Q1B33G024R01	11	102
Q1B33G024R02(2)	11	102
Q1B33G024R05	11	101
Q1B33G105C01	11	101
Q1B33G105R01	11	101
Q1B33G105R02(2)	11	101
Q1B33G108C01	11	101
Q1B33G108R01(3)	11	101
Q1B33G108R02(2)	11	101
Q1B33G112R01	11	101
Q1B33G122R01	11	108
Q1B33G124R01	11	122

RECIRCULATION SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B33G128C01(2)	11	121
Q1B33G129C01	11	121
Q1B33G262R02	11	103
Q1B33G265C01	11	102
Q1B33G265R04	11	107
Q1B33G265R05	11	112
Q1B33G318R01	11	102
Q1B33G322R01(2)	11	112
Q1B33G331R02	11	111
Q1B33G337R02	11	109
Q1B33G339R01	11	111
Q1B33G346R01	11	105
Q1B33G355R01(2)	11	102

*Snubbers may be added to safety related systems without prior License Amendment to Table 3.7.4-2 provided that a revision to Table 3.7.4-2 is included with the next License Amendment request.

**The number in parentheses is the number of snubbers associated with the component support. If no number in parentheses appears, there is only one snubber associated with the support.

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

b. MAIN STEAM SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1B21G021C04	11	141
Q1B21G022R01(2)	11	135
Q1B21G022R03(2)	11	133
Q1B21G022R06(2)	11	124
Q1B21G022R12(2)	11	132
Q1B21G022R13(2)	11	131
Q1B21G022R14	11	126
Q1B21G022R15	11	125
Q1B21G022R16	11	121
Q1B21G023R03	11	137
Q1B21G023R05	11	133
Q1B21G023R06(2)	11	133
Q1B21G023R08	11	126
Q1B21G023R09	11	122
Q1B21G023R10	11	122
Q1B21G023R11(2)	11	120
Q1B21G023R14	11	141
Q1B21G023R15(2)	11	141
Q1B21G023R16	11	133
Q1B21G023R17	11	121
Q1B21G023R18(2)	11	119
Q1B21G023R20	11	120
Q1B21G024C01	11	131
Q1B21G024R04	11	137
Q1B21G024R05(2)	11	132
Q1B21G024R06	11	125
Q1B21G024R07(2)	11	119

MAIN STEAM SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B21G024R11	11	138
Q1B21G024R12(2)	11	127
Q1B21G024R13	11	123
Q1B21G024R17	11	128
Q1B21G025R02	11	128
Q1B21G025R03	11	125
Q1B21G025R04(2)	11	124
Q1B21G025R05	11	120
Q1B21G026C01(2)	11	143
Q1B21G026C02(2)	11	143
Q1B21G026R01	11	143
Q1B21G026R02(2)	11	153
Q1B21G026R03	11	149
Q1B21G026R04(2)	11	153
Q1B21G026R05	11	143
Q1B21G026R06(2)	11	143
Q1B21G026R07	11	143
Q1B21G026R08	11	149
Q1B21G026R03(2)	8	143
Q1B21G030R03	11	129
Q1B21G032R04	11	127
Q1B21G032R05	11	120
Q1B21G123R01	11	165
Q1B21G126R01	11	159
Q1B21G127R01(2)	11	193
Q1B21G127R04	11	186
Q1B21G127R01	11	150

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
MAIN STEAM SYSTEM (Continued)		
Q1B21G139R02	11	150
Q1B21G141R01	11	173
Q1B21G142R01(2)	11	173
Q1B21G144R01	11	173
Q1B21G146C03(2)	11	169
Q1B21G146C04	11	169
Q1B21G146R03	11	173
Q1B21G147C02	11	167
Q1B21G148C01(2)	11	173
Q1B21G1489R01(2)	11	172
Q1B21G153C01	11	174
Q1B21G153C02	11	182
Q1B21G153C03(2)	11	171
Q1B21G153R01	11	181
Q1B21G153R02(2)	11	175
Q1B21G153R03(2)	11	172
Q1B21G153R05(2)	11	170
Q1B21G162R01	11	113
Q1B21G163R01	11	113
Q1B21G163R02	11	113
Q1B21G171R01	11	165
Q1B21G174C01(2)	11	196
Q1B21G174R01	11	197
Q1B21G174R02	11	196
Q1B21G175R01(2)	11	153
Q1B21G175R02(2)	11	158
Q1B21G180R01	11	152

SNUBBER NO.	AREA	ELEVATION
MAIN STEAM SYSTEM (Continued)		
Q1B21G180R02(2)	11	158
Q1B21G180R03	11	161
Q1B21G181C01	11	158
Q1B21G183R01(2)	11	152
Q1B21G189R02	11	151
Q1B21G189R01	11	153
Q1B21G194R01	11	161
Q1B21G194R02(2)	11	159
Q1B21G195R01	11	161
Q1B21G195R02(2)	11	160
Q1B21G196R01(2)	11	151
Q1B21G197R01(2)	11	157
Q1B21G201R01	11	158
Q1B21G201R02(2)	11	157
Q1B21G204R01	11	152
Q1B21G204R02(2)	11	160
Q1B21G205R01	11	159
Q1B21G205R02(2)	11	160
Q1B21G208R01	11	157
Q1B21G208R03	11	160
Q1B21G210R01(2)	11	157
Q1B21G213R01	11	151
Q1B21G213R02(2)	11	152
Q1B21G217R02	11	159
Q1B21G219R01(2)	11	157
Q1B21G222R01	11	160
Q1B21G224R01	11	152

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

MAIN STEAM SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B21G225R01	11	147
Q1B21G226C03	11	168
Q1B21G226R01(2)	11	173
Q1B21G304R01	11	156
Q1B21G306R01	11	151
Q1B21G311R01(2)	11	152
Q1B21G355R01	11	147
Q1B21G357C03	11	148
Q1B21G359C03	11	148
Q1B21G361C03	11	147
Q1B21G369R01(2)	11	148
Q1B21G372R01(2)	11	148
Q1B21G382R02(2)	11	152
Q1B21G384R01	11	152
Q1B21G423R01	11	147
Q1B21G424R01	11	147
Q1B21G490R03	11	152

c. **SLC SYSTEM**

SNUBBER NO.	AREA	ELEVATION
Q1C41G113C02	11	185
Q1C41G113C03	11	181
Q1C41G113R02	11	181
Q1C41G113R03	11	181
Q1C41G117C02	11	145
Q1C41G117R01	11	151
Q1C41G119R01(2)	11	129
Q1C41G119R03	11	114
Q1C41G119R04	11	112
Q1C41G119R05	11	112
Q1C41G120C05	11	155
Q1C41G124R01	11	159
Q1C41G124R03	11	162

d. **RESIDUAL HEAT REMOVAL SYSTEM**

SNUBBER NO.	AREA	ELEVATION
Q1E12G009R03	7	134
Q1E12G009R04	7	134
Q1E12G009R05	8	134

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

RESIDUAL HEAT REMOVAL SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1E12G009R06	8	134
Q1E12G010R02	8	105
Q1E12G010R04	8	103
Q1E12G010R05	8	125
Q1E12G010R07	8	133
Q1E12G010R10	8	142
Q1E12G010R11	8	142
Q1E12G010R13(2)	8	113
Q1E12G010R15	8	103
Q1E12G010R16	8	104
Q1E12G010R17(2)	8	104
Q1E12G010R18(2)	8	96
Q1E12G011R02(3)	8	99
Q1E12G012R02(2)	7	114
Q1E12G012R04	7	142
Q1E12G012R05	7	142
Q1E12G012R08	8	104
Q1E12G012R09	8	102
Q1E12G012R13	7	119
Q1E12G012R15	7	133
Q1E12G012R16	7	99
Q1E12G012R18	11	133
Q1E12G012R19	11	133
Q1E12G013C01	7	110
Q1E12G013C02	7	130
Q1E12G013R02(2)	7	115
Q1E12G013R03	7	110

RESIDUAL HEAT REMOVAL SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1E12G013R04	7	119
Q1E12G013R05(2)	7	100
Q1E12G013R06(3)	7	120
Q1E12G013R07	7	121
Q1E12G013R08	7	105
Q1E12G013R11	7	97
Q1E12G014C01	8	110
Q1E12G014C03	8	106
Q1E12G014C04	8	130
Q1E12G014R01(2)	8	129
Q1E12G014R03(2)	8	98
Q1E12G014R04(3)	8	122
Q1E12G104R05	8	105
Q1E12G014R07	8	106
Q1E12G014R10(2)	8	109
Q1E12G014R11(2)	8	110
Q1E12G015R02	11	156
Q1E12G015R04(2)	11	143
Q1E12G015R06	11	143
Q1E12G015R07	11	214
Q1E12G015R08	11	210
Q1E12G015R11	11	143
Q1E12G015R17	11	210
Q1E12G015R19	11	214
Q1E12G015R20	11	144
Q1E12G015R21(2)	11	140
Q1E12G015R28(3)	11	192

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
RESIDUAL HEAT REMOVAL SYSTEM (Continued)		
Q1E12G015R33(2)	11	205
Q1E12G015R38	11	157
Q1E12G016C01	11	143
Q1E12G016R01	11	146
Q1E12G016R02	11	143
Q1E12G016R03	11	143
Q1E12G016R05(2)	11	143
Q1E12G019R05(2)	8	139
Q1E12G019R07	8	149
Q1E12G019R08	7	149
Q1E12G019R09(2)	7	143
Q1E12G020R01(2)	8	148
Q1E12G020R02(2)	7	148
Q1E12G020R03	8	148
Q1E12G020R04(2)	8	148
Q1E12G020R05	7	147
Q1E12G020R07(2)	7	147
Q1E12G020R09	7	147
Q1E12G021R01	8	147

SNUBBER NO.	AREA	ELEVATION
RESIDUAL HEAT REMOVAL SYSTEM (Continued)		
Q1E12G021R03(2)	8	146
Q1E12G025C01(2)	8	95
Q1E12G025R01	8	110
Q1E12G119R02	7	152
Q1E12G159R01	7	126
Q1E12G159R03	7	126
Q1E12G159R04	7	131
e. LPCS SYSTEM		
Q1E21G001R05	9	96
Q1E21G001R07(2)	9	96
Q1E21G002R01	11	150
Q1E21G002R02	11	150
Q1E21G002R03	11	151
Q1E21G002R04	11	153
Q1E21G002R05	11	153
Q1E21G002R06	11	153
Q1E21G002R07	11	150

