License No. NPF-85

Limerick Generating Station, Unit No. 2

Docket No. 50-353

Issued by the
U.S. Nuclear Regulatory
Commission

Office of Nuclear Reactor Regulation

LIMERICK GENERATING STATION
UNIT 2 OPERATING LICENSE NPF-85 PAGE REVISION LIST
(Generated by Exelon - Not part of Operating License)

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4	Revised by letter dated May 31, 2007
4a	Revised by letter dated August 9, 2007
5 thru 5a	149
6	Original Issue

License Amendment Change List (Generated by Exelon)

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i	Dated December 19, 1994

EXELON GENERATION COMPANY, LLC

LIMERICK GENERATING STATION, UNIT 2

DOCKET NO. 50-353

ADMINISTRATIVE LICENSE CHANGE TO FACILITY OPERATING LICENSE

License No. NPF-85

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. Consistent with Order EA-03-086, the Order requiring compliance with the revised design basis threat, (DBT Order) issued on April 29, 2003, conforming administrative changes to Facility Operating Licenses (FOLs) are required to ensure implementation of DBT Order requirements. Therefore, an administrative license change to FOL No. NPF-85 is being made to incorporate the reference to the revised Physical Security Plan, Safeguards Contingency Plan, and Training and Qualification Plan required by the DBT Order. These changes comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this administrative license change can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this administrative license change will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this administrative license change is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the FOL is changed, as indicated in the attachment.

3. This administrative license change is effective as of its date of issuance and shall be implemented on or before October 29, 2004.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

John A. Nakoski, Section Chief
Security Plan Review Team
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the FOL

Date of Issuance: October 28, 2004

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-353

LIMERICK GENERATING STATION, UNIT 2

FACILITY OPERATING LICENSE

License No. NPF-85

1. The Nuclear Regulatory Commission (the Commission or the NRC) has found that:

   A. The application for license filed by Exelon Generation Company, LLC (Exelon Generation Company or the licensee) complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I, and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the Limerick Generating Station, Unit 2 (the facility) has been substantially completed in conformity with Construction Permit No. CPPR-107 and the application, as amended, the provisions of the Act and the regulations of the Commission;

   C. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the regulations of the Commission (except as exempted from compliance in Section 2.D. below);

   D. There is reasonable assurance: (i) that the activities authorized by this operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I (except as exempted from compliance in Section 2.D. below);

   E. The licensee is technically qualified to engage in the activities authorized by this license in accordance with the Commission's regulations set forth in 10 CFR Chapter I;

   F. The licensee has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

   G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public;

H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of this Facility Operating License No. NPF-85, subject to the conditions for protection of the environment set forth in the Environmental Protection Plan attached as Appendix B, is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied; and

I. The receipt, possession, and use of source, byproduct and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70.

2. Based on the foregoing findings and the Decision of the Atomic Safety and Licensing Board, LBP-85-25, dated July 22, 1985, the Commission's Order dated July 7, 1989, and the Commission's Memorandum and Order dated August 25, 1989, regarding this facility, Facility Operating License NPF-85 is hereby issued to the Exelon Generation Company (the licensee), to read as follows:

A. This license applies to the Limerick Generating Station, Unit 2, a boiling water nuclear reactor and associated equipment, owned by Exelon Generation Company. The facility is located on the licensee's site in Montgomery and Chester Counties, Pennsylvania on the banks of the Schuylkill River approximately 1.7 miles southeast of the city limits of Pottstown, Pennsylvania and 21 miles northwest of the city limits of Philadelphia, Pennsylvania, and is described in the licensee's Final Safety Analysis Report, as supplemented and amended, and in the licensee's Environmental Report-Operating License Stage, as supplemented and amended.

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses Exelon Generation Company:

(1) Pursuant to Section 103 of the Act and 10 CFR Part 50, to possess, use, and operate the facility at the designated location in Montgomery and Chester Counties, Pennsylvania, in accordance with the procedures and limitations set forth in this license;

(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess and to use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility, and to receive and possess, but not separate, such source, byproduct, and special nuclear materials as contained in the fuel assemblies and fuel channels from the Shoreham Nuclear Power Station.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I (except as exempted from compliance in Section 2.D. below) and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Exelon Generation Company is authorized to operate the facility at reactor core power levels of 3458 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 158, are hereby incorporated into this license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Fire Protection (Section 9.5, SSER-2, -4)*

Exelon Generation Company shall implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Final Safety Analysis Report for the facility, and as approved in the NRC Safety Evaluation Report dated August 1983 through Supplement 9, dated August 1989, and Safety Evaluation dated November 20, 1995, subject to the following provision:

The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

*The parenthetical notation following the title of license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(4) Physical Security and Safeguards

Exelon Generation Company shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans[1], submitted by letter dated May 17, 2006, is entitled: "Limerick Generating Station Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan, Revision 2." The set contains Safeguards Information protected under 10 CFR 73.21.

(5) Exelon Generation Company shall provide to the Director of the Office of Nuclear Reactor Regulation a copy of any application, at the time it is filed, to transfer (excluding grants of security interests or liens) from Exelon Generation Company to its direct or indirect parent, or to any other affiliated company, facilities for the production, transmission or distribution of electric energy having a depreciated book value exceeding ten percent (10%) of Exelon Generation Company's consolidated net utility plant, as recorded on Exelon Generation Company's book of accounts.

(6) Exelon Generation Company shall have decommissioning trust funds for Limerick, Unit 2, in the following minimum amount, when Limerick, Unit 2, is transferred to Exelon Generating Company:

Limerick, Unit 2	$59,687,081

(7) The decommissioning trust agreement for Limerick, Unit 2, at the time the transfer of the unit to Exelon Generation Company is effected and thereafter, is subject to the following:

(a) The decommissioning trust agreement must be in a form acceptable to the NRC.

(b) With respect to the decommissioning trust fund, investments in the securities or other obligations of Exelon Corporation or affiliates thereof, or their successors or assigns are prohibited. Except for investments tied to market indexes or other non-nuclear sector mutual funds, investments in any entity owning one or more nuclear power plants are prohibited.

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[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

(c) The decommissioning trust agreement for Limerick, Unit 2, must provide that no disbursements or payments from the trust shall be made by the trustee unless the trustee has first given the Director of the Office of Nuclear Reactor Regulation 30 days prior written notice of payment. The decommissioning trust agreement shall further contain a provision that no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the NRC.

(d) The decommissioning trust agreement must provide that the agreement can not be amended in any material respect without 30 days prior written notification to the Director of the Office of Nuclear Reactor Regulation.

(e) The appropriate section of the decommissioning trust agreement shall state that the trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations.

(8) Exelon Generation Company shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for approval of the transfer of Limerick, Unit 2, license and the requirements of the Order approving the transfer, and consistent with the safety evaluation supporting the Order.

(9) Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(10) The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

(11) Upon implementation of Amendment No. 149 adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 4.7.2.2.a, in accordance with TS 6.16.c.(i), the assessment of CRE habitability as required by Specification 6.16.c.(ii), and the measurement of CRE pressure as required by Specification 6.16.d, shall be considered met. Following implementation:

(a) The first performance of SR 4.7.2.2.a, in accordance with Specification 6.16.c.(i), shall be within the specified Frequency of 6 years, plus the 18-month allowance of SR 4.0.2, as measured from September 16, 2004, the date of the most recent successful tracer gas test, as stated in the December 10, 2004 letter response to Generic Letter 2003-01, or within the next 18 months if the time period since the most recent successful tracer gas test is greater than 6 years.

(b) The first performance of the periodic assessment of CRE habitability, Specification 6.16.c.(ii), shall be within 3 years, plus the 9-month allowance of SR 4.0.2, as measured from September 16, 2004, the date of the most recent successful tracer gas test, as stated in the December 10, 2004 letter response to Generic Letter 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.

(c) The first performance of the periodic measurement of CRE pressure, Specification 6.16.d, shall be within 24 months, plus the 180 days allowed by SR 4.0.2, as measured from September 16, 2004, the date of the most recent successful pressure measurement test, or within 180 days if not performed previously.

D. The facility requires exemptions from certain requirements of 10 CFR Part 50 and 10 CFR Part 70. These include (a) exemption from the requirement of Appendix J, the testing of containment air locks at times when the containment integrity is not required (Section 6.2.6.1 of the SER and SSER-3), (b) exemption from the requirements of Appendix J, the leak rate testing of the Main Steam Isolation Valves (MSIVs) at the peak calculated containment pressure, Pa, and exemption from the requirements of Appendix J that the measured MSIV leak rates be included in the summation for the local leak rate test (Section 6.2.6.1 of SSER-3), (c) exemption from the requirement of Appendix J, the local leak rate testing of the Traversing Incore Probe Shear Valves (Section 6.2.6.1 of the SER and SSER-3), and (d) an exemption from the schedule requirements of 10 CFR 50.33(k)(l) related to availability of funds for decommissioning the facility (Section 22.1, SSER 8). The special circumstances regarding exemptions (a), (b) and (c) are identified in Sections 6.2.6.1 of the SER and SSER 3. An exemption from the criticality monitoring requirements of 10 CFR 70.24 was previously granted with NRC materials license No. SNM-1977 issued November 22, 1988. The licensee is hereby exempted from the requirements of 10 CFR 70.24 insofar as this requirement applies to the handling and storage of fuel assemblies held under this license.

These exemptions are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security. The exemptions in items a, b, c, and d above are granted pursuant to 10 CFR 50.12. With these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

E. Deleted

F. The licensee shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

G. This license is effective as of the date of issuance and shall expire at midnight on June 22, 2029.

FOR THE NUCLEAR REGULATORY COMMISSION

Thomas E Murley

Thomas E. Murley, Director
Office of Nuclear Reactor Regulation

Enclosures:

1. Appendix A - Technical Specifications (NUREG-1376)
2. Appendix B - Environmental Protection Plan

Date of Issuance: August 25, 1989

AUG 2 5 1989

UNIT 2 OPERATING LICENSE NPF-85

LICENSE AMENDMENT CHANGE LIST

(Generated by PECO from NRC Issued Amendments)

License Section 2.C.(2)

The License and the Technical Specifications contained in Appendix A have been revised through the Amendment number on the cover sheet of the License. The Technical Specifications as contained in Appendix A are hereby incorporated into this license. PECO Energy shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Technical Specifications Limerick Generating Station, Unit No. 2

Docket No. 50–353

Appendix "A" to
License No. NPF–85

Issued by the
U.S. Nuclear Regulatory
Commission

Office of Nuclear Reactor Regulation

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1.0 DEFINITIONS

The following terms are defined so that uniform interpretation of these specifications may be achieved. The defined terms appear in capitalized type and shall be applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a Specification which prescribes remedial measures required under designated conditions.

AVERAGE PLANAR EXPOSURE

1.2 The AVERAGE PLANAR EXPOSURE shall be applicable to a specific planar height and is equal to the sum of the exposure of all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

AVERAGE PLANAR LINEAR HEAT GENERATION RATE

1.3 The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) shall be applicable to a specific planar height and is equal to the sum of the LINEAR HEAT GENERATION RATES for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions and channel failure trips.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is tested.

CORE ALTERATION

1.7 CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components within the reactor vessel with the vessel head removed and fuel in the vessel. The following exceptions are not considered to be CORE ALTERATIONS:

a) Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special moveable detectors (including undervessel replacement); and
b) Control rod movement, provided there are no fuel assemblies in the associated core cell.

Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.

CORE OPERATING LIMITS REPORT

1.7a The CORE OPERATING LIMITS REPORT (COLR) is the unit-specific document that provides the core operating limits for the current operating reload cycle. These cycle-specific core operating limits shall be determined for each reload cycle in accordance with Specifications 6.9.1.9 thru 6.9.12. Plant operation within these limits is addressed in individual specifications.

CRITICAL POWER RATIO

1.8 The CRITICAL POWER RATIO (CPR) shall be the ratio of that power in the assembly which is calculated by application of the (GEXL) correlation to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.

DOSE EQUIVALENT I-131

1.9 DOSE EQUIVALENT I-131 shall be that concentration of I-131, microcuries per gram, which alone would produce the same inhalation committed effective dose equivalent (CEDE) as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The inhalation committed effective dose equivalent (CEDE) conversion factors used for this calculation shall be those listed in Table 2.1 of Federal Guidelines Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," ORNL, 1989, as described in Regulatory Guide 1.183. The factors in the column headed "effective" yield doses corresponding to the CEDE.

DOWNSCALE TRIP SETPOINT (DTSP)

1.9a The downscale trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting.

1.10 (Deleted)

EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME

1.11 The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function, i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16a The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

ISOLATION SYSTEM RESPONSE TIME

1.17 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

LOGIC SYSTEM FUNCTIONAL TEST

1.20 A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components, i.e., all relays and contacts, all trip units, solid state logic elements, etc, of a logic circuit, from sensor through and including the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total system steps such that the entire logic system is tested.

LOW (POWER) TRIP SETPOINT (LTSP)

1.20a The low power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 30% and 65% reactor thermal power.

1.21 (Deleted)

MEMBER(S) OF THE PUBLIC

1.22 MEMBER OF THE PUBLIC means any individual except when that individual is receiving an occupational dose.

MAPFAC(F)-(MAPLHGR FLOW FACTOR)

1.22a A core flow dependent multiplication factor used to flow bias the standard Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) limit.

MAPFAC(P)-(POWER DEPENDENT MAPLHGR MULTIPLIER)

1.22b A core power dependent multiplication factor used to power bias the standard Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) limit.

MINIMUM CRITICAL POWER RATIO (MCPR)

1.23 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be the smallest CPR which exists in the core (for each class of fuel). Associated with the minimum critical power ratio is a core flow dependent (MCPR(F)) and core power dependent (MCPR(P)) minimum critical power ratio.

OFFSITE DOSE CALCULATION MANUAL

1.24 The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm/trip setpoints, and in the conduct of the Radiological Environmental Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.9.1.7 and 6.9.1.8.

OPERABLE - OPERABILITY

1.25 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL CONDITION - CONDITION
1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS
1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE
1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRIMARY CONTAINMENT INTEGRITY
1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM
1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With SOLIDIFICATION or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering, based on laboratory scale and full scale testing or experience.

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PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3458 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a.

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.34 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY (Continued)

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

ROD DENSITY

1.38 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

SHUTDOWN MARGIN

1.39 SHUTDOWN MARGIN shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming all control rods are fully inserted except for the single control rod of highest reactivity worth which is assumed to be fully withdrawn and the reactor is in the shutdown condition; cold, i.e. 68°F; and xenon free.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.42 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals.

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

THERMAL POWER

1.43 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TURBINE BYPASS SYSTEM RESPONSE TIME

1.43A The TURBINE BYPASS SYSTEM RESPONSE TIME shall be that time interval from when the turbine bypass control unit generates a turbine bypass valve flow signal until the turbine bypass valves travel to their required position. The response time may be measured by any series of sequential, overlapping, or total steps such that the entire response time is measured.

UNIDENTIFIED LEAKAGE

1.44 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.45 UNRESTRICTED AREA means an area, access to which is neither limited nor controlled by the licensee.

VENTILATION EXHAUST TREATMENT SYSTEM

1.46 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine or radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.47 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

TABLE 1.1

SURVEILLANCE FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 184 days.
A	At least once per 366 days.
E	At least once per 18 months (550 days).
R (Refueling Interval)	At least once per 24 months (731 days).
S/U	Prior to each reactor startup.
P	Prior to each radioactive release.
N.A.	Not applicable.

TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any temperature
2. STARTUP	Startup/Hot Standby	Any temperature
3. HOT SHUTDOWN	Shutdown# ***	> 200°F
4. COLD SHUTDOWN	Shutdown# ## ***	≤ 200°F ****
5. REFUELING*	Shutdown or Refuel** #	NA

#The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that the control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

##The reactor mode switch may be placed in the Refuel position while a single control rod drive is being removed from the reactor pressure vessel per Specification 3.9.10.1.

*Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

**See Special Test Exceptions 3.10.1 and 3.10.3.

***The reactor mode switch may be placed in the Refuel position while a single control rod is being moved provided that the one-rod-out interlock is OPERABLE.

****See Special Test Exception 3.10.8.

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

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2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.07 for two recirculation loop operation and shall not be less than 1.09 for single recirculation loop operation with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.07 for two recirculation loop operation or less than 1.09 for single recirculation loop operation and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

APPLICABILITY: OPERATION CONDITIONS 1, 2, 3, and 4.

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4, and 5

ACTION:

With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required. Comply with the requirements of Specification 6.7.1.

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.

*The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

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-Upscale (Setdown)	≤ 15.0% of RATED THERMAL POWER	≤ 20.0% of RATED THERMAL POWER
b. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.66 W + 62.8% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.66 W + 63.3% and ≤ 117.0% of RATED THERMAL POWER
- Single Recirculation Loop Operation***	≤ 0.66 (W-7.6%) + 62.8% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.66 (W-7.6%) + 63.3% and ≤ 117.0% of RATED THERMAL POWER
c. Neutron Flux - Upscale	118.3% of RATED THERMAL POWER	118.7% of RATED THERMAL POWER
d. Inoperative	N.A.	N.A.
e. 2-Out-Of-4 Voter	N.A.	N.A.
f. OPRM Upscale	****	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤ 1096 psig	≤ 1103 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed
6. DELETED	DELETED	DELETED
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	≤ 261' 1 1/4" elevation**	≤ 261' 9 1/4" elevation
b. Float Switch	≤ 261' 1 1/4" elevation**	≤ 261' 9 1/4" elevation

* See Bases Figure B 3/4.3-1.

** Equivalent to 25.58 gallons/scram discharge volume.

*** The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

**** See COLR for OPRM period based detection algorithm trip setpoints. OPRM Upscale trip output auto-enable (not bypassed) setpoints shall be APRM Simulated Thermal Power ≥ 30% and recirculation drive flow < 60%.

TABLE 2.2.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
9. Turbine Stop Valve - Closure	$\leq$ 5% closed	$\leq$ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	$\geq$ 500 psig	$\geq$ 465 psig
11. Reactor Mode Switch Shutdown Position	N.A.	N.A.
12. Manual Scram	N.A.	N.A.

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BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principle barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.07 for two recirculation loop operation and 1.09 for single recirculation loop operation. MCPR greater than 1.07 for two recirculation loop operation and 1.09 for single recirculation loop operation represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the (GEXL) correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

SAFETY LIMITS

BASES

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity Safety Limit is defined as the CPR in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition considering the power distribution within the core and all uncertainties.

The Safety Limit MCPR is determined using a statistical model that combines all of the uncertainties in operating parameters and the procedures used to calculate critical power. Calculation of the Safety Limit MCPR is described in Reference 1.

Reference:

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

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2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. 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 less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant 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 - Upscale (Setdown) 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 - Upscale 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 Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 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.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 62.8% and 63.3% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 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 APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

References 2, 3 and 4 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (30%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 30% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

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 and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting 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. 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 MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs 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.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.58 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, "Single-Loop Operation Analysis for Limerick Generating Station, Unit 1," August 1986.

2. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), "Guidelines for Stability Option III 'Enable Region' (TAC M92882)," September 17, 1996.

SECTIONS 3.0 and 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the Limiting Conditions for Operation contained in the succeeding Specifications is required during the OPERATIONAL CONDITIONS or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a Specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the ACTION requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within one hour action shall be initiated to place the unit in an OPERATIONAL CONDITION in which the Specification does not apply by placing it, as applicable, in:

a. At least STARTUP within the next 6 hours,
b. At least HOT SHUTDOWN within the following 6 hours, and
c. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specifications.

This Specification is not applicable in OPERATIONAL CONDITION 4 or 5.

3.0.4 When a Limiting Condition for Operation is not met, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability shall only be made:

a. When the associated ACTION requirements to be entered permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time; or

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications; or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements or that are part of a shutdown of the unit.

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for individual Limiting Conditions for Operation, unless otherwise stated in the Surveillance Requirement. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the Limiting Condition for Operation. Failure to perform a Surveillance within the specified Surveillance time interval and allowed extension per Specification 4.0.2, shall be failure to meet the Limiting Condition for Operation except as provided in Specification 4.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 Each Surveillance Requirement shall be performed within the specified surveillance time interval with a maximum allowable extension not to exceed 25% of the surveillance interval.

4.0.3 If it is discovered that a Surveillance was not performed within its specified Surveillance time interval and allowed extension per Specification 4.0.2, then compliance with the requirement to declare the Limiting Condition for Operation not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the Limiting Condition for Operation must immediately be declared not met, and the applicable ACTION requirements must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the Limiting Condition for Operation must immediately be declared not met, and the applicable ACTION requirements must be entered.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified condition in the Applicability of a Limiting Condition for Operation shall only be made when the Limiting Condition for Operation's Surveillance Requirements have been met within their Surveillance time interval, except as provided in Specification 4.0.3. When a Limiting Condition for Operation is not met due to its Surveillance Requirements not having been met, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability shall only be made in accordance with Specification 3.0.4.

This provision shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements or that are part of a shutdown of the unit.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, & 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR Part 50, Section 50.55a. Inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR Part 50, Section 50.55a.

APPLICABILITY

SURVEILLANCE REQUIREMENTS (Continued)

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection activities, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda for inservice testing activities, shall be applicable as follows in these Technical Specifications:

ASME Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities. In addition, the provision of Specification 4.0.2 are applicable to other normal and accelerated frequencies specified as 2 years or less in the Inservice Testing Program for performing inservice testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Code shall be construed to supersede the requirements of any Technical Specification.

f. The Inservice Inspection (ISI) Program for piping identified in NRC Generic Letter 88-01 shall be performed in accordance with the staff positions on schedule, methods and personnel, and sample expansion included in the Generic Letter, or in accordance with alternate measures approved by the NRC staff. Details for implementation of these requirements are included as augmented inspection requirements in the ISI Program.

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3/4.1.1 SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.1.1 The SHUTDOWN MARGIN shall be equal to or greater than:

a. 0.38% $\Delta k/k$ with the highest worth rod analytically determined, or

b. 0.28% $\Delta k/k$ with the highest worth rod determined by test.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5.

ACTION:

With the SHUTDOWN MARGIN less than specified:

a. In OPERATIONAL CONDITION 1 or 2, reestablish the required SHUTDOWN MARGIN within 6 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4, immediately verify all insertable control rods to be inserted and suspend all activities that could reduce the SHUTDOWN MARGIN. In OPERATIONAL CONDITION 4, establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

c. In OPERATIONAL CONDITION 5, suspend CORE ALTERATIONS and other activities that could reduce the SHUTDOWN MARGIN and insert all insertable control rods within 1 hour. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.1 The SHUTDOWN MARGIN shall be determined to be equal to or greater than specified at any time during the fuel cycle:

a. By measurement, prior to or during the first startup after each refueling.

b. By measurement, within 500 MWD/T prior to the core average exposure at which the predicted SHUTDOWN MARGIN, including uncertainties and calculation biases, is equal to the specified limit.

c. Within 12 hours after detection of a withdrawn control rod that is immovable, as a result of excessive friction or mechanical interference, or is untrippable, except that the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod.

3/4.1.2 REACTIVITY ANOMALIES

LIMITING CONDITION FOR OPERATION

3.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall not exceed 1% $\Delta k/k$.

APPLICABILITY: OPERATIONAL CONDITION 1 and 2.

ACTION:

With the reactivity equivalence difference exceeding 1% $\Delta k/k$:

a. Within 12 hours perform an analysis to determine and explain the cause of the reactivity difference; operation may continue if the difference is explained and corrected.

b. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall be verified to be less than or equal to 1% $\Delta k/k$:

a. During the first startup following CORE ALTERATIONS, and

b. At least once per 31 effective full power days during POWER OPERATION.

c. The provisions of Specification 4.0.4 are not applicable.

REACTIVITY CONTROL SYSTEMS

3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION

3.1.3.1 All control rods and scram discharge volume vent and drain valves shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3***

ACTION:

a. With one withdrawn control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable:

1. Within 1 hour:

a) Verify that the inoperable withdrawn control rod is separated from all other inoperable withdrawn control rods by at least two control cells in all directions.

b) Disarm the associated directional control valves** either:

1) Electrically, or

2) Hydraulically by closing the drive water and exhaust water isolation valves.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

2. Restore the inoperable withdrawn control rod to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. With one or more control rods trippable but inoperable for causes other than addressed in ACTION a, above:

1. If the inoperable control rod(s) is withdrawn, within 1 hour:

a) Verify that the inoperable withdrawn control rod(s) is separated from all other inoperable withdrawn control rods by at least two control cells in all directions, and

b) Demonstrate the insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range*.

*The inoperable control rod may then be withdrawn to a position no further withdrawn than its position when found to be inoperable.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

***OPERATIONAL CONDITION 3 is only applicable to the scram discharge volume vent and drain valves.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

2. If the inoperable control rod(s) is inserted, within 1 hour disarm the associated directional control valves** either:

a) Electrically, or

b) Hydraulically by closing the drive water and exhaust water isolation valves.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

c. With more than 8 control rods inoperable, be in at least HOT SHUTDOWN within 12 hours.

d. With one or more scram discharge volume (SDV) vent or drain lines with one valve inoperable, restore the inoperable valve(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

e. With one or more SDV vent or drain lines with both valves inoperable, isolate the associated line within 8 hours **** or be in at least HOT SHUTDOWN within the next 12 hours*** and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The scram discharge volume drain and vent valves shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by:

a. Verifying each valve to be open,* and

b. Cycling each valve through at least one complete cycle of full travel.

* These valves may be closed intermittently for testing under administrative controls.

** May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

***Separate Action entry is allowed for each SDV vent and drain line.

****An isolated line may be unisolated under administrative control to allow draining and venting of the SDV.

SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.2 When above the preset power level of the RWM, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. In accordance with the Surveillance Frequency Control Program, and

b. Within 24 hours from discovery that a control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6, and 4.1.3.7.

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves:

   1. Close within 30 seconds after receipt of a signal for control rods to scram, and

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume scram and control rod block level instrumentation in accordance with the Surveillance Frequency Control Program.

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 5, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the maximum scram insertion time of one or more control rods exceeding 7 seconds:

a. Declare the control rod(s) with the slow insertion time inoperable, and

b. Perform the Surveillance Requirements of Specification 4.1.3.2c. at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

Otherwise, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement and, during single control rod scram time tests, the control rod drive pumps shall be isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER with reactor coolant pressure greater than or equal to 950 psig, following CORE ALTERATIONS or after a reactor shutdown that is greater than 120 days.

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods in accordance with either "1" or "2" as follows:

1.a Specifically affected individual control rods shall be scram time tested at zero reactor coolant pressure and the scram insertion time from the fully withdrawn position to notch position 05 shall not exceed 2.0 seconds, and

1.b Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure prior to exceeding 40% of RATED THERMAL POWER.

2. Specifically affected individual control rods shall be scram time tested at greater than or equal to 950 psig reactor coolant pressure.

c. For at least 10% of the control rods, with reactor coolant pressure greater than or equal to 950 psig, on a rotating basis, and in accordance with the Surveillance Frequency Control Program.

CONTROL ROD AVERAGE SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.3 The average scram insertion time of all OPERABLE control rods from the fully withdrawn position, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.43
39	0.86
25	1.93
05	3.49

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the average scram insertion time exceeding any of the above limits, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.3 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

FOUR CONTROL ROD GROUP SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.4 The average scram insertion time, from the fully withdrawn position, for the three fastest control rods in each group of four control rods arranged in a two-by-two array, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.45
39	0.92
25	2.05
5	3.70

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the average scram insertion times of control rods exceeding the above limits:

a. Declare the control rods with the slower than average scram insertion times inoperable until an analysis is performed to determine that required scram reactivity remains for the slow four control rod group, and

b. Perform the Surveillance Requirements of Specification 4.1.3.2c. at least once per 60 days when operation is continued with an average scram insertion time(s) in excess of the average scram insertion time limit.

Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.4 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

CONTROL ROD SCRAM ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.1.3.5 All control rod scram accumulators shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:

1. With one control rod scram accumulator inoperable, within 8 hours:

   a) Restore the inoperable accumulator to OPERABLE status, or
   b) Declare the control rod associated with the inoperable accumulator inoperable.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

2. With more than one control rod scram accumulator inoperable, declare the associated control rods inoperable and:

   a) If the control rod associated with any inoperable scram accumulator is withdrawn, immediately verify that at least one control rod drive pump is operating by verifying that control rod charging water header pressure is ≥1400 psig or by inserting at least one withdrawn control rod at least one notch. If no control rod drive pump is operating and:

      1) If reactor pressure is ≥900 psig, then restart at least one control rod drive pump within 20 minutes or place the reactor mode switch in the shutdown position, or

      2) If reactor pressure is <900 psig, then place the reactor mode switch in the Shutdown position.

   b) Insert the inoperable control rods and disarm the associated control valves either:

      1) Electrically, or
      2) Hydraulically by closing the drive water and exhaust water isolation valves.

   Otherwise, be in at least HOT SHUTDOWN within 12 hours.

b. In OPERATIONAL CONDITION 5*:

1. With one withdrawn control rod with its associated scram accumulator inoperable, insert the affected control rod and disarm the associated directional control valves within one hour, either:

   a) Electrically, or
   b) Hydraulically by closing the drive water and exhaust water isolation valves.

*At least the accumulator associated with each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

2. With more than one withdrawn control rod with the associated scram accumulator inoperable or no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position.

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that the indicated pressure is greater than or equal to 955 psig unless the control rod is inserted and disarmed or scrammed.

CONTROL ROD DRIVE COUPLING

LIMITING CONDITION FOR OPERATION

3.1.3.6 All control rods shall be coupled to their drive mechanisms.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*.

ACTION:

a. In OPERATIONAL CONDITIONS 1 and 2 with one control rod not coupled to its associated drive mechanism, within 2 hours:

  1. If permitted by the RWM, insert the control rod drive mechanism to accomplish recoupling and verify recoupling by withdrawing the control rod, and:

     a) Observing any indicated response of the nuclear instrumentation, and

     b) Demonstrating that the control rod will not go to the overtravel position.

     Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

  2. If recoupling is not accomplished on the first attempt or, if not permitted by the RWM, then until permitted by the RWM, declare the control rod inoperable, insert the control rod and disarm the associated directional control valves** either:

     a) Electrically, or

     b) Hydraulically by closing the drive water and exhaust water isolation valves.

     Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod not coupled to its associated drive mechanism, within 2 hours either:

  1. Insert the control rod to accomplish recoupling and verify recoupling by withdrawing the control rod and demonstrating that the control rod will not go to the overtravel position, or

  2. If recoupling is not accomplished, insert the control rod and disarm the associated directional control valves** either:

     a) Electrically, or

     b) Hydraulically by closing the drive water and exhaust water isolation valves.

---

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.3.6 Each affected control rod shall be demonstrated to be coupled to its drive mechanism by observing any indicated response of the nuclear instrumentation while withdrawing the control rod to the fully withdrawn position and then verifying that the control rod drive does not go to the overtravel position:

a. Prior to reactor criticality after completing CORE ALTERATIONS that could have affected the control rod drive coupling integrity,

b. Anytime the control rod is withdrawn to the "Full out" position in subsequent operation, and

c. Following maintenance on or modification to the control rod or control rod drive system which could have affected the control rod drive coupling integrity.

CONTROL ROD POSITION INDICATION

LIMITING CONDITION FOR OPERATION

3.1.3.7 The control rod position indication system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2 with one or more control rod position indicators inoperable, within 1 hour:

   1. Determine the position of the control rod by using an alternate method, or:

      a) Moving the control rod, by single notch movement, to a position with an OPERABLE position indicator,

      b) Returning the control rod, by single notch movement, to its original position, and

      c) Verifying no control rod drift alarm at least once per 12 hours, or

   2. Move the control rod to a position with an OPERABLE position indicator, or

   3. When THERMAL POWER is:

      a) Within the preset power level of the RWM, declare the control rod inoperable.

      b) Greater than the preset power level of the RWM, declare the control rod inoperable, insert the control rod and disarm the associated directional control valves** either:

         1) Electrically, or

         2) Hydraulically by closing the drive water and exhaust water isolation valves.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod position indicator inoperable, move the control rod to a position with an OPERABLE position indicator or insert the control rod.

---

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.3.7 The control rod position indication system shall be determined OPERABLE by verifying:

a. In accordance with the Surveillance Frequency Control Program that the position of each control rod is indicated,

b. That the indicated control rod position changes during the movement of the control rod drive when performing Surveillance Requirement 4.1.3.1.2, and

c. That the control rod position indicator corresponds to the control rod position indicated by the "Full out" position indicator when performing Surveillance Requirement 4.1.3.6b.

CONTROL ROD DRIVE HOUSING SUPPORT

LIMITING CONDITION FOR OPERATION

3.1.3.8 The control rod drive housing support shall be in place.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the control rod drive housing support not in place, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.8 The control rod drive housing support shall be verified to be in place by a visual inspection prior to startup any time it has been disassembled or when maintenance has been performed in the control rod drive housing support area.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.1.4.1 The rod worth minimizer (RWM) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*, **, when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER.

ACTION:

a. With the RWM inoperable after the first 12 control rods are fully withdrawn, operation may continue provided that control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or technically qualified member of the unit technical staff.

b. With the RWM inoperable before the first 12 control rods are fully withdrawn, one startup per calendar year may be performed provided that control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or technically qualified member of the unit technical staff.

c. Otherwise, with the RWM inoperable, control rod movement shall not be permitted except by full scram.***

*See Special Test Exception 3.10.2.

**Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RWM prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

***Control rods may be moved, under administrative control, to permit testing associated with demonstrating OPERABILITY of the RWM.

SURVEILLANCE REQUIREMENTS

4.1.4.1 The RWM shall be demonstrated OPERABLE:

a. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, and in OPERATIONAL CONDITION 1 within 1 hour after RWM automatic initiation when reducing THERMAL POWER, by verifying proper indication of the selection error of at least one out-of-sequence control rod.

b. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, by verifying the rod block function by demonstrating inability to withdraw an out-of-sequence control rod.

c. In OPERATIONAL CONDITION 1 within 1 hour after RWM automatic initiation when reducing THERMAL POWER, by verifying the rod block function by demonstrating inability to withdraw an out-of-sequence control rod.

d. By verifying that the control rod patterns and sequence input to the RWM computer are correctly loaded following any loading of the program into the computer.

3.1.4.2 Deleted.

4.1.4.2 Deleted.

ROD BLOCK MONITOR

LIMITING CONDITION FOR OPERATION

3.1.4.3 Both rod block monitor (RBM) channels shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER and less than 90% of RATED THERMAL POWER with MCPR less than 1.70, or THERMAL POWER greater than or equal to 90% of rated with MCPR less than 1.40.

ACTION:

a. With one RBM channel inoperable:

1. Verify that the reactor is not operating on a LIMITING CONTROL ROD PATTERN, and

2. Restore the inoperable RBM channel to OPERABLE status within 24 hours.

Otherwise, place the inoperable rod block monitor channel in the tripped condition within the next hour.

b. With both RBM channels inoperable, place at least one inoperable rod block monitor channel in the tripped condition within 1 hour.

SURVEILLANCE REQUIREMENTS

4.1.4.3 Each of the above required RBM channels shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION for the OPERATIONAL CONDITIONS specified in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

b. CHANNEL FUNCTIONAL TEST prior to control rod withdrawal when the reactor is operating on a LIMITING CONTROL ROD PATTERN.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system shall be OPERABLE and consist of a minimum of the following:

a. In OPERATIONAL CONDITIONS 1 and 2, two pumps and corresponding flow paths,

b. In OPERATIONAL CONDITION 3, one pump and corresponding flow path.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3

ACTION:

a. With only one pump and corresponding explosive valve OPERABLE, in OPERATIONAL CONDITION 1 or 2, restore one inoperable pump and corresponding explosive valve to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With standby liquid control system otherwise inoperable, in OPERATIONAL CONDITION 1, 2, or 3, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that:

1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

2. The available volume of sodium pentaborate solution is at least 3160 gallons.

3. The temperature of the pump suction piping is within the limits of Figure 3.1.5-1 for the most recent concentration analysis.

SURVEILLANCE REQUIREMENTS (Continued)

b. In accordance with the Surveillance Frequency Control Program by:

1. Verifying the continuity of the explosive charge.

2. Determining by chemical analysis and calculation* that the available weight of Boron-10 is greater than or equal to 185 lbs; the concentration of sodium pentaborate in solution is less than or equal to 13.8% and within the limits of Figure 3.1.5-1 and; the following equation is satisfied:

$$\frac{C}{13\%\ \text{wt.}} \times \frac{E}{29\ \text{atom}\ \%} \times \frac{Q}{86\ \text{gpm}} \geq 1$$

where

C = Sodium pentaborate solution (% by weight)
Q = Two pump flowrate, as determined per surveillance requirement 4.1.5.c.
E = Boron 10 enrichment (atom % Boron 10)

3. Verifying 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.

c. Demonstrating that, when tested pursuant to Specification 4.0.5, the minimum flow requirement of 41.2 gpm per pump at a pressure of greater than or equal to 1230±25 psig is met.

d. In accordance with the Surveillance Frequency Control Program by:

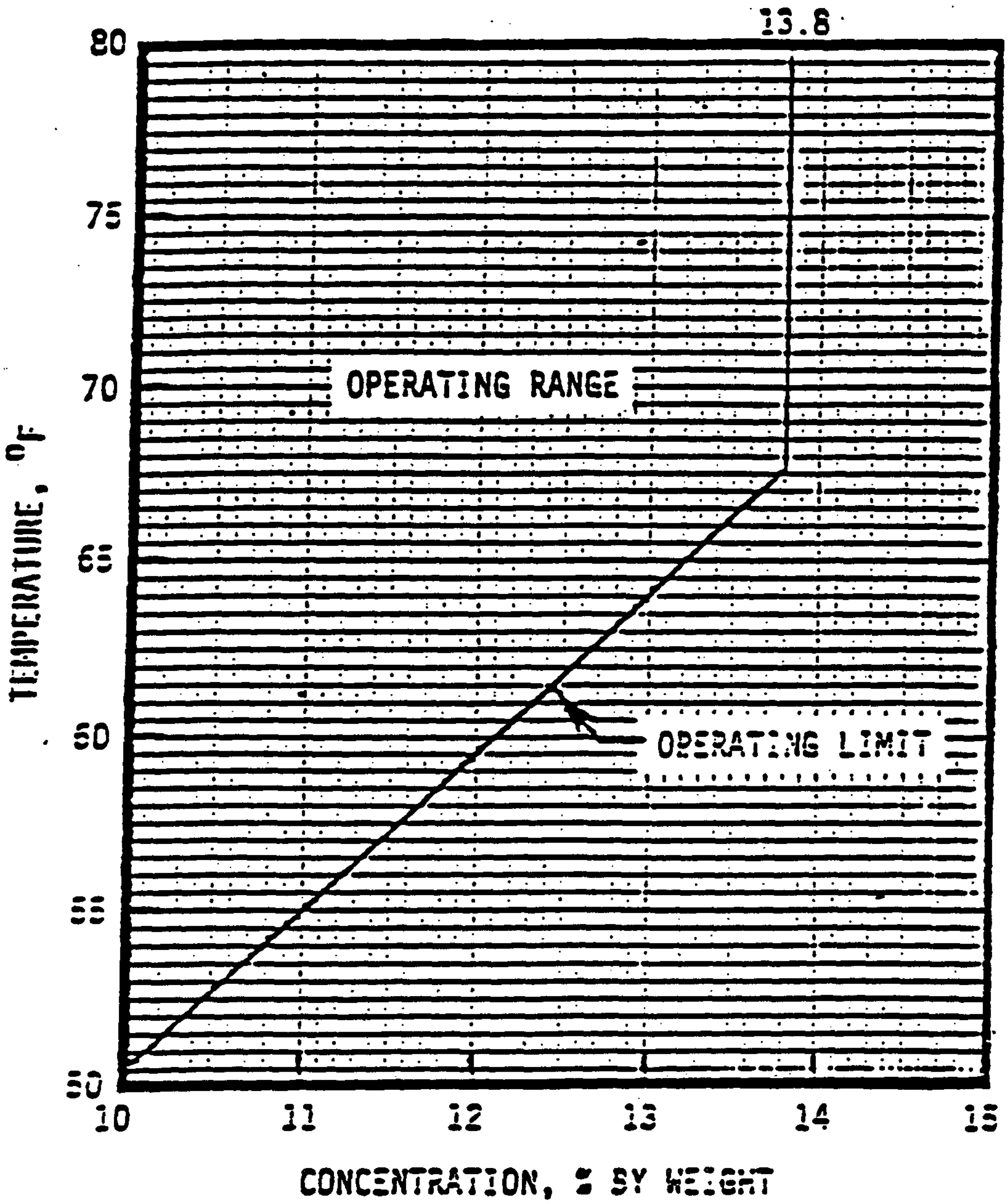
1. Initiating at least one of the standby liquid control system loops, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of the batch successfully fired. All injection loops shall be tested in 3 operating cycles.