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

f. HPCS SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1E22G001R10(2)	8	96
Q1E22G002R02(2)	8	96
Q1E22G002R03	8	96
Q1E22G003R01	11	153
Q1E22G003R02	11	153
Q1E22G003R03	11	149
Q1E22G003R04	11	150
Q1E22G003R05	11	151

g. RCS LEAK DETECTION SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1E31G116R01	11	169
Q1E31G122R01(2)	11	149
Q1E31G124R01(2)	11	151
Q1E31G126C01	11	149
Q1E31G140R01	11	159
Q1E31G140R02(2)	11	159
Q1E31G148R01(2)	11	151
Q1E31G149R01(2)	11	151
Q1E31G168R01	11	158
Q1E31G174R01(2)	11	151
Q1E31G176C01	11	147
Q1E31G178R08	11	179
Q1E31G178R09	11	179
Q1E31G181R01	11	156
Q1E31G243R01	11	144
Q1E31G243R02	11	140
Q1E31G246R01(2)	11	144

h. MSIV LEAKAGE CONTROL SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1E32G103C01(2)	8	122
Q1E32G106C01	8	121
Q1E32G109C01	8	122
Q1E32G119C01	8	148

i. FEEDWATER LEAKAGE CONTROL SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1E38G102R01	8	145

j. RCIC SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1E51G001R05	8	104
Q1E51G001R06	8	109
Q1E51G001R09	11	133
Q1E51G001R10(2)	11	134
Q1E51G001R15	11	178
Q1E51G001R17(2)	11	190
Q1E51G001R18	11	194
Q1E51G001R19(2)	11	194
Q1E51G003R03	7	126
Q1E51G003R04	7	117
Q1E51G003R05(2)	7	127
Q1E51G003R07	8	112
Q1E51G003R08(2)	8	112
Q1E51G003R09(2)	8	109
Q1E51G003R10	8	105
Q1E51G003R11(2)	8	100
Q1E51G003R12(2)	8	106

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
RCIC SYSTEM (Continued)		
Q1E51G004C02(2)	8	97
Q1E51G004R01(2)	8	98
Q1E51G004R05(2)	8	106
Q1E51G004R06(2)	8	96
Q1E51G004R07(2)	8	97
Q1E51G004R08(2)	11	164
Q1E51G004R11	8	97
Q1E51G004R13(2)	11	167
Q1E51G004R14(2)	11	152
Q1E51G158R03(2)	11	143
Q1E51G180R01	8	97
k. COMBUSTIBLE GAS CONTROL SYSTEM		
Q1E61G001R07	11	189
l. RWCU SYSTEM		
Q1G33G002C03(2)	11	113
Q1G33G002R03(2)	8	136
Q1G33G002R05(2)	11	140
Q1G33G002R08(2)	11	102
Q1G33G002R09(3)	11	102
Q1G33G002R10(2)	11	102
Q1G33G002R11	11	102
Q1G33G002R12	11	102
Q1G33G002R13(2)	11	102
Q1G33G002R14(2)	11	102
Q1G33G002R16	11	112
Q1G33G002R17(2)	8	125

SNUBBER NO.	AREA	ELEVATION
RWCU SYSTEM (Continued)		
Q1G33G002R18	8	116
Q1G33G002R19	8	116
Q1G33G002R21(2)	11	102
Q1G33G002R22	11	102
Q1G33G002R24	11	102
Q1G33G011R01	11	140
Q1G33G011R03(2)	11	145
Q1G33G012R01(2)	11	142
Q1G33G012R02	11	152
Q1G33G015R01(3)	11	103
m. FPCC SYSTEM		
Q1G41G006R01	9	114
Q1G41G006R07(3)	7	99
Q1G41G015R09	11	204
Q1G41G016C08	11	163
Q1G41G016R04	11	166
Q1G41G016R24	11	163
Q1G41G016R27(2)	11	203
Q1G41G016R28(2)	11	206
Q1G41G016R32	11	197
Q1G41G018R06	9	197
n. SSW SYSTEM		
Q1P41G001R14(2)	7	98
Q1P41G002R10(2)	8	106
Q1P41G002R12(2)	8	106
Q1P41G006C01	8	99

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SSW SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1P41G006C17	8	99
Q1P41G007R19	025A	144
Q1P41G007R20	025A	144
Q1P41G007R23(2)	025A	138
Q1P41G007R24(2)	025A	137

o. CCW SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1P42G002R06(2)	9	193
Q1P42G002R07(2)	9	186
Q1P42G002R11(2)	9	186
Q1P42G002R13(2)	9	186

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*, **

2. NON-Q MECHANICAL SNUBBERS

a. MAIN STEAM SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1B21G118R01	11	148
N1B21G118R02	11	147
N1B21G191C02	11	137
N1B21G192C03	11	136
N1B21G193R01(2)	11	138
N1B21G193R04	11	136
N1B21G231R01(2)	11	163

b. RECIRCULATION SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1B33G104R02	11	102
N1B33G105C01	11	101
N1B33G105C03	11	101
N1B33G105C04	11	101
N1B33G105C05	11	101
N1B33G105R01	11	101
N1B33G106R01	11	102
N1B33G107R01	11	102
N1B33G107R02	11	102
N1B33G108C02	11	101
N1B33G108R03(2)	11	101
N1B33G108R05	11	101
N1B33G108R06(2)	11	101
N1B33G108R07	11	101
N1B33G119R04	11	112
N1B33G120R03	11	101
N1B33G123C01	11	102
N1B33G362R03	11	102

c. RESIDUAL HEAT REMOVAL SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1E12G172R02	11	129
N1E12G212R01	11	136
N1E12G212R03	11	133

d. REACTOR CORE ISOLATING COOLING SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1E51G120R01	11	127

e. REACTOR WATER CLEANUP SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1G33G002R01	7	120
N1G33G002R02	8	118
N1G33G002R03	8	123
N1G33G002R04	8	123
N1G33G002R05(2)	11	147
N1G33G002R08(2)	11	164
N1G33G002R10(2)	11	147
N1G33G002R11(3)	11	180
N1G33G002R12(3)	11	180
N1G33G002R13	11	178
N1G33G002R14	8	120
N1G33G002R21	8	120

3/4.7.5 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.5 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 10 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limit, withdraw the sealed source from use and either:

   1. Decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.5.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.5.2 Test Frequencies - Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

a. Sources in use - At least once per six months for all sealed sources containing radioactive material:

   1. With a half-life greater than 30 days, excluding Hydrogen 3, and

   2. In any form other than gas.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The measurement of response time at the specified frequencies provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the accident analysis. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that

ISOLATION ACTUATION INSTRUMENTATION (continued)

the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 13 second diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13 second delay. It follows that checking the valve speeds and the 13 second time for emergency power establishment will establish the response time for the isolation functions. However, to enhance overall system reliability and to monitor instrument channel response time trends, the isolation actuation instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971 and NEDO-24222, dated December 1979, and Section 15.8 Appendix 15A of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a part of the Reactor Protection System and is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions should not be made without this flux level information available to the operator. When the intermediate range monitors are on scale adequate information is available without the SRMs and they can be retracted.

3/4.3.7.7 TRAVERSING IN-CORE PROBE SYSTEM

The OPERABILITY of the traversing in-core probe system with the specified minimum complement of equipment ensures that the measurements obtained from use of this equipment accurately represent the spatial neutron flux distribution of the reactor core.

3/4.3.7.8 CHLORINE DETECTION SYSTEM

The OPERABILITY of the chlorine detection system ensures that an accidental chlorine release will be detected promptly and the necessary protective actions will be automatically initiated to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the isolation mode of operation to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95 "Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release", Revision 1, January 1977.

3/4.3.7.9 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the fire detection instrumentation ensures that adequate warning capability is available for the prompt detection of fires. This capability is required in order to detect and locate fires in their early stages. Prompt detection of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program.

In the event that a portion of the fire detection instrumentation is inoperable, increasing the frequency of fire watch patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

3/4.3.7.10 LOOSE-PART DETECTION SYSTEM

The OPERABILITY of the loose-part detection system ensures that sufficient capability is available to detect loose metallic parts in the primary system and avoid or mitigate damage to primary system components. The allowable out-of-service times and surveillance requirements are consistent with the recommendations of Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors," May 1981.

3/4.3.7.11 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The radioactive liquid effluent monitoring instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

3/4.3.7.12 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

The radioactive gaseous effluent monitoring instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. This instrumentation of potentially explosive gas mixtures in the waste gas holdup system. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 ad 64 of Appendix A to 10 CFR Part 50.

3/4.3.8 PLANT SYSTEMS ACTUATION INSTRUMENTATION

The plant systems actuation instrumentation is provided to initiate action to mitigate the consequences of accidents that are beyond the ability of the operator to control. The LPCI mode of the RHR system is automatically initiated on a high drywell pressure signal and/or a low reactor water level, level 1, signal. The containment spray system will then actuate automatically following high drywell and high containment pressure signals. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell and containment pressure-high. A 10-minute minimum, 13-minute maximum time delay exists between initiation of LPCI and containment spray actuation. A high reactor water level, level 8, signal will actuate the feedwater system/main turbine trip system.

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

ECCS division 1 consists of the low pressure core spray system and low pressure coolant injection subsystem "A" of the RHR system and the automatic depressurization system (ADS) as actuated by trip system "A". ECCS division 2 consists of low pressure coolant injection subsystems "B" and "C" of the RHR system and the automatic depressurization system as actuated by trip system "B".

The low pressure core spray (LPCS) system is provided to assure that the core is adequately cooled following a loss-of-coolant accident and, together with the LPCI system, provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The LPCS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the LPCS system will be OPERABLE when required. Flow and total developed head values for surveillance testing include system losses to ensure design requirements are met. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. The LPCI system, together with the LPCS system, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Flow and total developed head values for surveillance testing include system losses to ensure design requirements are met. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

ECCS division 3 consists of the high pressure core spray system. The high pressure core spray (HPCS) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCS system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCS system operates over a range of 1160 psid, differential pressure between reactor vessel and HPCS suction source, to 0 psid.

ECCS-OPERATING and SHUTDOWN (Continued)

The capacity of the system is selected to provide the required core cooling. The HPCS pump is designed to deliver greater than or equal to 1440/5010 gpm at differential pressures of 1160/200 psi. Initially, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

With the HPCS system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the LPCS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCS out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems.

The surveillance requirements provide adequate assurance that the HPCS system will be OPERABLE when required. Flow and total developed head values for surveillance testing include system losses to ensure design requirements are met. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCS system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety-relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 135 psig even though low pressure core cooling systems provide adequate core cooling up to 350 psig.

ADS automatically controls eight selected safety-relief valves although the safety analysis only takes credit for seven valves. It is therefore appropriate to permit one valve to be out-of-service for up to 14 days without materially reducing system reliability.