2. Verify all heat-treated piping between storage tank and pump suction is unblocked.**

e. Prior to addition of Boron to storage tank verify sodium pentaborate enrichment to be added is ≥ 29 atom % Boron 10.

* This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after water or boron addition or solution temperature is restored.

** This test shall also be performed whenever suction piping temperature drops below the limits of Figure 3.1.5-1 for the most recent concentration analysis, within 24 hours after solution temperature is restored.



SODIUM PENTABORATE SOLUTION
TEMPERATURE/CONCENTRATION REQUIREMENTS

FIGURE 3.1.5-1

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3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of axial location and AVERAGE PLANAR EXPOSURE shall be within limits based on applicable APLHGR limit values which have been determined by approved methodology for the respective fuel and lattice types. When hand calculations are required, the APLHGR for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limiting value for the most limiting lattice (excluding natural uranium) as shown in the CORE OPERATING LIMITS REPORT (COLR). During operation, the APLHGR for each fuel type shall not exceed the above values multiplied by the appropriate reduction factors for power and flow as defined in the COLR.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limiting value, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limiting value:

a. In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

d. The provisions of Specification 4.0.4 are not applicable.

Figures on pages
3/4 2-2 thru 3/4 2-6
have been removed from Technical
Specifications, and relocated to the
CORE OPERATING LIMITS REPORT.

Technical Specifications pages
3/4 2-3 thru 3/4 2-6a
have been INTENTIONALLY OMITTED.

Section 3/4.2.2 (DELETED)

INFORMATION CONTAINED ON

THIS PAGE HAS BEEN

DELETED

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the rated MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, provided that the end-of-cycle recirculation pump trip (EOC-RPT) system is OPERABLE per Specification 3.3.4.2 and the main turbine bypass system is OPERABLE per Specification 3.7.8, with:

$$\tau = \frac{(\tau_{ave} - \tau_B)}{\tau_A - \tau_B}$$

where:

τ_A = 0.86 seconds, control rod average scram insertion time limit to notch 39 per Specification 3.1.3.3,

$$\tau_B = 0.672 + 1.65 \left(\frac{N_1}{\sum_{i=1}^{n} N_i} \right)^{1/2} (0.016),$$

$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i},$$

n = number of surveillance tests performed to date in cycle,

N_i = number of active control rods measured in the i^{th} surveillance test,

τ_i = average scram time to notch 39 of all rods measured in the i^{th} surveillance test, and

N_1 = total number of active rods measured in Specification 4.1.3.2.a.

APPLICABILITY:

OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) EOC-RPT inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

c. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) main turbine bypass valve inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2a and during reactor startups prior to control rod scram time tests in accordance with Specification 4.1.3.2.b.1.b, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit including application of the MCPR(P) and MCPR(F) factors as determined from the CORE OPERATING LIMITS REPORT.

a. In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

Figures on pages
3/4 2-10 thru 3/4 2-11
have been removed from
Technical Specifications, and
relocated to the CORE OPERATING
LIMITS REPORT.

Technical Specifications pages
3/4 2-10a and 3/4 2-11
have been INTENTIONALLY OMITTED.

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3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed the value in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGRs shall be determined to be equal to or less than the limit:

a. In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and in accordance with the Surveillance Frequency Control Program when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each channel.

a. With the number of OPERABLE channels in either trip system for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, within one hour for each affected functional unit either verify that at least one* channel in each trip system is OPERABLE or tripped or that the trip system is tripped, or place either the affected trip system or at least one inoperable channel in the affected trip system in the tripped condition.

b. With the number of OPERABLE channels in either trip system less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) or the affected trip system** in the tripped condition within 12 hours.***

c. With the number of OPERABLE channels in both trip systems for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) in one trip system or one trip system in the tripped condition within 6 hours**.***

d. If within the allowable time allocated by Actions a, b or c, it is not desired to place the inoperable channel or trip system in trip (e.g., full scram would occur), Then no later than expiration of that allowable time initiate the action identified in Table 3.3.1-1 for the applicable Functional Unit.

* For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, at least two channels shall be OPERABLE or tripped. For Functional Unit 5, both trip systems shall have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or tripped. For Function 9, at least three channels per trip system shall be OPERABLE or tripped.

** For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, inoperable channels shall be placed in the tripped condition to comply with Action b. Action c does not apply for these Functional Units.

*** A channel or trip system which has been placed in the tripped condition to satisfy Action b. or c. may be returned to the untripped condition under administrative control for up to two hours solely to perform testing required to demonstrate its operability or the operability of other equipment provided Action a. continues to be satisfied.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, 2.e, and 2.f. Functions 2.a, 2.b, 2.c, 2.d, and 2.f do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM and OPRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific reactor trip system.

TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
1. Intermediate Range Monitors[b]:			
a. Neutron Flux - High	2 3(i), 4(i) 5(i)	3 3 3(d)	1 2 3
b. Inoperative	2 3(i), 4(i) 5(i)	3 3 3(d)	1 2 3
2. Average Power Range Monitor[e]:			
a. Neutron Flux - Upscale (Setdown)	2	3(m)	1
b. Simulated Thermal Power - Upscale	1	3(m)	4
c. Neutron Flux - Upscale	1	3(m)	4
d. Inoperative	1, 2	3(m)	1
e. 2-Out-Of-4 Voter	1, 2	2	1
f. OPRM Upscale	1(o)(p)	3(m)	10
3. Reactor Vessel Steam Dome Pressure - High	1, 2(f)	2	1
4. Reactor Vessel Water Level - Low, Level 3	1, 2	2	1
5. Main Steam Line Isolation Valve-Closure	1(g)	1/valve	4

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TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
6. DELETED	DELETED	DELETED	DELETED
7. Drywell Pressure - High	1, 2(h)	2	1
8. Scram Discharge Volume Water Level - High			
a. Level Transmitter	1, 2 5(i)	2 2	1 3
b. Float Switch	1, 2 5(i)	2 2	1 3
9. Turbine Stop Valve - Closure	1(j)	4(k)	6
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1(j)	2(k)	6
11. Reactor Mode Switch Shutdown Position	1, 2 3, 4 5	2 2 2	1 7 3
12. Manual Scram	1, 2 3, 4 5	2 2 2	1 8 9

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION STATEMENTS

ACTION 1 - Be in at least HOT SHUTDOWN within 12 hours.

ACTION 2 - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the SHUTDOWN position within 1 hour.

ACTION 3 - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.

ACTION 4 - Be in at least STARTUP within 6 hours.

ACTION 5 - Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.

ACTION 6 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

ACTION 7 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 8 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 9 - Suspend all operations involving CORE ALTERATIONS, and insert all insertable control rods and lock the reactor mode switch in the SHUTDOWN position within 1 hour.

ACTION 10 - a. If the condition exists due to a common-mode OPRM deficiency*, then initiate alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours AND restore required channels to OPERABLE status within 120 days,

OR

b. Reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

* Unanticipated characteristic of the instability detection algorithm or equipment that renders all OPRM channels inoperable at once.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) This function shall automatically be bypassed when the reactor mode switch is in the Run position.

(c) DELETED

(d) The noncoincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per Trip System is 6 IRMs.

(e) An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration).

(f) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

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

(j) This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 30% of RATED THERMAL POWER.

(k) Also actuates the EOC-RPT system.

(l) DELETED

(m) Each APRM channel provides inputs to both trip systems.

(n) DELETED

(o) With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 30% or recirculation drive flow is ≥ 60%.

(p) A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - High	N.A.
b. Inoperative	N.A.
2. Average Power Range Monitor*:	
a. Neutron Flux - Upscale (Setdown)	N.A.
b. Simulated Thermal Power - Upscale	N.A.
c. Neutron Flux - Upscale	N.A.
d. Inoperative	N.A.
e. 2-Out-Of-4 Voter	≤0.05*
f. OPRM Upscale	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤0.55
4. Reactor Vessel Water Level - Low, Level 3	≤1.05#
5. Main Steam Line Isolation Valve - Closure	≤0.06
6. DELETED	DELETED
7. Drywell Pressure - High	N.A.
8. Scram Discharge Volume Water Level - High	
a. Level Transmitter	N.A.
b. Float Switch	N.A.
9. Turbine Stop Valve - Closure	≤0.06
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≤0.08**
11. Reactor Mode Switch Shutdown Position	N.A.
12. Manual Scram	N.A.

* Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For application of Specification 4.3.1.3, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.

** Measured from start of turbine control valve fast closure.

\# Sensor is eliminated from response time testing for the RPS circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (n)	CHANNEL FUNCTIONAL TEST (n)	CHANNEL CALIBRATION(a)(n)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	(b)			2
		(j)		3(i), 4(i), 5(i)
b. Inoperative	N.A.	(j)	N.A.	2, 3(i), 4(i), 5(i)
2. Average Power Range Monitor(f):				
a. Neutron Flux - Upscale (Setdown)	(b)	(l)		2
b. Simulated Thermal Power - Upscale		(e)	(d), (g)	1
c. Neutron Flux - Upscale			(d)	1
d. Inoperative	N.A.		N.A.	1, 2
e. 2-Out-Of-4 Voter			N.A.	1, 2
f. OPRM Upscale		(e)	(c)(g)	1(m)
3. Reactor Vessel Steam Dome Pressure - High				1, 2(h)
4. Reactor Vessel Water Level- Low, Level 3				1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.			1
6. DELETED				
7. Drywell Pressure - High				1, 2
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter				1, 2, 5(i)
b. Float Switch	N.A.			1, 2, 5(i)

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK (n)	CHANNEL FUNCTIONAL TEST (n)	CHANNEL CALIBRATION(a)(n)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Turbine Stop Valve - Closure	N.A.			1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.			1
11. Reactor Mode Switch Shutdown Position	N.A.		N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.		N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for a least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.
(c) Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 30% and for recirculation drive flow is < 60%.
(d) The more frequent calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.
(e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.
(f) The LPRMs shall be calibrated at least once per 2000 effective full power hours (EFPH).
(g) The less frequent calibration includes the flow input function.
(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.
(k) DELETED
(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.
(m) With THERMAL POWER ≥ 25% of RATED THERMAL POWER.
(n) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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 requirements for one trip system:

1. If placing the inoperable channel(s) in the tripped condition would cause an isolation, the inoperable channel(s) shall be restored to OPERABLE status within 6 hours. If this cannot be accomplished, the ACTION required by Table 3.3.2-1 for the affected trip function shall be taken, or the channel shall be placed in the tripped condition.

or

2. If placing the inoperable channel(s) in the tripped condition would not cause an isolation, the inoperable channel(s) and/or that trip system shall be placed in the tripped condition within:

a) 12 hours for trip functions common* to RPS Instrumentation,

b) 24 hours for trip functions not common* to RPS Instrumentation.

---

* Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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 1 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 shown in Table 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.

4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operations of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

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 in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times the frequency specified in accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.

** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low-Level 2	B	2	1, 2, 3	21
2) Low, Low, Low-Level 1	C	2	1, 2, 3	21
b. DELETED	DELETED	DELETED	DELETED	DELETED
c. Main Steam Line Pressure - Low	P	2	1	22
d. Main Steam Line Flow - High	E	2/line	1, 2, 3	20
e. Condenser Vacuum - Low	Q	2	1, 2**, 3**	21
f. Outboard MSIV Room Temperature - High	F(f)	2	1, 2, 3	21
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	F(f)	14	1, 2, 3	21
h. Manual Initiation	NA	2	1, 2, 3	24
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level Low - Level 3	A	2	1, 2, 3	23
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	V	2	1, 2, 3	23
c. Manual Initiation	NA	1	1, 2, 3	24

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TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	J	1	1, 2, 3	23
b. RWCS Area Temperature - High	J	6	1, 2, 3	23
c. RWCS Area Ventilation Δ Temperature - High	J	6	1, 2, 3	23
d. SLCS Initiation	$Y^{(d)}$	NA	1, 2, 3	23
e. Reactor Vessel Water Level - Low, Low - Level 2	B	2	1, 2, 3	23
f. Manual Initiation	NA	1	1, 2, 3	24
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	L	1	1, 2, 3	23
b. HPCI Steam Supply Pressure - Low	LA	2	1, 2, 3	23
c. HPCI Turbine Exhaust Diaphragm Pressure - High	L	2	1, 2, 3	23
d. HPCI Equipment Room Temperature - High	L	1	1, 2, 3	23
e. HPCI Equipment Room Δ Temperature - High	L	1	1, 2, 3	23

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
f. HPCI Pipe Routing Area Temperature - High	L	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
h. HPCI Steam Line Δ Press Timer	NA	1	1, 2, 3	23
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	K	1	1, 2, 3	23
b. RCIC Steam Supply Pressure - Low	KA	2	1, 2, 3	23
c. RCIC Turbine Exhaust Diaphragm Pressure - High	K	2	1, 2, 3	23
d. RCIC Equipment Room Temperature - High	K	1	1, 2, 3	23
e. RCIC Equipment Room Δ Temperature - High	K	1	1, 2, 3	23
f. RCIC Pipe Routing Area Temperature - High	K	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
h. RCIC Steam Line Δ Pressure Timer	NA	1	1, 2, 3	23

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION		ISOLATION SIGNAL[a]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM [b]	APPLICABLE OPERATIONAL CONDITION	ACTION
6.	PRIMARY CONTAINMENT ISOLATION				
a.	Reactor Vessel Water Level				
	1) Low, Low - Level 2	B	2	1, 2, 3	20
	2) Low, Low, Low - Level 1	C	2	1, 2, 3	20
b.	Drywell Pressure - High	H	2	1, 2, 3	20
c.	North Stack Effluent Radiation - High [g]	W	1	1, 2, 3	23
d.	Deleted				
e.	Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	S	2	1, 2, 3	23
f.	Deleted				
g.	Deleted				
h.	Drywell Pressure - High/ Reactor Pressure - Low	G	2/2	1, 2, 3	26
i.	Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	M	1	1, 2, 3	26
j.	Manual Initiation	NA	1	1, 2, 3	24

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL[(a),(c)]	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[(b)]	APPLICABLE OPERATIONAL CONDITION	ACTION
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2	B	2	1, 2, 3	25
b. Drywell Pressure - High	H	2	1, 2, 3	25
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	R	2	*#	25
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	R	2	*#	25
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	S	2	1, 2, 3	25
e. Deleted				
f. Deleted				
g. Reactor Enclosure Manual Initiation	NA	1	1, 2, 3	24
h. Refueling Area Manual Initiation	NA	1	*	25

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION
ACTION STATEMENTS

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

ACTION 21 - 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 22 - Be in at least STARTUP within 6 hours.

ACTION 23 - In OPERATIONAL CONDITION 1 or 2, verify the affected system isolation valves are closed within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

ACTION 24 - 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 or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 26 - Close the affected system isolation valves within 1 hour.

TABLE NOTATIONS

* Required when (1) handling RECENTLY IRRADIATED FUEL in the secondary containment, or (2) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

** May be bypassed under administrative control, with all turbine stop valves closed.

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

(a) DELETED

(b) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.

TABLE 3.3.2-1 (Continued)

TABLE NOTATIONS

(c) Actuates secondary containment isolation valves. Signal B, H, S, and R also start the standby gas treatment system.

(d) RWCU system inlet outboard isolation valve closes on SLCS "B" initiation. RWCU system inlet inboard isolation valve closes on SLCS "A" or SLCS "C" initiation.

(e) Manual initiation isolates the steam supply line outboard isolation valve and only following manual or automatic initiation of the system.

(f) In the event of a loss of ventilation the temperature - high setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

(g) Wide range accident monitor per Specification 3.3.7.5.

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TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	≥ - 38 inches*	≥ - 45 inches
2) Low, Low, Low - Level 1	≥ - 129 inches*	≥ - 136 inches
b. DELETED	DELETED	DELETED
c. Main Steam Line Pressure - Low	≥ 756 psig	≥ 736 psig
d. Main Steam Line Flow - High	≤ 122.1 psid	≤ 123 psid
e. Condenser Vacuum - Low	10.5 psia	≥10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	≤ 192°F	≤ 200°F
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	≤ 165°F	≤ 175°F
h. Manual Initiation	N.A.	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level Low - Level 3	≥ 12.5 inches*	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 75 psig	≤ 95 psig
c. Manual Initiation	N.A.	N.A.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
3.	REACTOR WATER CLEANUP SYSTEM ISOLATION		
a.	RWCS Δ Flow - High	≤ 54.9 gpm	≤ 65.2 gpm
b.	RWCS Area Temperature - High	≤ 155°F or ≤ 132°F**	≤ 160°F or ≤ 137°F**
c.	RWCS Area Ventilation Δ Temperature - High	≤ 52°F or ≤ 32°F**	≤ 60°F or ≤ 40°F**
d.	SLCS Initiation	N.A.	N.A.
e.	Reactor Vessel Water Level - Low, Low, - Level 2	≥ -38 inches *	≥ -45 inches
f.	Manual Initiation	N.A.	N.A.
4.	HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION		
a.	HPCI Steam Line Δ Pressure - High	≤ 974" H_2O	≤ 984" H_2O
b.	HPCI Steam Supply Pressure - Low	≥ 100 psig	≥ 90 psig
c.	HPCI Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d.	HPCI Equipment Room Temperature - High	225°F	≥ 218°F, ≤ 247°F
e.	HPCI Equipment Room Δ Temperature - High	≤ 126°F	≤ 130.5°F
f.	HPCI Pipe Routing Area Temperature - High	175°F	≥ 165°F, ≤ 200°F
g.	Manual Initiation	N.A.	N.A.
h.	HPCI Steam Line Δ Pressure - Timer	$3 \leq \tau \leq 12.5$ seconds	$2.5 \leq \tau \leq 13$ seconds

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
5.	REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a.	RCIC Steam Line Δ Pressure - High	≤ 373" H_2O	≤ 381" H_2O
b.	RCIC Steam Supply Pressure - Low	≥ 64.5 psig	≥ 56.5 psig
c.	RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig
d.	RCIC Equipment Room Temperature - High	205°F	≥ 198°F, ≤ 227°F
e.	RCIC Equipment Room Δ Temperature - High	≤ 109°F	≤ 113.5°F
f.	RCIC Pipe Routing Area Temperature - High	175°F	≥ 165°F, ≤ 200°F
g.	Manual Initiation	N.A.	N.A.
h.	RCIC Steam Line Δ Pressure Timer	$3 \leq \tau \leq 12.5$ seconds	$2.5 \leq \tau \leq 13$ seconds

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
6.	PRIMARY CONTAINMENT ISOLATION		
a.	Reactor Vessel Water Level		
	1. Low, Low - Level 2	≥ -38 inches*	≥ -45 inches
	2. Low, Low, Low, Level 1	≥ -129 inches*	≥ -136 inches
b.	Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c.	North Stack Effluent Radiation - High	≤ 2.1 μCi/cc	≤ 4.0 μCi/cc
d.	Deleted		
e.	Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	≤ 1.35 mR/h	≤ 1.5 mR/h
f.	Deleted		
g.	Deleted		
h.	Drywell Pressure - High/ Reactor Pressure - Low	≤ 1.68 psig/ ≥ 455 psig (decreasing)	≤ 1.88 psig/ ≥ 435 psig (decreasing)
i.	Primary Containment Instrument Gas to Drywell Δ Pressure - Low	≥ 2.0 psi	≥ 1.9 psi
j.	Manual Initiation	N.A.	N.A.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
7. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low, Low - Level 2	≥ -38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	≤ 2.0 mR/h	≤ 2.2 mR/h
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	≤ 2.0 mR/h	≤ 2.2 mR/h
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	≤ 1.35 mR/h	≤ 1.5 mR/h
e. Deleted		
f. Deleted		
g. Reactor Enclosure Manual Initiation	N.A.	N.A.
h. Refueling Area Manual Initiation	N.A.	N.A.

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

** The low setpoints are for the RWCU Heat Exchanger Rooms; the high setpoints are for the pump rooms.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION		RESPONSE TIME (Seconds)#
1.	MAIN STEAM LINE ISOLATION	
a.	Reactor Vessel Water Level	
	1) Low, Low - Level 2	N.A.
	2) Low, Low, Low - Level 1	≤1.0###*
b.	DELETED	DELETED
c.	Main Steam Line Pressure - Low	≤1.0###*
d.	Main Steam Line Flow - High	≤0.5###*
e.	Condenser Vacuum - Low	N.A.
f.	Outboard MSIV Room Temperature - High	N.A.
g.	Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
h.	Manual Initiation	N.A.
2.	RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a.	Reactor Vessel Water Level Low - Level 3	N.A.
b.	Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c.	Manual Initiation	N.A.
3.	REACTOR WATER CLEANUP SYSTEM ISOLATION	
a.	RWCS Δ Flow - High	N.A.##
b.	RWCS Area Temperature - High	N.A.
c.	RWCS Area Ventilation Δ Temperature - High	N.A.
d.	SLCS Initiation	N.A.
e.	Reactor Vessel Water Level - Low, Low - Level 2	N.A.
f.	Manual Initiation	N.A.

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TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	N.A.
b. HPCI Steam Supply Pressure - Low	N.A.
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure - High	N.A.
b. RCIC Steam Supply Pressure - Low	N.A.
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

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TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
6. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	N.A.
2) Low, Low, Low - Level 1	N.A.
b. Drywell Pressure - High	N.A.
c. North Stack Effluent Radiation - High	N.A.
d. Deleted	
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	N.A.
f. Deleted	
g. Deleted	
h. Drywell Pressure - High/ Reactor Pressure - Low	N.A.
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.
j. Manual Initiation	N.A.
7. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level Low, Low - Level 2	N.A.
b. Drywell Pressure - High	N.A.
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	N.A.
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	N.A.
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	N.A.
e. Deleted	

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TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
f. Deleted	
g. Reactor Enclosure Manual Initiation	N.A.
h. Refueling Area Manual Initiation	N.A.

TABLE NOTATIONS

(a) DELETED

(b) DELETED

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

** DELETED

Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to the isolation time for the valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

With 45 second time delay.

Sensor is eliminated from response time testing for the MSIV actuation logic circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2				1, 2, 3
2) Low, Low, Low - Level 1				1, 2, 3
b. DELETED				DELETED
c. Main Steam Line Pressure - Low				1
d. Main Steam Line Flow - High				1, 2, 3
e. Condenser Vacuum - Low				1, 2**, 3**
f. Outboard MSIV Room Temperature - High				1, 2, 3
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High				1, 2, 3
h. Manual Initiation	N.A.		N.A.	1. 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level## Low - Level 3				1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High				1, 2, 3
c. Manual Initiation	N.A.		N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High				1, 2, 3
b. RWCS Area Temperature - High				1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High				1, 2, 3
d. SLCS Initiation	N.A.		N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2				1, 2, 3
f. Manual Initiation	N.A.		N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High				1, 2, 3
b. HPCI Steam Supply Pressure, Low				1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. HPCI Equipment Room Temperature - High				1, 2, 3
e. HPCI Equipment Room Δ Temperature - High				1, 2, 3
f. HPCI Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
h. HPCI Steam Line Δ Pressure Timer	N.A.			1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High				1, 2, 3
b. RCIC Steam Supply Pressure - Low				1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. RCIC Equipment Room Temperature - High				1, 2, 3
e. RCIC Equipment Room Δ Temperature - High				1, 2, 3
f. RCIC Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
h. RCIC Steam Line Δ Pressure Timer	N.A.			1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2				1, 2, 3
2) Low, Low, Low - Level 1				1, 2, 3
b. Drywell Pressure ## - High				1, 2, 3
c. North Stack Effluent Radiation - High				1, 2, 3
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High				1, 2, 3
f. Deleted				
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low				1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.			1, 2, 3
j. Manual Initiation	N.A.		N.A.	1, 2, 3

TABLE 4.3.2.1-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2				1, 2, 3
b. Drywell Pressure## - High				1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High				*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High				*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High				1, 2, 3
e. Deleted				
f. Deleted				
g. Reactor Enclosure Manual Initiation	N.A.		N.A.	1, 2, 3
h. Refueling Area Manual Initiation	N.A.		N.A.	*

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

*Required when (1) handling RECENTLY IRRADIATED FUEL in the secondary containment, or (2) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, 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 one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days, provided that the HPCI and RCIC systems are OPERABLE.

   2. 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS 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 shown in Table 4.3.3.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY SYSTEM***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2/pump[(b)]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2/pump[(b)]	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	6[(b)]	1, 2, 3 4*, 5*	31 32
d. Manual Initiation	2[(e)]	1, 2, 3, 4*, 5*	33
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	2	1, 2, 3	31
d. Injection Valve Differential Pressure-Low (Permissive)	1/valve	1, 2, 3, 4*, 5*	31
e. Manual Initiation	1	1, 2, 3, 4*, 5*	33
3. HIGH PRESSURE COOLANT INJECTION SYSTEM##			
a. Reactor Vessel Water Level - Low Low, Level 2	4	1, 2, 3	34
b. Drywell Pressure - High	4	1, 2, 3	34
c. Condensate Storage Tank Level - Low	2[(c)]	1, 2, 3	35
d. Suppression Pool Water Level - High	2	1, 2, 3	35
e. Reactor Vessel Water Level - High, Level 8	4[(d)]	1, 2, 3	31
f. Manual Initiation	1/system	1, 2, 3	33

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
4. AUTOMATIC DEPRESSURIZATION SYSTEM#***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31
e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
g. Manual Initiation	2	1, 2, 3	33
h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

TRIP FUNCTION	TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	1/bus	1/bus	1/bus	1, 2, 3, 4**, 5**	36
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	1/source/bus	1/source/bus	1/source/bus	1, 2, 3, 4**, 5**	37

***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also provides input to actuation logic for the associated emergency diesel generators.

(c) One trip system. Provides signal to HPCI pump suction valves only.

(d) On 1 out of 2 taken twice logic, provides a signal to trip the HPCI pump turbine only.

(e) The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic.

(f) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

* When the system is required to be OPERABLE per Specification 3.5.2.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

** 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 200 psig.

TABLE 3.3.3-1 (Continued)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
ACTION STATEMENTS

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 24 hours or declare the associated system inoperable.

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

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ECCS inoperable within 24 hours.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 24 hours.

ACTION 33 - 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 24 hours or declare the associated ECCS inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the HPCI system inoperable.

b. With more than one channel inoperable, declare the HPCI system inoperable.

ACTION 35 - 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 24 hours or declare the HPCI system inoperable.

ACTION 36 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator and the associated offsite source breaker that is not supplying the bus inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

TABLE 3.3.3-1 (Continued)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
ACTION STATEMENTS

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable.
	127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

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TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Manual Initiation	N.A.	N.A.
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Injection Valve Differential Pressure - Low	≥ 74 psid, (decreasing)	≥ 64 psid and ≤ 84 psid
e. Manual Initiation	N.A.	N.A.
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Condensate Storage Tank Level - Low	≥ 167.8 inches**	≥ 164.3 inches
d. Suppression Pool Water Level - High	≤ 24 feet 1.5 inches	≤ 24 feet 3 inches
e. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 60 inches
f. Manual Initiation	N.A.	N.A.
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. ADS Timer	≤ 105 seconds	≤ 117 seconds
d. Core Spray Pump Discharge Pressure - High	≥ 145 psig,(increasing)	≥ 125 psig, (increasing),
e. RHR LPCI Mode Pump Discharge Pressure-High	≥ 125 psig,(increasing)	≥ 115 psig, (increasing)
f. Reactor Vessel Water Level-Low, Level 3	≥ 12.5 inches	≥ 11.0 inches
g. Manual Initiation	N.A.	N.A.
h. ADS Drywell Pressure Bypass Timer	≤ 420 seconds	≤ 450 seconds

*See Bases Figure B 3/4.3-1.

**Corresponds to 2.3 feet indicated.

TABLE 3.3.3-2 (Continued)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION			TRIP SETPOINT	ALLOWABLE VALUE
5. LOSS OF POWER	RELAY			
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY			
	127-11X0X and 102-11X0X	a.	4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b.	120 V Basis 83 ± 3 volts	83 ± 4 volts
		c.	≤ 1 second time delay	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a.	4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b.	120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c.	≤ 52 second time delay	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 10 second time delay	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 61 second time delay	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS		RESPONSE TIME (Seconds)
1.	CORE SPRAY SYSTEM	≤ 27#
2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	≤ 40#
3.	AUTOMATIC DEPRESSURIZATION SYSTEM	N.A.
4.	HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 60#
5.	LOSS OF POWER	N.A.

ECCS actuation instrumentation is eliminated from response time testing.

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TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3, 4*, 5*
b. Drywell Pressure - High				1, 2, 3
c. Reactor Vessel Pressure - Low				1, 2, 3, 4*, 5*
d. Manual Initiation	N.A.		N.A.	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3, 4*, 5*
b. Drywell Pressure - High				1, 2, 3
c. Reactor Vessel Pressure - Low				1, 2, 3
d. Injection Valve Differential Pressure - Low (Permissive)				1, 2, 3, 4*, 5*
e. Manual Initiation	N.A.		N.A.	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM***				
a. Reactor Vessel Water Level - Low Low, Level 2				1, 2, 3
b. Drywell Pressure - High				1, 2, 3
c. Condensate Storage Tank Level - Low				1, 2, 3
d. Suppression Pool Water Level - High				1, 2, 3
e. Reactor Vessel Water Level - High, Level 8				1, 2, 3
f. Manual Initiation	N.A.		N.A.	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3
b. Drywell Pressure - High				1, 2, 3
c. ADS Timer	N.A.			1, 2, 3
d. Core Spray Pump Discharge Pressure - High				1, 2, 3
e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3
f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
h. ADS Drywell Pressure Bypass Timer	N.A.			1, 2, 3
5. LOSS OF POWER				
a. 4.16 kV Emergency Bus Under voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**
b. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)				1, 2, 3, 4**, 5**

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

* When the system is required to be OPERABLE per Specification 3.5.2.

** Required OPERABLE when ESF equipment is required to be OPERABLE.

*** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

\## Loss of Voltage Relay 127-11X is not field setable.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 24 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

    1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within 24 hours, or, if this action will initiate a pump trip, declare the trip system inoperable.

    2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM *
1. Reactor Vessel Water Level - Low Low, Level 2	2
2. Reactor Vessel Pressure - High	2

* One channel may be placed in an inoperable status for up to 6 hours for required surveillance provided the other channel is OPERABLE.

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches
2. Reactor Vessel Pressure - High	≤ 1149 psig	≤ 1156 psig

* See Bases Figure B3/4.3-1.

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END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

    1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

    2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM*
1. Turbine Stop Valve - Closure	2**
2. Turbine Control Valve-Fast Closure	2**

* A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.

** This function shall be automatically bypassed when turbine first stage pressure is equivalent to THERMAL POWER LESS than 30% of RATED THERMAL POWER.

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	$\leq$ 5% closed	$\leq$ 7% closed
2. Turbine Control Valve-Fast Closure	$\geq$ 500 psig	$\geq$ 465 psig

TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Milliseconds)
1. Turbine Stop Valve-Closure	$\leq$ 175
2. Turbine Control Valve-Fast Closure	$\leq$ 175

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3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The reactor core isolation cooling (RCIC) system actuation instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.5-2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, 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 one or more RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each of the required RCIC system actuation instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. CHANNEL CHECK and CHANNEL CALIBRATION are not required for manual initiation.

4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

FUNCTIONAL UNITS	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION*	ACTION
a. Reactor Vessel Water Level - Low ~~Low,~~ Level 2	4#	50
b. Reactor Vessel Water Level - High, Level 8	4#	51
c. Condensate Storage Tank Water Level - Low	2**	52
d. Manual Initiation	1/system***	53

*A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided all other channels monitoring that parameter are OPERABLE.

**One trip system with one-out-of-two logic.

***One trip system with one channel.

#One trip system with one-out-of-two twice logic.

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM
ACTION STATEMENTS

ACTION 50 - 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 24 hours or declare the RCIC system inoperable.

b. With more than one channel inoperable, 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 within 24 hours.

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 24 hours or declare the RCIC system inoperable.

ACTION 53 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the RCIC system inoperable.

TABLE 3.3.5-2

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNITS	TRIP SETPOINT	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low Low, Level 2	$\geq$-38 inches*	$\geq$-45 inches
b. Reactor Vessel Water Level - High, Level 8	$\leq$ 54 inches	$\leq$ 60 inches
c. Condensate Storage Tank Level - Low	$\geq$ 135.8** inches	$\geq$ 132.3 inches
d. Manual Initiation	N.A.	N.A.

*See Bases Figure B 3/4.3-1.

**Corresponds to 2.3 feet indicated.

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INSTRUMENTATION

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint** less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, 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 Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

* A channel may be placed in an inoperable status for up to 6 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.

**The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 3.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. ROD BLOCK MONITOR[a]			
a. Upscale	2	1*	60
b. Inoperative	2	1*	60
c. Downscale	2	1*	60
2. APRM			
a. Simulated Thermal Power - Upscale	3	1	61
b. Inoperative	3	1, 2	61
c. Neutron Flux - Downscale	3	1	61
d. Simulated Thermal Power - Upscale (Setdown)	3	2	61
e. Recirculation Flow - Upscale	3	1	61
f. LPRM Low Count	3	1, 2	61
3. SOURCE RANGE MONITORS ***			
a. Detector not full in [b]	3	2	61
	2	5	61
b. Upscale[c]	3	2	61
	2	5	61
c. Inoperative[c]	3	2	61
	2	5	61
d. Downscale[d]	3	2	61
	2	5	61
4. INTERMEDIATE RANGE MONITORS			
a. Detector not full in	6	2, 5**	61
b. Upscale	6	2, 5**	61
c. Inoperative	6	2, 5**	61
d. Downscale[e]	6	2, 5**	61
5. SCRAM DISCHARGE VOLUME			
a. Water Level-High	2	1, 2, 5**	62
6. DELETED	DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	2	3, 4	63

TABLE 3.3.6-1 (Continued)

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION

ACTION STATEMENTS

ACTION 60 - Declare the affected RBM channel inoperable and take the ACTION required by Specification 3.1.4.3.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 12 hours or place the inoperable channel in the tripped condition.

b. Two or more 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.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 12 hours.

ACTION 63 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, initiate a rod block.

NOTES

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

(a) The RBM shall be automatically bypassed when a peripheral control rod is selected or the reference APRM channel indicates less than 30% of RATED THERMAL POWER.

(b) This function shall be automatically bypassed if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(c) This function is automatically bypassed when the associated IRM channels are on range 8 or higher.

(d) This function is automatically bypassed when the IRM channels are on range 3 or higher.

(e) This function is automatically bypassed when the IRM channels are on range 1.

(f) DELETED

TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale[a]		
1) Low Trip Setpoint (LTSP)	*	*
2) Intermediate Trip Setpoint (ITSP)	*	*
3) High Trip Setpoint (HTSP)	*	*
b. Inoperative	N/A	N/A
c. Downscale (DTSP)	*	*
d. Power Range Setpoint[b]		
1) Low Power Setpoint (LPSP)	28.1% RATED THERMAL POWER	28.4% RATED THERMAL POWER
2) Intermediate Power Setpoint (IPSP)	63.1% RATED THERMAL POWER	63.4% RATED THERMAL POWER
3) High Power Setpoint (HPSP)	83.1% RATED THERMAL POWER	83.4% RATED THERMAL POWER
2. APRM		
a. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.66 W + 55.2% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.66 W + 55.7% and ≤ 108.4% of RATED THERMAL POWER
- Single Recirculation Loop Operation****	≤ 0.66 (W-7.6%) + 55.2% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.66 (W-7.6%) + 55.7% and ≤ 108.4% of RATED THERMAL POWER
b. Inoperative	N.A.	N.A.
c. Neutron Flux - Downscale	≥ 3.2% of RATED THERMAL POWER	≥ 2.8% of RATED THERMAL POWER
d. Simulated Thermal Power - Upscale (Setdown)	≤ 12.0% of RATED THERMAL POWER	≤ 13.0% of RATED THERMAL POWER
e. Recirculation Flow - Upscale	*	*
f. LPRM Low Count	< 20 per channel < 3 per axial level	< 20 per channel < 3 per axial level
3. SOURCE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 1 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 3 cps**	≥ 1.8 cps**

TABLE 3.3.6-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High a. Float Switch	≤ 257' 7 3/8" elevation***	≤ 257' 9 3/8" elevation
6. DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	N.A.

* Refer to the COLR for these setpoints.

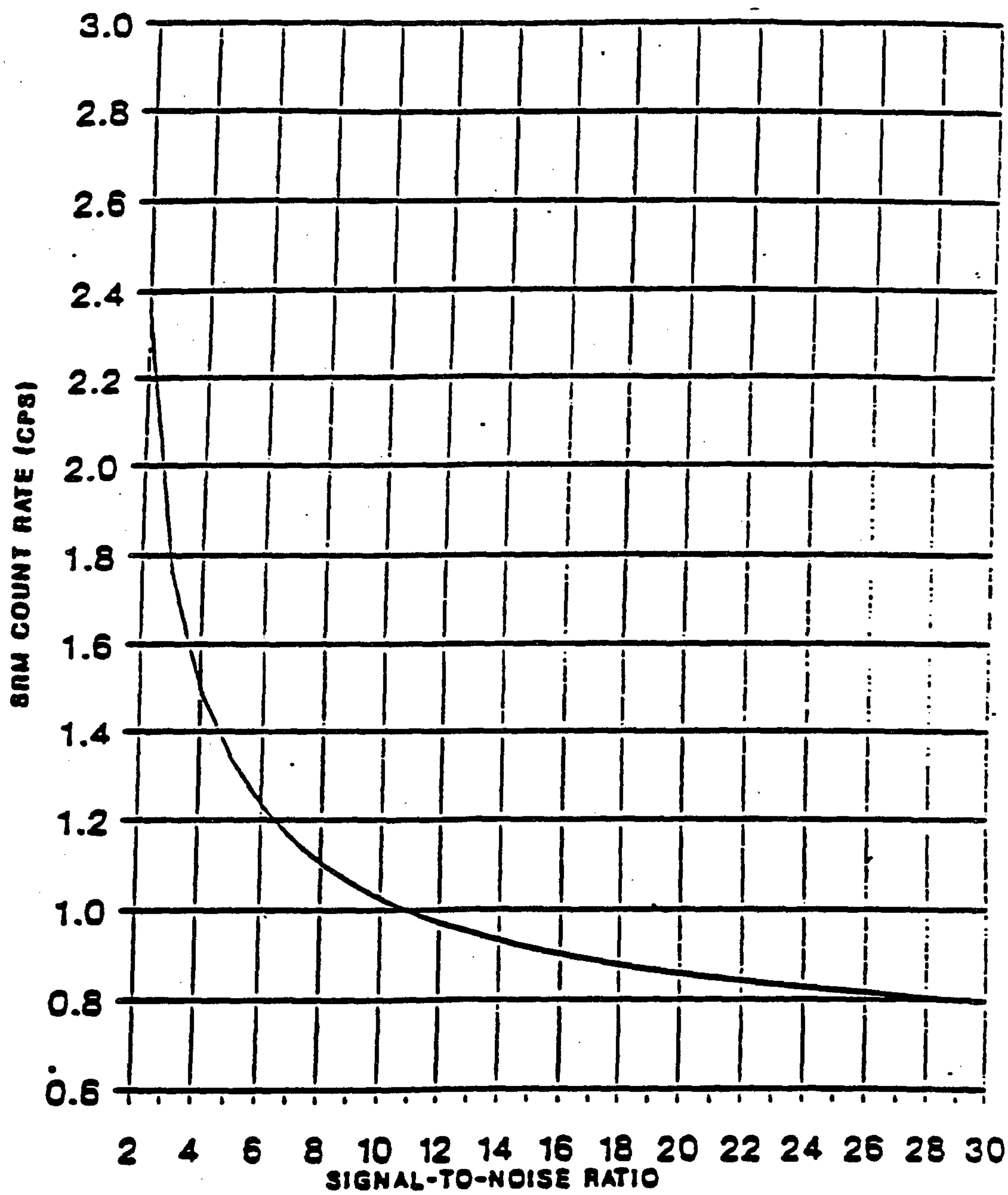
** May be reduced, provided the Source Range Monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.

*** Equivalent to 13.56 gallons/scram discharge volume.

**** The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

(a) There are three upscale trip levels. Each is applicable only over its specified operating core thermal power range. All RBM trips are automatically bypassed below the low power setpoint (LPSP). The upscale LTSP is applied between the low power setpoint (LPSP) and the intermediate power setpoint (IPSP). The upscale ITSP is applied between the intermediate power setpoint and the high power setpoint (HPSP). The HTSP is applied above the high power setpoint.