3/4.5.3 SUPPRESSION POOL

The supression pool is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCS, LPCS and LPCI systems in the event of a LOCA. This limit on suppression pool minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression pool in OPERATIONAL CONDITIONS 1, 2 or 3 is required by Specification 3.6.3.1.

Repair work might require making the suppression pool inoperable. This specification will permit those repairs to be made and at the same time give assurance that the irradiated fuel has an adequate cooling water supply when the suppression pool must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

SUPPRESSION POOL (Continued)

In OPERATIONAL CONDITION 4 and 5 the suppression chamber minimum required water volume is reduced because the reactor coolant is maintained at or below 200°F. Since pressure suppression is not required below 212°F, the minimum required water volume is based on NPSH, recirculation volume, and vortex prevention plus a 1'2" safety margin for conservatism.

NUCLEAR REGULATORY COMMISSION

DOCKET NO. 50-416

MISSISSIPPI POWER AND LIGHT COMPANY, ET AL.

GRAND GULF NUCLEAR STATION, UNIT 1

RECEIPT OF PETITION FOR ACTION UNDER 10 CFR 2.206

Notice is hereby given that by petition dated March 29, 1984, the Jacksonians United For Livable Energy Policies has asked that the Commission order the Mississippi Power and Light Company, et al. to show cause why the license for Grand Gulf Nuclear Station, Unit 1, should not be revoked and a stay of operation not be issued. The petitioner bases its request for relief on discrepancies discovered in technical specifications since the issuance of the license in 1982 and on problems associated with the capabilities of diesel generators used at the plant which were designed and manufactured by Transamerica Delaval, Incorporated. The petitioner also asks for modification of the license to remove management personnel responsible for problems at Grand Gulf and to ensure implementation and verification of corrective actions for identified deviations from NRC requirements. The petition is being treated under 10 CFR 2.206 and, accordingly, appropriate action will be taken on the petition within a reasonable time.

Copies of the petition are available for public inspection in the Commission's Public Document Room at 1717 H Street, N.W., Washington.

D.C. 20555 and in the local public document room for the Grand Gulf Nuclear Station at the Hinds Jr. College, George M. McLendon Library, Raymond, Mississippi 39154.

Dated at Bethesda, Maryland this day of May 1984.

FOR THE NUCLEAR REGULATORY COMMISSION

HR Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

FROM:
Cynthia Stewart
Jacksonians United for Livable Energy
Policies (JULEP)

TO:
Commissioners

ACTION CONTROL	DATES
COMPL DEADLINE	5/8/84
INTERIM REPLY	
FINAL REPLY	
FILE LOCATION	

CONTROL NO. 14329

DATE OF DOCUMENT 3/29/84

PREPARE FOR SIGNATURE OF:
☐ CHAIRMAN
☐ EXECUTIVE DIRECTOR
OTHER: ____________

DESCRIPTION ☐ LETTER ☐ MEMO ☐ REPORT ☐ OTHER

2.206 - Show Cause Petition requesting revocation of low ~~###~~ power license and denial of a full power operating license for Grand Gulf Nuclear Station Unit 1

SPECIAL INSTRUCTIONS OR REMARKS

ASSIGNED TO	DATE	INFORMATION ROUTING
Cunningham, ELD	4/11/84	Denton
		DeYoung
Eisenhut	6/19/84	O'Reilly
		Case/Denton
		1. PPAS
		2. Speis
		3. Mattson
		4. Vollmer
		5. Thompson 6. SnyHdr

NRC FORM 232
(6-80)

EXECUTIVE DIRECTOR FOR OPERATIONS
PRINCIPAL CORRESPONDENCE CONTROL

March 29, 1984

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

DOCKETED
USNRC

BEFORE THE COMMISSION

'84 APR 10 P12:01

OFFICE OF SECRETARY
DOCKETING & SERVICE
BRANCH

In the Matter of	)	
	)	
MISSISSIPPI POWER & LIGHT COMPANY, et al.	)	Docket No.
	)	
(Grand Gulf Nuclear Station, Unit 1)	)	

SHOW CAUSE PETITION FROM JACKSONIANS UNITED FOR LIVABLE ENERGY POLICIES ON T. D. I. GENERATORS, REQUESTING REVOCATION OF LOW POWER LICENSE AND DENIAL OF A FULL POWER OPERATING LICENSE FOR GRAND GULF NUCLEAR STATION UNIT 1

I. INTRODUCTION

1. Comes now Jacksonians United for Livable Energy Policies (hereinafter "Petitioner" or "JULEP") to petition the Commissioners of the U. S. Nuclear Regulatory Commission (NRC), pursuant to Title 10 of the Code of Federal Regulations, Section 2.206, to serve upon Mississippi Power and Light Company ("Licensee" or "MP&L") an order to show cause, pursuant to 10 C.F.R. 2.202(a), why the low power license for Grand Gulf Nuclear Station, Unit 1, should not be revoked, a stay of operation issued, the pending application for an operating license denied, and a proceeding initiated under 42 U.S.C. 2239(a).

II. DESCRIPTION OF PETITIONER

2. JULEP is a public interest organization formed in 1979 to address issues of nuclear power, and utility rates and conduct. Members have testified at Atomic Safety and Licensing Board Panel hearings and environmental hearings on Grand Gulf and have written letters protesting Grand Gulf to the NRC. The organization is currently involved in proceedings to challenge certain technical changes in the operating license for Grand Gulf, Unit 1. Several members of JULEP live within 20 miles or less of Grand Gulf.

III. AUTHORITY

3. Title 10 of the Code of Federal Regulations, 2.206(a), establishes the right of the public to petition the Commission to institute a proceeding pursuant to 2.202(a) to modify,

suspend, or revoke a license or for other relief. Such a petition must set forth the factual basis and the relief requested. The Commission may, pursuant to 10 C.F.R. 2.202(a), institute such a proceeding by servicing upon the licensee an order to show cause.

IV. DISCRETIONARY HEARING

4. The Atomic Energy Act of 1954 gives discretion to revoke, suspend, or modify the construction permit of an NRC licensee:

> A license or construction permit may be revoked, suspended or modified in whole or in part, for any material false statement in the application for license or in the supplemental or other statement of fact required by the applicant or because of conditions revealed by the application for license or statement of fact or any report, record, inspection, or other means which would warrant the Commission to refuse to grant a license in an original application; or for failure to construct or operate a facility in accordance with the terms of the construction permit or license or the technical specifications in the application; or for the violation of or failure to observe any of the terms and provisions of this chapter, or of any regulation of the Commission.

42 U.S.C. 2236. Notwithstanding the discretionary aspect of this statute, the NRC has a mandatory duty to exercise its authority when necessary and is required to determine that there will be adequate protection of the public health and safety. See Natural Resource Defense Council vs. U. S. Nuclear Regulatory Commission, 528 F. 2d 166 (2d Cir. 1978). The Supreme Court has determined that the Atomic Energy Act mandates that "the public safety is the first, last and permanent consideration in any decision of . . . a license to operate a nuclear facility." Power Reactor Co. v. Electricians, 367 U.S. 396, 402 (1961), quoting In re Power Reactor Development Co., 1 A.E.C. 128, 136 (1959).

5. JULEP seeks consideration of whether the Licensee has met and will continue to meet the requirements of the Rules and Regulations of the NRC, and further, whether there exists reasonable assurance that continued low power operation, and issuance of a full power license to the Licensee, will not jeopardize the public health and safety.

6. There is no existing forum to address the matters at issue. The operating license for Grand Gulf was uncontested. A request for hearing and petition to intervene filed at this stage pursuant to 10 C.F.R. 2.714 would be untimely. At the time the Operating License application for Grand Gulf, Unit 1, was noticed, JULEP did not represent affected members of the public, and was unable to contemplate an active role as intervenor.

7. The lack of an existing forum does not alter the fact that a utility bears the burden of proof. As the Commission has stated:

> We think it ineluctable that a utility must bear the burden of proving compliance with the Commission's safety regulations not only at the beginning and at the end of the nuclear licensing process — but, as in this case — when called upon at some interim point to "show cause" why a construction permit should not be lifted for unsafe construction practices.

Consumer Power Company (Midland Plant, Units 1 and 2), ALAB-315, 3 N.R.C. 101, 104 (1976). A petitioner need only provide the NRC staff with "sufficient reason" to look into the matter of revocation of a license, but is not required to assume the burden itself. Consolidated Edison Company of New York, et al. (Indian Point Units 1, 2 and 3), CLI-75-8, 2 N.R.C. 173, 177 (1975). Public safety, as well as the right of the public to due process of law, dictate that this should be so.

8. Regardless of the lack of an existing forum, the public is entitled to a hearing in order to protect the public interest in its health and safety. As Scenic Hudson Preservation Conference v. Federal Power Commission, 354 F. 2d 608 (1965), demonstrates, the NRC is under an obligation to consider all relevant information in an effort to protect the public interest, especially in an issue of this type where concern for public health and safety is so great.

9. A petitioner, in requesting a show cause order, must show that "substantial health or safety issues [have] been raised." Indian Point, supra, at 177. Another test against which any request for a discretionary hearing must be judged is whether such a proceeding would serve any "useful purpose." Public Service Company of Indiana (Marble Hill Nuclear Generating Station, Units 1 and 2), CLI-80-10, 11 N.R.C. 438, 443 (1980). In the instant case, the lack of intervention in the licensing of Grand Gulf notwithstanding, the matter of the operation of the plant is of great concern to residents of Mississippi. Enormous cost overruns, resulting predicted increases in utility rates, and a history of delays, management and technical difficulties, and the falsification of training data of employees at Grand Gulf have given rise to tremendous interest and concern about the plant. As will be shown, the problems forming the base of this request point to an inevitability of harm to public health and safety. The understandable interest of the public can only be addressed in a public forum. The long history of problems has caused the public to lose faith in the regulatory process. Regulation of Grand Gulf, because of the lack of prior public intervention, has been conducted largely out of the public eye.

10. The "useful purpose" served by a discretionary hearing is the technical resolution of problems resulting in a greater degree of safety afforded to the public. Suspending orders can be used to remove a threat to the public health and safety. The primary test of "useful purpose" is based on what type of regulatory action best serves the public welfare.

11. Given the Licensee's constant failures to meet regulations — indeed, its apparently deliberate breaking of regulations in the case of employee training — and the enormous number of discrepancies between physical plant and specifications, it can only be concluded that neither the NRC nor the Licensee knows what has been constructed. The relief requested by the petitioner, including 100% review of the design and as-built plant and an adjudicatory determination of both the quality of the Licensee's plant and management, is the only method of determining that operation of this facility will not pose a threat to the public health and safety. This, in essence, is a determination of the "inevitability of harm," based on the extent to which the Licensee has conformed to the NRC's regulations.