(b) Power range setpoints control enforcement of appropriate upscale trips over the proper core thermal power ranges. The power signal to the RBM is provided by the APRM.



SRM COUNT RATE VERSUS SIGNAL-TO-NOISE RATIO

Figure 3.3.6-1

TABLE 4.3.6-1
CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (h)	CHANNEL FUNCTIONAL TEST (h)	CHANNEL CALIBRATION(a)(h)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	(c)		1*
b. Inoperative	N.A.	(c)	N.A.	1*
c. Downscale	N.A.	(c)		1*
2. APRM				
a. Simulated Thermal Power - Upscale	N.A.			1
b. Inoperative	N.A.		N.A.	1, 2
c. Neutron Flux - Downscale	N.A.			1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.			2
e. Recirculation Flow - Upscale	N.A.			1
f. LPRM Low Count	N.A.			1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	(e)	N.A.	2, 5
b. Upscale	N.A.	(e)		2, 5
c. Inoperative	N.A.	(e)	N.A.	2, 5
d. Downscale	N.A.	(e)		2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.		N.A.	2, 5**
b. Upscale	N.A.			2, 5**
c. Inoperative	N.A.		N.A.	2, 5**
d. Downscale	N.A.			2, 5**
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.			1, 2, 5**
6. DELETED				
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	(g)	N.A.	3, 4

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** Deleted.

(d) Deleted

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) Deleted

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

(h) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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 3.3.7.1-1 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 Specification 3.0.3 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 shown in Table 4.3.7.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted 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	ACTION
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	4	1,2,3, and *	1 x 10^{-5} µCi/cc	70
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	2	(a)	≥ 5 mR/h and ≤20mR/h[(b)]	71
b. Control Room Direct Radiation Monitor	1	At All Times	N.A.[(b)]	73
3. Reactor Enclosure Cooling Water Radiation Monitor	1	At All Times	≤ 3 x Background[(b)]	72

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

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

(b) Alarm only.

ACTION STATEMENTS

ACTION 70 - With one monitor inoperable, restore the inoperable monitor to the OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the radiation isolation mode of operation.

With two or more of the monitors inoperable, within one hour, initiate and maintain operation of the control room emergency filtration system in the radiation mode of operation.

ACTION 71 - With one of the required monitor inoperable, assure a portable continuous monitor with the same alarm setpoint is OPERABLE in the vicinity of the installed monitor during any fuel movement. If no fuel movement is being made, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 72 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 73 - With the required monitor inoperable, assure a portable alarming monitor is OPERABLE in the vicinity of the installed monitor or perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK(c)	CHANNEL FUNCTIONAL TEST(c)	CHANNEL CALIBRATION(c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor				1, 2, 3, and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool				(a)
b. Control Room Direct Radiation Monitor				At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor			(b)	At All Times

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

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

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(c) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

Section 3.3.7.2 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TRM. TECHNICAL SPECIFICATIONS PAGES 3/4 3-69 THROUGH 3/4 3-72 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

Section 3.3.7.3 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 3-74 THROUGH 3/4 3-75 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

INSTRUMENTATION

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system instrumentation and controls shown in Table 3.3.7.4-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the number of OPERABLE remote shutdown system instrumentation channels less than required by Table 3.3.7.4-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE remote shutdown system controls less than required in Table 3.3.7.4-1, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each of the above required remote shutdown monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK* and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.7.4.2 Each of the above remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) in accordance with the Surveillance Frequency Control Program.

* Control is not required to be transferred to perform the CHANNEL CHECK.

TABLE 3.3.7.4-1

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
1. Reactor Vessel Pressure	1
2. Reactor Vessel Water Level	1
3. Safety/Relief Valve Position, 3 valves	1/valve
4. Suppression Chamber Water Level	1
5. Suppression Chamber Water Temperature	1
6. Drywell Pressure	1
7. Drywell Temperature	1
8. RHR System Flow	1
9. RHR Service Water Pump Discharge Pressure	1
10. RHR Heat Exchanger Service Water Outlet Pressure	1
11. RCIC System Flow	1
12. RCIC Turbine Speed	1
13. Emergency Service Water Pump Discharge Pressure	1
14. Condensate Storage Tank Level	1
15. RHR Heat Exchanger Bypass Valve (HV-C-51-2F048A) Position Indication (0 - 100%)	1
16. RCIC Turbine Tripped Indication	1
17. RCIC Turbine Bearing Oil Pressure Low Indication	1
18. RCIC Bearing Oil Temperature High Indication	1
19. RHR Heat Exchanger Discharge Line High Radiation Indication	1

TABLE 3.3.7.4-1 (Continued)

REMOTE SHUTDOWN SYSTEM CONTROLS

RCIC SYSTEM

HSS-49-291	Control-Transfer Switch
HSS-49-292	Control-Transfer Switch
HSS-49-293	Control-Transfer Switch
HSS-49-295	Control-Transfer Switch
HSS-49-296	Control-Transfer Switch
HV-49-2F076	Control-Steam Line warmup bypass valve
HV-49-2F060	Control-RCIC turb exhaust to suppression pool isolation
HV-50-212	Control-Turb trip throttle valve
HV-50-2F045	Control-Turbine steam supply valve
HV-49-2F008	Control-Turbine steam line outboard isolation valve
HV-49-2F007	Control-Turbine steam line inboard isolation valve
HV-49-2F031	Control-RCIC pump suction from suppression pool
HV-49-2F029	Control-RCIC pump suction from suppression pool
HV-49-2F010	Control-RCIC pump suction from condensate storage tank
HV-49-2F019	Control-Minimum flow bypass to suppression pool
HV-49-2F022	Control-Test return to condensate storage tank
HV-50-2F046	Control-RCIC turbine cooling water valve
HV-49-2F012	Control-RCIC pump disch valve
HV-49-2F013	Control-RCIC pump disch valve
20P220	Control-Vacuum tank condensate pump
20P219	Control-Barometric condenser vacuum pump
HV-49-2F002	Control-Barometric condenser vacuum pump disch

Table 3.3.7.4-1 (Continued)

RCIC SYSTEM (Continued)

HV-49-2F080	Control-Vacuum breaker outboard isolation valve
HV-49-2F084	Control-Vacuum breaker inboard isolation valve
FIC-49-2R001	Controller-RCIC discharge flow control
E51-S45	RCIC Turbine Trip Bypass

NUCLEAR BOILER SYSTEM

HSS-41-291	Control-Transfer switch
PSV-41-2F013A	Control-Main steam line safety/relief valve
PSV-41-2F013C	Control-Main steam line safety/relief valve
PSV-41-2F013N	Control-Main steam line safety/relief valve

RHR SYSTEM

HSS-51-195	Control-Transfer switch
HSS-51-196	Control-Transfer switch
HSS-51-292	Control-Transfer switch
HSS-51-293	Control-Transfer switch
HSS-51-294	Control-Transfer switch
HSS-51-295	Control-Transfer switch
HSS-51-296	Control-Transfer switch
HSS-51-297	Control-Transfer switch
HSS-51-298	Control-Transfer switch
HV-51-2F009	Control-RHR pump shutdown cooling suction inboard isolation
HV-51-2F008	Control-RHR shutdown cooling suction outboard isolation
HV-51-2F006A	Control-2A RHR loop shutdown cooling suction
HV-51-2F006B	Control-2B RHR loop shutdown cooling suction
HV-51-2F004A	Control-2A RHR pump suction
2AP202	Control-2A RHR pump

RHR SYSTEM (Continued)

HV-43-2F023A	Control-Recirculation pump A suction valve
HSS-43-291	Control-Transfer switch
HV-51-2F007A	Control-2A RHR pump minimum flow bypass valve
HV-51-2F048A	Control-2A heat exchanger shell side bypass
HV-51-2F015A	Control-2A shutdown cooling injection valve
HV-51-2F016A	Control-Reactor containment spray
HV-51-2F017A	Control-2A RHR loop injection valve
HV-51-2F024A	Control-2A RHR loop test return
HV-51-2F027A	Control-Suppression pool sparger isolation
HV-51-2F047A	Control-2A Heat exchanger shell side inlet
HV-51-2F003A	Control-2A Heat exchanger shell side outlet
HV-51-2F049	Control-RHR Discharge to radwaste outboard isolation
HV-51-225A	Control-2A/2C test return line to suppression pool

RHR SERVICE WATER SYSTEM

HSS-12-015A-2	Control-Spray pond/cooling tower select
HSS-12-015C-2	Control-Spray pond/cooling tower select
HSS-12-016A-2	Control-Spray/bypass select
HSS-12-016C-2	Control-Spray/bypass select

Table 3.3.7.4-1 (Continued)

RHR SERVICE WATER SYSTEM (Continued)

HSS-12-094	Control-Transfer switch
HSS-12-093	Control-Transfer switch
HV-51-2F014A	Control-2A RHR heat exchanger tube side inlet
OCP506	Control-RHR Service Water pump
HV-51-2F068A	Control-2A RHR Heat exchanger tube side outlet

EMERGENCY SERVICE WATER SYSTEM

OAP548	Control-A emergency service water pump
HV-11-011A	Control-A emergency service water disch to RHR service water
HSS-11-091	Control-Transfer switch
HSS-11-092	Control-Transfer switch
HSS-11-093	Control-Transfer switch

The following valves of the ESW and RHRSW systems are actuated by signals from the transfer switches:

HV-12-005	ESW and RHRSW pumps wetwell intertie gate
HV-11-015A	ESW loop A discharge to RHRSW loop B
HV-12-017A	ESW and RHRSW cooling tower return cross-tie

STANDBY AC POWER SUPPLY

152-11509/CSR	101-D21 Safeguard SWGR feeder bkr.
152-11609/CSR	101-D22 Safeguard SWGR feeder bkr.
152-11709/CSR	101-D23 Safeguard SWGR feeder bkr.
152-11502/CSR	201-D21 Safeguard SWGR feeder bkr.
152-11602/CSR	201-D22 Safeguard SWGR feeder bkr.
152-11702/CSR	201-D23 Safeguard SWGR feeder bkr.
152-11505/CSR	D214 Safeguard LC XFMR breaker

Table 3.3.7.4-1 (Continued)

STANDBY AC POWER SUPPLY (Continued)

152-11605/CSR	D224 Safeguard LC XFMR breaker
152-11705/CSR	D234 Safeguard LC XFMR breaker
143-115/CS	Transfer switch
143-116/CS	Transfer switch
143-117/CS	Transfer switch

INFORMATION ON THIS PAGE HAS BEEN DELETED

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 specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.5-1.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1,2	80
2. Reactor Vessel Water Level	2	1	1,2	80
3. Suppression Chamber Water Level	2	1	1,2	80
4. Suppression Chamber Water Temperature	8, 6 locations	6, 1/location	1,2	80
5. Deleted				
6. Drywell Pressure	2	1	1,2	80
7. Deleted				
8. Deleted				
9. Deleted				
10. Deleted				
11. Primary Containment Post-LOCA Radiation Monitors	4	2	1,2,3	81
12. North Stack Wide Range Accident Monitor**	3*	3*	1,2,3	81
13. Neutron Flux	2	1	1,2	80

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

TABLE NOTATIONS

*Three noble gas detectors with overlapping ranges (10^{-7} to 10^{-1}, 10^{-4} to 10^{2}, 10^{-1} to 10^{5} μCi/cc).
**High range noble gas monitor.

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.

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.

ACTION 81 - With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, initiate the preplanned alternate method of monitoring the appropriate parameters within 72 hours, and

a. Either restore the inoperable channel(s) to OPERABLE status within 7 days of the event, or

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 - DELETED

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)
1. Reactor Vessel Pressure		
2. Reactor Vessel Water Level		
3. Suppression Chamber Water Level		
4. Suppression Chamber Water Temperature		
5. Deleted		
6. Primary Containment Pressure		
7. Deleted		
8. Deleted		
9. Deleted		
10. Deleted		
11. Primary Containment Post LOCA Radiation Monitors		**
12. North Stack Wide Range Accident Monitor***		
13. Neutron Flux		

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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

***High range noble gas monitors.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least the following source range monitor channels shall be OPERABLE:

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

APPLICABILITY: OPERATIONAL CONDITIONS 2*#, 3, and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least three source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK in accordance with the Surveillance Frequency Control Program:

a) in CONDITION 2*, and
b) in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** in accordance with the Surveillance Frequency Control Program.

b. Performance of a CHANNEL FUNCTIONAL TEST in accordance with the Surveillance Frequency Control Program.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3.0 cps*** with the detector fully inserted.#

*With IRM's on range 2 or below in CONDITION 2.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.
#During initial startup test program, SRM detectors may be partially withdrawn prior to IRM on-scale indication provided that the SRM channels remain on scale above 100 cps and respond to changes in the neutron flux.

Section 3/4.3.7.7

THE INFORMATION FROM THIS TECHNICAL SPECIFICATION
HAS BEEN RELOCATED TO THE TECHNICAL REQUIREMENTS MANUAL (TRM)

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.1 Two independent chlorine detection system subsystems shall be OPERABLE with their alarm and trip setpoints adjusted to actuate at a chlorine concentration of less than or equal to 0.5 ppm

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detection subsystem 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 chlorine isolation mode of operation.

b. With both chlorine detection subsystem inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration system subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.1 Each of the above required chlorine detection system subsystems shall be demonstrated OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

INSTRUMENTATION

TOXIC GAS DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8.2 Three independent toxic gas detection system subsystems shall be OPERABLE with their alarm setpoints adjusted to actuate at a toxic gas concentration of less than or equal to:

CHEMICAL	MONITOR SET POINT (ppm)
Ammonia	25
Ethylene Oxide	50
Formaldehyde	5
Vinyl Chloride	10
Phosgene	0.4

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one toxic gas detection subsystem inoperable, place the inoperable subsystem in the tripped condition within 24 hours.

b. With two toxic gas detection system subsystems inoperable, place one inoperable subsystem in the tripped condition within 1 hour, restore one inoperable detection subsystem to OPERABLE status within 7 days, or initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

c. With three toxic gas detection subsystems inoperable, within 1 hour initiate and maintain operation of at least one control room emergency filtration subsystem in the chlorine isolation mode of operation.

SURVEILLANCE REQUIREMENTS

4.3.7.8.2 Each of the above required toxic gas detection system subsystems shall be demonstrated OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION in accordance with the Surveillance Frequency Control Program.

Section 3/4.7.9 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TECHNICAL REQUIREMENTS MANUAL (TRM) FIRE PROTECTION SECTION. TECHNICAL SPECIFICATIONS PAGES 3/4 3-92 THROUGH 3/4 3-96 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

INFORMATION CONTAINED ON THIS PAGE HAS BEEN DELETED

Section 3.3.7.11 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 3-99 THROUGH 3/4 3-102 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

INSTRUMENTATION

OFFGAS GAS MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.12 The offgas monitoring instrumentation channels shown in Table 3.3.7.12-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specifications 3.11.2.5 and 3.11.2.6 respectively, are not exceeded.

APPLICABILITY: As shown in Table 3.3.7.12-1

ACTION:

a. With an offgas monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Specification, declare the channel inoperable, and take the ACTION shown in Table 3.3.7.12-1.

b. With less than the minimum number of offgas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.12-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or explain why this inoperability was not corrected in a timely manner in the next Annual Radioactive Effluent Release Report.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each offgas monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.12-1.

TABLE 3.3.7.12-1

OFFGAS MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	1	**	110
2. (Deleted)			
3. (Deleted)			
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR			
a. Noble Gas Activity Monitor	1	**	115
5. (Deleted)			

TABLE 3.3.7.12-1 (Continued)

TABLE NOTATIONS

* (Deleted)

** During operation of the main condenser steam jet air ejector and offgas treatment system.

*** (Deleted)

ACTION STATEMENTS

ACTION 110 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of main condenser offgas treatment system may continue for up to 30 days provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours.

ACTION 111-114 (Deleted)

ACTION 115 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, releases to the environment may continue for up to 72 hours provided that the North Stack Effluent Noble Gas Activity Monitor is OPERABLE; otherwise, be in at least HOT SHUTDOWN within 12 hours.

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TABLE 4.3.7.12-1

OFFGAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (5)	SOURCE CHECK (5)	CHANNEL CALIBRATION(5)	CHANNEL FUNCTIONAL TEST (5)	MODES IN WHICH SURVEILLANCE IS REQUIRED
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor		N.A.	(3)		**
2. (Deleted)					
3. (Deleted)					
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR (STEAM JET AIR EJECTOR)					
a. Noble gas activity monitor			(2)	(1)	**
5. (Deleted)					

TABLE 4.3.7.12-1 (Continued)

TABLE NOTATIONS

* (Deleted)

** During operation of the main condenser steam jet air ejector and offgas treatment system.

*** (Deleted)

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.

2. Circuit failure.

3. Instrument indicates a downscale failure.

4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Institute of Standards and Technology (NIST), previously National Bureau of Standards, or using standards that have been obtained from suppliers that participate in measurement assurance activities with NIST. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(3) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. 0.0 volume percent hydrogen, balance nitrogen, and

2. 4 volume percent hydrogen, balance nitrogen.

(4) (Deleted)

(5) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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SPECIFICATIONS SECTION HAS BEEN
RELOCATED TO THE TRM.
TECHNICAL SPECIFICATIONS PAGE 3/4 3-111
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3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in the Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. 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.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels 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.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each of the required feedwater/main turbine trip system actuation instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

TABLE 3.3.9-1

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Water Level-High, Level 8	4	1*

* With Thermal Power greater than or equal to 25% of Rated Thermal Power.

TABLE 3.3.9-2

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel Water Level-High, Level 8	$\leq$ 54 inches*	$\leq$ 55.5 inches

*See Bases Figure B 3/4.3-1

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3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

   1. Within 4 hours:

      a. Place the recirculation flow control system in the Local Manual mode, and

      b. Reduce THERMAL POWER to ≤ 76.2% of RATED THERMAL POWER, and,

      c. Limit the speed of the operating recirculation pump to less than or equal to 90% of rated pump speed, and

      d. Verify that the differential temperature requirements of Surveillance Requirement 4.4.1.1.5 are met if THERMAL POWER is ≤ 30% of RATED THERMAL POWER or the recirculation loop flow in the operating loop is ≤ 50% of rated loop flow, or suspend the THERMAL POWER or recirculation loop flow increase.

*See Special Test Exception 3.10.4.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

2. Within 6 hours:

   Reduce the Average Power Range Monitor (APRM) Simulated Thermal Power - Upscale Scram and Rod Block Trip Setpoints and Allowable Values, to those applicable for single recirculation loop operation per Specifications 2.2.1 and 3.3.6, or declare the associated channel(s) inoperable and take the actions required by the referenced specifications.

3. Otherwise be in at least HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant system recirculation loops in operation, initiate measures to place the unit in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 DELETED

4.4.1.1.2 DELETED

4.4.1.1.3 DELETED

4.4.1.1.4 With one reactor coolant system recirculation loop not in operation, in accordance with the Surveillance Frequency Control Program, verify that:

a. Reactor THERMAL POWER is ≤ 76.2% of RATED THERMAL POWER,

b. The recirculation flow control system is in the Local Manual mode, and

c. The speed of the operating recirculation pump is ≤ 90% of rated pump speed.

4.4.1.1.5 With one reactor coolant system recirculation loop not in operation, within 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 30% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow.

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant,

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements of Specification 4.4.1.1.5b. and c. do not apply when the loop not in operation is isolated from the reactor pressure vessel.

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JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. During two recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER and in accordance with the Surveillance Frequency Control Program while greater than 25% of RATED THERMAL POWER by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when both recirculation loop indicated flows are in compliance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established pump speed-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established patterns by more than 10%.

SURVEILLANCE REQUIREMENTS (Continued)

b. During single recirculation loop operation, each of the above required jet pumps shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by verifying that no two of the following conditions occur:

1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established pump speed-loop flow characteristics.

2. The indicated total core flow differs by more than 10% from the established total core flow value derived from single recirculation loop flow measurements.

3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established single recirculation loop patters by more than 10%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 25% of RATED THERMAL POWER and upon entering single recirculation loop operation.

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RECIRCULATION PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of each other with core flow greater than or equal to 70% of rated core flow.

b. 10% of each other with core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2* during two recirculation loop operation.

ACTION:

With the recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. Shutdown one of the recirculation loops within the next 8 hours and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits in accordance with the Surveillance Frequency Control Program.

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*See Special Test Exception 3.10.4.

IDLE RECIRCULATION LOOP STARTUP

LIMITING CONDITION FOR OPERATION

3.4.1.4 An idle recirculation loop shall not be started unless the temperature differential between the reactor pressure vessel steam space coolant and the bottom head drain line coolant is less than or equal to 145°F, and:

a. When both loops have been idle, unless the temperature differential between the reactor coolant within the idle loop to be started up and the coolant in the reactor pressure vessel is less than or equal to 50°F, or

b. When only one loop has been idle, unless the temperature differential between the reactor coolant within the idle and operating recirculation loops is less than or equal to 50°F and the operating loop flow rate is less than or equal to 50% of rated loop flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and 4.

ACTION:

With temperature differences and/or flow rates exceeding the above limits, suspend startup of any idle recirculation loop.

SURVEILLANCE REQUIREMENTS

4.4.1.4 The temperature differentials and flow rate shall be determined to be within the limits within 15 minutes prior to startup of an idle recirculation loop.

REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The safety valve function of at least 12 of the following reactor coolant system safety/relief valves shall be OPERABLE with the specified code safety valve function lift settings:*#

4 safety/relief valves @ 1170 psig ±3%
5 safety/relief valves @ 1180 psig ±3%
5 safety/relief valves @ 1190 psig ±3%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the safety valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. DELETED

c. DELETED

SURVEILLANCE REQUIREMENTS

4.4.2.1 DELETED

4.4.2.2 At least 1/2 of the safety relief valves shall be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations in accordance with the Surveillance Frequency Control Program, and they shall be rotated such that all 14 safety relief valves are removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations in accordance with the Surveillance Frequency Control Program. All safety valves will be recertification tested to meet a ±1% tolerance prior to returning the valves to service.

* The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

\# Up to 2 inoperable valves may be replaced with spare OPERABLE valves with lower setpoints until the next refueling.

REACTOR COOLANT SYSTEM

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.3.1 The following reactor coolant leakage detection systems shall be OPERABLE:

a. The primary containment atmosphere gaseous radioactivity monitoring system,

b. The drywell floor drain sump flow monitoring system,

c. The drywell unit coolers condensate flow rate monitoring system, and

d. The primary containment pressure and temperature monitoring system.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.*
* - The primary containment gaseous radioactivity monitor is not required to be operable until Operational Condition 2.

ACTIONS:

A. With the primary containment atmosphere gaseous radioactivity monitoring system inoperable, analyze grab samples of primary containment atmosphere at least once per 12 hours AND restore primary containment atmosphere gaseous radioactivity monitoring system to OPERABLE status within 30 days.

B. With the drywell floor drain sump flow monitoring system inoperable, restore the drywell floor drain sump flow monitoring system to OPERABLE status within 30 days AND increase monitoring frequency of drywell unit cooler condensate flow rate (SR 4.4.3.2.1.c) to once every 8 hours.

C. With the drywell unit coolers condensate flow rate monitoring system inoperable, AND the primary containment atmosphere gaseous radioactivity monitoring system OPERABLE, perform a channel check of the primary containment atmosphere gaseous radioactivity monitoring system (SR 4.4.3.1.a) once per 8 hours.

D. With the primary containment pressure and temperature monitoring system inoperable, restore the primary containment pressure and temperature monitoring system to OPERABLE status within 30 days. Note: All other Tech Spec Limiting Conditions For Operation and Surveillance Requirements associated with the primary containment pressure/temperature monitoring system still apply. Affected Tech Spec Sections include: 3/4.3.7.5, 4.4.3.2.1, 3/4.6.1.6, and 3/4.6.1.7.

E. With the primary containment atmosphere gaseous radioactivity monitoring system inoperable AND the drywell unit coolers condensate flow rate monitoring system inoperable, restore the primary containment atmosphere gaseous radioactivity monitoring system to OPERABLE status within 30 days OR restore the drywell unit coolers condensate flow rate monitoring system to OPERABLE status within 30 days. With the primary containment atmosphere gaseous radioactivity monitoring system inoperable, analyze grab samples of primary containment atmosphere at least once per 12 hours.

ACTIONS (Continued)

F. With any other two or more leak detection systems inoperable other than ACTION E above OR with required Actions and associated Completion Time of ACTIONS A, B, C, D or E not met, be in HOT SHUTDOWN within 12 hours AND in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The reactor coolant system leakage detection systems shall be demonstrated operable by:

a. Perform a CHANNEL CHECK of the primary containment atmosphere gaseous radioactivity monitoring system in accordance with the Surveillance Frequency Control Program.

b. Perform a CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

c. Perform a CHANNEL CALIBRATION of required leakage detection instrumentation in accordance with the Surveillance Frequency Control Program. This does not apply to containment pressure and temperature monitoring system.

d. Monitor primary containment pressure <u>AND</u> primary containment temperature in accordance with the Surveillance Frequency Control Program.

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REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more of the high/low pressure interface valve leakage pressure monitors inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the specified allowable values by performance of a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

TABLE 3.4.3.2-1 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATION SECTION HAS BEEN RELOCATED TO THE TECHNICL REQUIREMENTS MANUAL (TRM).

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THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TECHNICAL REQUIREMENTS MANUAL (TRM). TECHNICAL SPECIFICATIONS PAGES 3/4 4-13 AND 3/4 4-14 HAVE BEEN INTENTIONALLY OMITTED.

3/4.4.5 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.5 The specific activity of the primary coolant shall be limited to:

a. Less than or equal to 0.2 microcurie per gram DOSE EQUIVALENT I-131.

b. (Deleted)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and 4.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3 with the specific activity of the primary coolant;

1. Greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram, DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or greater than 4.0 microcuries per gram DOSE EQUIVALENT I-131, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours. The provisions of Specification 3.0.4.c are applicable.

2. (Deleted)

b. In OPERATIONAL CONDITION 1, 2, 3, or 4, with the specific activity of the primary coolant greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131, perform the sampling and analysis requirements of Item 4.a of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit.

c. In OPERATIONAL CONDITION 1 or 2, with:

1. THERMAL POWER changed by more than 15% of RATED THERMAL POWER in 1 hour*, or

2. The off-gas level, at the SJAE, increased by more than 10,000 microcuries per second in 1 hour during steady-state operation at release rates less than 75,000 microcuries per second, or

3. The off-gas level, at the SJAE, increased by more than 15% in 1 hour during steady-state operation at release rates greater than 75,000 microcuries per second,

perform the sampling and analysis requirements of Item 4.b of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit.

*Not applicable during the startup test program.

SURVEILLANCE REQUIREMENTS

4.4.5 The specific activity of the reactor coolant shall be demonstrated to be within the limits by performance of the sampling and analysis program of Table 4.4.5-1.

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	OPERATIONAL CONDITIONS IN WHICH SAMPLE AND ANALYSIS IS REQUIRED
1. (Deleted)		
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	In accordance with the Surveillance Frequency Control Program	1
3. (Deleted)		
4. Isotopic Analysis for Iodine	a) At least once per 4 hours whenever the specific activity exceeds a limit, as required by ACTION b.	1**, 2**, 3**, 4**
	b) At least one sample, between 2 and 6 hours following the change in THERMAL POWER or off-gas level, as required by ACTION c.	1, 2
5. Isotopic Analysis of an Off-gas Sample Including Quantitative Measurements for at least Xe-133, Xe-135, and Kr-88	In accordance with the Surveillance Frequency Control Program	1

**Until the specific activity of the primary coolant system is restored to within its limits.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1 (1) curve A for hydrostatic or leak testing; (2) curve B for heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS; and (3) curve C for operations with a critical core other than low power PHYSICS TESTS, with:

a. A maximum heatup of 100°F in any 1-hour period,

b. A maximum cooldown of 100°F in any 1-hour period,

c. A maximum temperature change of less than or equal to 20°F in any 1-hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange temperature greater than or equal to 70°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figure 3.4.6.1-1 curves A, B or C as applicable, in accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.6.1.2 The reactor coolant system temperature and pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curve C within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and in accordance with the Surveillance Frequency Control Program during system heatup.

4.4.6.1.3 DELETED

4.4.6.1.4 DELETED

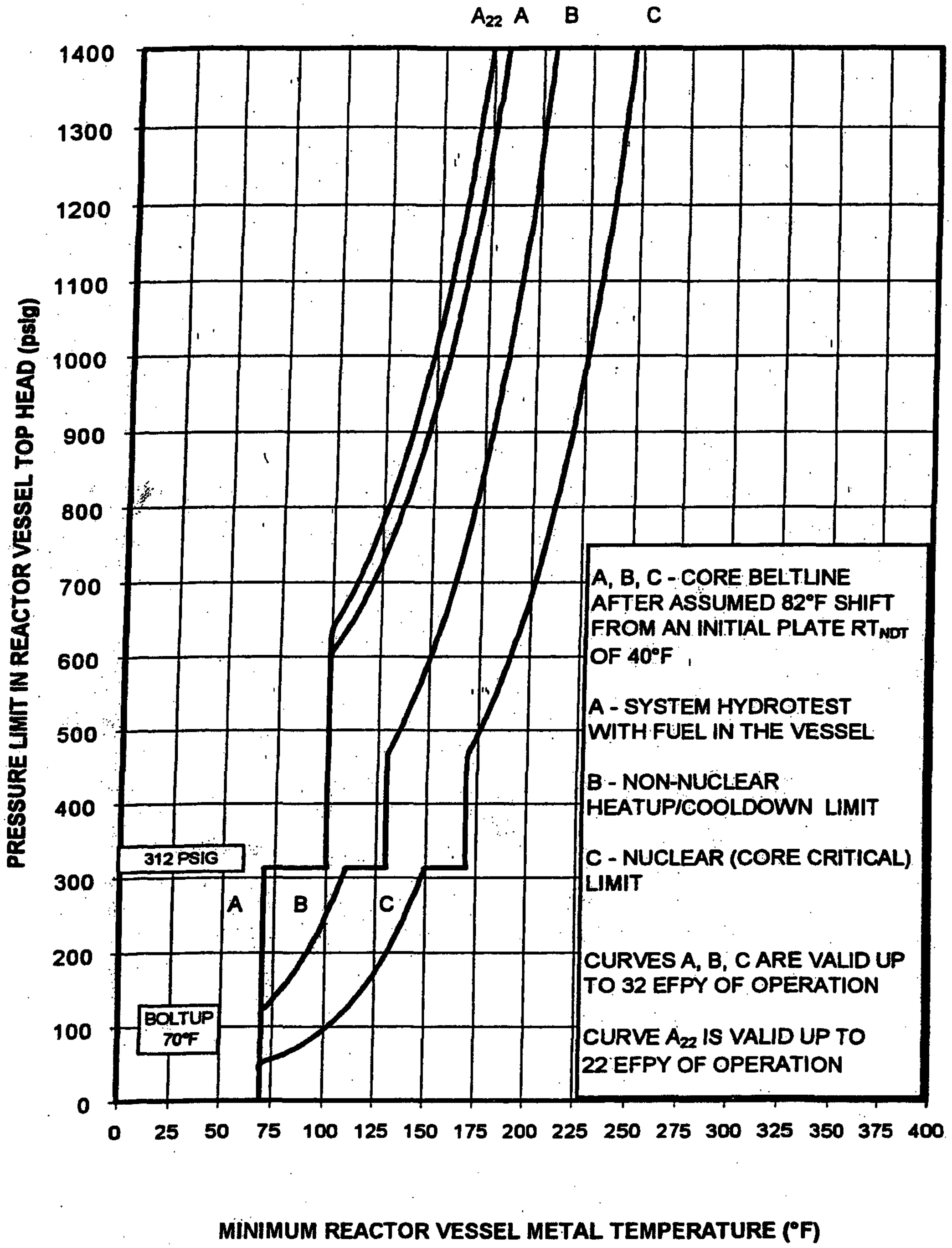
4.4.6.1.5 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 70°F:

a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

   1. ≤ 100°F, in accordance with the Surveillance Frequency Control Program.

   2. ≤ 90°F, in accordance with the Surveillance Frequency Control Program.

b. Within 30 minutes prior to and in accordance with the Surveillance Frequency Control Program during tensioning of the reactor vessel head bolting studs.



MINIMUM REACTOR VESSEL METAL TEMPERATURE VS. REACTOR VESSEL PRESSURE
FIGURE 3.4.6.1-1

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REACTOR COOLANT SYSTEM

REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1053 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1053 psig, reduce the pressure to less than 1053 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1053 psig in accordance with the Surveillance Frequency Control Program.

*Not applicable during anticipated transients.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more MSIVs inoperable:

a. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either:

   1. Restore the inoperable valve(s) to OPERABLE status, or

   2. Isolate the affected main steam line by use of a deactivated MSIV in the closed position.

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

SURVEILLANCE REQUIREMENTS

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

3/4.4.8 STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.8 The structural integrity of ASME Code Class 1, 2, and 3 components shall be maintained in accordance with Specification 4.4.8.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5.

ACTION:

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the reactor coolant system temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the reactor coolant system temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

SURVEILLANCE REQUIREMENTS

4.4.8 No requirements other than Specification 4.0.5.

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two (2) independent RHR shutdown cooling subsystems shall be OPERABLE, and, with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

Each independent RHR shutdown cooling subsystem shall consist of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger, not common to the two (2) independent subsystems.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required independent RHR shutdown cooling subsystems OPERABLE, immediately initiate corrective action to return the required independent subsystems to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, verify the availability of at least one alternate method capable of decay heat removal for each inoperable independent RHR shutdown cooling subsystem. Be in at least COLD SHUTDOWN within 24 hours.****

b. With no independent RHR shutdown cooling subsystem in operation, immediately initiate corrective action to return at least one (1) independent subsystem to operation as soon as possible. Within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one independent RHR shutdown cooling subsystem or alternate method shall be determined to be in operation and circulating reactor coolant in accordance with the Surveillance Frequency Control Program.

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*One independent RHR shutdown cooling subsystem may be inoperable for up to 2 hours for surveillance testing provided the other independent subsystem is OPERABLE and in operation.

**The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period provided the other independent subsystem is OPERABLE.

***The independent RHR shutdown cooling subsystem may be removed from operation during hydrostatic testing.

****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.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and with no recirculation pump in operation, at least one (1) RHR shutdown cooling subsystem shall be in operation. * ** ***

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION: #

a. With one (1) or two (2) RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable RHR shutdown cooling subsystem.

b. With no RHR shutdown cooling subsystems in operation and no recirculation pump in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulating by an alternate method; and

   2. Once per hour monitor reactor coolant temperature and pressure.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one (1) RHR shutdown cooling subsystem or recirculation pump is operating or an alternate method shall be determined to be in operation and circulating reactor coolant in accordance with the Surveillance Frequency Control Program.

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* Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up two (2) hours per eight hour (8) period.

** One (1) RHR shutdown cooling subsystem may be inoperable for up to two (2) hours for the performance of Surveillances.

*** The shutdown cooling subsystem may be removed from operation during hydrostatic testing.

Separate Action entry is allowed for each shutdown cooling subsystem.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

   1. Two OPERABLE CSS pumps, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

   1. One OPERABLE LPCI pump, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

   1. One OPERABLE HPCI pump, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) with at least five OPERABLE ADS valves.

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

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*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:

1. With one CSS subsystem inoperable, provided that at least two LPCI subsystems are OPERABLE, restore the inoperable CSS subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With both CSS subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. For the LPCI system:

1. With one LPCI subsystem inoperable, provided that at least one CSS subsystem is OPERABLE, restore the inoperable LPCI pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one RHR cross-tie valve (HV-51-282 A or B) open, or power not removed from one closed RHR cross-tie valve operator, close the open valve and/or remove power from the closed valves operator within 72 hours, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3. With no RHR cross-tie valves (HV-51-282 A, B) closed, or power not removed from both closed RHR cross-tie valve operators, or with one RHR cross-tie valve open and power not removed from the other RHR cross-tie valve operator, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

4. With two LPCI subsystems inoperable, provided that at least one CSS subsystem is OPERABLE, restore at least three LPCI subsystems to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With all four LPCI subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.*

*Whenever both shutdown cooling 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.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. For the HPCI system:

1. With the HPCI system inoperable, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE, restore the HPCI system 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 ≤ 200 psig within the following 24 hours.

2. With the HPCI system inoperable, and one CSS subsystem, and/or LPCI subsystem inoperable, and provided at least one CSS subsystem, three LPCI subsystems, and ADS are operable, restore the HPCI to OPERABLE within 8 hours, or be in HOT SHUTDOWN in the next 12 hours, and in COLD SHUTDOWN in the next 24 hours.

3. Specification 3.0.4.b is not applicable to HPCI.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, 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 ≤ 100 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 ≤ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated CSS and/or LPCI, as applicable, inoperable.

f. 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 usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

a) 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.

b) Verifying 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.

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-282 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, 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.

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* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72-hours.

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

3. Performing a CHANNEL CALIBRATION of the CSS, LPCI, and HPCI system discharge line "keep filled" alarm instrumentation.

4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid.

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid.

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

   c) DELETED

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. Core spray system (CSS) subsystems with a subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

   a) From the suppression chamber, or

   b) When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank containing at least 135,000 available gallons of water, equivalent to a level of 29 feet.

b. Low pressure coolant injection (LPCI) system subsystems with a subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.**

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5*.

ACTION:

a. With one of the above required subsystems inoperable, restore at least two subsystems to OPERABLE status within 4 hours or suspend all operations with a potential for draining the reactor vessel.

b. With both of the above required subsystems inoperable, suspend CORE ALTERATIONS and all operations with a potential for draining the reactor vessel. Restore at least one subsystem to OPERABLE status within 4 hours or establish SECONDARY CONTAINMENT INTEGRITY within the next 8 hours.

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*The ECCS is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the spent fuel pool gates are removed, and water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

**One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

SURVEILLANCE REQUIREMENTS

4.5.2.1 At least the above required ECCS shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1.*

4.5.2.2 The core spray system shall be determined OPERABLE in accordance with the Surveillance Frequency Control Program by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2a.2.b).

*One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable.

3/4.5.3 SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3 with a contained water volume of at least 122,120 ft^3, equivalent to a level of 22'0".

b. In OPERATIONAL CONDITION 4 and 5* with a contained water volume of at least 88,815 ft^3, equivalent to a level of 16'0", except that the suppression chamber level may be less than the limit or may be drained provided that:

1. No operations are performed that have a potential for draining the reactor vessel,

2. The reactor mode switch is locked in the Shutdown or Refuel position,

3. The condensate storage tank contains at least 135,000 available gallons of water, equivalent to a level of 29 feet, and

4. The core spray system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression chamber water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

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*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying the water level to be greater than or equal to, as applicable:

a. 22'0" in accordance with the Surveillance Frequency Control Program.

b. 16'0" in accordance with the Surveillance Frequency Control Program.

4.5.3.2 With the suppression chamber level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, in accordance with the Surveillance Frequency Control Program:

a. Verify the required conditions of Specification 3.5.3b. to be satisfied, or

b. Verify footnote conditions * to be satisfied.

*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

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3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing in accordance with the Primary Containment Leakage Rate Testing Program.

b. In accordance with the Surveillance Frequency Control Program by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except for valves that are opened under administrative control as permitted by Specification 3.6.3. |

c. By verifying the primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

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* See Special Test Exception 3.10.1

**Except valves, blind flanges, and deactivated automatic valves which are located inside the containment, and are locked, sealed, or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed when the primary containment has not been deinerted since the last verification or more often than once per 92 days.

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate (Type A Test) in accordance with the Primary Containment Leakage Rate Testing Program.

b. A combined leakage rate in accordance with the Primary Containment Leakage Rate Testing Program for all primary containment penetrations and all primary containment isolation valves that are subject to Type B and C tests, except for: main steam line isolation valves*, valves which are hydrostatically tested, and those valves where an exemption to Appendix J of 10 CFR 50 has been granted.

c. *Less than or equal to 100 scf per hour through any one main steam isolation valve not to exceed 200 scf per hour for all four main steam lines, when tested at P_t, 22.0 psig.

d. A combined leakage rate of less than or equal to 1 gpm times the total number of containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a, 48.4 psig.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate (Type A Test) exceeding the leakage rate specified in the Primary Containment Leakage Rate Testing Program, or

b. The measured combined leakage rate exceeding the leakage rate specified in the Primary Containment Leakage Rate Testing Program for all primary containment penetrations and all primary containment isolation valves that are subject to Type B and C tests, except for: main steam line isolation valves*, valves which are hydrostatically tested, and those valves where an exemption to Appendix J of 10 CFR 50 has been granted, or

c. The measured leakage rate exceeding 100 scf per hour through any one main steam isolation valve, or exceeding 200 scf per hour for all four main steam lines, or

d. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves,

restore:

a. The overall integrated leakage rate(s) (Type A Test) to be in accordance with the Primary Containment Leakage Rate Testing Program, and

*Exemption to Appendix J of 10 CFR Part 50.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. The combined leakage rate to be in accordance with the Primary Containment Leakage Rate Testing Program for all primary containment penetrations and all primary containment isolation valves that are subject to Type B and C tests, except for: main steam line isolation valves*, valves which are hydrostatically tested, and those valves where an exemption to Appendix J of 10 CFR 50 has been granted, and

c. The leakage rate to ≤100 scf per hour for any main steam isolation valve that exceeds 100 scf per hour, and restore the combined maximum pathway leakage to ≤200 scf per hour, and

d. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves,

prior to increasing reactor coolant system temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The primary containment leakage rates shall be demonstrated to be in accordance with the Primary Containment Leakage Rate Testing Program, or approved exemptions, for the following:

a. Type A Test

b. Type B and C Tests (including air locks)

c. Main Steam Line Isolation Valves

d. Hydrostatically tested Containment Isolation Valves

*Exemption to Appendix "J" to 10 CFR Part 50.

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PRIMARY CONTAINMENT AIR LOCK

LIMITING CONDITION FOR OPERATION

3.6.1.3 The primary 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 in accordance with the Primary Containment Leakage Rate Testing Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3.

ACTION:

a. With one primary 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.

b. With the primary 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.

*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.1.3 The primary containment air lock shall be demonstrated OPERABLE:

a. By verifying the seal leakage rate is in accordance with the Primary Containment Leakage Rate Testing Program.

b. By conducting an overall air lock leakage test in accordance with the Primary Containment Leakage Rate Testing Program.

c. In accordance with the Surveillance Frequency Control Program by verifying that only one door in the air lock can be opened at a time.***

***Except that the airlock doors need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the airlock doors' interlock is tested within 8 hours after the primary containment has been deinerted and provided the shield door to the airlock is maintained locked closed.

MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

LIMITING CONDITION FOR OPERATION

3.6.1.4 The MSIV Leakage Alternate Drain Pathway shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the MSIV Leakage Alternate Drain Pathway inoperable, restore the pathway to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The MSIV Leakage Alternate Drain Pathway shall be demonstrated OPERABLE:

a. In accordance with 4.0.5, by cycling each motor operated valve, required to be repositioned, through at least one complete cycle of full travel.

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PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.5 The structural integrity of the primary containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the structural integrity of the primary containment not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5.1 The structural integrity of the exposed accessible interior and exterior surfaces of the primary containment, including the liner plate, shall be determined by a visual inspection of those surfaces. This inspection shall be performed in accordance with the Primary Containment Leakage Rate Testing Program.

4.6.1.5.2 Reports Any abnormal degradation of the primary containment structure detected during the above required inspections shall be reported in a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days. This report shall include a description of the condition of the liner and concrete, the inspection procedure, the tolerances on cracking, and the corrective actions taken.

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CONTAINMENT SYSTEMS

DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.6 Drywell and suppression chamber internal pressure shall be maintained between -1.0 and +2.0 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell and/or suppression chamber internal pressure outside of the specified limits, restore the internal pressure to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.6 The drywell and suppression chamber internal pressure shall be determined to be within the limits in accordance with the Surveillance Frequency Control Program.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Drywell average air temperature shall not exceed 145°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With the drywell average air temperature greater than 145°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The drywell average air temperature shall be the volumetric average of the temperatures at the following locations and shall be determined to be within the limit in accordance with the Surveillance Frequency Control Program:

	Approximate Elevation	Number of Installed Sensors*
a.	330'	3
b.	320'	3
c.	260'	3
d.	248'	6

* At least one reading from each elevation is required for a volumetric average calculation.

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and suppression chamber purge system may be in operation with the supply and exhaust isolation valves in one supply line and one exhaust line open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With a drywell and/or suppression chamber purge supply and/or exhaust isolation valve open, except as permitted above, close the valve(s) within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8 In accordance with the Surveillance Frequency Control Program, verify each primary containment purge valve [18" or 24"] is closed.*, **

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* Only required to be met in OPERATIONAL CONDITIONS 1, 2, and 3.

** Not required to be met when the primary containment purge valves are open for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require these valves to be open.

3/4.6.2 DEPRESSURIZATION SYSTEMS

SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression chamber shall be OPERABLE with:

a. The pool water:

1. Volume* between 122,120 ft^3 and 134,600 ft^3, equivalent to a level between 22' 0" and 24' 3", and a

2. Maximum average temperature of 95°F except that the maximum average temperature may be permitted to increase to:

   a) 105°F during testing which adds heat to the suppression chamber.

   b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.

   c) 120°F with the main steam line isolation valves closed following a scram, one in each of the eigth locations.

b. Drywell-to-suppression chamber bypass leakage less than or equal to 10% of the acceptable $A/\sqrt{K}$ design value of 0.0500 ft^2.

c. At least eight suppression pool water temperature instrumentation indicators, one in each of the eight locations.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With the suppression chamber water level outside the above limits, restore the water level to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the suppression chamber average water temperature greater than 95°F, restore the average temperature to less than or equal to 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above:

1. With the suppression chamber average water temperature greater than 105°F during testing which adds heat to the suppression chamber, stop all testing which adds heat to the suppression chamber and restore the average temperature to less than 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With the suppression chamber average water temperature greater than:

   a) 95°F for more than 24 hours and THERMAL POWER greater than 1% of RATED THERMAL POWER, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

   b) 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.

*Includes the volume inside the pedestal.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

c. With only one suppression chamber water level indicator OPERABLE and/or with less than eight suppression pool water temperature indicators, one in each of the eight locations OPERABLE, restore the inoperable indicator(s) to OPERABLE status within 7 days or verify suppression chamber water level and/or temperature to be within the limits at least once per 12 hours.

d. With no suppression chamber water level indicators OPERABLE and/or with less than seven suppression pool water temperature indicators covering at least seven locations OPERABLE, restore at least one water level indicator and at least seven water temperature indicators 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.

e. With the drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits in accordance with the Surveillance Frequency Control Program.

b. In accordance with the Surveillance Frequency Control Program by verifying the suppression chamber average water temperature to be less than or equal to 95°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per hour when suppression chamber average water temperature is greater than or equal to 95°F, by verifying:

a) Suppression chamber average water temperature to be less than or equal to 110°F, and

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER 12 hours after suppression chamber average water temperature has exceeded 95°F for more than 24 hours.

3. At least once per 30 minutes following a scram with suppression chamber average water temperature greater than or equal to 95°F, by verifying suppression chamber average water temperature less than or equal to 120°F.

c. By verifying at least 8 suppression pool water temperature indicators in at least 8 locations, OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the temperature alarm setpoint for:

1. High water temperature:

    a) First setpoint ≤ 95°F

    b) Second setpoint ≤ 105°F

    c) Third setpoint ≤ 110°F

    d) Fourth setpoint ≤ 120°F

d. By verifying at least two suppression chamber water level indicators OPERABLE by performance of a CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program with the water level alarm setpoint for high water level ≤ 24'1-1/2".

e. Drywell-to-suppression chamber bypass leak tests shall be conducted to coincide with the Type A test at an initial differential pressure of 4 psi and verifying that the $A/\sqrt{k}$ calculated from the measured leakage is within the specified limit. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 24 months until two consecutive tests meet the specified limit, at which time the test schedule may be resumed.

f. By conducting a leakage test on the drywell-to-suppression chamber vacuum breakers at a differential pressure of at least 4.0 psi and verifying that the total leakage area $A/\sqrt{k}$ contributed by all vacuum breakers is less than or equal to 24% of the specified limit and the leakage area for an individual set of vacuum breakers is less than or equal to 12% of the specified limit. The vacuum breaker leakage test shall be conducted during each refueling outage for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted.

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger and the suppression pool spray sparger(s).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool spray loop inoperable, restore the inoperable loop to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying 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. By verifying that each of the required RHR pumps develops a flow of at least 500 gpm on recirculation flow through the RHR heat exchanger and the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

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* Whenever both 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.

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying 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. By verifying that each of the required RHR pumps develops a flow of at least 10,000 gpm on recirculation flow through the flow path including the RHR heat exchanger and its associated closed bypass valve, the suppression pool and the full flow test line when tested pursuant to Specification 4.0.5.

*Whenever both 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.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each primary containment isolation valve and each instrumentation line excess flow check valve shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more of the primary containment isolation valves inoperable,** maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

   1. Restore the inoperable valve(s) to OPERABLE status, or

   2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

   3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*

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

b. With one or more of the instrumentation line excess flow check valves inoperable, operation may continue and the provisions of Specification 3.0.3 are not applicable provided that within 4 hours either:

   1. The inoperable valve is returned to OPERABLE status, or

   2. The instrument line is isolated and the associated instrument is declared inoperable.

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

c. With one or more scram discharge volume vent or drain valves inoperable, perform the applicable actions specified in Specification 3.1.3.1.

* Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

** Except for the scram discharge volume vent and drain valves.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each primary containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

4.6.3.2 Each primary containment automatic isolation valve shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.3.3 The isolation time of each primary containment power operated or automatic valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

4.6.3.4 A representative sample of instrumentation line excess flow check valves shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program, such that each valve is tested in accordance with the Surveillance Frequency Control Program, by verifying that the valve checks flow.*

4.6.3.5 Each traversing in-core probe system explosive isolation valve shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying the continuity of the explosive charge.

b. In accordance with the Surveillance Frequency Control Program by removing the explosive squib from the explosive valve, such that each explosive squib in each explosive valve will be tested in accordance with the Surveillance Frequency Control Program, and initiating the explosive squib. The replacement charge for the exploded squib shall be from the same manufactured batch as the one fired or from another batch which has been certified by having at least one of that batch successfully fired. No squib shall remain in use beyond the expiration of its shelf-life and/or operating life, as applicable.

*The reactor vessel head seal leakage detection line (penetration 29A) excess flow check valve is not required to be tested pursuant to this requirement.

TABLE 3.6.3-1 (Deleted)

THE INFORMATION FROM THIS
TECHNICAL SPECIFICATION SECTION
HAS BEEN RELOCATED TO THE
TECHNICAL REQUIREMENTS MANUAL (TRM), PCIV SECTION.

TECHNICAL SPECIFICATION PAGES 3/4 6-19 THROUGH 3/4 6-43a
HAVE BEEN INTENTIONALLY OMITTED.

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3/4.6.4 VACUUM RELIEF

SUPPRESSION CHAMBER - DRYWELL VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.4.1 Three pairs of suppression chamber - drywell vacuum breakers shall be OPERABLE and all suppression chamber - drywell vacuum breakers shall be closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more vacuum breakers in one of the three required pairs of suppression chamber - drywell vacuum breaker pairs inoperable for opening but known to be closed, restore at least one inoperable pair of vacuum breakers to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one suppression chamber - drywell vacuum breaker open, verify the other vacuum breaker in the pair to be closed within 2 hours; restore the open vacuum breaker to the closed position within 72 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 position indicator of any suppression chamber - drywell vacuum breaker inoperable:

   1. Verify the other vacuum breaker in the pair to be closed within 2 hours and at least once per 15 days thereafter, or

   2. Verify the vacuum breaker(s) with the inoperable position indicator to be closed by conducting a test which demonstrates that the ΔP is maintained at greater than or equal to 0.7 psi for one hour without makeup within 24 hours and at least once per 15 days thereafter.

   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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SURVEILLANCE REQUIREMENTS

4.6.4.1 Each suppression chamber - drywell vacuum breaker shall be:

a. Verified closed in accordance with the Surveillance Frequency Control Program.

b. Demonstrated OPERABLE:

1. In accordance with the Surveillance Frequency Control Program and within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel.

2. In accordance with the Surveillance Frequency Control Program by verifying both position indicators OPERABLE by observing expected valve movement during the cycling test.

3. In accordance with the Surveillance Frequency Control Program by:

a) Verifying each valve's opening setpoint, from the closed position, to be 0.5 psid ± 5%, and

b) Verifying both position indicators OPERABLE by performance of a CHANNEL CALIBRATION.

c) Verifying that each outboard valve's position indicator is capable of detecting disk displacement ≥0.050", and each inboard valve's position indicator is capable of detecting disk displacement ≥0.120".

3/4.6.5 SECONDARY CONTAINMENT

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Without REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY, restore REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying in accordance with the Surveillance Frequency Control Program that the pressure within the reactor enclosure secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying in accordance with the Surveillance Frequency Control Program that:

   1. All reactor enclosure secondary containment equipment hatches and blowout panels are closed and sealed.

   2. At least one door in each access to the reactor enclosure secondary containment is closed.

   3. All reactor enclosure secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, slide gate dampers or deactivated automatic dampers/valves secured in position.

c. In accordance with the Surveillance Frequency Control Program:

   1. Verifying that one standby gas treatment subsystem will draw down the reactor enclosure secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 916 seconds with the reactor enclosure recirc system in operation, and

   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the reactor enclosure secondary containment at a flow rate not exceeding 2500 cfm with wind speeds of $\leq$ 7.0 mph as measured on the wind instrument on Tower 1, elevation 30' or, if that instrument is unavailable, Tower 2, elevation 159'.

3/4.6.5 SECONDARY CONTAINMENT

REFUELING AREA SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: When RECENTLY IRRADIATED FUEL is being handled in the secondary containment, or during operations with a potential for draining the reactor vessel, with the vessel head removed and fuel in the vessel.

ACTION:

Without REFUELING AREA SECONDARY CONTAINMENT INTEGRITY, suspend handling of RECENTLY IRRADIATED FUEL in the secondary containment, and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying in accordance with the Surveillance Frequency Control Program that the pressure within the refueling area secondary containment is greater than or equal to 0.25 inch of vacuum water gauge.

b. Verifying in accordance with the Surveillance Frequency Control Program that:

   1. All refueling area secondary containment equipment hatches and blowout panels are closed and sealed.

   2. At least one door in each access to the refueling area secondary containment is closed.

   3. All refueling area secondary containment penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, slide gate dampers or deactivated automatic dampers/valves secured in position.

c. In accordance with the Surveillance Frequency Control Program:

   Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.25 inch of vacuum water gauge in the refueling area secondary containment at a flow rate not exceeding 764 cfm.

REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.1 The reactor enclosure secondary containment ventilation system automatic isolation valves shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more of the reactor secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated valve secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve, blind flange or slide gate damper.

Otherwise, 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.

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 Each reactor enclosure secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

a. Prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

b. In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit in accordance with the Surveillance Frequency Control Program.

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TRM.

CONTAINMENT SYSTEMS

REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.2.2 The refueling area secondary containment ventilation system automatic isolation valves shall be OPERABLE.

APPLICABILITY: When RECENTLY IRRADIATED FUEL is being handled in the secondary containment, or during operations with a potential for draining the reactor vessel, with the vessel head removed and fuel in the vessel.

ACTION:

With one or more of the refueling area secondary containment ventilation system automatic isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 8 hours either:

a. Restore the inoperable valves to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated valve secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve, blind flange or slide gate damper.

Otherwise, suspend handling of RECENTLY IRRADIATED FUEL in the refueling area secondary containment, and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.2.2 Each refueling area secondary containment ventilation system automatic isolation valve shall be demonstrated OPERABLE:

a. Prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

b. In accordance with the Surveillance Frequency Control Program by verifying that on a containment isolation test signal each isolation valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit in accordance with the Surveillance Frequency Control Program.

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TRM.

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE TRM.

STANDBY GAS TREATMENT SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With the Unit 1 diesel generator for one standby gas treatment subsystem inoperable for more than 30 days, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one standby gas treatment subsystem inoperable and the other standby gas treatment subsystem with an inoperable Unit 1 diesel generator, restore the inoperable subsystem to OPERABLE status or restore the inoperable Unit 1 diesel generator to OPERABLE status within 72 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. With the Unit 1 diesel generators for both standby gas treatment system subsystems inoperable for more than 72 hours, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. When (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS, or (3) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel:

1. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS, and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

2. With both standby gas treatment subsystems inoperable, if in progress, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATIONS, and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

SURVEILLANCE REQUIREMENTS (Continued)

b. In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 5764 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

3. Verify that when the fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III) when tested in accordance with ANSI N510-1980.

4. Verify that the pressure drop across the refueling area to SGTS prefilter is less than 0.25 inches water gage while operating at a flow rate of 2400 cfm ± 10%.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 0.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F), at a relative humidity of 70% and at a face velocity of 66 fpm.

d. In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 9.1 inches water gauge while operating the filter train at a flow rate of 8400 cfm ± 10%.

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the fan starts and isolation valves necessary to draw a suction from the refueling area or the reactor enclosure recirculation discharge open on each of the following test signals:

   a) Manual initiation from the control room, and

   b) Simulated automatic initiation signal.

3. Verifying that the temperature differential across each heater is ≥ 15°F when tested in accordance with ANSI N510-1980.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 5764 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 5764 cfm ± 10%.

g. After any major system alteration:

1. Verify that when the SGTS fan is running the subsystem flowrate is 2800 cfm minimum from each reactor enclosure (Zones I and II) and 2200 cfm minimum from the refueling area (Zone III).

2. Verify that one standby gas treatment subsystem will drawdown reactor enclosure Zone II secondary containment to greater than or equal to 0.25 inch of vacuum water gauge in less than or equal to 916 seconds with the reactor enclosure recirculation system in operation and the adjacent reactor enclosure and refueling area zones are in their isolation modes.

CONTAINMENT SYSTEMS

REACTOR ENCLOSURE RECIRCULATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.4 Two independent reactor enclosure recirculation subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one reactor enclosure recirculation subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both reactor enclosure recirculation subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.4 Each reactor enclosure recirculation subsystem shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates properly.

b. In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

   1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 60,000 cfm ± 10%.

   2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

   3. Verifying a subsystem flow rate of 60,000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980.

SURVEILLANCE REQUIREMENTS (Continued)

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) an a relative humidity of 70%.

d. In accordance with the Surveillance Frequency Control Program by:

   1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the filter train at a flow rate of 60,000 cfm ± 10%, verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

   2. Verifying that the filter train starts and the isolation valves which take suction on and return to the reactor enclosure open on each of the following test signals:

      a. Manual initiation from the control room, and

      b. Simulated automatic initiation signal.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 60,000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 60,000 cfm ± 10%.

PRIMARY CONTAINMENT HYDROGEN RECOMBINER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.6.1 DELETED

DRYWELL HYDROGEN MIXING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.2 Four independent drywell unit cooler hydrogen mixing subsystems (2AV212, 2BV212, 2GV212, 2HV212) shall be OPERABLE with each subsystem consisting of one unit cooler fan.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell unit cooler hydrogen mixing subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 Each drywell unit cooler hydrogen mixing subsystem shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by:

a. Starting the system from the control room, and

b. Verifying that the system operates for at least 15 minutes.

CONTAINMENT SYSTEMS

DRYWELL AND SUPPRESSION CHAMBER OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.6.6.3 The drywell and suppression chamber atmosphere oxygen concentration shall be less than 4% by volume.

APPLICABILITY: OPERATIONAL CONDITION 1*, during the time period:

a. Within 24 hours** after THERMAL POWER is greater than 15% of RATED THERMAL POWER, following startup, to

b. Within 24 hours** prior to reducing THERMAL POWER to less than 15% of RATED THERMAL POWER, preliminary to a scheduled reactor shutdown.

ACTION:

With the drywell and/or suppression chamber oxygen concentration exceeding the limit, restore the oxygen concentration to within the limit within 24 hours or be in at least STARTUP within the next 8 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.3 The drywell and suppression chamber oxygen concentration shall be verified to be within the limit within 24 hours after THERMAL POWER is greater than 15% of RATED THERMAL POWER and in accordance with the Surveillance Frequency Control Program thereafter.

*See Special Test Exception 3.10.5.
**Specification 3.6.1.8 is applicable during this 24 hour period.

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3/4.7.1 SERVICE WATER SYSTEMS

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 At least the following independent residual heat removal service water (RHRSW) system subsystems, with each subsystem comprised of:

a. Two OPERABLE RHRSW pumps, and

b. An OPERABLE flow path capable of taking suction from the RHR service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water through one Unit 2 RHR heat exchanger,

shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3, two subsystems.

b. In OPERATIONAL CONDITIONS 4 and 5, the subsystem(s) associated with systems and components required OPERABLE by Specification 3.4.9.2, 3.9.11.1, and 3.9.11.2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With one RHRSW pump inoperable, restore the inoperable pump to OPERABLE status within 30 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one RHRSW pump in each subsystem inoperable, restore at least one of the inoperable RHRSW pumps to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one RHRSW subsystem otherwise inoperable, restore the inoperable subsystem to OPERABLE status with at least one OPERABLE RHRSW pump within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. With both RHRSW subsystems otherwise inoperable, restore at least one subsystem to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

*Whenever both RHRSW 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.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

5. With two RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With three RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

7. With four RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required residual heat removal service water system subsystem(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

*A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

3.7.1.2 At least the following independent emergency service water system loops, with each loop comprised of:

a. Two OPERABLE emergency service water pumps, and

b. An OPERABLE flow path capable of taking suction from the emergency service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water to the associated Unit 2 and common safety-related equipment,

shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3, two loops.

b. In OPERATIONAL CONDITIONS 4, 5, and *, one loop.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5, and *.

ACTION:

a. In OPERATION CONDITION 1, 2, or 3:

1. With one emergency service water pump inoperable, restore the inoperable pump to OPERABLE status within 45 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one emergency service water pump in each loop inoperable, restore at least one inoperable pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one emergency service water system loop otherwise inoperable, declare all equipment aligned to the inoperable loop inoperable**, restore the inoperable loop to OPERABLE status with at least one OPERABLE pump within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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*When handling irradiated fuel in the secondary containment.

**The diesel generators may be aligned to the OPERABLE emergency service water system loop provided confirmatory flow testing has been performed. Those diesel generators not aligned to the OPERABLE emergency service water system loop shall be declared inoperable and the actions of 3.8.1.1 taken.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

4. With three ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With four ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5:

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated safety related equipment inoperable and take the ACTION required by Specifications 3.5.2 and 3.8.1.2.

c. In OPERATIONAL CONDITION *

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or verify adequate cooling remains available for the diesel generators required to be OPERABLE or declare the associated diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENT

4.7.1.2 At least the above required emergency service water system loop(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each automatic valve actuates to its correct position on its appropriate ESW pump start signal.

2. Each pump starts automatically when its associated diesel generator starts.

* When handling irradiated fuel in the secondary containment.

** An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, than the ESW pump/diesel generator pair is inoperable.

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The spray pond shall be OPERABLE with:

a. A minimum pond water level at or above elevation 250'-10" Mean Sea Level, and

b. A pond water temperature of less than or equal to 88°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5, and *.

ACTION:

With the requirements of the above specification not satisfied:

a. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITION 4 or 5, declare the RHRSW system and the emergency service water system inoperable and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2.

c. In OPERATIONAL CONDITION *, declare the emergency service water system inoperable and take the ACTION required by Specification 3.7.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The spray pond shall be determined OPERABLE:

a. By verifying the pond water level to be greater than its limit in accordance with the Surveillance Frequency Control Program.

b. By verifying the water surface temperature (within the upper two feet of the surface) to be less than or equal to 88°F:

1. in accordance with the Surveillance Frequency Control Program when the spray pond temperature is greater than or equal to 80°F; and

2. in accordance with the Surveillance Frequency Control Program when the spray pond temperature is greater than or equal to 85°F; and

3. in accordance with the Surveillance Frequency Control Program when the spray pond temperature is greater than 32°F.

c. By verifying all piping above the frost line is drained:

1. within one (1) hour after being used when ambient air temperature is below 40°F; or

2. when ambient air temperature falls below 40°F if the piping has not been previously drained.

*When handling irradiated fuel in the secondary containment.

PLANT SYSTEMS

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency fresh air supply system subsystems shall be OPERABLE.

NOTE: The main control room envelope (CRE) boundary may be opened intermittently under administrative control.

APPLICABILITY: All OPERATIONAL CONDITIONS and when RECENTLY IRRADIATED FUEL is being handled in the secondary containment, or during operations with a potential for draining the reactor vessel.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With the Unit 1 diesel generator for one control room emergency fresh air supply subsystem inoperable for more than 30 days, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one control room emergency fresh air supply subsystem inoperable for reasons other than Condition a.5, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one control room emergency fresh air supply subsystem inoperable for reasons other than Condition a.5, and the other control room emergency fresh air supply subsystem with an inoperable Unit 1 diesel generator, restore the inoperable subsystem to OPERABLE status or restore the Unit 1 diesel generator to OPERABLE status within 72 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. With the Unit 1 diesel generators for both control room emergency fresh air supply subsystems inoperable for more than 72 hours, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With one or more control room emergency fresh air supply subsystems inoperable due to an inoperable CRE boundary,

   a. Initiate action to implement mitigating actions immediately or be in HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours; and

   b. Within 24 hours, verify mitigating actions ensure CRE occupant exposures to radiological and chemical hazards will not exceed limits and actions to mitigate exposure to smoke hazards are taken or be in HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours; and

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. Restore CRE boundary to operable status within 90 days or be in HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4, 5 or when RECENTLY IRRADIATED FUEL is being handled in the secondary containment, or during operations with a potential for draining the reactor vessel:

1. With one control room emergency fresh air supply subsystem inoperable for reasons other than Condition b.3, restore the inoperable subsystem to OPERABLE status within 7 days, or initiate and maintain operation of the OPERABLE subsystem in the radiation isolation mode of operation.

2. With both control room emergency fresh air supply subsystem inoperable for reasons other than Condition b.3, immediately suspend handling of RECENTLY IRRADIATED FUEL in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

3. With one or more control room emergency fresh air subsystems inoperable due to an inoperable CRE boundary, immediately suspend handling of RECENTLY IRRADIATED FUEL in the secondary containment and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.2.1 Each control room emergency fresh air supply subsystem shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying the control room air temperature to be less than or equal to 85°F effective temperature.

b. In accordance with the Surveillance Frequency Control Program on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

c. In accordance with the Surveillance Frequency Control Program or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 3000 cfm ± 10%.

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SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

3. Verifying a subsystem flow rate of 3000 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, shows the methyl iodide penetration of less than 2.5% when tested in accordance with ASTM D3803-1989 at a temperature of 30°C (86°F) and a relative humidity of 70%.

e. In accordance with the Surveillance Frequency Control Program by:

1. Verifying that the pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks is less than 6 inches water gauge while operating the subsystem at a flow rate of 3000 cfm ± 10%; verifying that the prefilter pressure drop is less than 0.8 inch water gauge and that the pressure drop across each HEPA is less than 2 inches water gauge.

2. Verifying that on each of the below chlorine isolation mode actuation test signals, the subsystem automatically switches to the chlorine isolation mode of operation and the isolation valves close within 5 seconds:

a) Outside air intake high chlorine, and

b) Manual initiation from the control room.

3. Verifying that on each of the below radiation isolation mode actuation test signals, the subsystem automatically switches to the radiation isolation mode of operation:

a) Outside air intake high radiation, and

b) Manual initiation from control room.

SURVEILLANCE REQUIREMENTS (Continued)

f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 3000 cfm ± 10%.

g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 3000 cfm ± 10%.

4.7.2.2 The control room envelope boundary shall be demonstrated OPERABLE:

a. At a frequency in accordance with the Control Room Envelope Habitability Program by performance of control room envelope unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.

PLANT SYSTEMS

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. In the event the RCIC 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.

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by:

   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. Verifying 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.

   3. Verifying that the pump flow controller is in the correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

SURVEILLANCE REQUIREMENTS (Continued)

c. In accordance with the Surveillance Frequency Control Program by:

1. Performing a system functional test which includes simulated automatic actuation and restart 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.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

4. Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

3/4.7.4 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.4 All snubbers shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3. OPERATIONAL CONDITIONS 4 and 5 for snubbers located on systems required OPERABLE in those OPERATIONAL CONDITIONS.

ACTION:

With one or more snubbers inoperable on any system, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.4g on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.4 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Inspection Types

As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 4.7.4-1. The visual inspection interval for each type of snubber shall be determined based upon the criteria provided in Table 4.7.4-1 and the first inspection interval determined using this criteria shall be based upon the previous inspection interval as established by the requirements in effect before amendment no. 15.

TABLE 4.7.4-1
SNUBBER VISUAL INSPECTION INTERVAL

NUMBER OF UNACCEPTABLE SNUBBERS

Population or Category (Notes 1 and 2)	Column A Extend Interval (Notes 3 and 6)	Column B Repeat Interval (Notes 4 and 6)	Column C Reduce Interval (Notes 5 and 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These catergories may be examined separately or jointly. However, the licensee must make and document that decision before any inspection and shall use that decision as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

TABLE 4.7.4-1 (continued)
SNUBBER VISUAL INSPECTION INTERVAL

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are secure, and (3) fasteners for attachment of the snubber to the component and to the snubber anchorage are secure. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, providing that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type on that system that may be generically susceptible; and/or (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specifications 4.7.4f. For those snubbers common to more than one system, the OPERABILITY of such snubbers shall be considered in assessing the surveillance schedule for each of the related systems. A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the ACTIONS requirements shall be met.

d. Transient Event Inspection

An inspection shall be performed of all snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients, as determined from a review of operational data or a visual inspection of the systems, within 72 hours for accessible systems and 6 months for inaccessible systems following this determination. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

SURVEILLANCE REQUIREMENTS (Continued)

e. Functional Tests

At least once per 24 months a representative sample of each type ofsnubber shall be tested using the following sample plans. The sample plan(s) shall be selected for each type prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan(s) selected for each type prior to the test period or the sample plan(s) used in the prior test period shall be implemented:

1) At least 13.3% of the total population of a snubber type shall be functionally tested. For each snubber of that type that does not meet the functional test acceptance criteria of Specification 4.7.4f., an additional sample of at least 1/2 the size of the initial sample shall be tested until the total number tested is equal to the initial sample multiplied by the factor, 1+C/2, where C is the total number of unacceptable snubbers or until all the snubbers of that type have been tested; or

2) A representative sample of 37 snubbers of a snubber type shall be functionally tested in accordance with Figure 4.7.4-1. "C" is the total number of snubbers of that type found not meeting the acceptance requirements of Specification 4.7.4f. The cumulative number of snubbers of the type tested is denoted by "N". If at any time the point plotted falls in the "Accept" region, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region, or all the snubbers of that type have been tested.

The representative sample selected for the function test sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure as far as practical that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of that type. Snubbers placed in the same locations as snubbers which failed in the previous functional test period shall be retested at the time of the next functional test period but shall not be included in the sample plan, and failure of this functional test shall not be the sole cause for increasing the sample size under the sample plan. Testing equipment failure during functional testing may invalidate the day's testing and allow that day's testing to resume anew at a later time provided all snubbers tested with the failed equipment during the day of equipment failure are retested.

If during the functional testing, additional testing is required due to failure of snubbers, the unacceptable snubbers may be catergorized into failure mode group(s). A failure mode group shall include all unacceptable snubbers that have a given failure mode and all other snubbers subject to the same failure mode. Once a failure mode group has been established, it can be separated for continued testing apart from the general population of snubbers. However, all unacceptable snubbers in the failure mode group shall be counted as one unacceptable snubber for additional testing in the general population. Testing in the failure mode group shall be based on the number of unacceptable snubbers and shall continue in accordance with the sample plan selected for the type or until all snubbers in the failure mode group have been tested. Any additional unacceptable snubbers found in the failure mode group shall be counted for continue testing only for that test failure mode group. In the event that a snubber(s) becomes included in more than one test failure mode group, it shall be counted in each failure mode group and shall be subject to the corrective action of each test failure mode group.

f. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1) Activation (restraining action) is achieved within the specified range in both tension and compression;

2) Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range (hydraulic snubbers only);

3) For mechanical snubbers, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

4) For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

For the snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers which have repairs which might affect the functional test result shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

i. Snubber Service Life Replacement Program

The service life of all snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for various seals, springs, and other critical parts shall be extended or shortened based on monitored test results and failure history. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. The parts replacements shall be documented and the documentation shall be retained in accordance with Specification 6.10.3.

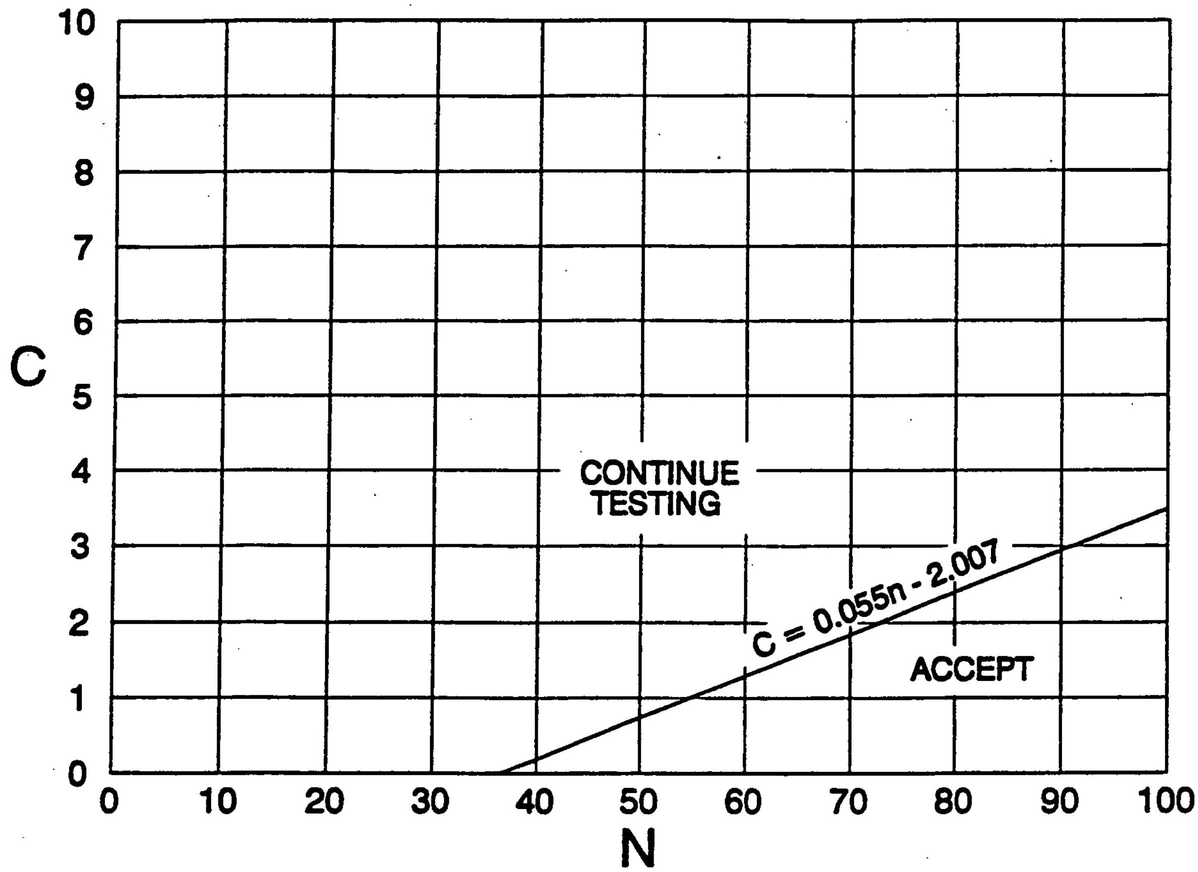

Figure 4.7.4-1

SAMPLE PLAN 2) FOR SNUBBER FUNCTIONAL TEST

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 5 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcurie 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 Specification 3.0.3 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 microcurie 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 - In accordance with the Surveillance Frequency Control Program 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.

SURVEILLANCE REQUIREMENTS (Continued)

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous 6 months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source* and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

4.7.5.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcurie of removable contamination.

*Except the Cf-252 startup sources which shall be tested within 6 months prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

Section 3/4.7.6 through 3/4.7.7 (Deleted)

THE INFORMATION FROM THESE TECHNICAL SPECIFICATIONS SECTIONS HAVE BEEN RELOCATED TO THE TECHNICAL REQUIREMENTS MANUAL (TRM) FIRE PROTECTION SECTION. TECHNICAL SPECIFICATIONS PAGES 3/4 7-19 THROUGH 3/4 7-32 HAVE BEEN INTENTIONALLY OMITTED.

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3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE as determined by the number of operable main turbine bypass valves being greater than or equal to that specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or take the ACTION required by Specification 3.2.3.c.

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program:

a. By cycling each turbine bypass valve through at least one complete cycle of full travel,

b. By performing a system functional test which includes simulated automatic actuation, and by verifying that each automatic valve actuates to its correct position, and

c. By determining TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to the value specified in the CORE OPERATING LIMITS REPORT.

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3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and
b. Four separate and independent diesel generators, each with:

   1. A separate day tank containing a minimum of 250 gallons of fuel,

   2. A separate fuel storage system containing a minimum of 33,500 gallons of fuel, and

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 24 hours and at least once per 7 days thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining operable diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 24 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore the inoperable diesel generator to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

b. With two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the inoperable diesel generators to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With three diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and perform Surveillance Requirement 4.8.1.1.2.a.4 for the remaining diesel generator, within 1 hour. Restore at least one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

d. With one offsite circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

e. In addition to the ACTIONS above:

1. For two train systems, with one or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least one of the required two train system subsystem, train, components, and devices is OPERABLE and its associated diesel generator is OPERABLE. Otherwise, restore either the inoperable diesel generator or the inoperable system subsystem to an OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. For the LPCI systems, with two or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least two of the required LPCI system subsystems, trains, components and devices are OPERABLE and its associated diesel generator is OPERABLE. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

This ACTION does not apply for those systems covered in Specifications 3.7.1.1 and 3.7.1.2.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

f. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore at least two offsite circuits to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With two of the above required offsite circuits inoperable, restore at least one of the inoperable offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

h. With one offsite circuit and two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the above required inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and at least three of the above required diesel generators to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

i. Specification 3.0.4.b is not applicable to diesel generators.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program on a STAGGERED TEST BASIS by:

1. Verifying the fuel level in the day fuel tank.

2. Verifying the fuel level in the fuel storage tank.

3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank.

4. Verify that the diesel can start* and gradually accelerate to synchronous speed with generator voltage and frequency at 4280 ± 120 volts and 60 ± 1.2 Hz.

5. Verify diesel is synchronized, gradually loaded* to an indicated 2700-2800 kW** and operates with this load for at least 60 minutes.

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 225 psig.

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*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

b. By removing accumulated water:

1) From the day tank in accordance with the Surveillance Frequency Control Program and after each occasion when the diesel is operated for greater than 1 hour, and

2) From the storage tank in accordance with the Surveillance Frequency Control Program.

c. By sampling new fuel oil in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1) By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

a) An API Gravity of within 0.3 degrees at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

c) A flash point equal to or greater than 125°F, and

d) A clear and bright appearance with proper color when tested in accordance with ASTM D4176-82.

2) By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

d. In accordance with the Surveillance Frequency Control Program by obtaining a sample of fuel oil from the storage tanks in accordance with ASTM D2276-78, and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-78, Method A, except that the filters specified in ASTM D2276-78, Sections 5.1.6 and 5.1.7, may have a nominal pore size of up to three (3) microns.

e. In accordance with the Surveillance Frequency Control Program by:

1) Deleted

2) Verifying each diesel generator's capability to reject a load of greater than or equal to that of its single largest post-accident load, and:

a) Following load rejection, the frequency is ≤ 66.5 Hz;

b) Within 1.8 seconds following the load rejection, voltage is 4285 ± 420 volts, and frequency is 60 ± 1.2 Hz; and

c) After steady-state conditions are reached, voltage is maintained at 4280 ± 120 volts.

SURVEILLANCE REQUIREMENTS (Continued)

3. Verifying the diesel generator capability to reject a load of 2850 kW without tripping. The generator voltage shall not exceed 4784 volts during and following the load rejection.

4. Simulating a loss-of-offsite power by itself, and:

   a) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency buses within 10 seconds, energizes the auto-connected loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

5. Verifying that on an ECCS actuation test signal, without loss-of-offsite power, the diesel generator starts* on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. Simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, and:

   a) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency buses within 10 seconds, energizes the auto-connected shutdown loads through the individual load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4280 ± 120 volts and 60 ± 1.2 Hz during this test.