V. 10 C.F.R. SECTION 50, APPENDIX A, CRITERIA

12. Grand Gulf, Unit 1, received a low power license in June 1982. Discovery of a design flaw requiring modifications delayed completion of low power testing until late last year. In the NRC-conducted Systematic Assessment of Licensee Performance (SALP) annual Board reviews, MP&L management has consistently scored poorly. Grand Gulf received a license despite the fact that approximately 200 technical specifications and 600 surveillance procedures were in error, despite the fact that the qualifications of operators were apparently falsified, and despite the fact that the drywell cooling system was inadequately designed and constructed. Some of the erroneous surveillance procedures were submitted for equipment that does not even exist at the plant. Some of the incorrect technical specifications were written for a different size and type containment building than the one at Grand Gulf. Grand Gulf, Unit 1, is the first U.S. boiling water reactor to use Mark III containment. MP&L has no previous nuclear experience. Until very recently, none of the operating staff had operated a commercial reactor. In light of all these factors, Grand Gulf should have received the strictest scrutiny by the NRC. Hugh Thompson of the Office of Nuclear Reactor Regulation has admitted that neither staff nor applicant review of the technical specifications was adequate (*Inside NRC*, March 5, 1984, p. 9). Prior to licensing, the NRC sent MP&L a copy of technical specifications for a Mark II containment plant, expecting the licensee to review and adjust them to meet the actual physical plant. MP&L did not do this. NRC *assumed* that it had and issued a low power license. None of the problems — the considerable discrepancies in technical specifications and surveillance procedures, the falsification of operator training data, a design flaw requiring modification — were even discovered until *after* issuance of the license. No public hearing has been held on these

issues, nor was a prior public hearing held when the NRC agreed to waive certain technical requirements in September 1983. In spite of these problems, and consistent poor performance of Licensee management, the NRC has repeatedly assured itself that corrective actions have been initiated which will result in the fulfillment of NRC regulations. Nothing in the existence or history of this plant justifies this excusing.

13. The Licensee has been, and continues to be, incapable of meeting NRC requirements, particularly Appendix A to 10 C.F.R. Section 50. Criterion 17 under II in Appendix A states:

> The onsite electric power supplies, including the batteries and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure."

VI. INADEQUATE ONSITE ELECTRIC DISTRIBUTION

14. Two of the three electrical generating engines at Grand Gulf are Model DSRV 16, supplied by Transamerica Delaval (TDI). These engines have experienced significant problems in completing the pre-operational test program, have had several major failures, including a fuel line break which caused a fire, and many minor failures. The problems to date include:

3/81	Excessive turbocharger thrust bearing wear;
4/81	*Non-class* 1E motors supplied with EDG auxiliary system pumps;
11/81	Piston crown separation during operation;
1/82	Governor lube oil cooler located too high, creating possibility of trapping air in the system;
3/82	Air start sensing line not seismically supported;
3/82	Engine pneumatic logic improperly designed, creating possibility of premature engine shutdown;
3/82	The crankcase cover capscrew failed, with head lodging in and shorting out the generator;
6/82	Air starting valve capscrews replaced because they were too long for holes;
8/82	The flexible drive coupling material incompatible with the operating environment;
8/82	The latching relay failed during testing;
7/83	Air start valve failures;
8/83	High pressure fuel injection line failed;
8/83	Cracks in connecting push rod welds discovered;
9/83	The fuel oil line failed, causing a *major fire*;
9/83	Unqualified instrument cable;
10/83	Fuel oil leak;
10/83	Cracked push rod weld;
1983	Turbocharger mounting bolt failures;
1983	Cracked jacket water welds;
1983	Turbocharger vibration;
12/83	Cylinder head cracks;
12/83	Cracks in piston skirts in Division II EDG;
During EDG Installation	Cylinder head cracks.

15. The long history of problems with TDI generators at Grand Gulf and other plants (see Attachment 1) demonstrates that they cannot be depended upon to function when needed. This leaves only one dependable source of electric power in the event of an emergency. This does not meet the redundancy required by the NRC.

16. The Licensee proposes to jury rig gas turbines to overcome the problem (see Attachment 2). At the February 29 NRC Commission meeting, MP&L indicated that these gas turbines would require 10-15 *minutes* to come to power as opposed to the 10-15 *seconds* now required for the diesel generators (February 29 Briefing on the Status of Grand Gulf before the NRC, page 18). This long delay is totally unacceptable in the course of an accident.

17. MP&L has proposed to switch the third non-TDI diesel generator, which is dedicated to the High Pressure Core Spray system (HPCS), over to carry other loads during an accident. This would result in the HPCS being taken out of service (February 29 Briefing, page 18). This results in a loss of a vital emergency response system.

18. It is clear that the TDI generators are completely unreliable. The NRC has expressed concern over the multiple and seemingly endless problems with the generators. Harold Denton, the NRC's director of Nuclear Reactor Regulation, has directed that no nuclear plant be allowed to operate with a TDI emergency diesel generator until technical questions about their operating history are answered (see Attachment 3). Last October, Darrell G. Eisenhut, Director, Division of Licensing, in a letter to NRC Commissioners stated that "the identification of QA problems at TDI, taken together with the number of operational problems and the Shoreham crankshaft failure, has reduced the staff's level of confidence in the reliability of all TDI diesel generators." (See Attachment 4.) Certainly no exception or reduction in scrutiny should be made for Grand Gulf, particularly in light of the fact that it is precisely the lack of vigilant regulation and scrutiny that has resulted in a plant with the magnitude of problems present at Grand Gulf being permitted to operate at all.

19. The proposals of the Licensee to deal with this, to jury rig gas turbines and to switch the HPCS diesel power over, are makeshift measures to try and compensate for serious deficiencies. This licensee has been unable to conform specifications to physical plant. It is questionable, given the poor management, training data falsification, and discrepancies in specifications and surveillance procedures, whether MP&L really understands the construction and operation of Grand Gulf, Unit 1. If they have not proved competent to even conform to the most basic regulations, they certainly should not be considered competent to implement makeshift measures. For the NRC to allow this, and once again permit MP&L to proceed in the face of problems and inadequate scrutiny, would be inexcusable.

20. The crankshafts of the TDI generators are inadequately designed. In similar TDI diesel engines at the Shoreham Nuclear Station operated by Long Island Lighting, one crankshaft broke

and cracks appeared on the remaining crankshafts. Crankshaft problems have also occurred at the Catawba plant operated by Duke Power Company. The TDI generators at Catawba and Grand Gulf are identical.

21. The pistons are inadequately designed. Early on at Grand Gulf, piston crown separation occurred during operation. They were returned to TDI for rework. TDI is the source of the TDI generator malfunctions. There is no indication that any change in design has occurred to ensure that the separation, or other problems, will not recur. Defective performance of the pistons has occurred almost across the board with TDI generators, both at nuclear plants and on marine operation. (See Attachment 1.)

22. The cylinder heads are inadequately designed. At Grand Gulf, three heads have already had to be replaced due to cracks. Again, cylinder malfunctions have occurred across the board with TDI generators. Only redesign, and not replacement, will ensure proper operation!

23. The fuel lines are inadequately designed and/or installed. Numerous fuel line failures have occurred at Grand Gulf. One resulted in a major fire. Fuel oil lines at Shoreham ruptured.

VII. N. R. C. ENFORCEMENT

24. The responsibilities of the NRC Office of Inspection and Enforcement (I & E) are established by 10 C.F.R. 1.64:

> The Office of Inspection and Enforcement develops policies and administers programs for: Inspecting licensees to ascertain whether they are complying with NRC regulations, rules, orders, and license provisions, and to determine whether these licensees are taking appropriate actions to protect nuclear materials and facilities, the environment, and the health and safety of the public; inspecting applicants for licenses, as a basis for recommending issuance or denial of a limited work authorization, construction permit or an operating license; inspecting suppliers of safety-related services, components, and equipment to determine whether they have established quality assurance programs that meet NRC criteria; investigating incidents, accidents, allegations, and unusual circumstances including those involving loss, theft, or diversion of special nuclear material; enforcing Commission orders, regulations, rules, and license provisions; recommending changes in licenses and standards, based on the results of inspections, investigations, and enforcement actions; and notifying licensees regarding generic problems so as to achieve appropriate precautionary or corrective action. . . . NRC's five Regional Offices are responsible for carrying out inspections and investigations.

25. The lack of decisive actions on the part of I & E, Region II, to ensure that this Licensee meets Appendix A requirements, as well as other regulations, has resulted in conditions that present a serious threat to public health and safety. The staff has allowed the Licensee to get by with prospective commitments, with the result that past defects are not adequately analyzed or corrected. It is inappropriate and totally unacceptable for the NRC to continue to accept the Licensee coming forward with new "plans" in which it proposes to meet NRC criteria.

26. There is no assurance that the public record, upon which the Petitioner must rely, is in any way complete. It is relevant to note that James J. Cummings, director of the Office of Investigator and Auditor (OIA), responsible for authorizing all investigations, was removed from his position by the Commissioners in September 1983. The public has no way to know what matters the NRC and the Licensee have "settled" between themselves, whether properly or improperly.

VIII. RELIEF REQUESTED

27. Petitioner, having shown herein that the Licensee, Mississippi Power and Light Company, has failed to meet the criteria of 10 C.F.R. Section 50 for electric power systems, requests the revocation of the low power license of Grand Gulf Nuclear Station, Unit 1, and a stay of operation, in that prior knowledge of the scope and substance of the Licensee's failure to meet NRC requirements would have caused the Commission to refuse the original application. Moreover, the foregoing has demonstrated that the NRC cannot yet make the finding required by 10 C.F.R. Section 50.57 for issuance of an operating license that there is reasonable assurance that the activities authorized could be conducted without endangering the public health and safety, and thus the pending application for full power license should be denied.

28. The request for a revocation of the low power license notwithstanding, the petitioner requests further relief, to include:

(1) Appointment of an independent panel of investigators from outside the agency to investigate (a) possible improprieties and illegal acts by NRC inspectors and investigators; (b) the handling by the OIA of the improprieties which have been previously identified; and (c) the effectiveness of NRC Region II in fulfilling the mandated responsibility to enforce the regulations of the NRC which exist to ensure protection of the public health and safety;

(2) Modification of the operating license to include (a) removal from the management organization of those responsible for past failures at Grand Gulf; (b) implementation and verification of corrective actions for all identified deviations from requirements; and

(3) Hearings before an Atomic Safety and Licensing Board.

IX. CONCLUSION

29. As the foregoing petition has illustrated, the Licensee has not designed, constructed and documented Grand Gulf in compliance with the regulations of 10 C.F.R. Section 50 and

in conformity with the terms of its technical specifications and operating license. The evidence presented herein is only that which is in the public record and is but a fraction of the findings made by the NRC over the course of the regulatory history of Grand Gulf.