7. Verifying that all automatic diesel generator trips, except engine overspeed and generator differential over-current are automatically bypassed upon an ECCS actuation signal.

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*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warm up procedures, and as applicable regarding loading and shutdown recommendations.

SURVEILLANCE REQUIREMENTS (Continued)

8. a) Verifying the diesel generator operates* for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to an indicated 2950-3050 kW** and during the remaining 22 hours of this test, the diesel generator shall be loaded to an indicated 2700-2800 kW**.

   b) Verifying that, within 5 minutes of shutting down the diesel generator after the diesel generator has operated* for at least 2 hours at an indicated 2700-2800 kW**, the diesel generator starts*. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal.

9. Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 3100 kW.

10. Verifying the diesel generator's capability to:

    a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

    b) Transfer its loads to the offsite power source, and

    c) Be restored to its standby status.

11. Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

12. Verifying that the automatic load sequence timers are OPERABLE with the interval between each load block within ± 10% of its design interval.

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* This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

** This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

13. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

    a) Control Room Switch In Pull-To-Lock (With Local/Remote Switch in Remote)

    b) Local/Remote Switch in Local.

    c) Emergency Stop

f. In accordance with the Surveillance Frequency Control Program or after any modifications which could affect diesel generator interdependence by starting* all four diesel generators simultaneously, during shutdown, and verifying that all four diesel generators accelerate to at least 882 rpm in less than or equal to 10 seconds.

g. In accordance with the Surveillance Frequency Control Program by:

    1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite or equivalent solution, and

    2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000.

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

h. In accordance with the Surveillance Frequency Control Program the diesel generator shall be started* and verified to accelerate to synchronous speed in less than or equal to 10 seconds. The generator voltage and frequency shall reach 4280 ± 120 volts and 60 ± 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual***

b) Simulated loss-of-offsite power by itself.

c) Simulated loss-of-offsite power in conjunction with an ECCS actuation test signal.

d) An ECCS actuation test signal by itself.

The generator shall be manually synchronized to its appropriate emergency bus, loaded to an indicated 2700-2800 KW** and operate for at least 60 minutes. This test, if it is performed so it coincides with the testing required by Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5, may also serve to concurrently meet those requirements as well.

4.8.1.1.3 Deleted

*This test shall be conducted in accordance with the manufacturer's recommendations regarding engine prelube and warmup procedures, and as applicable regarding loading and shutdown recommendations.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing under direct monitoring by the manufacturer or momentary variations due to changing bus loads shall not invalidate the test.

***If diesel generator started manually from the control room, 10 seconds after the automatic prelube period.

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A.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two diesel generators each with:

   1. A day fuel tank containing a minimum of 250 gallons of fuel.

   2. A fuel storage system containing a minimum of 33,500 gallons of fuel.

   3. A fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With less than the above required A.C. electrical power sources OPERABLE, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment, operations with a potential for draining the reactor vessel and crane operations over the spent fuel storage pool when fuel assemblies are stored therein. In addition, when in OPERATIONAL CONDITION 5 with the water level less than 22 feet above the reactor pressure vessel flange, immediately initiate corrective action to restore the required power sources to OPERABLE status as soon as practical.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.1.2 At least the above required A.C. electrical power sources shall be demonstrated OPERABLE per Surveillance Requirements 4.8.1.1.1 and 4.8.1.1.2.

*When handling irradiated fuel in the secondary containment.

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall be OPERABLE:

a. Division 1, Consisting of:
   1. 125-Volt Battery 2A1 (2A1D101).
   2. 125-Volt Battery 2A2 (2A2D101).
   3. 125-Volt Battery Charger 2BCA1 (2A1D103).
   4. 125-Volt Battery Charger 2BCA2 (2A2D103).

b. Division 2, Consisting of:
   1. 125-Volt Battery 2B1 (2B1D101).
   2. 125-Volt Battery 2B2 (2B2D101).
   3. 125-Volt Battery Charger 2BCB1 (2B1D103).
   4. 125-Volt Battery Charger 2BCB2 (2B2D103).

c. Division 3, Consisting of:
   1. 125-Volt Battery 2C (2CD101).
   2. 125-Volt Battery Charger 2BCC (2CD103).

d. Division 4, Consisting of:
   1. 125-Volt Battery 2D (2DD101).
   2. 125-Volt Battery Charger 2BCD (2DD103).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or two battery chargers on one division inoperable:

   1. Restore battery terminal voltage to greater than or equal to the minimum established float voltage within 2 hours,

   2. Verify associated Division 1 or 2 float current $\leq$ 2 amps, or Division 3 or 4 float current $\leq$ 1 amp within 18 hours and once per 12 hours thereafter, and

   3. Restore battery charger(s) to OPERABLE status within 7 days.

b. With one or more batteries inoperable due to:

   1. One or two batteries on one division with one or more battery cells float voltage < 2.07 volts, perform 4.8.2.1.a.1 and 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore affected cell(s) voltage $\geq$ 2.07 volts within 24 hours.

   2. Division 1 or 2 with float current > 2 amps, or with Division 3 or 4 with float current > 1 amp, perform 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore battery float current to within limits within 18 hours.

ACTION: (Continued)

3. One or two batteries on one division with one or more cells electrolyte level less than minimum established design limits, if electrolyte level was below the top of the plates restore electrolyte level to above top of plates within 8 hours and verify no evidence of leakage(*) within 12 hours. In all cases, restore electrolyte level to greater than or equal to minimum established design limits within 31 days.

4. One or two batteries on one division with pilot cell electrolyte temperature less than minimum established design limits, restore battery pilot cell temperature to greater than or equal to minimum established design limits within 12 hours.

5. Batteries in more than one division affected, restore battery parameters for all batteries in all but one division to within limits within 2 hours.

6. (i) Any battery having both (Action b.1) one or more battery cells float voltage < 2.07 volts and (Action b.2) float current not within limits, and/or

   (ii) Any battery not meeting any Action b.1 through b.5,

   Restore the battery parameters to within limits within 2 hours.

c. With any battery(ies) on one division of the above required D.C. electrical power sources inoperable for reasons other than Action b., restore the inoperable division battery to OPERABLE status within 2 hours.

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

(*) Contrary to the provisions of Specification 3.0.2, if electrolyte level was below the top of the plates, the verification that there is no evidence of leakage is required to be completed regardless of when electrolyte level is restored.

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SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required division batteries and chargers shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each Division 1 and 2 battery float current is $\leq$ 2 amps, and Division 3 and 4 battery float current is $\leq$ 1 amp when battery terminal voltage is greater than or equal to the minimum established float voltage of 4.8.2.1.a.2, and

2. Total battery terminal voltage for each 125-volt battery is greater than or equal to the minimum established float voltage.

b. In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each battery pilot cell voltage is $\geq$ 2.07 volts,

2. Each battery connected cell electrolyte level is greater than or equal to minimum established design limits, and

3. The electrolyte temperature of each pilot cell is greater than or equal to minimum established design limits.

c. In accordance with the Surveillance Frequency Control Program by verifying that each battery connected cell voltage is $\geq$ 2.07 volts.

d. In accordance with the Surveillance Frequency Control Program by verifying that:

1. The battery chargers will supply the currents listed below at greater than or equal to the minimum established float voltage for at least 4 hours:

Charger	Current (Amperes)
2BCA1	300
2BCA2	300
2BCB1	300
2BCB2	300
2BCC	75
2BCD	75

2. The battery capacity is adequate to supply and maintain in OPERABLE status the required emergency loads for the design duty cycle when subjected to a battery service test.

SURVEILLANCE REQUIREMENTS (Continued)

e. In accordance with the Surveillance Frequency Control Program by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test or modified performance discharge test. The modified performance discharge test may be performed in lieu of the battery service test (Specification 4.8.2.1.d.2).

f. Performance discharge tests or modified performance discharge tests of battery capacity shall be given as follows:

   1. In accordance with the Surveillance Frequency Control Program when:
      (a) The battery shows degradation or
      (b) The battery has reached 85% of expected life with battery capacity < 100% of manufacturer's rating, and

   2. In accordance with the Surveillance Frequency Control Program when battery has reached 85% of expected life with battery capacity ≥ 100% of manufacturer's rating.

TABLE 4.8.2.1-1 (DELETED)

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D.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, two of the following four divisions of the D.C. electrical power sources system shall be OPERABLE with:

a. Division 1, Consisting of:
   1. 125-Volt Battery 2A1 (2A1D101).
   2. 125-Volt Battery 2A2 (2A2D101).
   3. 125-Volt Battery Charger 2BCA1 (2A1D103).
   4. 125-Volt Battery Charger 2BCA2 (2A2D103).

b. Division 2, Consisting of:
   1. 125-Volt Battery 2B1 (2B1D101).
   2. 125-Volt Battery 2B2 (2B2D101).
   3. 125-Volt Battery Charger 2BCB1 (2B1D103).
   4. 125-Volt Battery Charger 2BCB2 (2B2D103).

c. Division 3, Consisting of:
   1. 125-Volt Battery 2C (2CD101).
   2. 125-Volt Battery Charger 2BCC (2CD103).

d. Division 4, Consisting of:
   1. 125-Volt Battery 2D (2DD101).
   2. 125-Volt Battery Charger 2BCD (2DD103).

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With one or two required battery chargers on one required division inoperable:

   1. Restore battery terminal voltage to greater than or equal to the minimum established float voltage within 2 hours,

   2. Verify associated Division 1 or 2 float current $\leq$ 2 amps, or Division 3 or 4 float current $\leq$ 1 amp within 18 hours and once per 12 hours thereafter, and

   3. Restore battery charger(s) to OPERABLE status within 7 days.

b. With one or more required batteries inoperable due to:

   1. One or two batteries on one division with one or more battery cells float voltage < 2.07 volts, perform 4.8.2.1.a.1 and 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore affected cell(s) voltage $\geq$ 2.07 volts within 24 hours.

*When handling irradiated fuel in the secondary containment.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

2. Division 1 or 2 with float current > 2 amps, or with Division 3 or 4 with float current > 1 amp, perform 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore battery float current to within limits within 18 hours.

3. One or two batteries on one division with one or more cells electrolyte level less than minimum established design limits, if electrolyte level was below the top of the plates restore electrolyte level to above top of plates within 8 hours and verify no evidence of leakage(*) within 12 hours. In all cases, restore electrolyte level to greater than or equal to minimum established design limits within 31 days.

4. One or two batteries on one division with pilot cell electrolyte temperature less than minimum established design limits, restore battery pilot cell temperature to greater than or equal to minimum established design limits within 12 hours.

5. Batteries in more than one division affected, restore battery parameters for all batteries in one division to within limits within 2 hours.

6. (i) Any battery having both (Action b.1) one or more battery cells float voltage < 2.07 volts and (Action b.2) float current not within limits, and/or

   (ii) Any battery not meeting any Action b.1 through b.5,

   Restore the battery parameters to within limits within 2 hours.

c. 1. With the requirements of Action a. and/or Action b. not met, or

   2. With less than two divisions of the above required D.C. electrical power sources OPERABLE for reasons other than Actions a. and/or b.,

   Suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.2.2 At least the above required batteries and chargers shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.1.

(*) Contrary to the provisions of Specification 3.0.2, if electrolyte level was below the top of the plates, the verification that there is no evidence of leakage is required to be completed regardless of when electrolyte level is restored.

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3/4.8.3 ONSITE POWER DISTRIBUTION SYSTEMS

DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.3.1 The following power distribution system divisions shall be energized:

a. A.C. power distribution:

1. Unit 2 Division 1, Consisting of;

a)	4160-VAC Bus:	D21 (20A115)
b)	480-VAC Load Center:	D214 (20B201)
c)	480-VAC Motor Control Centers:	D214-R-C (20B213) D214-R-G (20B211) D214-R-G1 (20B215) D214-D-G (20B515)
d)	120-VAC Distribution Panels:	20Y101 20Y206

2. Unit 2 Division 2, Consisting of:

a)	4160-VAC Bus:	D22 (20A116)
b)	480-VAC Load Center:	D224 (20B202)
c)	480-VAC Motor Control Centers:	D224-R-C (20B214) D224-R-G (20B212) D224-R-G1 (20B216) D224-D-G (20B516)
d)	120-VAC Distribution Panels:	20Y102 20Y207

3. Unit 2 Division 3, Consisting of:

a)	4160-VAC Bus:	D23 (20A117)
b)	480-VAC Load Center:	D234 (20B203)
c)	480-VAC Motor Control Centers:	D234-R-H1 (20B221) D234-R-H (20B217) D234-R-E (20B223) D234-D-G (20B517)
d)	120-VAC Distribution Panels:	20Y103 20Y163

4. Unit 2 Division 4, Consisting of:

a)	4160-VAC Bus:	D24 (20A118)
b)	480-VAC Load Center:	D244 (20B204)
c)	480-VAC Motor Control Centers:	D244-R-H1 (20B222) D244-R-H (20B218) D244-R-E (20B224) D244-D-G (20B518)
d)	120-VAC Distribution Panels:	20Y104 20Y164

LIMITING CONDITION FOR OPERATION (Continued)

5. Unit 1 and Common Division 1, Consisting of:

a)	4160-VAC Bus:	D11	(10A115)
b)	480-VAC Load Center:	D114	(10B201)
c)	480-VAC Motor Control Centers:	D114-R-C	(10B213)
		D114-R-C1	(10B219)
		D114-D-G	(10B515)
		D114-S-L	(00B519)
d)	120-VAC Distribution Panels:	10Y101	
		10Y206	
		01Y501	

6. Unit 1 and Common Division 2, Consisting of:

a)	4160-VAC Bus:	D12	(10A116)
b)	480-VAC Load Center:	D124	(10B202)
c)	480-VAC Motor Control Centers:	D124-R-C	(10B214)
		D124-R-C1	(10B220)
		D124-D-G	(10B516)
		D124-S-L	(00B520)
d)	120-VAC Distribution Panels:	10Y102	
		10Y207	
		02Y501	

7. Unit 1 and Common Division 3, Consisting of:

a)	4160-VAC Bus:	D13	(10A117)
b)	480-VAC Load Center:	D134	(10B203)
c)	480-VAC Motor Control Centers:	D134-R-E	(10B223)
		D134-C-B	(00B131)
		D134-D-G	(10B517)
		D234-S-L	(00B521)
d)	120-VAC Distribution:	10Y103	
		10Y163	
		03Y501	

8. Unit 1 and Common Division 4, Consisting of:

a)	4160-VAC Bus:	D14	(10A118)
b)	480-VAC Load Center:	D144	(10B204)
c)	480-VAC Motor Control Centers:	D144-R-E	(10B224)
		D144-C-B	(00B132)
		D144-D-G	(10B518)
		D244-S-L	(00B522)
d)	120-VAC Distribution:	10Y104	
		10Y164	
		04Y501	

b. D.C. Power Distribution Panels

1. Unit 2 Division 1, Consisting of:

a)	250-V DC Fuse Box:	2FA	(2AD105)
b)	250-V DC Motor Control Center:	2DA	(20D201)
c)	125-V DC Distribution Panels:	2PPA1	(2AD102)
		2PPA2	(2AD501)
		2PPA3	(2AD162)

2. Unit 2 Division 2, Consisting of:

a)	250-V DC Fuse Box:	2FB	(2BD105)
b)	250-V DC Motor Control Centers:	2DB-1	(20D202)
		2DB-2	(20D203)
c)	125-V DC Distribution Panels:	2PPB1	(2BD102)
		2PPB2	(2BD501)
		2PPB3	(2BD162)

3. Unit 2 Division 3, Consisting of:

a)	125-V DC Fuse Box:	2FC	(2CD105)
b)	125-V DC Distribution Panels:	2PPC1	(2CD102)
		2PPC2	(2CD501)
		2PPC3	(2CD162)

4. Unit 2 Division 4, Consisting of:

a)	125-V DC Fuse Box:	2FD	(2DD105)
b)	125-V DC Distribution Panels:	2PPD1	(2DD102)
		2PPD2	(2DD501)
		2PPD3	(2DD162)

5. Unit 1 and Common Division 1, Consisting of:

a)	250-V DC Fuse Box:	1FA	(1AD105)
b)	125-V DC Distribution Panels:	1PPA1	(1AD102)
		1PPA2	(1AD501)

6. Unit 1 and Common Division 2, Consisting of:

a)	250-V DC Fuse Box:	1FB	(1BD105)
b)	125-V DC Distribution Panels:	1PPB1	(1BD102)
		1PPB2	(1BD501)

7. Unit 1 and Common Division 3, Consisting of:

a)	125-V DC Fuse Box:	1FC	(1CD105)
b)	125-V DC Distribution Panels:	1PPC1	(1CD102)
		1PPC2	(1CD501)

8. Unit 1 and Common Division 4, Consisting of:

a)	125-V DC Fuse Box:	1FD	(1DD105)
b)	125-V DC Distribution Panels:	1PPD1	(1DD102)
		1PPD2	(1DD501)

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LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one of the above required Unit 2 A.C. distribution system divisions not energized, reenergize the division within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 2 D.C. distribution system divisions not energized, reenergize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any of the above required Unit 1 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system divisions shall be determined energized in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.3.2 As a minimum, 2 of the 4 divisions of the power distribution system shall be energized with:

a. A.C. power distribution:

1. Unit 2 Division 1, Consisting of:

a) 4160-VAC Bus:	D21 (20A115)
b) 480-VAC Load Center:	D214 (20B201)
c) 480-VAC Motor Control Centers:	D214-R-C (20B213)
	D214-R-G (20B211)
	D214-R-G1 (20B215)
	D214-D-G (20B515)
d) 120-VAC Distribution Panels:	20Y101
	20Y206

2. Unit 2 Division 2, Consisting of:

a) 4160-VAC Bus:	D22 (20A116)
b) 480-VAC Load Center:	D224 (20B202)
c) 480-VAC Motor Control Centers:	D224-R-C (20B214)
	D224-R-G (20B212)
	D224-R-G1 (20B216)
	D224-D-G (20B516)
d) 120-VAC Distribution Panels:	20Y102
	20Y207

3. Unit 2 Division 3, Consisting of:

a) 4160-VAC Bus:	D23 (20A117)
b) 480-VAC Load Center:	D234 (20B203)
c) 480-VAC Motor Control Centers:	D234-R-H1 (20B221)
	D234-R-H (20B217)
	D234-R-E (20B223)
	D234-D-G (20B517)
d) 120-VAC Distribution Panels:	20Y103
	20Y163

4. Unit 2 Division 4, Consisting of:

a) 4160-VAC Bus:	D24 (20A118)
b) 480-VAC Load Center:	D244 (20B204)
c) 480-VAC Motor Control Centers:	D244-R-H1 (20B222)
	D244-R-H (20B218)
	D244-R-E (20B224)
	D244-D-G (20B518)
d) 120-VAC Distribution Panels:	20Y104
	20Y164

5. Unit 1 and Common Division 1, Consisting of:

a) 4160-VAC Bus:	D11	(10A115)
b) 480-VAC Load Center:	D114	(10B201)

c) 480-VAC Motor Control Centers: D114-R-C (10B213)
D114-R-C1 (10B219)
D114-D-G (10B515)
D114-S-L (00B519)

d) 120-VAC Distribution Panels: 10Y101
10Y206
01Y501

6. Unit 1 and Common Division 2, Consisting of:

a) 4160-VAC Bus: D12 (10A116)
b) 480-VAC Load Center: D124 (10B202)
c) 480-VAC Motor Control Centers: D124-R-C (10B214)
D124-R-C1 (10B220)
D124-D-G (10B516)
D124-S-L (00B520)
d) 120-VAC Distribution Panels: 10Y102
10Y207
02Y501

7. Unit 1 and Common Division 3, Consisting of:

a) 4160-VAC Bus: D13 (10A117)
b) 480-VAC Load Center: D134 (10B203)
c) 480-VAC Motor Control Centers: D134-R-E (10B223)
D134-C-B (00B131)
D134-D-G (10B517)
D234-S-L (00B521)
d) 120-VAC Distribution: 10Y103
10Y163
03Y501

8. Unit 1 and Common Division 4, Consisting of:

a) 4160-VAC Bus: D14 (10A118)
b) 480-VAC Load Center: D144 (10B204)
c) 480-VAC Motor Control Centers: D144-R-E (10B224)
D144-C-B (00B132)
D144-D-G (10B518)
D244-S-L (00B522)
d) 120-VAC Distribution: 10Y104
10Y164
04Y501

b. D.C. power distribution:

1. Unit 2 Division 1, Consisting of:

a) 250-V DC Fuse Box: 2FA (2AD105)
b) 250-V DC Motor Control Center: 2DA (20D201)

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LIMITING CONDITION FOR OPERATION (Continued)

c) 125-V DC Distribution Panels: 2PPA1 (2AD102)
2PPA2 (2AD501)
2PPA3 (2AD162)

2. Unit 2 Division 2, Consisting of:

a) 250-V DC Fuse Box: 2FB (2BD105)
b) 250-V DC Motor Control Centers: 2DB-1 (20D202)
2DB-2 (20D203)
c) 125-V DC Distribution Panels: 2PPB1 (2BD102)
2PPB2 (2BD501)
2PPB3 (2BD162)

3. Unit 2 Division 3, Consisting of:

a) 125-V DC Fuse Box: 2FC (2CD105)
b) 125-V DC Distribution Panels: 2PPC1 (2CD102)
2PPC2 (2CD501)
2PPC3 (2CD162)

4. Unit 2 Division 4, Consisting of:

a) 125-V DC Fuse Box: 2FD (2DD105)
b) 125-V DC Distribution Panels: 2PPD1 (2DD102)
2PPD2 (2DD501)
2PPD3 (2DD162)

5. Unit 1 and Common Division 1, Consisting of:

a) 250-V DC Fuse Box: 1FA (1AD105)
b) 125-V DC Distribution Panels: 1PPA1 (1AD102)
1PPA2 (1AD501)

6. Unit 1 and Common Division 2, Consisting of:

a) 250-V DC Fuse Box: 1FB (1BD105)
b) 125-V DC Distribution Panels: 1PPB1 (1BD102)
1PPB2 (1BD501)

7. Unit 1 and Common Division 3, Consisting of:

a) 125-V DC Fuse Box: 1FC (1CD105)
b) 125-V DC Distribution Panels: 1PPC1 (1CD102)
1PPC2 (1CD501)

8. Unit 1 and Common Division 4, Consisting of:

a) 125-V DC Fuse Box: 1FD (1DD105)
b) 125-V DC Distribution Panels: 1PPD1 (1DD102)
1PPD2 (1DD501)

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION:

a. With less than two divisions of the above required Unit 2 A.C. distribution systems energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

* When handling irradiated fuel in the secondary containment.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. With less than two divisions of the above required Unit 2 D.C. distribution systems energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. With any of the above required Unit 1 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system divisions shall be determined energized in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

Section 3/4 8.4.1 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATION SECTION HAS BEEN RELOCATED TO THE TRM. TECHNICAL SPECIFICATIONS PAGES 3/4 8-21 THROUGH 3/4 8-26 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

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ELECTRICAL POWER SYSTEMS

MOTOR-OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of all Class 1E motor operated valves shall be either:

a. Continously bypassed for all valves with maintained position control switches; or,

b. Bypassed only under accident conditions for all valves with spring-return-to-normal control switches.

APPLICABILITY: Whenever the motor-operated valve is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required valves not bypassed continuously or only under accident conditions, as applicable, restore the thermal overload bypass within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection for the above required valves which are continuously bypassed and temporarily placed in force only when the valve motor is undergoing periodic or maintenance testing shall be verified to be bypassed following periodic or maintenance testing during which the thermal overload protection was temporarily placed in force.

4.8.4.2.2 In accordance with the Surveillance Frequency Control Program, a CHANNEL FUNCTIONAL TEST of all those valves which are bypassed only under accident conditions (valves with spring-return-to-normal control switches) shall be performed to verify that the thermal overload protection will be bypassed under accident conditions.

ELECTRICAL POWER SYSTEMS

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.3 Two reactor protection system (RPS) electric power monitoring channels for each inservice RPS Inverter or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS Inverter or alternate power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or remove the associated RPS Inverter or alternate power supply from service.

b. With both RPS electric power monitoring channels for an inservice RPS Inverter or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 24 hours or remove the associated RPS Inverter or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.3 The above specified RPS electric power monitoring channels shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed in the previous 6 months.

b. In accordance with the Surveillance Frequency Control Program by demonstrating the OPERABILITY of overvoltage, undervoltage, and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic, and output circuit breakers and verifying the following Allowable Values.

   1. Overvoltage ≤ 127.6 VAC,

   2. Undervoltage ≥ 110.7 VAC,

   3. Underfrequency ≥ 57.05 Hz.

3.4.9 REFUELING OPERATIONS

3/4.9.1 REACTOR MODE SWITCH

LIMITING CONDITION FOR OPERATION

3.9.1 The reactor mode switch shall be OPERABLE and locked in the Shutdown or Refuel position. When the reactor mode switch is locked in the Refuel position:

a. The Refuel position one-rod-out interlock shall be OPERABLE.

b. The following Refuel position interlocks shall be OPERABLE:

1. All rods in.
2. Refuel Platform (over-core) position.
3. Refuel Platform hoists fuel-loaded.
4. Service Platform hoist fuel-loaded (with Service Platform installed).

APPLICABILITY: OPERATIONAL CONDITION 5* **, OPERATIONAL CONDITIONS 3 AND 4 when the reactor mode switch is in the Refuel position.

ACTION:

a. With the reactor mode switch not locked in the Shutdown or Refuel position as specified, suspend CORE ALTERATIONS and lock the reactor mode switch in the Shutdown or Refuel position.

b. With the one-rod-out interlock inoperable, verify all control rods are fully inserted and disable withdraw capabilities of all control rods ***, or lock the reactor mode switch in the Shutdown position.

c. With any of the above required Refuel Platform Refuel position interlocks inoperable, take one of the ACTIONS listed below, or suspend CORE ALTERATIONS.

1. Verify control rods are fully inserted and disable withdraw capabilities of all control rods***, or
2. Verify Refuel Platform is not over-core (limit switches not reached) and disable Refuel Platform travel over-core, or
3. Verify that no Refuel Platform hoist is loaded and disable all Refuel Platform hoists from picking up (grappling) a load.

d. With the Service Platform installed over the vessel and any of the above required Service Platform Refuel position interlocks inoperable, take one of the ACTIONS listed below, or suspend CORE ALTERATIONS.

1. Verify all control rods are fully inserted and disable withdraw capabilities of all control rods***, or
2. Verify Service Platform hoist is not loaded and disable Service Platform hoist from picking up (grappling) a load.

---

* See Special Test Exceptions 3.10.1 and 3.10.3.

** The reactor shall be maintained in OPERATIONAL CONDITION 5 whenever fuel is in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

*** Except control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified in accordance with the Surveillance Frequency Control Program.

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks* shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST in accordance with the Surveillance Frequency Control Program during control rod withdrawal or CORE ALTERATIONS, as applicable.

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks* that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

*The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least two source range monitor (SRM) channels* shall be OPERABLE and inserted to the normal operating level with:

a. Continuous visual indication in the control room,

b. At least one with audible alarm in the control room,

c. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

d. Unless adequate SHUTDOWN MARGIN has been demonstrated, the "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn.**

APPLICABILITY: OPERATIONAL CONDITION 5.***

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. Performance of a CHANNEL CHECK,

2. Verifying the detectors are inserted to the normal operating level, and

3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

---

*These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core. The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

***See Special Test Exception, Specification 3/4.10.7.

SURVEILLANCE REQUIREMENTS (Continued)

b. Performance of a CHANNEL FUNCTIONAL TEST in accordance with the Surveillance Frequency Control Program.

c. Verifying that the channel count rate is at least 3.0 cps:*

   1. Prior to control rod withdrawal,

   2. Prior to and in accordance with the Surveillance Frequency Control Program during CORE ALTERATIONS, and

   3. In accordance with the Surveillance Frequency Control Program.

d. Verifying, within 8 hours prior to and in accordance with the Surveillance Frequency Control Program, that the RPS circuitry "shorting links" have been removed during:

   1. The time any control rod is withdrawn**, unless adequate shutdown margin has been demonstrated, or

   2. Shutdown margin demonstrations.

*May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1. These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

**Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS, except that one control rod may be withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified in accordance with the Surveillance Frequency Control Program.

*Except control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**See Special Test Exception 3.10.3.

3/4.9.4 DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.4 The reactor shall be subcritical for at least 24 hours.

APPLICABILITY: OPERATIONAL CONDITION 5, during movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than 24 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.

SURVEILLANCE REQUIREMENTS

4.9.4 The reactor shall be determined to have been subcritical for at least 24 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communication shall be maintained between the control room and refueling floor personnel.

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.*

ACTION:

When direct communication between the control room and refueling floor personnel cannot be maintained, immediately suspend CORE ALTERATIONS.*

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communication between the control room and refueling floor personnel shall be demonstrated in accordance with the Surveillance Frequency Control Program during CORE ALTERATIONS.*

*Except movement of control rods with their normal drive system.

3/4.9.6 REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6 The refueling platform shall be OPERABLE and used for handling fuel assemblies or control rods within the reactor pressure vessel.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel.

ACTION:

With the requirements for refueling platform OPERABILITY not satisfied, suspend use of any inoperable refueling platform equipment from operations involving the handling of control rods and fuel assemblies within the reactor pressure vessel after placing the load in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.6.1 The refueling platform main hoist used for handling of fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the start of such operations by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1150 ± 50 pounds.

b. Demonstrating operation of the hoist loaded control rod block interlock on the main hoist when the load exceeds 485 ± 50 pounds.

c. Demonstrating operation of the redundant loaded interlock on the main hoist when the load exceeds 550 + 0, - 115 pounds.

d. Demonstrating operation of the uptravel interlock when uptravel brings the top of the active fuel to not less than 8 feet 0 inches below the normal water level.

SURVEILLANCE REQUIREMENTS (Continued)

4.9.6.2 The refueling platform frame-mounted auxiliary hoist used for handling of control rods within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the use of such equipment by:

a. Demonstrating operation of the overload cutoff on the frame mounted hoist when the load exceeds 500 ± 50 pounds.

b. Demonstrating operation of the uptravel mechanical stop on the frame mounted hoist when uptravel brings the top of a control rod to not less than 6 feet 6 inches below the normal fuel storage pool water level.

4.9.6.3 The refueling platform monorail mounted auxiliary hoist used for handling of control rods within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the use of such equipment by:

a. Demonstrating operation of the overload cutoff on the monorail hoist when the load exceeds 500 ± 50 pounds.

b. Demonstrating operation of the uptravel mechanical stop on the monorail hoist when uptravel brings the top of a control rod to not less than 6 feet 6 inches below the normal fuel storage pool water level.

3/4.9.7 CRANE TRAVEL-SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 1200 pounds shall be prohibited from travel over fuel assemblies in the spent fuel storage pool racks.

APPLICABILITY: With fuel assemblies in the spent fuel storage pool racks.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 Crane interlocks which prevent crane travel over fuel assemblies in the spent fuel storage pool racks shall be demonstrated OPERABLE within 7 days prior to and in accordance with the Surveillance Frequency Control Program during crane operation.

3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least 22 feet of water shall be maintained over the top of the reactor pressure vessel flange.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth in accordance with the Surveillance Frequency Control Program during handling of fuel assemblies or control rods within the reactor pressure vessel.

3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.9 At least 22 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage pool area after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the spent fuel storage pool shall be determined to be at least at its minimum required depth in accordance with the Surveillance Frequency Control Program.

3/4.9.10 CONTROL ROD REMOVAL

SINGLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.1 One control rod and/or the associated control rod drive mechanism may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until a control rod and associated control rod drive mechanism are reinstalled and the control rod is fully inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Table 1.2 and Specification 3.9.1.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied, except that the control rod selected to be removed;

    1. May be assumed to be the highest worth control rod required to be assumed to be fully withdrawn by the SHUTDOWN MARGIN test, and

    2. Need not be assumed to be immovable or untrippable.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

APPLICABILITY: OPERATIONAL CONDITIONS 4 and 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of the control rod and/or associated control rod drive mechanism from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

SURVEILLANCE REQUIREMENTS

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and in accordance with the Surveillance Frequency Control Program thereafter until a control rod and associated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

MULTIPLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.2 Any number of control rods and/or control rod drive mechanisms may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Specification 3.9.1, except that the Refuel position "one-rod-out" interlock may be bypassed, as required, for those control rods and/or control rod drive mechanisms to be removed, after the fuel assemblies have been removed as specified below.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

SURVEILLANCE REQUIREMENTS

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and in accordance with the Surveillance Frequency Control Program thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE per Surveillance Requirement 4.3.1.1 or 4.9.1.2, as applicable, and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 One (1) RHR shutdown cooling subsystem shall be OPERABLE and in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With the required RHR shutdown cooling subsystem inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available.

b. With the required action and associated completion time of Action "a" above not met.

   1. Immediately suspend loading of irradiated fuel assemblies into the reactor pressure vessel; and

   2. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   3. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   4. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant in accordance with the Surveillance Frequency Control Program.

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* The required RHR shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two (2) RHR shutdown cooling subsystems shall be OPERABLE, and one (1) RHR shutdown cooling subsystem shall be in operation. *

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than 22 feet above the top of the reactor pressure vessel flange.

ACTION:

a. With one (1) or two (2) required RHR shutdown cooling subsystems inoperable:

   1. Within one (1) hour, and once per 24 hours thereafter, verify an alternate method of decay heat removal is available for each inoperable required RHR shutdown cooling subsystem.

b. With the required action and associated completion time of Action "a" above not met:

   1. Immediately initiate action to restore REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY to OPERABLE status; and

   2. Immediately initiate action to restore one (1) Standby Gas Treatment subsystem to OPERABLE status; and

   3. Immediately initiate action to restore isolation capability in each required Refueling Floor secondary containment penetration flow path not isolated.

c. With no RHR shutdown cooling subsystem in operation:

   1. Within one (1) hour from discovery of no reactor coolant circulation, and once per 12 hours thereafter, verify reactor coolant circulation by an alternate method; and

   2. Once per hour monitor reactor coolant temperature.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one (1) RHR shutdown cooling subsystem, or an alternate method, shall be verified to be in operation and circulating reactor coolant in accordance with the Surveillance Frequency Control Program.

* The required operating shutdown cooling subsystem may be removed from operation for up to two (2) hours per eight (8) hour period.

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3, and 3.9.1 and Table 1.2 may be suspended to permit the reactor pressure vessel closure head and the drywell head to be removed and the primary containment air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits in accordance with the Surveillance Frequency Control Program during low power PHYSICS TESTS.

SPECIAL TEST EXCEPTIONS

3/4.10.2 ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.10.2 The sequence constraints imposed on control rod groups by the rod worth minimizer (RWM) per Specification 3.1.4.1 may be suspended for the following tests provided that control rod movement prescribed for this testing is verified by a second licensed operator or other technically qualified member of the unit technical staff present at the reactor console:

a. Shutdown margin demonstration, Specification 4.1.1.

b. Control rod scram, Specification 4.1.3.2.

c. Control rod friction measurements.

d. Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2 when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER.

ACTION:

With the requirements of the above specifications not satisfied, verify that the RWM is OPERABLE per Specification 3.1.4.1.

SURVEILLANCE REQUIREMENTS

4.10.2 When the sequence constraints imposed by the RWM are bypassed, verify:

a. That movement of control rods is blocked or limited to the approved control rod withdrawal sequence during scram and friction tests.

b. That movement of control rods during shutdown margin demonstrations is limited to the prescribed sequence per Specification 3.10.3.

c. Conformance with this specification and test procedures by a second licensed operator or other technically qualified member of the unit technical staff.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3, and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

a. The source range monitors are OPERABLE with the RPS circuitry "shorting links" removed per Specification 3.9.2.

b. The rod worth minimizer is OPERABLE per Specification 3.1.4.1 and is programmed for the shutdown margin demonstration, or conformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The "continuous rod withdrawal" control shall not be used during out-of-sequence movement of the control rods.

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

4.10.3 Within 30 minutes prior to and in accordance with the Surveillance Frequency Control Program during the performance of a shutdown margin demonstration, verify that;

a. The source range monitors are OPERABLE per Specification 3.9.2,

b. The rod worth minimizer is OPERABLE with the required program per Specification 3.1.4.1 or a second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown margin demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

SPECIAL TEST EXCEPTIONS

3/4.10.4 RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER, or

b. The Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS and the Startup Test Program.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS and the Startup Test Program.

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER in accordance with the Surveillance Frequency Control Program during PHYSICS TESTS.

3/4.10.5 OXYGEN CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.10.5 The provisions of Specification 3.6.6.3 may be suspended until completion of the Startup Test Program or the reactor has operated for 120 Effective Full Power Days.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION

With the requirements of the above specification not satisfied, be in at least STARTUP within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.5 The Effective Full Power Days of operation shall be verified to be less than 120, by calculation, in accordance with the Surveillance Frequency Control Program during the Startup Test Program.

3/4.10.6 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.6 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.6 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits in accordance with the Surveillance Frequency Control Program during training startups.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

LIMITING CONDITION FOR OPERATION

3.10.7 During initial core loading within the Startup Test Program the provisions of Specification 3.9.2 may be suspended provided that at least two source range monitor (SRM) channels with detectors inserted to the normal operating level are OPERABLE with:

a. One of the required SRM channels continuously indicating* in the control room,

b. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant,**

c. The RPS "shorting links" shall be removed prior to and during fuel loading,

d. The reactor mode switch is OPERABLE and locked in the REFUEL position.

APPLICABILITY: OPERATIONAL CONDITION 5

ACTION:

With the requirements of the above specifications not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.10.7 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. Within 1 hour prior to and at least once per 12 hours during CORE ALTERATIONS:

1. Performance of a CHANNEL CHECK***

2. Confirming that the above required SRM detectors are at the normal operating level and located in the quadrants required by Specification 3.10.7.

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*Up to 16 fuel bundles may be loaded without a visual indication of count rate.

**The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

***Check may be performed by use of movable neutron source. Movement of the movable neutron source is not a CORE ALTERATION.

SURVEILLANCE REQUIREMENTS (Continued)

4.10.7 (Continued)

3. The RPS "shorting links" are removed.

4. The reactor mode switch is locked in the REFUEL position.

b. Performance of a CHANNEL FUNCTIONAL TEST within 24 hours prior to the start and at least once per 7 days during CORE ALTERATIONS.

c. Verifying for at least one SRM channel that the count rate is at least 0.7 cps*:

1. Immediately following the loading of the first 16 fuel bundles.

2. At least once per 12 hours thereafter during CORE ALTERATIONS.

*Provided signal-to-noise is $\geq$ 2 (for initial startup only). Otherwise, 3 cps.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITION FOR OPERATION

3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to 212°F, and operation considered not to be in OPERATIONAL CONDITION 3, to allow performance of an inservice leak or hydrostatic test provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. 3.3.2 ISOLATION ACTUATION INSTRUMENTATION, Functions 7.a, 7.c.1, 7.c.2 and 7.d of Table 3.3.2-1;
b. 3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2 REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3 STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F and less than or equal to 212°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

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Section 3/4 11.1.1 through 3/4 11.1.4 (Deleted)

THE INFORMATION FROM THESE TECHNICAL SPECIFICATIONS SECTIONS HAS BEEN RELOCATED TO THE ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 11-2 THROUGH 3/4 11-6 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

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RADIOACTIVE EFFLUENTS

LIQUID HOLDUP TANKS

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in any outside temporary tanks shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit and describe the events leading to this condition in the next Annual Radioactive Effluent Release Report.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each of the above tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents in accordance with the Surveillance Frequency Control Program when radioactive materials are being added to the tank.

Section 3/4 11.2.1 through Section 3/4 11.2.4 (Deleted)

THE INFORMATION FROM THESE TECHNICAL SPECIFICATIONS SECTIONS HAS BEEN RELOCATED TO THE ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 11-9 THROUGH 3/4 11-14 OF THESE SECTIONS HAVE BEEN INTENTIONALLY OMITTED.

RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of hydrogen in the main condenser offgas treatment system shall be limited to less than or equal to 4% by volume.

APPLICABILITY: Whenever the main condenser air ejector system is in operation.

ACTION:

a. With the concentration of hydrogen in the main condenser offgas treatment system exceeding the limit, restore the concentration to within the limit within 48 hours.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5 The concentration of hydrogen in the main condenser offgas treatment system shall be determined to be within the above limits by continuously monitoring the waste gases in the main condenser offgas treatment system with the hydrogen monitors required OPERABLE by Table 3.3.7.12-1 of Specification 3.3.7.12.