30. WHEREFORE, petitioner prays for an order granting the requested relief set forth above.

Respectfully submitted,

Cynthia Stewart

Cynthia Stewart
Jacksonians United for Livable
Energy Policies

Attachment 1

Delaval Diesel Generator Operation Experience

U. S. Nuclear Experience

In 1974, the Long Island Lighting Company (LILCo) contracted with TDI to purchase three emergency diesel generators for the Shoreham Nuclear Power Station. This was the first order received by TDI to provide an EDG for a commercial nuclear power station. In the next seven years, engines for 14 other plants were ordered from TDI.

San Onofre 1

- Two TDI Diesel Engines Installed in 1976 - DSRV-20
- Serial No. 75041/42, Rated at 6000KW (nominal)
  8800KW (peak)
- Engine Run Time to Date - 450 hours per engine

The first plant to actually place a TDI engine into nuclear service was San Onofre Unit 1 (SONGS 1), which purchased two V-20 units to provide emergency power for its feed pumps, which also serve as Emergency Core Cooling System pumps.

The engines at SONGS 1 were installed in 1976, and declared operational in April 1977. Since then, SONGS has experienced some problems with the operation of the engine turbochargers, a lube oil pressure sensing line failure which resulted in a fire, and several other minor problems. Because SONGS did not commit to meet the guidelines of Regulatory Guide 1.108, but rather Regulatory Guide 1.9, the program it used to test the engines before they were placed in service was more abbreviated than for a new plant. A detailed list of problems to date follows.

Date	Problem	Cause/Solution
12/80	Excessive Turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified. 10 CFR Part 21 report issued because problem generic.
7/81	Lube oil leak and fire.	Excessive vibration of a lube oil test line which had inadvertently been left installed by the licensee. Line removed.
12/81	Piston modification to prevent crown separation.	Pistons reworked by TDI to respond to Part 21 report. Problem identified at Grand Gulf.
9/83	Unqualified instrument cable.	Replaced in accordance with Part 21 report.

Grand Gulf

- ° Two TDI engines installed - Model DSRV-16
- ° Serial No. 74033/34, Rated at 7000KW
- ° Operating Hours to Date - Division I = 1100 hours; Division II = 700 hours

In 1981, Mississippi Power & Light (MP&L) commenced pre-operational testing of two V-16 engines installed at Grand Gulf Unit 1. They represent the first V-16 units ordered from TDI, and in fact, one of the Grand Gulf engines was used to qualify the entire TDI V-16 line of machines for nuclear applications.

The Grand Gulf engines have experienced significant problems in completing the pre-operational test program, have had several major failures, including a fuel line break which caused a fire, and many minor failures. A detailed list of problems at Grand Gulf follows.

Date	Problem	Cause/Solution
11/81	Piston crown separation during operation.	Holddown studs failed. Pistons returned to TDI for rework. Generic problem.
3/81	Excessive turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified.
6/11/82	Air starting valve capscrews replaced. Too long for holes.	Response to Part 21 report.
8/23/82	Flexible drive coupling material incompatible with operating environment.	Replaced with different material.
8/82	Latching relay failed during testing.	Relay replaced.
3/8/82	Air start sensing line not seismically supported.	Sensing line relocated and properly supported.
1/29/82	Governor lube oil cooler located too high. Possibility of trapping air in system.	Lube oil cooler relocated to lower elevation.
3/23/82	Engine pneumatic logic improperly design. Could result in premature engine shutdown.	Pneumatic logic design corrected.

Date	Problem	Cause/Solution
4/29/81	Non-Class 1E motors supplied with EDG auxiliary system pumps.	Motors replaced with Class 1E qualified motors.
3/15/82	Crankcase cover capscrew failed. Head lodged in generator and shorted it out.	Capscrews replaced with higher strength screws. Lock tab washers installed. Generator screens installed.
8/2/83	High pressure fuel injection line failed.	Manufacturing defect in tubing. Tubing replaced.
9/4/83	Fuel oil line failed. Caused major fire.	High cycle fatigue of Swagelock fitting. Additional tubing supports to be installed.
8/11/83	Cracks in connecting push rod welds.	All push rods replaced.
1983	Turbocharger vibration.	Turbocharger replaced.
1983	Cracked jacket water welds.	Excessive turbocharger vibration. Cracks re-welded.
1983	Turbocharger mounting bolt failures.	Excessive turbocharger vibration. Bolts replaced.
7/83	Air start valve failures.	Cause unknown. System cleaned and several valves replaced. More frequent maintenance scheduled.
10/28/83	Fuel oil leak. Cracked push rod weld.	Tubing replaced. Push rod replaced.
During EDG Installation	Cylinder head cracks.	Head replaced.
12/83	Cylinder head cracks.	Two heads replaced.
12/83	Cracks in piston skirts on Division II EDG.	All Division II pistons replaced. Division I pistons to be inspected.
9/83	Unqualified instrument cable.	Replaced in response to Part 21 report.

Shoreham

- Three TDI Diesel Engines installed, Model DSR-48
- Serial No. 74010-12, Rated at 3500KW
- Operating hours at time of crankshaft failure (8/83)
  - #101 = 646 (cracked crankshaft)
  - #102 = 718 (failed crankshaft)
  - #103 = 818 (cracked crankshaft)

The engines at Shoreham are the first straight-8 units to be placed in nuclear service in the U. S. One of the Shoreham engines (#101) was used to qualify the straight-8 series (R48) diesel engine for nuclear service.

Pre-operational testing of the engines at Shoreham started in late 1981 and continued until the major failure of the #102 crankshaft on August 12, 1983. After the performance of extensive tests in late September and early October, which were observed by staff members from NRR and Region I, as well as an NRC consultant, LILCo presented the results of its crankshaft failure investigation in a meeting on November 3, 1983. It reported that the crankshaft had been improperly designed, and had failed because the loading function used in the original design calculations was too small. LILCo also reported that it was investigating four failed connecting rod bearings which were discovered when the EDGs were disassembled. Their preliminary finding was that the failures occurred because the bearing material did not meet specifications, and the bearing loads had not been properly accounted for. A detailed list of the EDG problems at Shoreham follows.

Date	Problem	Cause/Solution
3/81	Excessive turbocharger thrust bearing wear.	No lube oil during standby. Lube oil system modified.
12/81	Piston modifications to prevent crown separation.	Pistons reworked by TDI to respond to Part 21 report. Problem identified at Grand Gulf.
9/82	Engine jacket water pump modifications.	Water pumps reworked by TDI.
6/82	Air starting valve capscrews replaced. Too long for holes.	Response to Part 21 report.
9/82	Engine jacket water pump shaft failed by fatigue.	Pump shafts redesigned and replaced.
Spring/1983	Cracks in engine cylinder heads.	Fabrication flaws. All heads replaced.

Date	Problem	Cause/Solution
3/83	Two fuel oil injection lines ruptured.	Manufacturing defect in tubing. Tubing replaced with shielded design.
3/83	Engine rocker arm shaft bolt failure.	High stress cycle fatigue. Bolts replaced with new design.
8/12/83	Broken crankshaft. Cracks in remaining crankshafts.	Inadequate design. Replaced with larger diameter crankshafts.
9/83	Cracked connecting rod bearings.	Inadequate design and substandard material. Replaced with new design.
10/83	Cracked piston skirts.	Replaced all piston skirts with new design. Generic problem.
11/83	Broken cylinder head stud nuts.	Replaced all head stud nuts.
9/83	Cracked bedplates in area of main journal bearings.	Cracks evaluated by LILCo and determined to not be significant.
9/83	Unqualified instrument cable.	Replaced in response to Part 21 report.

Operating Experience - Non-Nuclear

Marine Applications

Besides being used for stationary electric power generation, TDI diesel engines have been placed in service as propulsion units on commercial cargo vessels. As part of the Shoreham operating license hearing, an intervenor, Suffolk County, requested and was granted by the Licensing Board, subpoenas for the State of Alaska, U. S. Steel, and Titan Navigation, Inc. These three organizations operate vessels which use TDI V-16 diesel engines which are very similar to most of the TDI units installed in nuclear power plants. The responses which were received indicate that the TDI engines in marine service for these organizations have experienced severe reliability problems. Most have related to faulty cylinder heads, but they have also included problems with pistons, cylinder liners, turbochargers, cylinder blocks, connecting rods, connecting rod bearings, main journal bearings, and camshafts. A detailed experience list follows. The staff is reviewing this material to see how much of it is applicable to engines in nuclear service.

Marine Experience with TDI Diesel Generators

State of Alaska, M. V. Columbia

- Vessel fitted with two DMRV-16-4 Engines - Serial No. 72033/34
- Rated at 9200 HP (6900 KW) at 450 RPM
- Vessel and engines placed in service in June 1974.
- Each engine has approximately 30,000 hours of operating time to date.

Document Date	Problem Description
12/76	All cylinder liner seals replaced. All cylinder heads have been removed, reinstalled, or renewed at least three times.
	All pistons have been removed and reinstalled at least once.
	Turbochargers have been removed, repaired and reinstalled, or renewed 16 times due to leaking oil seals, vibration, rotor damage, or defective bearing seal housing.
	Exhaust manifolds have been removed and reinstalled because of frozen expansion joints and resulting cylinder head flange face damage.
	Lube oil consumption is excessive.
6/15/78	Rapid deteriorations of fire seal rings causing blowby across gasket surface of cylinder heads.
	Very low lube oil filter life (40 hours). Caused by blowby of pistons and valve guides.
	Stainless steel exhaust bellows burn out rapidly. Installed backwards by TDI.
11/28/78	(Letter to Alaska from TDI).
	Recommends timing changes to improve turbocharger performance.

Document Date	Problem Description
1/31/79	Valve seats and valve guides not concentric. Results in bad valve contact.
	Defective piston rings shipped as replacement parts.
	Reworked cylinder head received from TDI without all required modifications and with damaged gasket face.
	Newly furnished cylinder liners received with incorrect surface finish (twice).
	Connecting rod bearings furnished as spare parts were wrong size - 13" vice 12".
	Turbocharger exhaust flex section incorrectly furnished by TDI.
2/2/79	Chrome plating failure of piston rings. Caused heavy scoring of cylinder liner. Associated cylinder head found cracked.
	Seven cylinder heads replaced during 15 weeks of operation.
	Excessive lube oil filter change out rate. Due to piston blowby.
	Fuel injector spray tips changed at TDI recommendation to reduce carbon buildup and eliminate washing of liner walls with fuel oil.
	Three major overhauls of engines in 5 years of operation.
	Carbon accumulations in rocker box areas.
	Excessive oil vapor discharge from engine crankcases.
	Heavy carbon deposits on valve springs. Suspect valve blowby.
	When exhaust valve guides were modified by TDI, they did not follow the procedure outlined in their SIM (Service Information Memo).

Document Date	Problem Description
	Loose piston pin end caps.
	Incorrect piston crown to skirt bolt torque.
	Bad connecting rod bearings. Excessive wear, cracks.
	Damaged connecting rod bolts.
	Valve push rods cracked at weld of ball to pipe. QC problem.
	Crankshaft size changed after engines for ship installed. No notice to owners of reason for change.
	Excessive main bearing wear.
	Camshaft lobe hard facing worn.
	TDI recommended the installation of a new flexible exhaust duct which was too short (new design). Installation attempted at insistence of TDI. Unit damaged by attempt and returned to TDI for repair.
3/19/79	QC or material problems with respect to non-concentricity/out-of-round valve seats, push rods, rod bolts, bearing shells, valve stem plating.
6/14/79	Thermal growth and cracking of exhaust manifold.
12/26/79	Failure of new connecting bearings.
	Cracks of 25% of connecting rods.

Document Date	Problem Description
1/16/80	Ten (10) new cylinder heads have cracks. This includes 8 that were previously repaired.
	Fifteen (15) valves are defective with chrome flaking off the valve stems.
	Valve stems are being deformed.
	Five additional push rods have cracks.
	Turbocharger air cooler inlet housing is cracked for fourth time.
	Internal bracing in engine intercoolers is cracked.
2/5/80	Piston rings installed improperly because mistake by TDI in the drawing used by TDI shop.
2/29/80	Piston crown-to-skirt nut torque inconsistent among nuts on various pistons.
	Excessive link rod bushing bail wear caused by improperly relieved, drilled oil passages on the matching link rod pins.
3/24/80	Abnormal carbon deposits and formations noted on pistons and cylinder head assemblies.
	Fretting of jaw areas of connecting rods.
	Insufficient turbo (manifold) air except at near full speed operation.
	Cracked exhaust manifold end plates.
	Cracking of connecting rod boxes.
	Cracking of newly installed connecting rod bearing shells at 4500/hours.

Document Date	Problem Description
	Fretting of link rod and link rod pins at their attachment together.
	Fretting between link rod bushings and link rod bushing bore.
	Galling of link rod bushings in way of link rod pin outer drilled oil passages.
	Improper wear/contact pattern on newly installed connecting rod bearings at 4500/hours. Four-point loading.
	Insufficient connecting rod bearing wear/contact area to journal wherein it is less than 15% of the total bearing area.
	Upsetting of stems in valve keeper area.
	Damage to number four piston ring and ring groove on all pistons modified during the 1978-79 engine teardown and rebuilt after 4500/hours operation.
	Fretting between piston crown and skirts at 4500/hours since piston modifications.
	Variations in piston bolt torque, beyond specified limits, at 4500/hours since piston modifications.
	Damage to rod bolts, including cracking, and damage to threads on both the bolt and in the rod boxes.
4/18/80	Exhaust manifold conversion kits received with cuts and grooves in finished surface. Required rework by owner before installation.
5/12/80	New connecting rods received without required code (American Bureau of Shipping) approval. TDI did not have record of which rods were shipped with approval or without approval.
	Some new connecting rods shipped with oversize bearings but no note to customer informing of difference.

Document Date	Problem Description
5/14/80	Cylinder head returned to TDI has been lost by TDI. Cannot be located.
5/15/80	Customer received new connecting rod bolt in rusty condition with damaged threads.
5/27/80	Customer received reworked cylinder heads with lip left on exhaust seats which prevents valves from seating.
	Customer noted that it now was in possession of two cylinder heads with the same serial number.
	Could not install lockwire in new connecting rod cap screw. Hole drilled partway through with drill broken off in center of hole. Also noted that edges of lockwire holes on other screws had not been rounded to prevent damage to lockwire.
5/29/80	Discovered leaks in newly installed exhaust manifold head plates.
9/4/80	(Meeting Summary)
	TDI says that all cylinder head problems should be corrected by new design.
	TDI reports that connecting rod bearing cracks could have resulted from bad bearing alloy makeup by vendors. TDI looking at different bearing materials.
	TDI stated that they had erred on piston modifications. Effected others besides COLUMBIA.
9/30/80	Eleven remaining master connecting rods to be sent to TDI to have oversize bearings and other modifications installed.
	Many of the original cylinder heads that were returned to TDI for rework were exchanged for other used heads.

Document Date	Problem Description
11/6/80	Cylinder head changed due to heavy external water leakage.
	Severe smoke causing excessive lube oil contamination and engine room atmosphere problems. Engine secured to prevent possible crankcase explosion.
12/10/80	All connecting rods removed. New rod cap screws and washers to be installed because increased torque specified by TDI caused galling.
	New connecting rod bearing shell found cracked.
	Heavy wear noted on piston side thrust areas. Heavy hard carbon buildup noted in area of compression rings. Fourth ring groove area to be reworked by TDI due to design/machine error by TDI during previous modifications.
	Nineteen (19) of 32 cylinder liners exceed spec for out-of-round. TDI to modify limits to permit continued usage.
	Twenty-one (21) of 32 liners lost crush. New phenomena. Repairs require machining of engine block.
	Fuel injectors removed and to be changed from 140° spray pattern to 135° pattern. Original nozzles had 150° pattern.
1/16/81	Cylinder block bores found to be distorted.
	Four new engine camshafts installed.

Document Date	Problem Description
3/13/81	Reworked cylinder heads were returned to the customer without removing the grinding compound from the valves and valve seats.
	Two reworked pistons returned to customer without roll pins, which lock the securing nuts in place.
	Cylinder liner delivered with wrong surface finish.
	Cracks found in cylinder blocks. All replaced.
	Main engine blocks found to be cracked and warped. The main block-to-base through bolts appear to have been improperly torqued during initial assembly.
	One "new" camshaft found to be a rebuilt unit containing several damaged bearing journal areas.
	The threaded head stud holes in the new cylinder blocks were not counterbored deeper, as TDI had indicated they currently do. This was to eliminate cracking of the block near the stud holes. The customer re-machined each of the 256 head studs to accomplish the same intent.
4/9/81	Several reworked pistons were returned without groove pins.
	In response to a request for 20 1½" capscrews and washers, TDI supplied 1 7/8" capscrews.
	Drawings furnished by TDI for head stud modifications were not applicable to the studs in question.
	50% of the fuel pump bases would not fit onto the new cylinder blocks because of slight changes in the design of the blocks.

Document Date	Problem Description
	Two new cylinder liners provided with incorrect surface finish.
	One new cylinder liner provided with flange thickness larger than manufacturer's maximum tolerance.
	New connecting rod capscrews were found to be galled and unfit for use.
4/29/81	Service manual showed incorrect installation of engine camshafts.
	2/3 of fuel cam tappet assemblies on one engine could not be installed on one engine because the new cylinder blocks had not been properly counterbored.
	Cylinder liner counterbore depths were off to such an extent that difficulty experienced in establishing proper liner crush.
	Weld spatter noted on many seating surfaces.
	Dirt, sand, and metal showings found in passages and holes which should have been clean.
	Cylinder head water port outlet locations varied considerably, causing a water flow restriction.
	Air start distributor not properly assembled at factory.
6/1/81	Exhaust manifold head plate developed a leak. Cracks found around 2 of 3 tie rods due to poor initial welding.
11/19/81	Defective valve springs found on one engine.
7/29/82	Valve rotator failed.
	Cracks discovered in the intercooler.

Document Date	Problem Description
7/29/82	"In nine years of operation every basic engine component has been modified or replaced with an improved item, at least once, with the exception of the crankshaft (which is obsolete and has not been used for years), the engine base, the fuel pumps and the governor. The last two items are not manufactured by TDI."
10/15/82	Turbochargers replaced.
	Exhaust valve lubricating system to be installed.
3/9/83	Cracks discovered in three cylinder heads.
	Reworked cylinder returned to customer with tap broken off in threaded hole. Others returned with internal cracks and damaged flange faces.

Titan Navigation, M. V. Pride of Texas

- Vessel fitted with two DMRV-12-4 engines, Serial No. unknown
  Rated at 7800 HP at 450 RPM
- Engines installed 1981 - no information on total engine hours to date.

Document Date	Problem Description
7/16/82	Catastrophic piston failure. Due to crack in piston skirt. Engine had 5791 hours of operation.
4/1/82	Cylinder block broken and cracked.
	Cylinder head cracked.
	Cylinder liner cracked.
	Piston skirt fractured.
	Suspect that all of above problems caused by water leaking into cylinder from air intake manifold. Leaking tubes found in air intercooler.
8/19/82	Cracks discovered in six piston skirts.
7/22/82	Cracked exhaust valve seats in cylinder heads. Engine had 3000 hours service.
	Camshaft lobe design appears to be deficient. Causes excessive stress on fuel cam lobe and roller.
	Tappet assembly rollers severely galled. Believed to be due to camshaft and lobe placement and inadequate heat treatment.
	Fuel cam lobes have failed twice due to improper heat treatment.
	Chrome plating lost from one piston wrist pin.
	All four intercoolers have failed because of erosion due to high fluid velocity.
	Air start valves have suddenly ceased to function, for no apparent reason.

Document Date	Problem Description
	Plugs in crankshaft oil ways may be cracking because improper material used. Under investigation.
	Fuel oil return lines have failed. To be replaced with heavier wall tubing.
4/1/83	Exhaust valves fail after about 2000 hours of use. Serious problems with cylinder head cracks.
	Turbochargers experiencing difficulty supplying sufficient air.

U. S. Steel, MV E. H. Gott

- Vessel fitted with two DMRV engines (model unknown)
  Engine Serial No. 75039-40
- No information on engine hours to date.

Document Date	Problem Description
11/13/80	Cracked cylinder head. Replaced.
11/1/79	Cracked cylinder head. Replaced.
6/1/80	Cracked cylinder head. Replaced.
10/8/81	Cracked cylinder head. Replaced.

Note: This information was summarized from documents provided by U. S. Steel in response to a subpoena which asked specifically for information about cyliner head failures. Many other portions of the documents were deleted by U. S. Steel, and it appears that the deleted portions referred to problems with other engine parts.

Other Applications

The staff understands that other TDI engines are in service as stationary electric power generators. The operating history of these engines will be taken into consideration during the staff assessment of TDI engines.