MAIN CONDENSER

LIMITING CONDITION FOR OPERATION

3.11.2.6 The rate of the sum of the activities of the noble gases Kr-85m, Kr-87, Kr-88, Xe-133, Xe-135, and Xe-138 measured at the recombiner after-condenser discharge shall be limited to less than or equal to 330 millicuries/second.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3*.

ACTION:

With the rate of the sum of the activities of the specified noble gases at the recombiner after-condenser discharge exceeding 330 millicuries/second, restore the gross radioactivity rate to within its limit within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.11.2.6.1 The rate of the sum of the activities of noble gases at the recombiner after-condenser discharge shall be continuously monitored in accordance with Specification 3.3.7.12.

4.11.2.6.2 The rate of the sum of the activities of the specified noble gases from the recombiner after-condenser discharge shall be determined to be within the limits of Specification 3.11.2.6 at the following frequencies by performing an isotopic analysis of a representative sample of gases taken at the recombiner after condenser discharge:

a. In accordance with the Surveillance Frequency Control Program.

b. Within 4 hours following an increase, as indicated by the Main Condenser Off-Gas Pretreatment Radioactivity Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level or air in-leakage, in the nominal steady-state fission gas release from the primary coolant.

c. The provisons of Specification 4.0.4 are not applicable.

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*When the main condenser air ejector is in operation.

Section 3/4 11-2.7 (Deleted)

THE INFORMATION FROM THIS
TECHNICAL SPECIFICATIONS
SECTION HAS BEEN RELOCATED
TO THE ODCM.

Section 3/4 11.3 through 3/4 11.4 (Deleted)

THE INFORMATION FROM THESE TECHNICAL SPECIFICATIONS SECTIONS HAS BEEN RELOCATED TO THE PCP OR ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 11-19 THROUGH 3/4 11-20 OF THESE SECTIONS HAVE BEEN INTENTIONALLY OMITTED.

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS TECHNICAL SPECIFICATIONS SECTION HAS BEEN RELOCATED TO THE ODCM. TECHNICAL SPECIFICATIONS PAGES 3/4 12-2 THROUGH 3/4 12-14 OF THIS SECTION HAVE BEEN INTENTIONALLY OMITTED.

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BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

BASES

Specifications 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

> "Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. It is not intended that the shutdown ACTION requirement be used as an operation convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for reaching the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time. Compliance with ACTION requirements that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made in accordance with the provisions of the ACTION requirements.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

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Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the ACTION requirements for the applicable Limiting Condition for Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period or the variable is outside the specified limits, then the equipment is inoperable and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. Additionally, the Inservice Inspection Program conforms to the NRC staff positions identified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austinetic Stainless Steel Piping," as approved in NRC Safety Evaluations dated March 6, 1990 and October 22, 1990, or in accordance with alternate measures approved by the NRC staff.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL CONDITION or other specified condition takes precedence over the ASME Code provision that allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, which is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Code provision that allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% Δ k/k or R + 0.28% Δ k/k, as appropriate. The 0.38% Δ k/k includes uncertainties and calculation biases. The value of R in units of % Δ k/k is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of rod patterns. Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single

CONTROL RODS (Continued)

failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. ACTION "e" is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 Topical Report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containng a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 41.2 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants). As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 240 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 240 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

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3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10CFR50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as showm in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design anaylsis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a GE-core dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined mainly by the one dimensional transient code (Ref. 8). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits.

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial startup testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.

2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 2," NEDC-31930P (as amended).

4. Deleted

5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 2 Cycle 1, NEDC-31578P, March 1989 including Errata and Addenda Sheet No. 1 dated May 31, 1989.

6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.

7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

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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 APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 30% RATED THERMAL POWER causes a power increase to or beyond the 30% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is < 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow /

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). 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. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

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.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Progam and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

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. 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 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 10-second diesel startup and the 3 second load center loading delay. 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.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

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 an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

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. 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.

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3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

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 an allowance for instrument drift specifically allocated 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, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. 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 feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 30% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

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 an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

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 an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

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 an allowance for instrument drift specifically allocated for each trip in the safety analyses.

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3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variable following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

The OPERABILITY of the remote shutdown system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A. The Unit 1 RHR transfer switches are included only due to their potential impact on the RHRSW system, which is common to both units.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

3/4.3.7 MONITORING INSTRUMENTATION (Continued)

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 shall 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 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 CHLORINE AND TOXIC GAS DETECTION SYSTEMS

The OPERABILITY of the chlorine and toxic gas detection systems ensures that an accidental chlorine and/or toxic gas release will be detected promptly and the necessary protective actions will be automatically initiated for chlorine and manually initiated for toxic gas 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 chlorine isolation mode of operation to provide the required protection. Upon detection of a high concentration of toxic gas, the control room emergency ventilation system will manually be placed in the chlorine 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," February 1975.

There are three toxic gas detection subsystems. The high toxic chemical concentration alarm in the Main Control Room annunciates when two of the three subsystems detect a high toxic gas concentration. An Operate/Inop keylock switch is provided for each subsystem which allows an individual subsystem to be placed in the tripped condition. Placing the keylock switch in the INOP position initiates one of the two inputs required to initiate the alarm in the Main Control Room.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

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3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 OFFGAS MONITORING INSTRUMENTATION

This instrumentation includes provisions for monitoring the concentrations of potentially explosive gas mixtures and noble gases in the off-gas system.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

REFERENCES:

1. NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

4. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

5. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

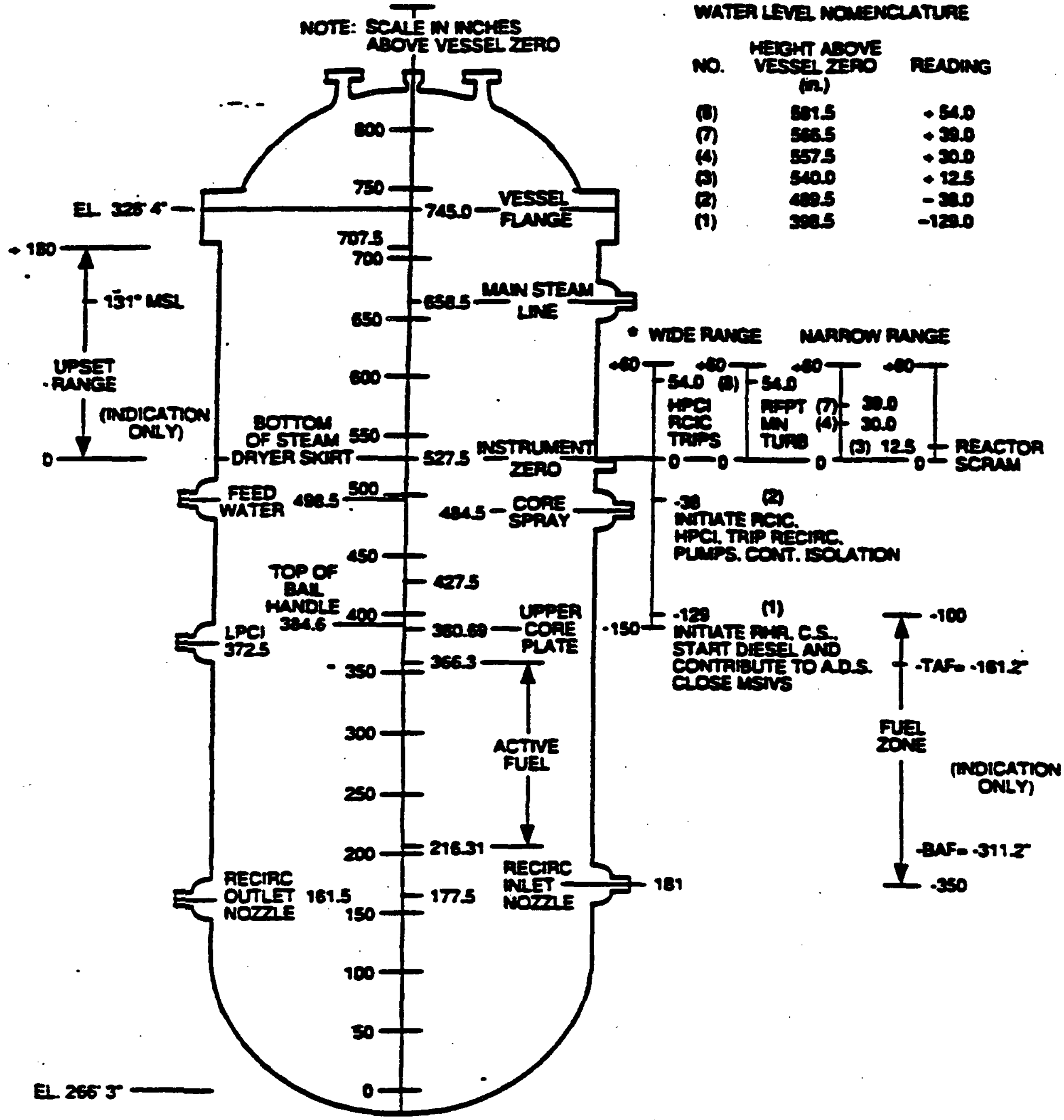
7. Letter, L. A. England (BWROG) to M. J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994.

8. GE Service Information Letter No. 516, "Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants," July 26, 1990.

9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), "Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2," May 02, 2001.

WATER LEVEL NOMENCLATURE

NO.	HEIGHT ABOVE VESSEL ZERO (in.)	READING
(8)	581.5	+ 54.0
(7)	566.5	+ 39.0
(4)	557.5	+ 30.0
(3)	540.0	+ 12.5
(2)	489.5	− 38.0
(1)	398.5	−129.0

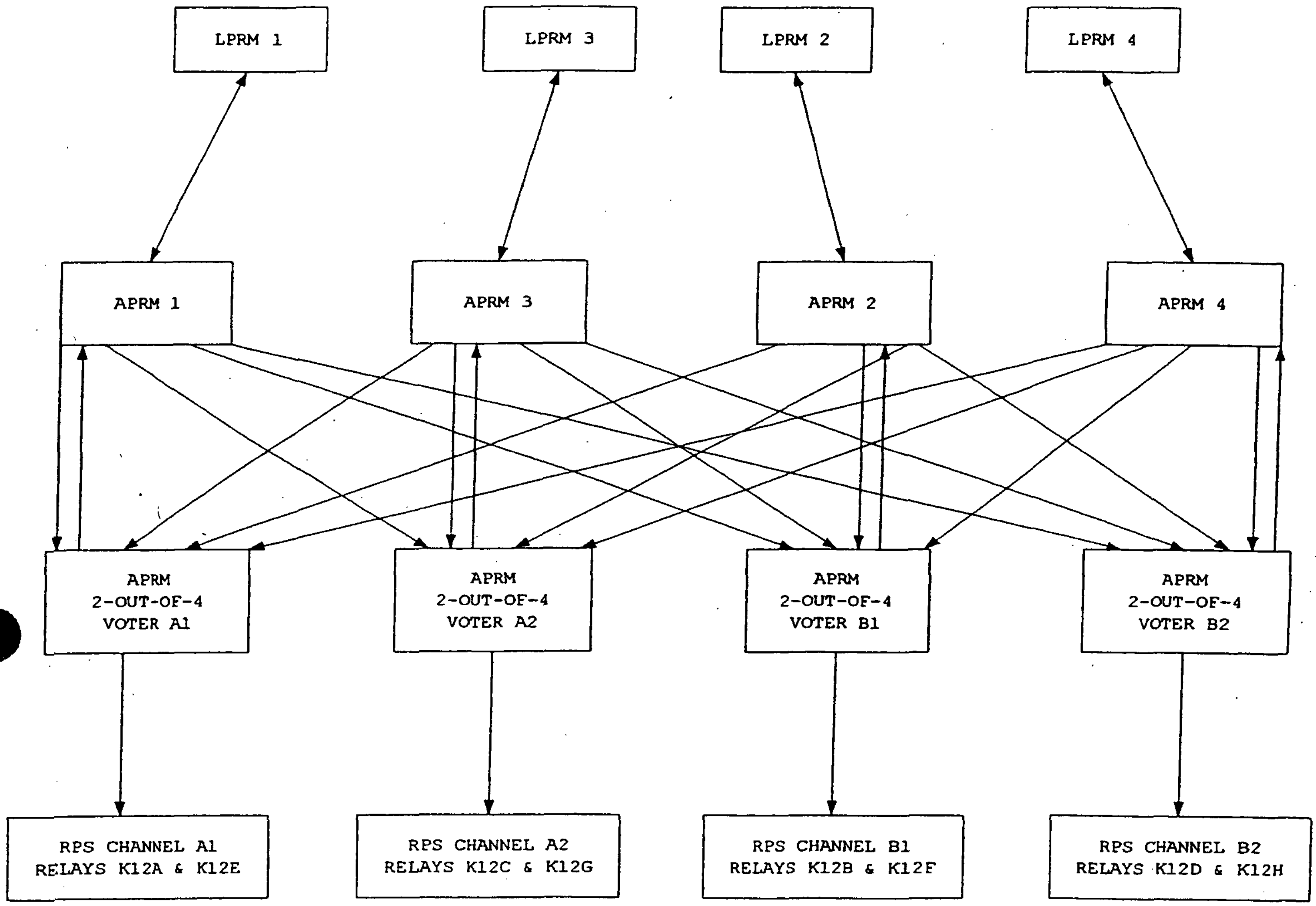


* Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.

BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4.3-2

APRM CONFIGURATION

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3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR fuel cladding safety limit is increased as noted by Specification 2.1.2, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internals vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates.

Systems for separating the leakage of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell drain sump level changes over time yielding drain flow rates, and drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell are the drywell floor drain sump flow monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

In addition to the drywell floor drain sump flow monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the "drywell floor drain flow totalizer", is not credited for drywell floor drain sump flow monitoring system operability.

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room. The primary containment atmospheric gaseous radioactivity monitoring system is not capable of quantifying leakage rates, but is sensitive enough to detect increased leakage rates of 1 gpm within 1 hour. Larger changes in leakage rates are detected in proportionally shorter times (Ref. 4).

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 5).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 6).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 7 and 8). Each of the leakage detection systems inside the drywell is designed with the capability of detecting leakage less than the established leakage rate limits and providing appropriate alarms of excess leakage in the control room.

A control room alarm allow the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 8). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

The drywell floor drain sump flow monitoring system is required to quantify the UNIDENTIFIED LEAKAGE from the RCS. The other monitoring systems provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With any leakage detection system inoperable, monitoring for leakage in the RCPB is degraded.

BASES

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

   The 12 hours interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

B. With the drywell floor drain sump flow monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

   With the drywell floor drain sump flow monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref: SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain sump monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

ACTIONS (Continued)

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment at a more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, Primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. If any required ACTION of Conditions A, B, C, D or E cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a
This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SURVEILLANCE REQUIREMENTS (Continued)

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string.

SR 4.4.3.1.c
This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3
4. LGS UFSAR, Section 5.2.5.2.1.5
5. LGS UFSAR, Section 5.2.5.2.1.4
6. LGS UFSAR, Section 5.2.5.2.1.1(2)
7. GEAP-5620, April 1968.
8. NUREG-75/067, October 1975.
9. LGS UFSAR, Section 5.2.5.6.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

3/4.4.3.2 OPERATIONAL LEAKAGE (Continued)

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in The Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

BASES

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2-hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves of Figure 3.4.6.1-1 are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are shown in Table B 3/4.4.6-1. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using Bases Figure B 3/4.4.6-1 and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curve, Figure 3.4.6.1-1, curves A, B and C, includes an assumed shift in RT_{NDT} for the conditions at 32 EFPY. In addition, an intermediate A curve has been provided for 22 EFPY. The A, B and C limit curves are predicted to be bounding for all areas of the RPV until 32 EFPY.

The pressure-temperature limit lines shown in Figures 3.4.6.1-1, curves C, and A, for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 STRUCTURAL INTEGRITY

The inspection programs for ASME Code Class 1, 2, and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant.

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code 1971 Edition and Addenda through Winter 1972.

The inservice inspection program for ASME Code Class 1, 2, and 3 components will be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a. Additionally, the Inservice Inspection Program conforms to the NRC staff positions identified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as approved in NRC Safety Evaluations dated March 6, 1990 and October 22, 1990, or in accordance with alternate measures approved by the NRC staff.

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exhanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, <u>and</u> the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

BASES TABLE B 3/4.4.6-1
REACTOR VESSEL TOUGHNESS*

LIMITING BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU (%)	Ni (%)	STARTING RT_{NDT} (°F)	ΔRT_{NDT} **(°F)	MIN.UPPER SHELF (LFT-LBS)	ART (°F)
Plate	SA-533 Gr. B,CL. 1	B 3416-1	.14	.65	+40	+48	NA	+122
Weld	AB (Field Weld)	640892/ J424B27AE	.09	1.0	-60	+58	NA	+54

NOTES: * Based on 110% of original power.
** These values are given only for the benefit of calculating the end-of-life (EOL/32 EFPY) RT_{NDT}

NON-BELTLINE COMPONENT	MT'L TYPE OR WELD SEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST STARTING RT_{NDT} (°F)
Top Shell Ring	SA 533, Gr. B, CL. 1	C9800-2	-16
Bottom Head Dome	"	C9245-2	+22
Bottom Head Torus	"	C9362-2	+28
Top Head Torus	"	C9646-2	-20
Top Head Flange	SA-508, CL. 2	123B300	+10
Vessel Flange	"	2L2058	+10
Feedwater Nozzle	"	Q2Q29W	0
Weld	Non-Beltline	All	-12
LPCI Nozzle***	SA-508, CL. 2	Q2Q33W	-4
Closure Studs	SA-540, Gr. B-24	All	Meet requirements of 45 ft-lbs and 25 mils Lat. Exp. at +10°F

*** The design of the LPCI nozzles results in their experiencing an EOL fluence in excess of 10^{17} N/Cm^2 which predicts an EOL (32 EFPY) RT_{NDT} of +35°F.

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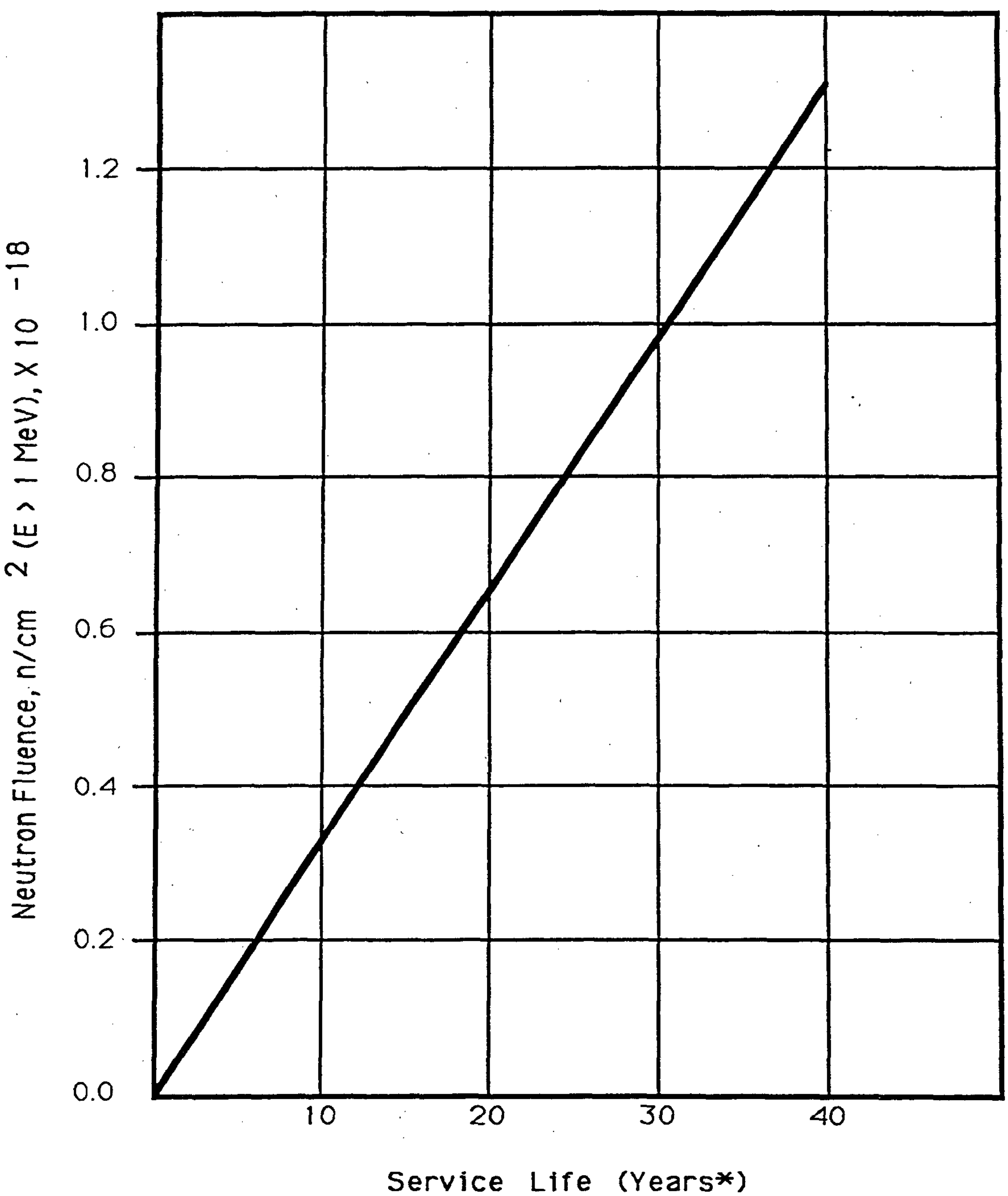

BASES FIGURE B 3/4.4.6-1

FAST NEUTRON FLUENCE (E>1 MeV) AT 1/4 T AS A FUNCTION OF SERVICE LIFE*

* At 90% of Rated Thermal Power and 90% availability

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

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and 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 CSS 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 CSS will be OPERABLE when required. 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. Four subsystems, each with one pump, 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. 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 high pressure coolant injection (HPCI) 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 HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HCPI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, 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 condensate storage tank water.

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ECCS - OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS 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 HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. 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 HPCI 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 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS sub-system out-of-service time allowances.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

ECCS - OPERATING and SHUTDOWN (Continued)

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

Repair work might require making the suppression chamber 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 chamber must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

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 water volume is based on NPSH, recirculation volume and vortex prevention plus a safety margin for conservatism.

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3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses for the design basis LOCA maximum peak containment accident pressure of 44 psig, P_a. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to $\leq$ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

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One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate ≥10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of $A/\sqrt{k}$ equal to 0.0500 ft² to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft² ensures that the design basis for the steam bypass analysis is met.

DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel, during CORE ALTERATIONS, or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel. The control room dose analysis for the fuel handling accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the standby gas treatment system to be aligned to the refueling area whenever irradiated fuel is being handled, during CORE ALTERATIONS or operations are being conducted that have the potential to drain the reactor vessel. The OPERABILITY of the standby gas treatment system however, ensures that release pathways do not result in a control room dose higher than determined in the refueling accident dose analysis. This is accomplished by assuring that the Standby Gas Treatment System is OPERABLE if releases from the refueling area are made through the North Stack following a FHA.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS is common to Unit 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses, therefore the inoperability of these Unit 1 supplies are addressed in the SGTS ACTION statements in order to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 Technical Specifications for SGTS and AC electrical power supply out of service condition combinations.

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of 5764 ± 10% cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

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3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The CREFAS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the system are from Unit 1 Safeguard busses, therefore, the inoperability of these Unit 1 supplies are addressed in the CREFAS ACTION statements in order to ensure adequate onsite power sources to CREFAS during a loss of offsite power event. The allowable out of service

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

times are consistent with those in the Unit 1 Technical Specifications for CREFAS and AC electrical power supply out of service condition combinations.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, the CREFAS System provides protection from radiation, smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4

2. UFSAR Section 9.5

3. Regulatory Guide 1.196

4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.

5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to start cooling at the earliest possible moment.

3/4.7.4 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety related system.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the Plant Operations Review Committee. The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.), and the recommendations of Regulatory Guides 8.8 and 8.10. The addition or deletion of any snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection schedule is based on the number of unacceptable snubbers found during the previous inspection in proportion to the sizes of the various snubber populations or categories. The visual inspection interval is based on a fuel cycle of up to 24 months and may be as long as two fuel cycles or 48 months depending on the number of unacceptable snubbers found during the previous visual inspection. The visual inspection schedule provides confidence that a constant level of snubber protection is being maintained and generally allows performance of visual inspections and corrective actions during plant outages. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results required a shorter inspection interval will override the previous schedule.

A snubber is considered inoperable if it fails the acceptance criteria of the visual inspection.

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SNUBBERS (Continued)

To provide assurance of snubber functional reliability one of two functional testing methods is used with the stated acceptance criteria:

1. Functionally test 13.3% sample of a type of snubber with an additional 1/2 sample tested for each functional testing failure, or

2. Functionally test 37 snubbers and determine sample acceptance using Figure 4.7.4-1.

Functional Testing sample plans are based on ASME/ANSI OMc-1990 Addenda to ASME/ANSI OM-1987, Part 4.

Figure 4.7.4-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (i.e., newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e,, sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

SEALED SOURCE CONTAMINATION (Continued)

The testing frequency for start-up sources and fission detectors is based upon physical limitations in leak testing. For example, the Californium 252 start-up neutron source must be leak tested by the manufacturer remotely in a hot cell facility. Due to the physical design of this source, a six month frequency for contamination testing provides reasonable assurance that the radioactive material is properly contained.

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformers 8A/8B) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 8A/8B transformers. Additionally, the Unit Auxiliary Buses do not transfer to the 8A/8B transformers; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3. Under Modes 1, 2 and 3, an offsite circuit is considered to be inoperable if it is not capable of supplying at least three Unit 2 4 kV emergency buses. If both offsite sources are capable of supplying

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

only three Unit 2 4 kV emergency buses, then each of the four Unit 2 4 kV emergency buses must be supplied from at least one operable offsite source. Onsite A.C. operability requirements for common systems such as CREFAS, SGTS, RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all remaining required systems, subsystems, trains, components, and devices, that depend on the OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action i, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, "Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation," dated September 27, 1993.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as $\leq$ 2 amps, and for Divisions 3 and 4 as $\leq$ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, (i.e., greater than the minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status. Under Modes 4, 5 and *, an offsite source is considered operable if it is capable of supplying all 4 kV emergency buses necessary for operating in that Mode.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Supplies, March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450-1995.

This Surveillance Requirement states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained the Actions of LCO 3.8.2.1, Action b., are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

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A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Bypassing motor operated valves thermal overload protection ensures that the thermal overload protection will not prevent safety related valves from performing their function. For motor operated valves with spring return-to-center control switches, the thermal overload is bypassed by the automatic control signals associated with the Class 1E valves. For Class 1E motor operated valves with maintained contact control switches, the thermal overloads do not interrupt the valve motor power circuit, but they alarm on an overload condition in the control room. The Surveillance Requirements for demonstrating the bypassing of the thermal overload protection continuously are met by functionally testing the automatic operation of the motor operated valve and ensuring that the motor thermal overload protection design does not change and is in accordance with Regulatory Guide 1.106 "Thermal Overload Protection for Electric Motors on Motor Operated Valves", Revision 1, March 1977.

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

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3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core unloading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3.4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

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3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

This special test exception permits relief from the requirements for a minimum count rate while loading the first 16 fuel bundles to allow sufficient source-to-detector coupling such that minimum count rate can be achieved on an SRM. This is acceptable because of the significant margin to criticality while loading the initial 16 fuel bundles.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F and less than or equal to 212°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 2 and 3. Operations with the Potential for Draining the Vessel, Core alterations, and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

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HAS BEEN RELOCATED TO THE ODCM.

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3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4 11.2.2 through 3/4 11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.2.5 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the main condenser offgas treatment system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen below its flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.7, 3/4.11.3, and 3/4.11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION
HAS BEEN RELOCATED TO THE ODCM.
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SECTION 5.0

DESIGN FEATURES

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5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1.2-1.

MAPS DEFINING UNRESTRICTED AREAS AND SITE BOUNDARY FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 Information regarding radioactive gaseous and liquid effluents, which will allow identification of structures and release points as well as definition of UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBER OF THE PUBLIC, shall be as shown in Figures 5.1.3-1a and 5.1.3-1b.

5.1.4 (Deleted)

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The primary containment is a steel lined reinforced concrete structure consisting of a drywell and suppression chamber. The drywell is a steel-lined reinforced concrete vessel in a shape of a truncated cone on top of a water filled suppression chamber and is separated by a diaphragm slab and connected to the suppression chamber through a series of downcomer vents. The drywell has a maximum free air volume of 243,580 cubic feet at a minimum suppression pool level of 22 feet. The suppression chamber has a maximum air region of 159,540 cubic feet and a minimum water region of 122,120 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

5.2.2 The primary containment is designed and shall be maintained for:

a. Maximum internal pressure 55 psig.

b. Maximum internal temperature: drywell 340°F.
suppression pool 220°F.

c. Maximum external to internal differential pressure 5 psid.

d. Maximum floor differential pressure: 30 psid, downward.
20 psid, upward.

FIGURE 5.1.1-1

EXCLUSION AREA

FIGURE 5.1.2-1

LOW POPULATION ZONE

FIGURE 5.1.3-1a

MAP DEFINING UNRESTRICTED AREAS AND SITE BOUNDARY
FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

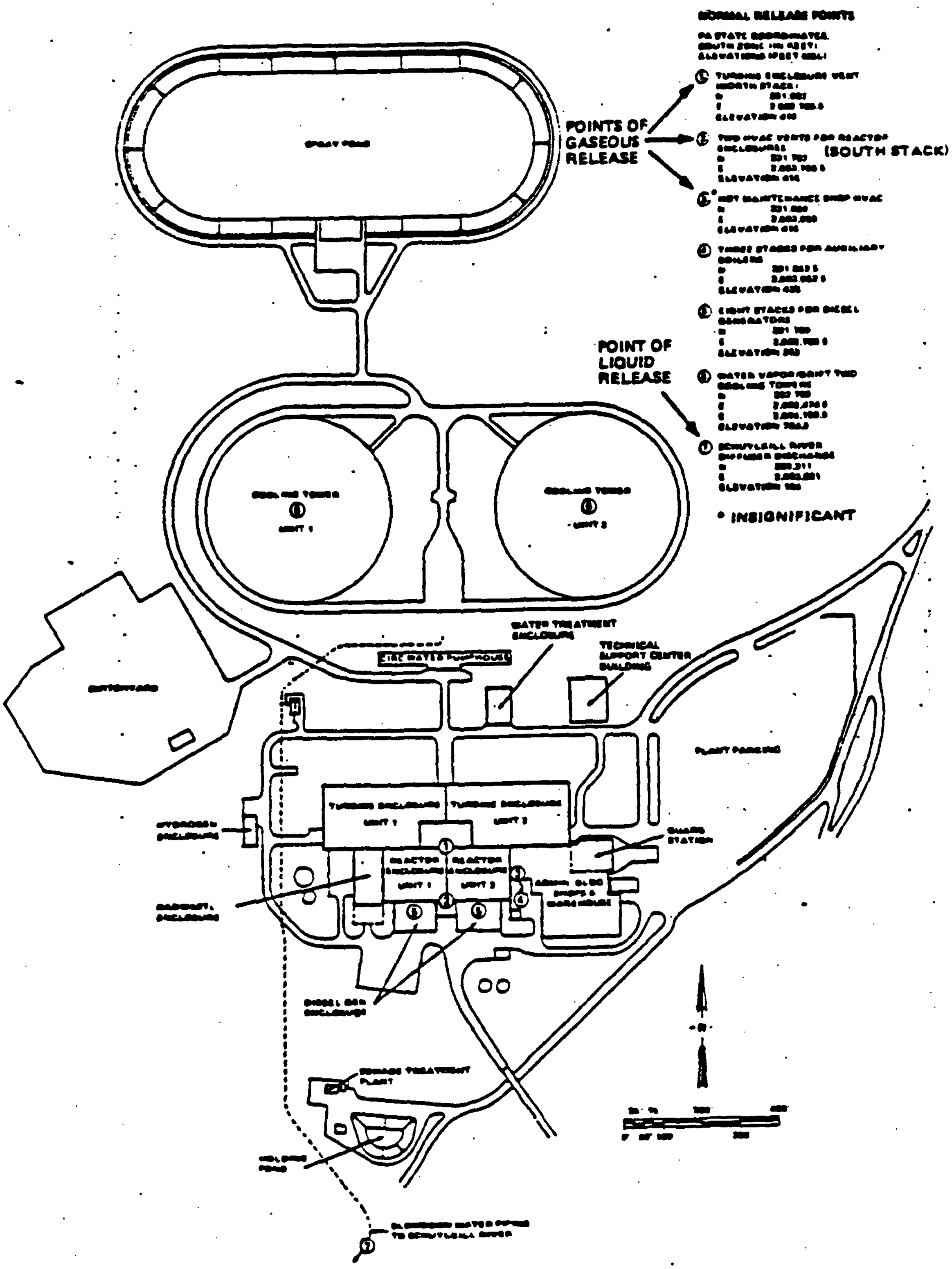

FIGURE 5.1.3-1b

MAP DEFINING UNRESTRICTED AREAS AND SITE BOUNDARY
FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

THE FIGURE ON THIS PAGE HAS BEEN RELOCATED TO THE ODCM.

SECONDARY CONTAINMENT

5.2.3 The secondary containment consists of three distinct isolatable zones. Zones I and II are the Unit 1 and Unit 2 reactor enclosures respectively. Zone III is the common refueling area. Each zone has an independent normal ventilation system which is capable of providing secondary containment zone isolation as required.

Each reactor enclosure (Zone I or II) completely encloses and provides secondary containment for its corresponding primary containment and reactor auxiliary or service equipment, and has a minimum free volume of 1,800,000 cubic feet.

The common refueling area (Zone III) completely encloses and provides secondary containment for the refueling servicing equipment and spent fuel storage facilities for Units 1 and 2, and has a minimum free volume of 2,200,000 cubic feet.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall consist of not more than 764 fuel assemblies and shall be limited to those fuel assemblies which have been analyzed with NRC approved codes and methods and have been shown to comply with all Safety Design Bases in the Final Safety Analysis Report (FSAR).

CONTROL ROD ASSEMBLIES

5.3.2 The reactor core shall contain 185 cruciform-shaped control rod assemblies.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements, DESIGN PRESSURE AND TEMPERATURE (Continued)

b. For a pressure of:

1. 1250 psig on the suction side of the recirculation pump.

2. 1500 psig from the recirculation pump discharge to the outlet side of the discharge shutoff valve.

3. 1500 psig from the discharge shutoff valve to the jet pumps.

c. For a temperature of 575°F.

VOLUME

5.4.2 The total water and steam volume of the reactor vessel and recirculation system is approximately 22,400 cubic feet at a nominal steam dome saturation temperature of 552°F.

5.5 FUEL STORAGE

CRITICALITY

5.5.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, including all calculational uncertainties and biases as described in Section 9.1.2 of the FSAR.

b. A nominal center-to-center distance between fuel assemblies placed in the storage racks of greater than or equal to 6.244 inches.

5.5.1.2 The k_{eff} for new fuel for the first core loading stored dry in the spent fuel storage racks shall not exceed 0.98 when aqueous foam moderation is assumed.

DRAINAGE

5.5.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 346'0".

CAPACITY

5.5.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 4117 fuel assemblies.

5.6 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.6.1 The components identified in Table 5.6.1-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.6.1-1.

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TABLE 5.6.1-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor	120 heatup and cooldown cycles	70°F to 560°F to 70°F
	80 step change cycles	Loss of feedwater heaters
	180 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	130 hydrostatic pressure and leak tests	Pressurized to $\geq$ 930 and $\leq$ 1250 psig

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SECTION 6.0

ADMINISTRATIVE CONTROLS

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6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Plant Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Shift Manager, or during his absence from the control room, a designated individual shall be responsible for the control room command function. A management directive to this effect, signed by the Vice President, Limerick Generating Station shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

6.2.1 OFFSITE AND ONSITE ORGANIZATIONS

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organizational positions. These relationships shall be documented and updated, as appropriate, in the form of organizational charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Limerick Quality Assurance Program.

b. The Plant Manager shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. The Vice President, Limerick Generating Station shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

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6.2.2 UNIT STAFF

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2.2-1;

b. At least one licensed Operator shall be in the control room when fuel is in the reactor. In addition, while the unit is in OPERATIONAL CONDITION 1, 2, or 3, at least one licensed Senior Operator shall be in the control room;

c. A Health Physics Technician* shall be on site when fuel is in the reactor;

d. ALL CORE ALTERATIONS shall be observed and directly supervised by either a licensed Senior Operator or licensed Senior Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation;

e. (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

f. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions (e.g., licensed Senior Operators, licensed Operators, health physicists, auxiliary operators, and key maintenance personnel).

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a nominal 40-hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major unit modifications, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.

*The Health Physics Technician position may be less than the minimum requirements for a period of time not to exceed 2 hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required position.

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6.2.2 UNIT STAFF (Continued)

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the Plant Manager or personnel designated in administrative procedures or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the Plant Manager, or the appropriate designated personnel to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized; and

g. The individual filling the position of Operations Manager as defined by ANSI/ANS-3.1-1978 or another Manager in Operations shall hold a Senior Reactor Operator License.

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TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION

TWO UNITS WITH A COMMON CONTROL ROOM

WITH UNIT 1 IN CONDITION 4 OR 5 OR DEFUELED

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 OR 5
SM	1*	1*
SRO	2*	2*
RO	2	1
NLO	2	2**
STA	1***	None

WITH UNIT 1 IN CONDITION 1, 2, OR 3

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SM	1*	1*
SRO	2*	2*
RO	2**	1
NLO	2**	1
STA	1*,***	None

TABLE NOTATIONS

* Individual(s) may fill the same position on Unit 1.
** One of the two required individuals may fill the same position on Unit 1.
***The STA position may be filled by an on-shift SM or SRO provided the individual meets the 1985 NRC Policy Statement on Engineering Expertise on Shift.
SM - Shift Manager with a Senior Operator license on Unit 2.
SRO - Individual with a Senior Operator license on Unit 2.
RO - Individual with an Operator license on Unit 2.
NLO - Non-licensed operator properly qualified to support the unit to which assigned.
STA - Shift Technical Advisor

Except for the Shift Manager (SM), the shift crew composition may be one less than the minimum requirements of Table 6.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an upcoming shift crewman being late or absent.

During any absence of the Shift Manager (SM) from the control room while the unit is in OPERATIONAL CONDITION 1, 2, or 3, an individual with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of the Shift Manager (SM) from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

6.2.3 DELETED. The information from this section is located in the UFSAR.

6.2.4 SHIFT TECHNICAL ADVISOR

6.2.4.1 The Shift Technical Advisor shall provide advisory technical support to Shift Supervision in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. The Shift Technical Advisor shall meet the qualifications specified by the 1985 NRC Policy Statement on Engineering Expertise on Shift.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions, except for the Manager - Radiation Protection who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, and the licensed operators who shall comply with the requirements of 10CFR55.

6.4 DELETED

6.5 DELETED

THE INFORMATION FROM SECTION 6.5 HAS BEEN RELOCATED TO THE QATR

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6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 to 10 CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the PORC and submitted to the NRB, Plant Manager and the Vice President, Limerick Generating Station.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. The Vice President, Limerick Generating Station, Plant Manager, and the NRB shall be notified within 24 hours.

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the NRB. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon unit components, systems, or structures, and (3) corrective action taken to prevent recurrence.

c. The Safety Limit Violation Report shall be submitted to the Commission, the NRB, Plant Manager, and the Vice President, Limerick Generating Station, within the 14 days of the violation.

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SAFETY LIMIT VIOLATION (Continued)

d. Critical operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

b. The applicable procedures required to implement the requirements of NUREG-0737 and Supplement 1 to NUREG-0737.

c. Refueling operations.

d. Surveillance and test activities of safety-related equipment.

e. Security Plan implementation.

f. Emergency Plan implementation.

g. Fire Protection Program implementation.

h. PROCESS CONTROL PROGRAM implementation.

i. OFFSITE DOSE CALCULATION MANUAL implementation.

j. Quality Assurance Program for effluent and environmental monitoring, using the guidance of Regulatory Guide 4.15, February 1979.