Reference List

Shoreham

Letter dated 1/6/84 from B. McCaffrey (LILCo) to H. Denton (NRC)

Board Notification 83-160 dated 10/21/83

Board Notification 83-160 dated 11/17/83

Letter dated 12/9/83 from J. Smith (LILCo) to T. Muley (NRC)

Letter dated 12/9/83 from A. Schwencer (NRC) to M. Pollock (LILCo)

Letter dated 12/29/83 from A. Schewncer (NRC) to M. Pollock (LILCo)

Letter dated 12/16/83 from C. Matthews (TDI) to T. Novak (NRC)

Letter dated 12/16/83 from J. Smith (LILCo) to T. Murley (NRC)

Letter dated 12/16/83 from A. Dynner (Suffolk County) to A. Earley (LILCo)

Letter dated 10/20/83 from A. Earley (LILCo) to L. Brenner (NRC)

Letter dated 10/16/83 from R. Boyer (TDI) to NRC

Letter dated 11/17/83 from A. Earley (LILCo) to L. Brenner (NRC)

IE Information Notice 83-51, dated 8/5/83

IE Inspection Report 99900334/83-01, dated 10/3/83

IE Information Notice 83-58, dated 8/30/83

Grand Gulf

Letter dated 11/15/83 from L. Dale (MP&L) to H. Denton (NRC)

Letter dated 10/19/83 from L. Dale (MP&L) to H. Denton (NRC)

LER 50-416/83-171/03L-0 dated 11/28/83

Letter dated 10/26/83 from L. Dale (MP&L) to H. Denton (NRC)

LER 50-416/83-082/01T-0

LER 50-416/83-126/01T-0

San Onofre Unit 1

LER 50-206/81-017 dated 8/12/81

Letter dated 9/15/81 from H. Ray (SCE) to R. Engelken (NRC)

LER 50-206/80-039 dated 12/23/80

Letter dated 6/8/81 from J. Haynes (SCE) to R. Engelken (NRC)

Marine Applications

Letter dated 12/21/83 from A. Dynner (Suffolk County) to A. Earley (LILCo)

Includes many other individual documents.

Attachment 2

the purpose of the plan to protect against sabotage. And "we were even more astounded" to find NRC inspection reports of the reactor for 1975-1979 and for 1982 indicating that NRC staff, in fact, examined UCLA's activities related to physical protection against sabotage. – *Michael Knapik, Washington*

FINDING SITES FOR FUTURE REACTORS WILL NOT BE A PROBLEM under more restrictive population-density guidelines being considered by NRC, according to an Oak Ridge National Laboratory study for the agency. The study, which has not been endorsed by NRC, concluded that "viable sites exist even in the states and service areas with the largest population densities."

In addition to 48 sites that already have reactors on them, the study identified 90 other sites that meet all six alternatives for population restrictions considered in the study. The alternative restrictions all started by requiring no population in a circle formed at a half-mile radius and no more than 250 persons per square mile the circle within a two-mile radius from the site. Beyond two miles, the effects were tested using several types of restrictions. The alternatives allowed either 500 or 750 persons per square mile in a circle with a 30-mile radius and varied from 1,000 to 3,000 persons per square mile as the maximum density allowed within any 22.5-degree sector drawn in the circle with the 30-mile radius.

The study identified five operating plants that would meet none of the alternatives. While the existing reactors would not be affected, new reactors could not be built on the sites if the new restrictions are adopted. They are Indian Point, Limerick, Millstone, Midland and Zion. Eight other plants met only the sector or radial restrictions. They are Ginna, Fermi, Seabrook, Oyster Creek, Waterford, Braidwood, Turkey Point and St. Lucie.

The study was done as part of an environmental impact study that NRC is preparing for possible revision of its siting regulations. The agency issued an advanced notice of proposed rulemaking in July 1980, but has suspended consideration of new siting regulations until it makes decisions on source term and severe accident issues. – *James Branscome, Washington*

GRAND GULF PROBLEMS MULTIPLY AS LOW POWER LICENSE THREATENED

Prospects are dim for quick issuance of a full-power license for Grand Gulf, and one NRC commissioner is recommending the plant's low-power license be suspended. At a hearing on the status of the plant last week, NRC staff said they couldn't recommend a full-power license until problems with the emergency diesel generators and with defective technical specifications are resolved. Commissioner Victor Gilinsky said problems at the plant are greater than he thought and he suggested the low-power license be suspended until the commissioners are convinced the problems are resolved. Chairman Nunzio Palladino and Commissioner James Asselstine stopped short of recommending the low-power license be suspended but said that before voting on full-power operation they would like a staff update on the areas where the utility did poorly on the last safety review.

Mississippi Power & Light (MP&L) officials said the plant is complete and will be ready for full-power operation as soon as the tech specs and generator problems are solved, but refused to say when that would be.

Grand Gulf is one of 20 plants in the country with Transamerica Delaval (TDI) emergency diesel generators. Because of problems discovered in TDI generators at the Shoreham plant and elsewhere, NRC is reviewing their use on a case-by-case basis. MP&L officials said that only two of their three generators are TDI's, that theirs are a different model than the ones at Shoreham, and that testing shows the generators have a 99% response rate. In addition, the plant has rented three gas turbines to serve as backups for the TDI generators, themselves a backup system. MP&L is also part of a TDI owners' group which is working with NRC to requalify the generators.

The problems with the tech specs are more complex. Grand Gulf is the first BWR 6/Mark III reactor in the country. Because tech specs weren't available, NRC sent MP&L Mark II specs instead as a draft copy, expecting the utility to review and adjust them to meet the actual plant description. Although MP&L didn't do so, NRC staff proceeded on the assumption that it had been done and a low-power license was issued in June 1982. The problem with the tech specs wasn't discovered until recently. MP&L has asked for 205 tech spec changes of which 45% deal with some function of the plant as built.

Gilinsky asked how an earlier utility review of surveillance procedures, which turned up a number of deficiencies in the tech specs and the surveillance procedures, didn't prompt the utility to look at the entire tech spec package. J.B. Richard, senior vice president for nuclear operations, said the review was focused on surveillance procedures, not on the tech specs as a whole. MP&L, he said, is working with NRC staff to come up with a position on the tech spec issue.

Neither staff nor applicant review of the specs was adequate, Hugh Thompson of the Office of Nuclear Reactor Regulation admitted. A long-term review is being conducted on how the problem occurred and how to prevent it from happening again, he said. In the short term, NRC is requiring utilities to certify in writing that their tech specs are correct, he said. A number "are struggling" with the requirement, he said, but he expects they will comply. For Grand Gulf, NRC has asked the Idaho National Engineering Laboratories to make certain that the final safety analysis report and the safety evaluation report reflect these correct specs. NRC Region II staff, meanwhile, is trying to determine if the specs match the plant as built. Both efforts have turned up discrepancies, Thompson added. Additionally, each NRC technical branch has been asked to review its earlier reports on Grand Gulf in light of the tech spec changes, he said.

Gilinsky was joined by Asselstine and Palladino in voicing concern over the latest systematic assessment of licensee performance (Salp) report on which Grand Gulf got the lowest possible rating on five out of nine categories. The five, Gilinsky noted, were the important operational categories (plant operations, maintenance surveillance, licensing activities and quality assurance). The lowest rating signifies that the plant is acceptable but needs some attention, the staff pointed out. But Asselstine commented that the staff found the plant was barely at lowest level in some of the categories, sometimes dipping even lower during the year-long assessment period.

NRC staff said the review showed MP&L has made progress in some of the weak areas. James O'Reilly, Region II administrator, said recent additions to the nuclear management staff are substantial improvements, that work has been done on procedures and they are now in "excellent shape," and that the operator recertification has been successfully completed.

Asselstine, still skeptical, suggested a special team be sent to the plant to review each of the categories before the plant comes up for full-power operation. "I think what we're saying is that before we can go forward, you have to have a satisfactory rating in each of these categories," Gilinsky added. – *Frances Seghers*

SEN. ALAN SIMPSON (R-WYO.) SAID NRC PROCEDURE ON THREE MILE ISLAND restart is more of a problem than the question of TMI management integrity. Simpson, chairman of the Senate Environment & Public Works Subcommittee on Nuclear Regulation, made his comments during a hearing on the NRC authorization bill for FY-84 and -85. He echoed complaints by Sen. Arlen Specter (R-Pa.) about the length of time it has taken the commission to deal with the TMI-1 restart.

"I don't think there's any way you could have constructed this hearing that could have taken any more time than you have," Specter said. The issues involved have been considered by five groups, Specter said. He asked why the commissioners hadn't just held a hearing themselves instead. NRC is considering the integrity of TMI top management, but didn't ask the top two people whether they knew about alleged leak rate falsification until five years after the TMI-2 accident and a week after he first raised the issue, Specter said. Simpson said NRC is "paralyzed by tentativeness," and said he would join with Specter in proposing legislation to simplify NRC procedures.

GPU NUCLEAR, NRC STAFF SPLIT ON STATUS OF INTEGRITY ISSUES

GPU Nuclear has told NRC that all but two issues, on a list of more than 60 potential issues of management integrity, have been resolved and should not hold up Three Mile Island-1 restart. The NRC staff is maintaining that the implications of five major issues remain unknown and should be resolved before TMI-1 ascends above 25% power, while intervenor groups claim the issues are unresolved and the issues list should be far longer

The conflicting claims were filed with the NRC commissioners, who had asked the parties in the restart proceedings to tell them whether the list was accurate and whether each issue had been resolved (INRC, 6 Feb., 5). The list was compiled by the commissioners' Offices of General Counsel and Policy Evaluation, and was released after an angry dispute among the commissioners over whether the list should be made public (INRC, 9 Jan., 1).

"Some of the issues included in the proposed list legitimately can be termed 'integrity' issues," GPU Nuclear said. "However, the vast majority of the issues on the proposed list of integrity issues have absolutely no factual relationship to the issue of licensee's (GPU Nuclear) integrity, other than mere assertion. In the absence of a substantial basis for linking each of these issues with licensees' integrity, that issue ought not be treated by the commission as an integrity issue."

Though the commission itself must make the final decisions that "resolve" issues, GPU Nuclear said, almost all of the issues on the list have been considered, and decided in GPU Nuclear's favor, by Atomic Safety & Licensing Boards or by NRC inspections or investigations. The only exceptions, the utility said, are allegations of falsified leak rates at TMI-1 and -2 before the March 1979 accident, which are two of the issues on the list. The GPU Nuclear filing was made before Metropolitan Edison, the General Public Utilities subsidiary that ran TMI before GPU Nuclear, pleaded guilty and no contest in federal court to criminal counts involving the TMI-2 leak rate tests. The issues on the list involve management knowledge of the alleged falsifications.