6.8.2 The information from Section 6.8.2 has been relocated to the QATR.

6.8.3 The information from Section 6.8.3 has been relocated to the QATR.

PROCEDURES AND PROGRAMS (Continued)

6.8.4 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the core spray, high pressure coolant injection, reactor core isolation cooling, residual heat removal, post-accident sampling system (until such time as a modification eliminates the PASS system as a potential leakage path), safeguard piping fill system, control rod drive scram discharge system, and containment air monitor systems. The program shall include the following:

1. Preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

c. DELETED

PROCEDURES AND PROGRAMS (Continued)

d. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 times the concentration values in 10 CFR Part 20, Appendix B, Table 2, Column 2,

3) Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

4) Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5) Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days,

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31-day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the SITE BOUNDARY shall be limited to the following:

   a. For noble gases: less than or equal to 500 mrem/yr to the total body and less than or equal to 3000 mrem/yr to the skin, and

   b. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: less than or equal to 1500 mrem/yr to any organ.

PROCEDURES AND PROGRAMS (Continued)

8) Limitations on the annual quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on venting and purging of the Mark II containment through the Standby Gas Treatment System to maintain releases as low as reasonably achievable, and

11) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

e. Meteorological Monitoring Program

A program shall be provided to provide meteorological information in the environs of the plant. The program shall provide sufficient meteorological data for estimating potential radiation doses to the public.

The program shall (1) be contained in the ODCM, (2) conform to the guidance of Regulatory Guide 1.23, "Safety Guide 23 - Onsite Meteorological Program", and (3) include limitations on the operability of meteorological monitoring instrumentation including surveillance tests in accordance with the methodology in the ODCM.

f. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

PROCEDURES AND PROGRAMS (Continued)

g. Primary Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54 (o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163 "Performance-Based Containment Leakage Test program," dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J":

a. Section 9.2.3: The first Type A test performed after May 21, 1999 shall be performed no later than May 21, 2014.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 44.0 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary Containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.60 L_a for the Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall airlock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a.

2) Seal leakage rate is less than or equal to 5 scf per hour when the gap between the door seals is pressurized to 10 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the tests described in the Primary Containment Leakage Rate Testing Program.

h. Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

A change in the TS incorporated in the license; or

A change to the UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of b. above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

PROCEDURES AND PROGRAMS (Continued)

i. Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries For Stationary Applications," of the following:

a. Actions to restore battery cells with float voltage < 2.13 volts, and

b. Actions to equalize and test battery cells that have been discovered with electrolyte level below the minimum established design limit.

j. Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The Program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 0.

c. The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the Regional Administrator of the Regional Office of the NRC unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

6.9.1.2 The startup report shall address each of the tests identified in Subsection 14.2.12 of the Final Safety Analysis Report and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation) supplementary reports shall be submitted at least every 3 months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year unless otherwise noted.

6.9.1.5 Reports required on an annual basis shall include:

a. Deleted

*A single submittal may be made for a multiple unit station.

ANNUAL REPORTS (Continued)

b. (Deleted)

c. Any other unit unique reports required on an annual basis.

d. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.4.5. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Cleanup system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

MONTHLY OPERATING REPORTS*

6.9.1.6 Deleted

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.7 The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The initial report shall be submitted prior to May 1 of the year following initial criticality. The report shall include summaries, interpretations, analysis of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR Part 50.

*A single submittal may be made for a multiple unit station.

ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.8 The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

*A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

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CORE OPERATING LIMITS REPORT

6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factor for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.3.6.

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 2.2.1.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

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THE INFORMATION FROM SECTION 6.10 HAS BEEN RELOCATED TO THE QATR

6.11 RADIATION PROTECTION PROGRAM

6.11.1 Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

6.12.1 High Radiation Areas with dose rates (deep dose equivalent) greater than 0.1 rem/hr and not exceeding 1.0 rem/hour (at 30 centimeters from the radiation sources or from any surface penetrated by the radiation):

a. Each accessible entryway to such an area shall be barricaded and conspicuously posted as a High Radiation Area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

HIGH RADIATION AREA (Continued)

b. Access to, and activities in, each such area shall be controlled by means of a Radiation Work Permit (RWP) or equivalent that includes radiation protection instructions, job coverage and monitoring requirements. Radiological information (i.e., dose rates) is included on the radiation surveys associated with the RWP or equivalent.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall be provided with or accompanied by one or more of the following:

    1. A radiation monitoring device that continuously displays radiation dose rates in the area ("radiation monitoring and indicating device"), OR

    2. A radiation monitoring device with the capability to display accumulated dose and which continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached ("alarming dosimeter"), OR

    3. A radiation monitoring device with the capability to display accumulated dose and which continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, OR

    4. A direct reading dosimeter AND:

        a) A health physics qualified individual (i.e., qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for controlling personnel radiation exposure within the area, OR

        b) Be under the surveillance, as specified in the RWP or equivalent, by means of closed circuit television, of a health physics qualified individual (i.e., qualified in radiation protection procedures), responsible for controlling personnel radiation exposure in the area.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been established and entry personnel are knowledgeable of them.

HIGH RADIATION AREA (Continued)

6.12.2 In addition to the requirements of Section 6.12.1, High Radiation Areas with dose rates (deep dose equivalent) greater than 1.0 rem/hour (at 30 centimeters from the radiation source or from any surface penetrated by the radiation), but less than 500 rad/hr (at 1 meter from the radiation source or from any surface penetrated by the radiation source) accessible to personnel shall be controlled as follows:

a. Each accessible entryway to such an area shall be conspicously posted as a High Radiation Area and shall be provided with a locked door, gate, or guard that prevents unauthorized entry, and in addition:

   1. All such door and gate keys shall be maintained under the administrative control of radiation protection supervision.

   2. Doors and gates shall remain locked or guarded except during periods of personnel or equipment entry or exit.

b. Such individual areas that are within a larger area, such as containment, that is controlled as a High Radiation Area, where no enclosure exists for purpose of locking and where no enclosure can reasonable be constructed around the individual area need not be controlled by a locked door or gate, but shall be barricaded and conspicuously posted as a High Radiation Area, and a conspicuous, clearly visible flashing light shall be activated at the area as a warning device.

c. Each individual entering such an area shall be provided with or accompanied by one or more of the following:

   1. A dose rate survey meter and a radiation monitoring device with the capability to display accumulated dose and an integrating alarm setpoint, OR

   2. A radiation monitoring device with the capability to display accumulated dose and which continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached ("alarming dosimeter"), OR

   3. A radiation monitoring device with the capability to display accumulated dose and which continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area AND with the means to communicate with the individuals in the area, OR

   4. A direct reading dosimeter AND:

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HIGH RADIATION AREA (Continued)

a) A health physics qualified individual (i.e., qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for controlling personnel radiation exposure within the area, OR

b) Be under the surveillance, as specified in the RWP or equivalent, by means of closed circuit television, of a health physics qualified individual (i.e., qualified in radiation protection procedures), responsible for controlling personnel radiation exposure in the area, and with the means to communicate with the individuals in the area.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 Changes to the PCP:

a. Shall be documented with the following information:

1. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

PROCESS CONTROL PROGRAM (Continued)

2. A determination that the change did not reduce the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

b. Shall become effective upon review and acceptance by the PORC and approval of the Plant Manager.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 Changes to the ODCM:

a. Shall be documented with the following information:

1. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

2. A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

b. Shall become effective upon review and acceptance by the PORC and the approval of the Plant Manager.

c. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.

6.15 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

6.16 CONTROL ROOM ENVELOPE HABITABILITY PROGRAM

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Fresh Air Supply (CREFAS) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance .

CONTROL ROOM ENVELOPE HABITABILITY PROGRAM (Continued)

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFAS, operating at the flow rate required by SR 4.7.2.1 c.1, at a Frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of Specification 4.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

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APPENDIX B

TO FACILITY OPERATING LICENSE NO. NPF-85

LIMERICK GENERATING STATION

UNIT 2

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-353

ENVIRONMENTAL PROTECTION PLAN

(NON-RADIOLOGICAL)

August 25, 1989

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LIMERICK GENERATING STATION

UNIT 2

ENVIRONMENTAL PROTECTION PLAN

(NON-RADIOLOGICAL)

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1.0 OBJECTIVES OF THE ENVIRONMENTAL PROTECTION PLAN

The Environmental Protection Plan (EPP) is to provide for protection of non-radiological environmental values during operation of the nuclear facility. The principal objectives of the EPP are as follows:

(1) Verify that the facility is operated in an environmentally acceptable manner, as established by the Final Environmental Statement-Operating License Stage (FES-OL) and other NRC environmental impact assessments.

(2) Coordinate NRC requirements and maintain consistency with other Federal, State and local requirements for environmental protection.

(3) Keep NRC informed of the environmental effects of facility operation and of actions taken to control those effects.

Environmental concerns identified in the FES-OL which relate to water quality matters are regulated by way of the licensee's NPDES permit.

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2.0 ENVIRONMENTAL PROTECTION ISSUES

In the FES-OL dated April, 1984, the staff considered the environmental impacts associated with the operation of the two unit Limerick Generating Station. Certain environmental issues were identified which required study or license conditions to resolve environmental concerns and to assure adequate protection of the environment.

2.1 Aquatic Issues

(1) During operation, the station blowdown temperature will exceed the maximum permissible temperatures set by the applicable water quality standards. However, the affected area of the Schuylkill River is expected to be smaller than the maximum area permitted by the Delaware River Basin Commission. (FES Section 5.3.2.2)

(2) The water quality of the station discharge, after initial mixing with the Schuylkill River, is predicted to, at times, exceed the applicable quality criteria for some constituents, based on source water maximum constituent concentrations. These exceedances are expected for constituents whose maximum river concentrations also exceed the applicable criteria. (FES Section 5.3.2.3)

(3) Chlorination of station cooling waters for condenser and cooling tower biofouling control may result in some adverse impacts to Schuylkill River biota in the vicinity of the station discharge. (FES Section 5.3.2.3)

(4) Operation of the Point Pleasant Diversion will alter the hydrology, aquatic habitats, and water quality of the headwater section of the East Branch of Perkiomen Creek but the diversion waters are expected to provide beneficial dilution of waste loads entering the stream in its middle and lower reaches. (FES Sections 5.3.2.3 and 5.2.2)

(5) The supplemental cooling water withdrawal from Perkiomen Creek using state-of-the-art technology will result in localized effects from entrainment of fish larvae. (FES Section 5.5.2)

2.2 Terrestrial Issues

No specific terrestrial issues were identified by the NRC staff in the FES-OL.

2.3 Noise Issues

(1) Tones from the Point Pleasant pumphouse transformers are predicted to be audible and may cause annoyance at a nearby residence. Noise monitoring and, if necessary, mitigative measures to make the tones inaudible have been mandated by the ASLB. (FES Sections 5.12.1 and 5.14.4.1)

(2) Noise from transformers and pumps in the Bradshaw Reservoir pumphouse may be audible at nearby residences. The licensee has committed to ambient and operational noise level monitoring and implementation of identified mitigative measures, if necessary, to reduce noise levels below those likely to cause annoyance and complaints. (FES Sections 5.12.2 and 5.14.4.2)

(3) Offsite noise levels in the vicinity of the Limerick site during station operation are not expected to be high enough above ambient levels to annoy nearby residents. But because of uncertainties in the assessment, a confirmatory noise monitoring program and implementation of mitigative measures, if necessary, will be undertaken. (FES Sections 5.12.3 and 5.14.4.3)

NRC requirements with regard to noise issues are specified in Section 4.3 of this EPP.

3.0 CONSISTENCY REQUIREMENTS

3.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such activities do not involve an unreviewed environmental question and do not involve a change in the EPP.* Changes in station design or operation or performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by Section 3.3 are not subject to the requirements of this Section.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable non-radiological environmental effects are confined to the on-site areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activity and obtain prior NRC approval. When such activity involves a change in the EPP, such activity and change to the EPP may be implemented only in accordance with an appropriate license amendment as set forth in Section 5.3 of this EPP.

A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns: (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the FES-OL, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) a significant change in effluents or

*This provision does not relieve the licensee of the requirements of 10 CFR 50.59

power level; or (3) a matter not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have a significant adverse environmental impact.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include written evaluations which provide bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question or constitute a decrease in the effectiveness of the EPP to meet the objectives specified in Section 1.0.

3.2 Reporting Related to the NPDES Permit and State Certification

Changes to, or renewals of, the NPDES Permit or the State certification shall be reported to the NRC within 30 days following the date the change or renewal is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

3.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments that are either regulated or mandated by Federal, State and local environmental regulations are not subject to the requirements of Section 3.1. However, if any environmental impacts of a change are not evaluated under other Federal, State, or local environmental regulations, then those impacts are subject to the requirements of Section 3.1.

4.0 ENVIRONMENTAL CONDITIONS

4.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to plant operation shall be recorded and reported to the NRC within 24 hours followed by a written report per Subsection 5.4.2. If an event is reportable under 10 CFR 50.72, then a duplicate immediate report under this subsection is not required. However, a follow-up written report is required in accordance with Subsection 5.4.2. The following are examples: excessive bird impaction events, onsite plant or animal disease outbreaks, mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973, fish kills, increase in nuisance organisms or conditions, and unanticipated or emergency discharge of waste water or chemical substances.

No routine monitoring programs are required to implement this condition.

4.2 Environmental Monitoring

4.2.1 Aquatic Monitoring

The certifications and permits required under the Clean Water Act provide mechanisms for protecting water quality and, indirectly, aquatic biota. The NRC will rely on the decisions made by the Commonwealth of Pennsylvania, under the authority of the Clean Water Act, for any requirements for aquatic monitoring.

4.2.2 Terrestrial Monitoring

No terrestrial monitoring is required.

4.2.3 Maintenance of Transmission Line Corridors

The use of herbicides within the Limerick Generating Station transmission line corridors (Limerick to Cromby, Cromby to Plymouth Meeting, Cromby to North Wales, and Limerick to Whitpain) shall conform to the approved use of selected herbicides as registered by the Environmental Protection Agency and approved by Commonwealth authorities and applied as directed on the pesticide label.

4.2.4 Noise Monitoring

All initial Environmental Noise Assessments have been completed.

The information in Subsections 4.2.4.1, 4.2.4.2,

4.2.4.3, and 4.2.4.4 has been deleted.

Pages 4-3, 4-4, and 4-5 have been removed from this Section.

5.0 ADMINISTRATIVE PROCEDURES

5.1 Review and Audit

The licensee shall provide for review and audit of compliance with the EPP. The audits shall be conducted independently of the individual or groups responsible for performing the specific activity. A description of the organizational structure utilized to achieve the independent review and audit function and results of the audit activities shall be maintained and made available for inspection.

5.2 Records Retention

Records associated with this Environmental Protection Plan shall be made and retained in a manner convenient for review and inspection. These records shall be made available to NRC on request.

Records of modifications to station structures, systems and components determined to potentially affect the continued protection of the environment shall be retained until the date of termination of the operating license. All other records relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Request for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revision to the EPP.

5.4 Plant Reporting Requirements

5.4.1 Deleted

5.4.2 Nonroutine Reports

A written report shall be submitted to the NRC within 30 days of occurrence of an Unusual or Important Environmental event. The report shall (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact and plant operating characteristics, (b) describe the probable cause of the event, (c) indicate the action taken to correct the reported event, (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems, and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided a copy of such report at the same time it is submitted to the other agency.

Exelon Nuclear
Limerick Generating Station

TITLE: Technical Requirements Manual

PURPOSE: Provides information and guidance on requirements for various plant conditions, actions, and testing similar to the Limerick Generating Station (LGS) Unit 1 and Unit 2 Technical Specifications (TS). The Technical Requirements Manual (TRM) is mainly required to support appropriate operation of the station in accordance with commitments. The TRM is under the control of Exelon Nuclear and all technical changes are to be evaluated for acceptance using the 10CFR50.59 process defined for the Nuclear Generation Group (and including a 10CFR50.54 review when required).

SCOPE: This manual contains a wide variety of information and requirements for various systems and processes, most of which existed in the LGS TS at some previous point in time.

INTENDED USE: The TRM is intended to be used by Operations and other station personnel as an aid used in conjunction with the TS and to provide operating guidance for certain non-TS plant equipment (e.g., valve and instrument lists). The same rules and conventions as in the TS apply to the use of the information in the TRM unless specifically stated in the TRM.

Noncompliance with TRM requirements requires the generation of a Condition Report (CR) per procedure LS-AA-125. This noncompliance is not a condition prohibited by TS, however, the noncompliance needs to be evaluated for other reportability requirements depending on the seriousness of the noncompliance (e.g., operation outside design basis).

The TRM title page and each individual page will be controlled as a procedure per AD-AA-101. Each page is assigned to a specific responsible organization as listed in the TRM Page Revision List, which follows the title page. The technical information on each page is the responsibilities of the assigned organization and revisions to individual pages are processed per AD-AA-101-1002. The responsibility for the administrative control of the manual is assigned to Regulatory Assurance.

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PAGE REVISION LIST

Page	Resp. Org.	Revision # and Date
Bases for Sections 3.0 and 4.0		
TRM - B 3/4 0-1	LSE	Rev. 0, Dated December 20, 1995
TRM - B 3/4 3-5	LEPN	Rev. 20, Dated June 10, 2005
TRM - B 3/4 3-6	LEPR	Rev. 3, Dated July 11, 1996
TRM - B 3/4 3-7	LEPB	Rev. 26, Dated June 07, 2006
TRM - B 3/4 4-3e	LEPN	Rev.25, Dated February 7, 2006
TRM - B 3/4 4-4	LSC	Rev.22, Dated September 21, 2005
TRM - B 3/4 5-3	LEPN	Rev. 0, Dated July 11, 2001
TRM - B 3/4 7-4	LEPB	Rev. 0, Dated December 20, 1995
TRM - B 3/4 7-4a	LEPB	Rev. 30, Dated August 2, 2007
TRM - B 3/4 7-4b	LEPB	Rev. 0, Dated December 20, 1995
TRM - B 3/4 7-4c	LEPB	Rev. 2, Dated July 11, 1996
TRM - B 3/4 8-1	LEPE	Rev. 17, February 27, 2003
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TRM - 6-2	LEPB	Rev. 2, Dated July 11, 1996

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LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

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DEFINITIONS

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1.0 DEFINITIONS

Specific terms are defined so that uniform interpretation of these requirements may be achieved. The terms appear in capitalized type throughout the TRM. The definitions of the terms are identical to the definitions in the Technical Specifications except if noted in a TRM Section. Except for the specific terms defined in the TRM, use the definitions contained in the Definitions Section of the Technical Specifications.

CONDITION FOR OPERATION

1.1 CONDITION FOR OPERATION shall be that part of the TRM Specification that describes requirements to perform the specified surveillance or maintenance activities in the TRM.

MAINTENANCE REQUIREMENTS

1.2 MAINTENANCE REQUIREMENTS shall be that part of the TRM Specification that describes the requirements to perform the specified maintenance activities in the TRM.

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SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

The requirements of TS Sections 3.0.1, 3.0.2, 3.0.3, 3.0.4, 4.0.1, 4.0.3, and 4.0.4 are applicable to the TRM. Refer to the TS Section for the actual requirements.

4.0.2 Each Surveillance Requirement shall be performed within the specified surveillance time interval with a maximum allowable extension not to exceed 25% of the surveillance interval. If a TRM ACTION requires a periodic performance on a once per ... basis (e.g., an hourly fire watch patrol) the 25% extension applies to each performance after the initial performance.

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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, prepare and submit a Special Report to the Nuclear Regulatory Commission pursuant to Specification 6.9.2 of the Technical Specifications 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 Specification 3.0.3 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 which is accessible during power operation and which is actuated during a seismic event greater than or equal to 0.01 g, and which does not self-reset, 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. A Special Report shall be prepared and submitted to the Nuclear Regulatory Commission pursuant to Specification 6.9.2 of the Technical Specifications within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

Each of the above seismic monitoring instruments which is actuated during a seismic event greater than or equal to 0.01 g but is not accessible during power operation shall be restored to OPERABLE status and a CHANNEL CALIBRATION performed the next time Unit 1 enters OPERATIONAL CONDITION 4 or below. A supplemental report shall then be prepared and submitted to the Nuclear Regulatory Commission within 14 days pursuant to Specification 6.9.2 of the Technical Specifications describing the additional data from these instruments.

*Shared with Unit 1.

TABLE 3.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelerometers (T/As)		
a. Sensors		
1) XE-VA-102 Primary Containment Foundation Sensor, located at Reactor Enclosure Basemat U/1 (Loc. 109-R15-177)	0 to 1 g	1
2) XE-VA-103 Containment Structure (Diaphragm Slab)	0 to 1 g	1
3) XE-VA-104 Reactor Enclosure Foundation (Loc. 111-R11-177)	0 to 1 g	1
4) XE-VA-105 Reactor Piping Support (Mn. Stm. Line 'D', El 313', in containment)	0 to 1 g	1
5) XE-VA-106 Outside Containment on Seismic Category I Equipment (RHR Heat Exchanger, Loc. 102-R15-177)	0 to 1 g	1
6) XRSH-VA-107* Foundation of an Independent Seismic Category I Structure (Spray Pond Pump House, El 237')	0 to 1 g	1
b. Records (Panel 00C693)		
1) XR-VA-102/103 for XE-VA-102	N.A.	1
2) XR-VA-102/103 for XE-VA-103	N.A.	1
3) XR-VA-104/105 for XE-VA-104	N.A.	1
4) XR-VA-104/105 for XE-VA-105	N.A.	1
5) XR-VA-106 for XE-VA-106	N.A.	1
2. Triaxial Response Spectrum Analyzer	1-33.5 Hz	1**

* Includes sensor, trigger, recorder, and backup power supply.

** With reactor control room indication and annunciation.

Receives signal from playback unit fed with data from Triaxial Accelerometers.

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TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Triaxial Time-History Accelerometers (T/As)			
a. Sensors			
1) XE-VA-102 Primary Containment Foundation Sensor, located at Reactor Enclosure Basemat U/1 (Loc. 109-R15-177)	N.A.	SA	R
2) XE-VA-103 Containment Structure (Diaphragm Slab)	N.A.	SA	R
3) XE-VA-104 Reactor Enclosure Foundation (Loc. 111-R11-177)	N.A.	SA	R
4) XE-VA-105 Reactor Piping Support (Mn. Stm. Line 'D', El 313', in containment)	N.A.	SA	R
5) XE-VA-106 Outside Containment on Seismic Category I Equipment, (RHR Heat Exchanger, Loc. 102-R15-177)	N.A.	SA	R
6) XRSH-VA-107* Foundation of an Independent Seismic Category I Structure (Spray Pond Pump House, El 237')	N.A.	SA	R
b. Recorders (Panel 00C693)			
1) XR-VA-102/103 for XE-VA-102	N.A.	SA	R
2) XR-VA-102/103 for XE-VA-103	N.A.	SA	R
3) XR-VA-104/105 for XE-VA-104	N.A.	SA	R
4) XR-VA-104/105 for XE-VA-105	N.A.	SA	R
5) XR-VA-106 for XE-VA-106	N.A.	SA	R
2. Triaxial Response Spectrum Analyzer	N.A.	SA	R

*Includes sensor, trigger, recorder, and backup power supply.

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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 the number of OPERABLE monitoring instrumentation channels less than required by the Minimum Channels Operable requirement, 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		REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1.	-	-	-	-	-
2.	-	-	-	-	-
3.	-	-	-	-	-
4.	-	-	-	-	-
5.	Deleted	-	-	-	-
6.	-	-	-	-	-
7.	Drywell Air Temperature -	1	1	1,2	83
8.	Drywell Oxygen Concentration Analyzer	1	1	1,2	82
9.	Drywell Hydrogen Concentration Analyzer	1	1	1,2	82
10.	Safety/Relief Valve Position Indicators (Acoustic or Tailpipe Thermocouple)	1/valve	1/valve	1,2	80
11.	-	-	-	-	-
12.	-	-	-	-	-
13	-	-	-	-	-

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

TABLE NOTATIONS

ACTION STATEMENTS

ACTION 80 -

With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore at least one of the inoperable channel(s) to OPERABLE status within 30 days. OTHERWISE, submit a Corrective Action Program (CAP) document within the following 24 hours outlining proposed restorative actions and an alternate monitoring method.

ACTION 82 -

With the number of OPERABLE monitoring instrumentation channels less than required by the Minimum Channels Operable requirement in Table 3.3.7.5-1, initiate the preplanned alternate monitoring method within 72 hours

AND

Restore the inoperable channel to OPERABLE status within 7 days, OTHERWISE, submit a Corrective Action Program (CAP) document within the following 24 hours to evaluate and capture the cause and resolution of the condition.

ACTION 83 –

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.

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

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT		CHANNEL CHECK	CHANNEL CALIBRATION
1.	-	-	-
2.	-	-	-
3.	-	-	-
4.	-	-	-
5.	Deleted	-	-
6.	-	-	-
7.	Drywell Air Temperature	M	R
8.	Drywell Oxygen Concentration Analyzer	M	SA#
9.	Drywell Hydrogen Concentration Analyzer	M	SA*
10.	Safety/Relief Valve Position Indicators		
	Acoustic Monitor	M	R
	Tailpipe Thermocouple	M N.A.	
11.	-	-	-
12.	-	-	-
13.	-	-	-

*Using calibration gas containing:
Seven volume percent hydrogen, balance nitrogen.
#Using calibration gas containing:
Seven volume percent oxygen, balance nitrogen

TRAVERSING IN-CORE PROBE SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.7 The traversing in-core probe system shall be OPERABLE with:

a. At least four OPERABLE detectors, drives and readout equipment to map the core, and

b. Indexing equipment to allow the OPERABLE detectors to be calibrated in a common location.

APPLICABILITY: When the traversing in-core probe is used for:

a. Recalibration of the LPRM detectors, and

b.* Monitoring the APLHGR, LHGR, MCPR, or MFLPD.

ACTION:

With the traversing in-core probe system inoperable, suspend use of the system for the above applicable monitoring or calibration functions. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.7 The traversing in-core probe system shall be demonstrated OPERABLE by normalizing each of the above required detector outputs within 72 hours prior to use for the LPRM calibration function.

*Only the detector(s) in the required measurement location(s) are required to be OPERABLE.

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INSTRUMENTATION

FIRE DETECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.9 As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.3.7.9-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the fire detection instrument is required to be OPERABLE.

ACTION:

a. With the number of OPERABLE fire detection instruments in one or more zones:

1. Less than, but more than one-half of, the Total Number of Instruments shown in Table 3.3.7.9-1 for Function A, restore the inoperable Function A instrument(s) to OPERABLE status within 14 days or within 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour, unless the instrument(s) is located inside an inaccessible zone, then inspect the area surrounding the inaccessible zone at least once per hour.

2. One less than the Total Number of Instruments shown in Table 3.3.7.9-1 for Function B, or one-half or less of the Total Number of Instruments shown in Table 3.3.7.9-1 for Function A, or with any two or more adjacent instruments inoperable, within 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour, unless the instruments(s) is located inside an inaccessible zone, then inspect the area surrounding the inaccessible zone at least once per hour.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.9.1 The above required fire detection instruments which are accessible during unit operation shall be demonstrated OPERABLE:

a. For smoke detectors, at least once per 24 months by performance of a CHANNEL FUNCTIONAL TEST.

b. For heat detectors, at least once per 12 months by performance of a CHANNEL FUNCTIONAL TEST on one or more detectors in each signal-initiation circuit. Detectors shall be selected such that different detectors are tested in each test. All detectors shall be tested at least once per 5 years.

SURVEILLANCE REQUIREMENTS (Continued)

c. For all other types of fire detectors, at lease once per 6 months by performance of a CHANNEL FUNCTIONAL TEST.

Fire detectors which are not accessible during unit operation shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST during each COLD SHUTDOWN exceeding 24 hours unless performed in the past 24 months for smoke detectors, 12 months for heat detectors, or 6 months for all other types of fire detectors.

4.3.7.9.2 The NFPA Standard 72D supervised circuits supervision associated with the detector alarms of each of the above required fire detection instruments shall be demonstrated OPERABLE at least once per 24 months.

TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
1L	Control	200'	Control Structure Chillers and Chilled Water Pump Area 258	NA	3/0	NA
1M	Control	200'	Control Structure Chillers and Chilled Water Pump Area 263	NA	3/0	NA
1N	Control	200'	Recombiner Access Area Rm. 259	NA	3/0	NA
2	Control	217'	13-kV Switchgear Area 336	NA	0/49	NA
5	Control	217'	Battery Room 360 (2D)	1/0	1/0	NA
6	Control	217'	Battery Room 361 (2C)	1/0	1/0	NA
7	Control	239'	Corridor 437	NA	5/0	NA
10A	Control	239'	Battery Room 426	1/0	2/0	NA
10B	Control	239'	Switchgear Maintenance Area 454	2/0	1/0	NA
11	Control	239'	Battery Room 427	1/0	2/0	NA
16	Control	239'	4-kV Switchgear Compartment 430	2/0	2/0	NA
17	Control	239'	4-kV Switchgear Compartment 431	2/0	2/0	NA
18	Control	239'	4-kV Switchgear Compartment 428	2/0	2/0	NA
19	Control	239'	4-kV Switchgear Compartment 429	2/0	2/0	NA
21	Control	254'	Static Inverter Room Unit 2 Area 453	NA	6/0	NA
23	Control	254'	Cable Spreading Room Unit 2 Area 450	NA	14/0	NA
24A	Control	269'	Control Room 533	NA	23(a)/0 11(b)/0	NA
24B	Control	269'	Control Room Utility Room 529	NA	1/0	NA
24C	Control	269'	Control Room Office 531	NA	1/0	NA
24D	Control	269'	Control Room Shift Supt. 536	NA	1/0	NA
24E	Control	269'	Control Room Shop 534	NA	1/0 (Photo-Elect)	NA
24F	Control	269'	Control Room Instrument Lab 535	NA	1/0 (Photo-Elect)	NA
24G	Control	269'	Control Room Shift Supt. 532	NA	1/0	NA

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
25	Control	289'	Auxiliary Equipment Room 542	0/88 (PGCC Floor) 0/8 (Non-PGCC Floor)	57/0 (Ceiling) 46/0 (PGCC Floor) 6/0 (Non-PGCC Floor) 32/0 (Terminal Cabinets)	NA
26	Control	289'	Remote Shutdown Panel Area 540	0/4 (Non-PGCC Floor)	3/0 (Ceiling Level) 2/0 (Non-PGCC Floor)	NA
27	Control	304'	Control Structure Fan Room 619	0/23 4/0 (inside plenum)	10/0	NA
28A	Control	332'	SGTS Access Area 625 (SGTS Room Ventilation Exhaust)	4/0 (inside plenum)	NA	NA
28B	Control	332'	SGTS Filter Compartment 624	4/0 (inside plenum)	NA	NA
28C	Control	332'	Control Room Fresh Air Intake Plenum	NA	3/0	NA
54	Unit 2 Reactor	177'	RHR Heat Exchanger & Pump Room 173 (A&C)	NA	8/0	NA
55	Unit 2 Reactor	177'	RHR Heat Exchanger & Pump Room 174 (B&D)	NA	7/0	NA
56	Unit 2 Reactor	177'	RCIC Pump Room 179	0/3	2/0	NA
57	Unit 2 Reactor	177'	HPCI Pump Room 180	0/4	3/0	NA
58	Unit 2 Reactor	177'	'B' Core Spray Pump Room 181	NA	2/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
59	Unit 2 Reactor	177'	'D' Core Spray Pump Room 184	NA	2/0	NA
60	Unit 2 Reactor	177'	'C' Core Spray Pump Room 185	NA	2/0	NA
61	Unit 2 Reactor	177'	'A' Core Spray Pump Room 188	NA	2/0	NA
62	Unit 2 Reactor	177'	Sump Room 186; Passageway 189	NA	4/0	NA
63	Unit 2 Reactor	177'	Corridor 182	NA	2/0	NA
64A	Unit 2 Reactor	201'	RECW Equipment Area 284	0/9	5/0	NA
65	Unit 2 Reactor	201'	Safeguard System Access Area 279	0/14	4/0	NA
66	Unit 2 Reactor	217'	Safeguard System Isolation Valve Area 376	NA	8/0	NA
67	Unit 2 Reactor	217'	Safeguard System Access Area 370	0/11 (Southeast) 0/11 (Northeast) 0/14 (Northwest)	28/0	NA
68A	Unit 2 Reactor	253'	CRD Hydraulic Equipment Area 475	0/10 (Northwest) 0/6 (Southeast)	20/0	NA
68B	Unit 2 Reactor	253'	Neutron Monitoring System Area 479	NA	2/0	NA
68C	Unit 2 Reactor	253'	CRD Repair Room 476	NA	2/0	NA
70A	Unit 2 Reactor	283'	Corridor 580; General Equipment Area 574	0/15	22/0	NA
70B	Unit 2 Reactor	295'	Isolation Valve Compartment 593	NA	2/0	NA
70C	Unit 2 Reactor	283'	Fuel Pool Cooling Water Pump and Heat Exchanger Area 585	NA	2/0	NA
70D	Unit 2 Reactor	283'	Isolation Valve Compartment 584/597	NA	1/0	NA

TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				TOTAL NUMBER OF INSTRUMENTS*		
FIRE ZONE	STRUCTURE	ELEV.	AREA	HEAT (x/y)	SMOKE (x/y)	FLAME (x/y)
71A	Unit 2 Reactor	313'	Laydown Areas 637 and 638; Corridor and RERS Fan Area 641	NA	18/0	NA
74A	Unit 2 Reactor	331'	RERS Filter Compartment 651	2/0 (inside plenum)	NA	NA
74B	Unit 2 Reactor	331'	RERS Filter Compartment 653	2/0 (inside plenum)	NA	NA
83	Diesel-Generator	217'	Diesel-Generator Cell Unit 2	1/5	NA	1/0
84	Diesel-Generator	217'	Diesel-Generator Cell Unit 2	1/5	NA	1/0
85	Diesel-Generator	217'	Diesel- Generator Cell Unit 2	1/5	NA	1/0
86	Diesel-Generator	217'	Diesel-Generator Cell Unit 2	1/5	NA	1/0
122A	Spray Pond Pump Structure	268'	ESW and RHRSW Pump Area	NA	4/0	NA
122E	Spray Pond Pump Structure	251'	RHRSW Valve Compartment	NA	2/0	NA
123A	Spray Pond Pump Structure	268'	ESW and RHRSW Pump Area	NA	4/0	NA
123E	Spray Pond Pump Structure	251'	RHRSW Valve Compartment	NA	2/0	NA
125A	Diesel-Generator	217'	Diesel-Generator Access Corridor 317	NA	4/0	NA
126A	Common Reactor	412'	North Stack Instrument Room 713	NA	2/0	NA

*(x/y): X is the number of Function A (Early Warning Fire Detection and Notification Only) Instruments.
Y is the number of Function B (Activation of Fire Suppression System and Early Warning Notification) Instruments.

(a) These smoke detectors are located below the suspended ceiling in the Control Room.
(b) These smoke detectors are located above the suspended ceiling in the Control Room.

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3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.8 At least one turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 AND 2.

ACTION:

a. With one turbine control valve and/or one turbine stop valve per high pressure turbine steam lead inoperable and/or with one turbine combined intermediate valve per low pressure turbine steam lead inoperable, restore the inoperable valve(s) to OPERABLE status within 72 hours or close at least one valve in the affected steam lead(s) or isolate the turbine from the steam supply within the next 6 hours.

b. With the above required turbine overspeed protection system otherwise inoperable, within 6 hours isolate the turbine from the steam supply.

SURVEILLANCE REQUIREMENTS

4.3.8.1 The provisions of Specification 4.0.4 are not applicable.

4.3.8.2 The above required turbine overspeed protection system shall be demonstrated OPERABLE:

a. At least once per 3 months by:

1. Cycling each of the following valves through at least one complete cycle from the running position:

a) For the overspeed protection control system;

1) Six low pressure turbine intercept valves, and

2) Four high pressure turbine control valves

b) For the electrical overspeed trip system and the mechanical overspeed trip system;

1) Four high pressure turbine stop valves,

2) Six low pressure turbine intermediate stop valves, and

3) Four high pressure turbine control valves

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 24 months by performance of a CHANNEL CALIBRATION of the turbine overspeed protection instrumentation.

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3/4.4.2 SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 The acoustic monitor for each of the reactor coolant system safety/relief valves shall be OPERABLE:

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more safety/relief valve acoustic monitors inoperable, verify the safety/relief valve tailpipe thermocouple for the affected valve(s) is functioning.

b. With both safety/relief valve acoustic monitor and tailpipe thermocouple inoperable, restore one method of determining valve position to OPERABLE within 30 days. OTHERWISE, submit a Corrective Action Program (CAP) document within the following 24 hours outlining proposed restorative actions and an alternate monitoring method.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be 0.20 of the full open noise level## by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 92 days, and a
b. CHANNEL CALIBRATION at least once per 24 months**.

** The provisions of Specification 4.0.4 are not applicable provided the Surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

Initial setting shall be in accordance with the manufacturer's recommendation. Adjustment to the valve full open noise level shall be accomplished during the startup test program.

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TABLE 3.4.3.2-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

1ST ISOLATION VALVE(S) NUMBER(S)	2ND ISOLATION VALVE(S) NUMBER(S)	ALARM SETPOINT (psig)	ALARM ALLOWABLE VALUE (psig)	SERVICE
HV-52-2F006A HV-52-2F039A	HV-52-2F005	≤475	≤495	'A' Core Spray Injection
HV-52-2F006B HV-52-2F039B	HV-52-208	≤475	≤495	'B' Core Spray/HPCI Injection
HV-51-2F041A HV-51-242A	HV-51-2F017A	≤400	≤420	'A' LPCI Injection
HV-51-2F041B HV-51-242B	HV-51-2F017B	≤400	≤420	'B' LPCI Injection
HV-51-2F041C HV-51-242C	HV-51-2F017C	≤400	≤420	'C' LPCI Injection
HV-51-2F041D HV-51-242D	HV-51-2F017D	≤400	≤420	'D' LPCI Injection
HV-51-2F050A HV-51-251A 51-2200A	HV-51-2F015A	≤400	≤420	'A' Shutdown Cooling Return to 'A' Recirc Loop
HV-51-2F050B HV-51-251B 51-2200B	HV-51-2F015B	≤400	≤420	'B' Shutdown Cooling Return to 'B' Recirc Loop
HV-51-2F009	HV-51-2F008	≤125	≤145	Shutdown Cooling Supply From 'B' Recirc Loop

REACTOR COOLANT SYSTEM

3/4.4.4 CHEMISTRY

LIMITING CONDITION FOR OPERATION

3.4.4 The chemistry of the reactor coolant system shall be maintained within the limits specified in Table 3.4.4-1.

APPLICABILITY: At all times.

ACTION:

a. In OPERATIONAL CONDITION 1:

1. With the conductivity or chloride concentration exceeding the limit specified in Table 3.4.4-1 for less than 72 hours during one continuous time interval and, for conductivity and chloride concentration, for less than 336 hours per year, initiate an entry into the corrective action process.

2. With the conductivity or chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 72 hours during one continuous time interval or with the conductivity and chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 336 hours per year, be in at least STARTUP within the next 8 hours.

3. With the conductivity exceeding 10 μmho/cm at 25°C or chloride concentration exceeding 0.5 ppm, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITION 2 and 3 with the conductivity or chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 48 hours during one continuous time interval, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. At all other times:

1. With the:

a) Conductivity exceeding the limit specified in Table 3.4.4-1, restore the conductivity to within the limit within 72 hours, or

b) Chloride concentration exceeding the limit specified in Table 3.4.4-1, restore the chloride concentration to within the limit within 24 hours, or

perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to OPERATIONAL CONDITION 3.

2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4 The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant for:

1. Chlorides at least once per:

   a) 72 hours, and

   b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

2. Conductivity at least once per 72 hours.

3. pH at least once per 72 hours during Noble Metals Chemical Application

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable, obtaining an in-line conductivity measurement at least once per:

1. 4 hours in OPERATIONAL CONDITIONS 1, 2, and 3, and

2. 24 hours at all other times.

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an inline flow cell at least once per:

1. 7 days, and

2. 24 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

TABLE 3.4.4-1

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS

OPERATIONAL CONDITION	CHLORIDES	CONDUCTIVITY (μmhos/cm @25°C)
1	≤ 0.2 ppm	≤ 1.0
2 and 3 [(a)]	≤ 0.1 ppm	≤ 2.0
3 (b)	<0.1 ppm	< 10.0
At all other times	≤ 0.5 ppm	≤ 10.0

(a) Except during Noble Metals Chemical Applications.
(b) During Noble Metals Chemical Applications.