But for all other issues, GPU Nuclear said, the commission has enough information to decide them for restart. "Most of the issues on the proposed list were fully addressed and resolved by the licensing board on the basis of extensive record evidence adduced during the restart proceeding. A few of the listed issues were addressed and sufficiently resolved, for purposes of deciding the question of restart, in documents, statements and pleadings provided to the commission. . . . Some of the items were unsuccessfully raised by the intervenors

Attachment 3

it whenever they felt it would be in the best interest of the company to do so. Pierce was associated with Lilco for 34 years. William Catacosinos, a Lilco director since 1978, has been named to replace Pierce. Catacosinos was chief executive officer of Applied Digital Data Systems Inc., a Long Island-based computer company, from 1969 until last November and prior to that was assistant director of the Brookhaven National Laboratory.

Another measure recently taken by Lilco to solve its Shoreham-related problems is to propose a special "business development rate" for established Long Island businesses. It is hoped that, if approved by the state rate commission, the incentive rate would result in larger power sales, possibly decreasing the overall rate increase needed to pay for Shoreham. Concern over the anticipated 56% rate increase has fueled opposition to Shoreham.

The utility's proposal is to give its customers with yearly demands of 100-kw or more – about 3000 businesses – a discount of about one cent per kilowatt hour for electricity consumed above their 1982 levels, according to another Lilco spokesman. "This is power that wouldn't be used otherwise," he said. "This should encourage them to use more power, our reserve power." Lilco expects no growth in consumption for the next year and, said the spokesman, any increase in power sold would translate into lower rates for everyone.

DENTON BANS OPERATIONS WITH DELAVAL DIESELS UNTIL PROBLEMS RESOLVED

No nuclear plant will be allowed to operate with a Transamerica Delaval Inc. (TDI) emergency diesel generator until technical questions about their operating history are answered, said Harold Denton, NRC's director of Nuclear Reactor Regulation (NRR). His decision most immediately puts a hurdle in the paths of the utilities trying to get Shoreham and Grand Gulf-1 on line, although there are nine others with TDI diesels.

It was a split crankshaft in one of three TDI diesels at Long Island Lighting Co.'s (Lilco) Shoreham that first drew attention to them (NW, 25 Aug. '83, 6). Discovery of more problems with similar diesels at other sites led NRC officials to declare in October 1983 that they would require case-by-case demonstrations of the adequacy of each diesel (Inside NRC, 31 Oct. '83, 10). Now, said Denton at a Jan. 26 meeting of his top staff and utility and TDI executives, further inspections at TDI's Oakland, Calif., plant and collection of more operating data have convinced NRC staff that the issue is "very serious." Some findings have been sent to NRC's Office of Investigations (OI). Based on findings to date, Darrell Eisenhut, Denton's director of licensing, said that "our overall confidence in TDI diesel generators had been significantly reduced," and "their reliability will have to be demonstrated."

Similar problems showed up during testing at Shoreham, Mississippi Power & Light's (MP&L) Grand Gulf-1, and Southern California Edison's (SCE) San Onofre-1, NRC staffers told the meeting. They said the same types of problems have occurred in marine use of the diesels. Cylinder head cracking, piston skirt cracks and crown separation, turbocharger vibrations, fuel line failures, and fires were all experienced in more than one of the diesels, whose operating times varied from 450 hours at San Onofre-1, which is shut for seismic repairs, to more than 30,000 hours for one in marine use. A review of nine NRC inspections of TDI since 1979 showed that more than 60 nonconformances and violations had been found. Those instances included missing quality control paperwork, inspections certified for parts that were not there, and inspections signed off for dates after equipment was actually shipped.

Eleven utilities with TDI diesels have formed an owners' group, hired consultants, and begun a study of both the overall designs and individual components of the TDI diesel models they own. James McGaughy, MP&L nuclear vice president who is chairing the group, said that Failure Analysis Associates, Stone & Webster and independent consultants have been hired for the effort at the Shoreham site and at TDI's plant. Lilco's William Museler said the group plans to produce "document packages" for each of the 57 diesels the group owns, detailing engine-specific design and operation studies and preoperational tests. The first packages, for the Shoreham and the Grand Gulf diesels, are due in March. Other utilities involved in the group and the plants for which they bought TDI diesels are: Gulf States Utilities at River Bend, Carolina Power & Light at Harris-1, Duke Power at Catawba, Cleveland Electric Illuminating at Perry, Texas Utilities Services at Comanche Peak, Georgia Power at Vogtle, Consumers Power at Midland, Sacramento Municipal Utility District at Rancho Seco, and SCE at San Onofre-1.

At the NRC meeting, TDI executives promised full cooperation with the owners' group. Clinton Mathews, TDI vice president and general manager, said the company "will apply all our resources to correct any problems." The company is "dedicated," he said, to quality, to supporting the nuclear industry and to "clearing our tarnished image." Don Bixby, chairman of the TDI board, said the company welcomed the owners' effort because "it would be difficult, on our own, to convince everyone these issues had been properly cared for."

Resolution of the issues is, however, on "the critical path" for Shoreham and Grand Gulf-1, Denton noted. The diesel generator issue is the only thing standing between Lilco and a low-power license for Shoreham, according to an NRC source. The Shoreham licensing board has issued a partial initial decision dismissing all health and safety issues except for the TDI generators, he said, adding that the board will probably have a

Attachment 4

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

October 21, 1983

Docket No. 50-416

MEMORANDUM FOR: Chairman Palladino
Commissioner Gilinsky
Commissioner Roberts
Commissioner Asselstine
Commissioner Bernthal

FROM: Darrell G. Eisenhut, Director
Division of Licensing

SUBJECT: NEW INFORMATION CONCERNING TRANSAMERICA DELAVAL (TDI) EMERGENCY DIESEL GENERATORS, BOARD NOTIFICATION 83-160

In accordance with NRC procedures for board notifications, the following information is being provided directly to the Commission. The appropriate boards and parties are being provided with a copy of this memorandum. The information is applicable to Grand Gulf (an uncontested case), which will be before the Commission for full power authorization in November, 1983.

On August 12, 1983, during post-modification testing, the main crankshaft on one of the three emergency diesel generators (EDG) at the Shoreham Nuclear Power Station failed and broke into two pieces. The applicant subsequently inspected the remaining two diesel generators at Shoreham and identified additional flaws in the crankshafts of those machines in locations similar to the failure of the first machine. A more detailed description of the failure is contained in Enclosure 1 (IE Information Notice No. 83-58).

The EDGs at Shoreham were manufactured by Transamerica DeLaval Incorporated (TDI). TDI has also provided EDGs to several other nuclear power plants (see Enclosure 1). The only currently operating reactor with TDI diesels is Grand Gulf. The TDI diesel at San Onofre is used by Unit 1, which is shutdown for seismic modifications, and the diesels at Rancho Seco are not yet installed.

Besides the failure of the crankshaft at Shoreham, the staff has noted the occurrence of many minor problems with TDI EDGs, which are summarized in Enclosure 2. The staff would expect minor problems to occur during the startup testing of any large piece of machinery, such as a diesel generator, but the number of minor problems experienced by the TDI machines in nuclear service appears to be abnormally high (also See Enclosure 4).

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Additionally, during vendor inspections of TDI which were performed recently by Region IV, in response to allegations, the staff identified conditions which imply that portions of the TDI Quality Assurance (QA) Program have not been carried out in accordance with the provisions of 10 CFR 50, Appendix B. Region IV has referred the QA problems to the Office of Investigations, which has requested that details not be revealed to avoid compromising the investigation. As a result of an inspection performed in July 1983, the staff identified a potential violation and several potential nonconformances which are described in IE Inspection Report No. 99900334/83-01, dated October 3, 1983 (Enclosure 5).

The Shoreham applicant is investigating the crankshaft failure, but does not expect to publish a report until later in October. The staff has asked the applicant to address a series of questions concerning the Shoreham EDG design, fabrication, operation, and maintenance in its failure report (see Enclosure 3). A similar list of questions is being developed for other applicants.

The identification of QA problems at TDI, taken together with the number of operational problems and the Shoreham crankshaft failure, has reduced the staff's level of confidence in the reliability of all TDI diesel generators. The staff will require, on a case by case basis, a demonstration that these concerns are not applicable to specific diesel generators because of subsequent inspections or testing performed specifically to address the above matters. Further developments and additional information on this subject will be reported to the appropriate Boards.

Darrell G. Eisenhut, Director
Division of Licensing

Enclosures:
(1) IE Information Notice 83-58
(2) Summary of DeLaval DG Problems (12/80-8/83)
(3) Summary of September 2, 1983 EDG Meeting on Shoreham
(4) IE Information Notice 83-51
(5) IE Inspection Report No. 99900334/83-01 With October 3, 1983 Transmittal Letter to TransAmerica DeLaval, Inc.

cc: See next page

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
MISSISSIPPI POWER & LIGHT COMPANY, et al.	)	Docket No. ________
	)	
(Grand Gulf Nuclear Station, Unit 1)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the above-entitled "SHOW CAUSE PETITION FROM JACKSONIANS UNITED FOR LIVABLE ENERGY POLICIES' have been served on the following by deposit in the United States Mail, First Class, this ________ day of April, 1984.

At the U. S. Nuclear Regulatory Commission
Washington, DC 20555:

Herbert Grossman, Chairman
Administrative Judge
Atomic Safety and Licensing Board Panel

Dr. James H. Carpenter
Administrative Judge
Atomic Safety and Licensing Board Panel

Dr. Peter A. Morris
Administrative Judge
Atomic Safety and Licensing Board Panel

Atomic Safety and Licensing Board Panel

Atomic Safety and Licensing
Appeal Board Panel

Docketing and Service Section
Office of the Secretary

NRC Staff, c/o Mary E. Wagner

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Mississippi Power & Light Company
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Assistant Vice President,
Nuclear Production
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Conner and Wetterhahn, P.C.
Suite 1050
1747 Pennsylvania Avenue, N.W.
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Individual Commissioners
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

____
Cynthia Stewart
JULEP

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

April 17, 1984

MEMORANDUM FOR: George Messenger, Acting Director
Office of Inspector and Auditor

FROM: James Lieberman, Director
and Chief Counsel
Regional Operations and Enforcement Division
Office of the Executive Legal Director

SUBJECT: 10 CFR 2.206 PETITION FILED BY JACKSONIANS UNITED FOR LIVABLE ENERGY POLICIES CONCERNING GRAND GULF NUCLEAR STATION, UNIT 1

Enclosed please find a copy of a petition dated March 29, 1984, filed pursuant to 10 CFR 2.206 by the Jacksonians United for Livable Energy Policies. The petition questions in part the propriety of the conduct of NRC personnel, including the Office of Inspector and Auditor. The petition is provided for your use as appropriate.

Jim Lieber

James Lieberman, Director
and Chief Counsel
Regional Operations and Enforcement Division
Office of the Executive Legal Director

Enclosure: as stated

cc:
H. Denton, NRR (w/out encl.)
J. O'Reilly, RII (w/out encl.)

May 22, 1984

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