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3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.4 LONG TERM GAS SUPPLY SYSTEM TO THE ADS VALVES

LIMITING CONDITION FOR OPERATION

3.5.4.1 The Long Term Gas Supply System to the ADS valves shall be OPERABLE with two independent subsystems, each subsystem consisting of:

a. One OPERABLE bottle bank with the sum of the individual bottle gas pressures ≥ 2400 psig, and
b. An OPERABLE flow path capable of supplying gas from the bottle bank and the external connection to the ADS valves.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 AND 4

ACTION:

a. With one subsystem of the long term gas supply system inoperable, restore the inoperable subsystem to OPERABLE within 14 days, or
b. With both subsystems of the long term gas supply system inoperable, restore at least one subsystem to OPERABLE within 3 days.
c. If the above conditions are not met, then establish an alternate long term gas supply within 24 hours.

SURVEILLANCE REQUIREMENTS

4.5.4.1.1 At least once per day, verify that the long term gas supply bottle pressure is ≥ 800 psig per bottle, and that the sum of the individual bottle pressures on each bottle bank is ≥ 2400 psig.
4.5.4.1.2 At least once per 31 days, perform a functional test of the swap over from the normal gas supply to the long term gas supply system.

EMERGENCY CORE COOLING SYSTEMS

LONG TERM GAS SUPPLY SYSTEM TO THE ADS VALVES

LIMITING CONDITION FOR OPERATION

3.5.4.2 Two independent ADS long term gas supply low pressure instrumentation channels shall be OPERABLE with their alarm setpoints set at 90 $\pm$ 2 psig on decreasing pressure.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 AND 4

ACTION

a. With one or more instrument channels inoperable, restore each inoperable channel to OPERABLE status within 72 hours, or
b. Verify that the associated ADS long term gas supply header pressure is $\geq$ 90 psig once per 12 hours, or
c. If the above conditions are not met, declare the associated long term gas supply subsystem inoperable.

SURVEILLANCE REQUIREMENTS

4.5.4.2.1 At least once per 31 days, perform a CHANNEL FUNCTIONAL TEST of the accumulator backup compressed gas system low pressure alarm system.

4.5.4.2.2 At least once per 24 months, perform a CHANNEL CALIBRATION of the accumulator backup compressed gas system low pressure alarm system.

TABLE 3.6.3-1

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
003B	CONTAINMENT INSTRUMENT GAS SUPPLY - HEADER 'B'	59-2005B (CK)		NA			59
			HV59-229B	7	C,H,S		
003D-2	CONTAINMENT INSTRUMENT GAS SUPPLY TO ADS VALVES E & K	59-2112(CK)		NA			
			HV59-251B	45	M		59
007A(B,C,D)	MAIN STEAM LINE 'A'(B,C,D)	HV41-2F022A (B,C,D)		5*	C,E,F,P,Q	6	41
			HV41-2F028A (B,C,D)	5*	C,E,F,P,Q	6	
008	MAIN STEAM LINE DRAIN	HV41-2F016		30	C,E,F,P,Q	4	41
			HV41-2F019	30	C,E,F,P,Q		
009A	FEEDWATER	41-2F010A(CK)		NA			41
			HV41-2F074A(CK)	NA			
			41-2036A(CK)	NA			
			HV41-230B	45			
			HV41-233A	45			
			HV41-209A	NA		32	
			HV41-2F032A(CK)	NA			
			HV55-2F105	30		7	
			HV44-2F039(CK) (X-9B)	NA			
			41-2016(X-9B, X-44)	NA		31	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
009B	FEEDWATER	41-2F010B(CK)		NA			
			HV41-2F074B(CK)	NA			41
			41-2036B(CK)	NA			
			HV41-230A	45			
			HV41-233B	45			
			HV41-209B	NA		32	
			HV41-2F032B(CK)	NA			
			HV49-2F013	23	LFCC		
			HV44-2F039(CK) (X-9A)	NA			
			41-2016(X-9A, X-44)	NA		31	
010	RCIC STEAM SUPPLY	HV49-2F007		7.2*	K, KA	5	49
			HV49-2F008	7.2*	K, KA		
			HV49-2F076	45	K, KA		
011	HPCI STEAM SUPPLY	HV55-2F002		12*	L, LA	5	55
			HV55-2F003	12*	L, LA		
			HV55-2F100	45	L, LA		
012	RHR SHUTDOWN COOLING SUPPLY	HV51-2F009		100	A,V	9,22	51
		PSV51-255		NA			
			HV51-2F008	100	A,V		
013A(B)	RHR SHUTDOWN COOLING RETURN	HV51-2F050A(B) (CK)		NA	A,V	9,22	51
		HV51-251A(B)		20	A,V		
		51-2200A(B)		NA			
			HV51-2F015A(B)	45	A,V		
014	RWCU - SUCTION	HV44-2F001		10*	B,J,Y		44
			HV44-2F004	10*	B,J,Y		

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
016A	CORE SPRAY INJECTION	HV52-2F006A(CK)		NA		9,22	52
		HV52-2F039A		7		9,22	
			HV52-2F005	18			
016B	CORE SPRAY INJECTION	HV52-2F006B(CK)		NA		9,22	52
		HV52-2F039B		7		9,22	
			HV52-208(CK)	NA			
021	SERVICE AIR TO DRYWELL	15-2140		NA			15
			15-2139	NA			
022	DRYWELL PRESSURE INSTRUMENTATION		HV42-247C	45		10	42
023	RECW SUPPLY TO RECIRC PUMPS	HV13-206		40	C,H	11	13
			HV13-208	30	C,H	11	
			HV13-209	NA		11,13	
024	RECW RETURN FROM RECIRC PUMPS	HV13-207		40	C,H	11	13
			HV13-211	30	C,H	11	
			HV13-210	NA		11,13	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
025	DRYWELL PURGE SUPPLY	HV57-221(X-201A)		5**	B,H,S,W,R	3,11,14	57
		HV57-223		5**	B,H,S,W,R	3,11,14	
			HV57-209 (X-201A)	6**	B,H,S,W,R	11	
			HV57-231 (X-201A)	5**	B,H,S,W,R	11	
			HV57-235	6**	B,H,S,W,R	11	
	HYDROGEN RECOMBINER "B" INLET	HV57-263		9	B,H,R,S	3,11,14	
			FV57-D0-201B	90	B,H,R,S	11,34	
026	DRYWELL PURGE EXHAUST	HV57-214		5**	B,H,S,W,R	3,11,14,33	57
		HV57-211		15**	B,H,S,R	11	
		SV57-239		5		10	
			HV57-215	6**	B,H,S,W,R	11,33	
			HV57-217	5**	B,H,S,R	11	
			SV57-245	5	B,H,R,S	11	
	HYDROGEN RECOMBINER "A" INLET	HV57-261		9	B,H,R,S	3,11,14	
			FV57-D0-201A	90	B,H,R,S	11,34	
027A	CONTAINMENT INSTRUMENT GAS SUPPLY TO ADS VALVES H,M,&S	59-2128(CK)		NA			59
			HV59-251A	45	M		
028A-1	RECIRC LOOP SAMPLE	HV43-2F019		10	B		43
			HV43-2F020	10	B		
028A-2	DRYWELL H2/02 SAMPLE	SV57-232		5	B,H,R,S	11	57
			SV57-242	5	B,H,R,S	11	
028A-3	DRYWELL H2/02 SAMPLE	SV57-234		5	B,H,R,S	11	57
			SV57-244	5	B,H,R,S	11	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF. APP. (20)	NOTES	P&ID
028B	DRYWELL H2/02 SAMPLE	SV57-233		5	B,H,R,S	11	57
			SV57-243	5	B,H,R,S	11	
			SV57-295	5	B,H,R,S	11	
030B-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-247A	45		10	42
035B	TIP PURGE	59-2056(CK) (DOUBLE "O" RING)		NA			59
			HV59-231	7	B,H,S	16	
035C-G	TIP DRIVES	XV59-241A-E (DOUBLE "O" RING)		NA	B,H	11,16,21	59
			XV59-240A-E	NA		11,16	
037A-D	CRD INSERT LINES	BALL CHECK		NA		12	47
			46-2101	NA		12,22	46
			46-2102	NA		12,22	
			46-2108	NA		12,22	
			46-2109	NA		12,22	
038A-D	CRD WITHDRAW LINES SDV VENTS & DRAINS		46-2115	NA		12,22	46
			46-2116	NA		12,22	
			46-2122	NA		12,22	
			46-2123	NA		12,22	
			XV47-2F010	25		30	47
			XV47-2F180	30		30	
			XV47-2F011	25		30	
			XV47-2F181	30		30	
039A(B)	DRYWELL SPRAY	HV51-2F021A(B)		160		4,11	51
			HV51-2F016A(B)	160		11	
040E	DRYWELL PRESSURE INSTRUMENTATION		HV42-247D	45		10	42
040F-2	CONTAINMENT INSTRUMENT GAS - SUCTION	HV59-201		45	C,H,S	5	59
			HV59-202	7	C,H,S		

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
040G-1	ILRT DATA ACQUISITION	60-2057		NA		11	60
			60-2058	NA		11	
040G-2	ILRT DATA ACQUISITION	60-2071		NA		11	60
			60-2070	NA		11	
040H-1	CONTAINMENT INSTRUMENT GAS SUPPLY - HEADER 'A'	59-2005A(CK)		NA			59
			HV59-229A	7	C,H,S		
042	STANDBY LIQUID CONTROL	48-2F007(CK)		NA			48
		(X-116)	HV48-2F006A	60		29	
043B	MAIN STEAM SAMPLE	HV41-2F084		10	B		41
			HV41-2F085	10	B		
044	RWCU ALTERNATE RETURN	41-2017		NA		5,31	41
			41-2016(X-9A, X-9B)	NA			
			PSV41-212	NA			
045A(B,C,D)	LPCI INJECTION 'A'(B,C,D)	HV51-2F041A(B,C, D)(CK)		NA		9,22	51
		HV51-242A(B,C, D)		7		9,22	
			HV51-2F017A (B,C,D)	38			
050A-1	DRYWELL PRESSURE INSTRUMENTATION		HV42-247B	45		10	42
053	DRYWELL CHILLED WATER SUPPLY - LOOP 'A'	HV87-228		60	C,H	11	87
			HV87-220A	60	C,H	11	
			HV87-225A	NA		35	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. IME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
054	DRYWELL CHILLED WATER RETURN - LOOP 'A'	HV87-229		60	C,H	11	87
			HV87-221A	60	C,H	11	
			HV87-224A	NA		35	
055	DRYWELL CHILLED WATER SUPPLY - LOOP 'B'	HV87-222		60	C,H	11	87
			HV87-220B	60	C,H	11	
			HV87-225B	NA		35	
056	DRYWELL CHILLED WATER RETURN - LOOP 'B'	HV87-223		60	C,H	11	87
			HV87-221B	60	C,H	11	
			HV87-224B	NA		35	
061-1	RECIRC PUMP 'A' SEAL PURGE	43-2004A(CK)		NA		15	43
			(XV43-203A - SEE PART B, THIS TABLE)	NA		1	
061-2	RECIRC PUMP 'B' SEAL PURGE	43-2004B(CK)		NA		15	43
			(XV43-203B - SEE PART B, THIS TABLE)	NA		1	
062	DRYWELL H2/02 SAMPLE RETURN, N2 MAKE-UP	SV57-250(X-220A)		5	B,H,R,S	11	57
			SV57-259 (X-220A)	5	B,H,R,S	11	
			HV57-216 (X-220A)	30**	B,H,R,S	11	
			SV57-290 (X-220A)	5	B,H,R,S	11	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
			SV57-291 (X-220A)	5	B,H,R,S	11	
116	STANDBY LIQUID CONTROL	48-2F007(CK)		NA			48
		(X-42)	HV48-2F006B	60		29	
117B-1	DRYWELL RADIATION	SV26-290A		5	B,H,R,S	11	26
	MONITORING SUPPLY		SV26-290B	5	B,H,R,S	11	
117B-2	DRYWELL RADIATION	SV26-290C		5	B,H,R,S	11	26
	MONITORING RETURN		SV26-290D	5	B,H,R,S	11	
201A	SUPPRESSION POOL PURGE	HV57-224		5**	B,H,S,W,R	3,11,14	57
	SUPPLY	HV57-231(X-25)		5**	B,H,S,W,R	3,11,14	
			HV57-209(X-25)	6**	B,H,S,W,R	11	
			HV57-247	6**	B,H,S,W,R	11	
			HV57-221(X-25)	5**	B,H,S,W,R	11	
	HYDROGEN RECOMBINER	HV57-264		9	B,H,R,S	3,11,14	
	"B" EXHAUST		HV57-269	9	B,H,R,S	11	
202	SUPPRESSION POOL PURGE	HV57-204		5**	B,H,S,W,R	3,11,14,33	57
	EXHAUST	HV57-205		15**	B,H,S,R	11	
			HV57-212	6**	B,H,S,W,R	11,33	
			HV57-218	5**	B,H,S,R	11	
			SV57-285	5	B,H,R,S	11	
	HYDROGEN RECOMBINER	HV57-262		9	B,H,R,S	3,11,14	
	"A" EXHAUST		HV57-266	9	B,H,R,S	11	
203A(B,C,D)	RHR PUMP SUCTION		HV51-2F004A (B,C,D)	240		29,36	51
			PSV51-2F030A (B,C,D)	NA		36	

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
204A(B)	RHR PUMP TEST LINE AND CONTAINMENT COOLING		HV51-225A(B)	180		29,36	51
205A(B)	SUPPRESSION POOL SPRAY		HV51-2F027A(B)	45	C,G	11	51
206A(B,C,D)	CS PUMP SUCTION		HV52-2F001A (B,C,D)	160		29,36	52
207A(B)	CS PUMP TEST AND FLUSH		HV52-2F015A(B)	23	C,G	36	52
208B	CS PUMP MINIMUM RECIRC		HV52-2F031B	45	LFCH	29,36	52
209	HPCI PUMP SUCTION		HV55-2F042	160	L,LA	36	55
210	HPCI TURBINE EXHAUST		HV55-2F072	N/A		29,36,37	55
212	HPCI PUMP TEST AND FLUSH		HV55-2F071	40	B,H	36	55
214	RCIC PUMP SUCTION		HV49-2F031	60		29,36	49
215	RCIC TURBINE EXHAUST		HV49-2F060	80		29,36	49
216	RCIC MINIMUM FLOW		HV49-2F019	8	LFRC	36	49

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
217	RCIC VACUUM PUMP DISCH	HV49-2F002		60		5,29	49
			49-2F028(CK)	NA			
218	INSTRUMENT GAS TO VACUUM RELIEF VALVES	59-2001(CK)		NA			59
			HV59-235	7	C,H,S		
219A	INSTRUMENTATION - SUPPRESSION POOL LEVEL	--	HV55-221	45		10	55
219B	INSTRUMENTATION - SUPPRESSION POOL LEVEL	--	HV55-220	45		10	55
220A	H2/02 SAMPLE RETURN	SV57-291(X-62)		5	B,H,R,S	11	57
			SV57-290(X-62)	5	B,H,R,S	11	
			HV57-216(X-62)	30**	B,H,R,S	11	
			SV57-250(X-62)	5	B,H,R,S	11	
			SV57-259(X-62)	5	B,H,R,S	11	
221A	WETWELL H2/02 SAMPLE	SV57-281		5	B,H,R,S	11	57
			SV57-241	5	B,H,R,S	11	
			SV57-284	5	B,H,R,S	11	
221B	WETWELL H2/02 SAMPLE	SV57-283		5	B,H,R,S	11	57
			SV57-286	5	B,H,R,S	11	

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
226A	RHR MINIMUM RECIRC		HV51-205A	40		29,36	51
226B	RHR MINIMUM RECIRC		HV51-205B	40		29,36	51
227	ILRT DATA ACQUISITION SYSTEM	60-2073	 60-2074	NA NA			60
228D	HPCI VACUUM RELIEF	HV55-2F095	 HV55-2F093	40 40	H,LA H,LA	4,11,24 11,24	55
229A	INSTRUMENTATION - SUPPRESSION POOL PRESSURE SUPPRESSION POOL LEVEL	--	SV57-201	5		10	57
230B	INSTRUMENTATION - DRYWELL SUMP LEVEL	--	HV61-212 HV61-232	45 45		23,29 23,29	61
231A	DRYWELL FLOOR DRAIN SUMP DISCHARGE	HV61-210	 HV61-211	30 30	B,H B,H	11,22 11,22	61
231B	DRYWELL EQUIPMENT DRAIN TANK DISCHARGE	HV61-230	 HV61-231	30 30	B,H B,H	11,22 11,22	61
235	CS PUMP MINIMUM RECIRC		HV52-2F031A	45	LFCH	29,36	52
236	HPCI PUMP MINIMUM RECIRC		HV55-2F012	15	LFHP	36	55

TABLE 3.6.3-1 (Continued)

PART A - PRIMARY CONTAINMENT ISOLATION VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
237-1	SUPPRESSION POOL CLEANUP PUMP SUCTION	HV52-227		60	B,H	4,11,22	52
			PSV52-227	NA		11,22	
			HV52-228	60	B,H	11,22	
237-2	SUPPRESSION POOL LEVEL INSTRUMENTATION		HV52-239	45		10	52
			SV52-239	6		10	
238	RHR RELIEF VALVE DISCHARGE		HV-C-51-2F104B	18	C,G		51
			PSV51-206B	NA		19	
239	RHR RELIEF VALVE DISCHARGE		HV-C-51-2F103A	18	C,G		51
			PSV51-206A	NA		19	
241	RCIC VACUUM RELIEF	HV49-2F084		40	H,KA	4,11,24	49
			HV49-2F080	40	H,KA	11,24	

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
003A-1	INSTRUMENTATION - 'D' MAIN STEAM LINE FLOW	–	XV41-2F070D XV41-2F073D			1	41
003A-2	INSTRUMENTATION - 'A' RECIRC PUMP SEAL PRESSURE	–	XV43-2F003A			1	43
003C-1	INSTR. - HPCI STEAM FLOW	–	XV55-2F024A			1	55
003C-2	INSTR. - HPCI STEAM FLOW	–	XV55-2F024C			1	55
003D-1	INSTR. - 'A' MAIN STEAM LINE FLOW	–	XV41-2F070A XV41-2F073A			1	41
007A(B,C,D)	INSTR. - 'A'(B,C,D) MAIN STEAM LINE PRESSURE	(HV41-2F022A(B, C,D) SEE PART A THIS TABLE)	(HV41-2F028A (B,C,D)	5* 5*	C,E,F,P,Q C,E,F,P,Q	6 6	41
020A-1	INSTR - RPV LEVEL	–	XV42-2F045B			1	42
020A-2	INSTR - 'B' LPCI DELTA P	–	XV51-202B			1	51
020A-3	INSTR - 'D' LPCI DELTA P	–	XV51-203B			1	51
020B-1	INSTR - RPV LEVEL	–	XV42-2F045C			1	42
020B-2	INSTR - 'C' LPCI DELTA P	–	XV51-202C			1	51

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
027B-1	INSTR - HPCI FLOW	--	XV55-2F024B			1	55
027B-2	INSTR - HPCI FLOW	--	XV55-2F024D			1	55
029A	INSTR - RPV FLANGE LEAKAGE	--	XV41-2F009			1,27	41
029B	INSTR - CS DELTA P	--	XV52-2F018A			1	52
030A	INSTR - 'D' MAIN STEAM FLOW	--	XV41-2F071D XV41-2F072D			1	41
030B-2	INSTR - 'C' MAIN STEAM LINE FLOW	--	XV41-2F071C XV41-2F072C			1	41
031A	INSTR - JET PUMP FLOW	--	XV42-2F059B (JP1) XV42-2F059D (JP2) XV42-2F059F (JP3)			1	42
031B	INSTR - JET PUMP FLOW	--	XV42-2F059H (JP4) XV42-2F051B (JP5) XV42-2F053B (JP5)			1	42

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
032A	INSTR - JET PUMP FLOW	–	XV42-2F059M (JP6) XV42-2F059P (JP7) XV42-2F059S (JP8)			1	42
032B	INSTR - JET PUMP FLOW	–	XV42-2F059U (JP9) XV42-2F051D (JP10) XV42-2F053D (JP10)			1	42
033A-1	INSTR-PRESSURE ABOVE CORE PLATE	–	XV42-2F055 XV42-2F076			1	42
033A-2	INSTR-PRESSURE BELOW CORE PLATE	–	XV42-2F061			1	42
033B	INSTR-RCIC STEAM FLOW	–	XV49-2F044A,C			1	49
034A	INSTR - 'C' MAIN STEAM LINE FLOW	–	XV41-2F070C XV41-2F073C			1	41
034B-1	INSTR - RECIRC FLOW	–	XV43-2F009C XV43-2F010D			1	43
034B-2	INSTR - RECIRC FLOW	–	XV43-2F009D XV43-2F010C			1	43

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
040A	INSTR - JET PUMP FLOW	–	XV42-2F059L (JP16) XV42-2F059N (JP17) XV42-2F059R (JP18)			1	42
040B	INSTR - JET PUMP FLOW	–	XV42-2F059G (JP14) XV42-2F051A (JP15) XV42-2F053A (JP15)			1	42
040C	INSTR - JET PUMP FLOW	–	XV42-2F059A (JP11) XV42-2F059C (JP12) XV42-2F059E (JP13)			1	42
040D-1	INSTR - PRESSURE BELOW CORE PLATE	–	XV42-2F057			1	42
040D-2	INSTR - RWCU BOTTOM DRAIN FLOW	–	XV44-270 XV44-271			1	44

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S) IF APP. (20)	NOTES	P&ID
040F-1	INSTR - RCIC STEAM FLOW	–	XV49-2F044B XV49-2F044D			1	49
040H-2	INSTR 'B' RECIRC PUMP COOLER FLOW	–	XV87-256B XV87-257B			17	87
041-1	INSTR - RWCU FLOW	–	XV44-202A,B			1	44
041-2	INSTR - 'A' LPCI DELTA P	–	XV51-203A			1	51
043A	INSTR - RECIRC LOOP 'A' DELTA P	–	XV43-2F040A,C			1	43
047	INSTR - RWCU FLOW	–	XV44-202D			1	44
048A-1	INSTR - RPV LEVEL	–	XV42-2F065B XV42-2F047B			1	42
048A-2	INSTR - CS DELTA P	–	XV52-2F018B			1	52
048B	INSTR - RPV LEVEL	–	XV42-2F065A XV42-2F047A			1	42
049A,B	INSTR - 'A' AND 'B' MAIN STEAM LINE FLOW	–	XV41-2F071A,B XV41-2F072A,B			1	41
050A-2	INSTR 'B' RECIRC FLOW	–	XV43-2F011A XV43-2F012B			1	43

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
050A-3	INSTR 'B' RECIRC FLOW	–	XV43-2F011B XV43-2F012A			1	43
050B-1	INSTR - 'A' RECIRC PUMP SEAL PRESSURE	–	XV43-2F004A			1	43
050B-2	INSTR - 'A' RECIRC PUMP COOLER FLOW	–	XV87-256A XV87-257A			17	87
051A-1	INSTR - 'A' RECIRC LINE FLOW	–	XV43-2F009A XV43-2F010B			1	43
051A-2	INSTR - 'A' RECIRC LINE FLOW	–	XV43-2F009B XV43-2F010A			1	43
051B	INSTR - JET PUMP FLOW	–	XV42-2F059T (JP19) XV42-2F051C (JP20) XV42-2F053C (JP20)			1	42
052A	INSTR - 'B' MAIN STEAM LINE FLOW	–	XV41-2F070B XV41-2F073B			1	41
052B-1	INSTR - 'B' RECIRC LINE FLOW	–	XV43-2F011C,D			1	43
052B-2	INSTR - 'B' RECIRC LINE FLOW	–	XV43-2F012C,D			1	43
057	INSTR - RWCU FLOW	–	XV44-202C			1	44

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLATION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
058A	INSTR - RECIRC LOOP 'B' DELTA P	--	XV43-2F040B			1	43
061-1	RECIRC PUMP SEAL PURGE	(43-2004A(CK)- See Part A of this table)	XV43-203A			15 1	43
061-2	RECIRC PUMP SEAL PURGE	(43-2004B(CK) See Part A of this table)	XV43-203B			15 1	43
063-1	INSTR - RECIRC LOOP 'B' DELTA P	--	XV43-2F040D			1	43
063-2	INSTR - 'B' RECIRC PUMP SEAL PRESSURE	--	XV43-2F004B XV43-2F003B			1	43
065A	INSTR - RPV PRESSURE	--	XV42-2F043B			1	42
065B	INSTR - RPV PRESSURE	--	XV42-2F049A			1	42
066A-1	INST-RPV LEVEL	--	XV42-2F045D			1	42
066A-2	INSTR - 'B' LPCI DELTA P	--	XV51-202D XV51-203D			1	51
066B-1	INST - RPV LEVEL	--	XV42-2F045A			1	42
066B-2	INST - 'A' LPCI DELTA P	--	XV51-202A XV51-203C			1	51
067A	INSTR - RPV PRESSURE	--	XV42-2F049B			1	42

TABLE 3.6.3-1 (Continued)

PART B - PRIMARY CONTAINMENT ISOLAION EXCESS FLOW CHECK VALVES

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
067B-1	INSTR - RPV PRESSURE	–	XV42-2F043A			1	42
067B-2	INSTR - RPV LEVEL	–	XV42-2F041			1	42
102A	INST - JET PUMP, REACTOR LEVEL	–	XV42-285A(JP15)			1	42
107	INST. - JET PUMP, REACTOR LEVEL	–	XV42-285B(JP5)			1	42

TABLE 3.6.3-1 (Continued)

PART C - PRIMARY CONTAINMENT PENETRATIONS (TYPE B)

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
NA	DRYWELL HEAD FLANGE	DOUBLE O-RING	--	--	--	2	60
001	EQUIPMENT ACCESS DOOR	DOUBLE O-RING	--	--	--	2	60
002	EQUIPMENT ACCESS DOOR AND PERSONNEL LOCK	DOUBLE O-RING	--	--	--	2,18	60
004	HEAD ACCESS MANHOLE	DOUBLE O-RING	--	--	--	2	60
006	CRD REMOVAL HATCH	DOUBLE O-RING	--	--	--	2	60
100A-D	NEUTRON MONITORING SYSTEM	CANISTER	--	--	--	8	60
101A-D	RECIRC PUMP POWER	CANISTER	--	--	--	8	60
103A,B	TEMPERATURE AND LOW LEVEL SIGNALS	CANISTER	--	--	--	8	60
104A-D	CRD POSITION INDICATOR	CANISTER	--	--	--	8	60
105A-E	MISCELLANEOUS LOW-VOLTAGE CONTROL POWER	CANISTER	--	--	--	8	60
106A-C	LOW-VOLTAGE CONTROL	CANISTER	--	--	--	8	60

TABLE 3.6.3-1 (Continued)

PART C - PRIMARY CONTAINMENT PENETRATIONS (TYPE B)

PENETRATION NUMBER	FUNCTION	INBOARD ISOLATION BARRIER	OUTBOARD ISOLATION BARRIER	MAX.ISOL. TIME.IF APP. (SEC)(26)	ISOL. SIGNAL(S), IF APP. (20)	NOTES	P&ID
200A,B	ACCESS HATCH	DOUBLE O-RING	--	--	--	2	60
222	INDICATION AND CONTROL	CANISTER	--	--	--	8	60
230A	STRAIN GAUGE INSTR.	CANISTER	--	--	--	8	60

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES

1. Instrumentation line isolation provisions consist of an orifice and excess flow-check valve or remote manual isolation valve. The excess flow-check valve is subjected to operability testing, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak tightness of the line is verified during the integrated leak rate test (Type A test).

2. Penetration is sealed by a blind flange or door with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings.

3. Inboard butterfly valve tested in the reverse direction.

4. Inboard gate valve tested in the reverse direction.

5. Inboard globe valve tested in the reverse direction.

6. The MSIVs and this penetration are tested by pressurizing between the valves. Testing of the inboard valve in the reverse direction tends to unseat the valve and is therefore conservative. The valves are Type C tested at a test pressure of 22 psig.

7. Gate valve tested in the reverse direction.

8. Electrical penetrations are tested by pressurizing between the seals.

9. The isolation provisions for this penetration consist of two isolation valves and a closed system outside containment. Because a water seal is maintained in these lines by the safeguard piping fill system, the inboard valve may be tested with water. The outboard valve will be pneumatically tested.

10. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leak tightness of the penetration is verified during the Type A test. Type C test is not required.

11. All isolation barriers are located outside containment.

12. Leakage monitoring of the control rod drive insert and withdraw line is provided by Type A leakage rate test. The outboard isolation provisions for the control rod insert and withdraw lines consist of two redundant Type C tested simple check valves located on each main water header (i.e. charging, cooling, drive and exhaust). Type C test is not required for the ball check valve.

13. The motor operators on HV-13-209 and HV-13-210 are not connected to any power supply.

14. Valve is provided with a separate testable seal assembly, with double concentric O-ring seals installed between the pipe flange and valve flange facing primary containment. Leakage through these seals is included within the Type C leakage rate for this penetration.

NOTES (Continued)

15. Check valve used instead of flow orifice.

16. Penetration is sealed by a flange with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings. Both the TIP Purge Supply (Penetration 35B) and the TIP Drive Tubes (Penetrations 35 C thru G) are welded to their respective flanges. Leakage through these seals is included in the Type C leakage rate total for this penetration. The ball valves (XV-241A thru E) are Type C tested. It is not practicable to leak test the shear valves (XV-240A thru E) because squib firing is required for closure. Shear valves (XV-240A thru E) are normally open.

17. Instrument line isolation provisions consist of an excess flow check valve. Because the instrument line is connected to a closed cooling water system inside containment, no flow orifice is provided. The excess flow check valves are subject to operability testing, but no Type C test is performed nor required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak tightness of the line is verified during the integrated leak rate test (Type A test).

18. In addition to double "O" ring seals, this penetration is tested by pressurizing volume between doors per Technical Specification 4.6.1.3.

19. The RHR system safety pressure relief valves are flanged to facilitate removal and are equipped with double O-ring seal assemblies on the flange closest to primary containment. These seals will be leak rate tested by pressurizing between the O-rings, and the results added into the Type C total for this penetration.

20. See Technical Specification 3.3.2, Table 3.3.2-1, for a description of the PCRVICS isolation signal(s) that initiate closure of each automatic isolation valve. In addition, the following non-PCRVICS isolation signals also initiate closure of selected valves:

    LFHP With HPCI pumps running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFRC With RCIC pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCH With CSS pump running, opens on low flow in associated pipe, closes when flow is above setpoint

    LFCC Steam supply valve fully closed or RCIC turbine stop valve fully closed

All power operated isolation valves may be opened or closed remote manually.

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES (Continued)

21. Automatic isolation signal causes TIP to retract; ball valve closes when probe is fully retracted.

22. Isolation barrier remains water filled or a water seal remains in the line post-LOCA. Isolation valve may be tested with water. Isolation valve leakage is not included in 0.60 La total Type B & C tests.

23. Valve does not receive an isolation signal. Valves will be open during Type A test. Type C test not required.

24. Both isolation signals required for valve closure.

25. Deleted

26. Valve stroke times listed are maximum times verified by testing per Technical Specification 4.0.5 acceptance criteria. The closure times for isolation valves in lines in which high-energy line breaks could occur are identified with a single asterisk. The closure times for isolation valves in lines which provide an open path from the containment to the environs are identified with a double asterisk.

27. The reactor vessel head seal leak detection line (penetration 29A) excess flow check valve is not subject to OPERABILITY testing. This valve will not be exposed to primary system pressure except under the unlikely conditions of a seal failure where it could be partially pressurized to reactor pressure. Any leakage path is restricted at the source; therefore, this valve need not be OPERABILITY tested.

28. (DELETED)

29. Valve may be open during normal operation; capable of manual isolation from control room. Position will be controlled procedurally.

30. Valve normally open, closes on scram signal.

31. Valve 41-2016 is an outboard isolation barrier for penetrations X-9A, B and X-44. Leakage through valve 41-2016 is included in the total for penetration X-44 only.

32. Feedwater long-path recirculation valves are sealed closed whenever the reactor is critical and reactor pressure is greater than 600 psig. The valves are expected to be opened only in the following instances:

    a. Flushing of the condensate and feedwater systems during plant startup.
    b. Reactor pressure vessel hydrostatic testing, which is conducted following each refueling outage prior to commencing plant startup.

    Therefore, valve stroke timing in accordance with Technical Specification 4.0.5 is not required.

33. Valve also constitutes a Unit 1 Reactor Enclosure Secondary Containment Automatic Isolation Valve and a Refueling Area Secondary Containment Automatic Isolation Valve.

34. Isolation signal causes recombiner to trip; valve closes when recombiner is not operating.

35. Auto isolation signals have been removed from HV-087-224 A/B and 225 A/B. Valves to be closed with associated circuit breakers locked open during OPCONs 1, 2, and 3 with the exception that valves may be open provided that the inboard PCIV for the associated penetration (HV-087-229, 223, 228 or 222) is closed and deactivated.

TABLE 3.6.3-1
PRIMARY CONTAINMENT ISOLATION VALVES
NOTATION

NOTES (Continued)

36. These valves are in lines that are below the minimum water level in the suppression pool, are part of closed systems outside primary containment, and are in portions of lines which a water seal will be present following an accident. Therefore, 10CFR50, Appendix J, Type C testing is not required.

37. This is a remote manual isolation valve. Valve stroke time does not provide an input to the Safety Analysis. Therefore, verification of isolation time is not required. Valve performance is monitored in accordance with Technical Specification 4.0.5.

TABLE 3.6.5.2.1-1

REACTOR ENCLOSURE SECONDARY CONTAINMENT VENTILATION SYSTEM
AUTOMATIC ISOLATION VALVES - SEPARATE ZONE SYSTEM ALIGNMENT

REACTOR ENCLOSURE (ZONE II)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS (a)
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U
7. Drywell Purge Exhaust Valve HV-76-030	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-031	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T

(a) See TS Specification 3.3.2, Table 3.3.2-1 for isolation signals that operate each automatic isolation valve.

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TABLE 3.6.5.2.2-1

REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM
AUTOMATIC ISOLATION VALVES - SEPARATE ZONE SYSTEM ALIGNMENT

REFUELING AREA (ZONE III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS (a)
1. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	R,T
2. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	R,T
3. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	R,T
4. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	R,T
5. Refueling Area Ventilation Supply Valve HV-76-217 (Unit 2)	5	R,T
6. Refueling Area Ventilation Supply Valve HV-76-218 (Unit 2)	5	R,T
7. Refueling Area Ventilation Exhaust Valve HV-76-267 (Unit 2)	5	R,T
8. Refueling Area Ventilation Exhaust Valve HV-76-268 (Unit 2)	5	R,T
9. Drywell Purge Exhaust Valve HV-76-030	5	B,H,S,U,R,T
10. Drywell Purge Exhaust Valve HV-76-031	5	B,H,S,U,R,T
11. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
12. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
13. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
14. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T

TABLE 3.6.5.2.2-1 (Continued)

REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM
AUTOMATIC ISOLATION VALVES - SEPARATE ZONE SYSTEM ALIGNMENT

REFUELING AREA (ZONE III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS (a)
15. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
16. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
17. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T
18. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T

(a) See TS Specification 3.3.2, Table 3.3.2-1 for isolation signals that operate each automatic isolation valve.

TABLE 3.6.5.2.3-1

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES - COMBINED ZONE SYSTEM ALIGNMENT

RX/REFUEL ENCL. (ZONE II & III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS (a)
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U,R,T
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U,R,T
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U,R,T
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U,R,T
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U,R,T
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U,R,T
7. Drywell Purge Exhaust Valve HV-76-030	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-031	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T
13. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	B,H,S,U,R,T
14. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	B,H,S,U,R,T
15. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	B,H,S,U,R,T
16. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	B,H,S,U,R,T

TABLE 3.6.5.2.3-1 (Continued)

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES - COMBINED ZONE SYSTEM ALIGNMENT

RX/REFUEL ENCL. (ZONE II & III Continued)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS (a)
17. Refueling Area Ventilation Supply Valve HV-76-217	5	B,H,S,U,R,T
18. Refueling Area Ventilation Supply Valve HV-76-218	5	B,H,S,U,R,T
19. Refueling Area Ventilation Exhaust Valve HV-76-267	5	B,H,S,U,R,T
20. Refueling Area Ventilation Exhaust Valve HV-76-268	5	B,H,S,U,R,T
21. Drywell Purge Exhaust Inboard Valve HV-57-214	5	B,H,S,U,W,R,T
22. Drywell Purge Exhaust Outboard Valve HV-57-215	6	B,H,S,U,W,R,T
23. Suppression Pool Purge Exhaust Inboard Valve HV-57-204	5	B,H,S,U,W,R,T
24. Suppression Pool Purge Exhaust Outboard Valve HV-57-212	6	B,H,S,U,W,R,T

(a) See TS Specification 3.3.2, Table 3.3.2-1 for isolation signals that operate each automatic isolation valve.

3/4.7.6 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 The fire suppression water system shall be OPERABLE with:

a. Two OPERABLE fire suppression pumps, one electric motor driven and one diesel engine driven, each with a capacity of 2500 gpm, with their discharge aligned to the fire suppression header,

b. Separate fire water supplies, each with a minimum contained volume of 311,000 gallons, and

c. An OPERABLE flow path capable of taking suction from the Unit 1 Cooling Tower Basin and the Unit 2 Cooling Tower Basin and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the last valve ahead of the water flow alarm device on each wet pipe sprinkler system and the last valve ahead of the deluge valve on each deluge, spray, or pre-action sprinkler system and the last valve ahead of the fire hose stations required to be OPERABLE per Specifications 3.7.6.2, 3.7.6.5, and 3.7.6.6.

APPLICABILITY: At all times.

ACTION:

a. With one pump and/or one water supply inoperable, restore the inoperable equipment to OPERABLE status within 7 days or provide an alternate backup pump or supply. The provisions of Specification 3.0.3 are not applicable.

b. With the fire suppression water system otherwise inoperable, establish a backup fire suppression water system within 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.6.1.1 The fire suppression water system shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying the minimum contained water supply volume.

b. At least once per 31 days by starting the electric motor-driven fire suppression pump and operating it for at least 15 minutes on recirculation flow.

c. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 12 months by performance of a system flush.

e. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

f. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence, and:

1. Verifying that each fire suppression pump develops at least 2500 gpm at a system head of 125 psig,

2. Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel, and

3. Verifying that each fire suppression pump starts to maintain the fire suppression water system pressure greater than or equal to 95 psig.

g. At least once per 3 years by performing a flow test of the system in accordance with Chapter 5, Section 11 of the Fire Protection Handbook, 14th Edition, published by the National Fire Protection Association.

4.7.6.1.2 The diesel-driven fire suppression pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the fuel day tank contains at least 330 gallons of fuel.

2. Starting the diesel-driven pump from ambient conditions and operating for greater than or equal to 30 minutes on recirculation flow.

b. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM-D270-75, is within the acceptable limits specified in Table 1 of ASTM D975-77 when checked for viscosity, water, and sediment.

c. At least once per 18 months by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.6.1.3 The diesel-driven fire pump starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The electrolyte level of each cell is above the plates,

2. The pilot cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.225, and

3. The overall battery voltage is greater than or equal to 24 volts.

b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that:

1. The batteries, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. Battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anticorrosion material.

PLANT SYSTEMS

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.2 The following spray and sprinkler systems shall be OPERABLE:

Fire Zone	Description
	Reactor Enclosure Hatchway Water Curtains:
	1. EL 253'
	2. EL 283'
	3. EL 313'
	Fire Area Separation Water Curtains:
71A	1. Area 638, EL 313'
68A	2. Area 475, EL 253'
67	3. Area 370, EL 217'
23	Cable Spreading Room, Room 450, EL 254'
27	Control Structure Fan Room, Room 619, EL 304'
27	CREFAS System Filters, EL 304'
28A	SGTS Access Area 625, EL 332'
28B	SGTS Filters, Compartment 624, EL 332'
56	RCIC Pump Room, Room 179, EL 177'
57	HPCI Pump Room, Room 180, EL 177'
64A	RECW Area 284, EL 201'
65	Safeguard System Access Area 279, EL 201'
67	Safeguard System Access Area 370, EL 217' (Partial) (3 systems)
68A	CRD Hydraulic Equipment Area 475, Reactor Enclosure, EL 253' (Partial) (3 systems)
70A	General Equipment Area 574 and Corridor 580, Reactor Enclosure, EL 283' (Partial)
74A & B	Reactor Enclosure Recirculation System Filters Areas 651 & 653, EL 331'
83,84,85,86	Diesel Generator cells (4 Cells)
2	13 kV Switchgear Area 336, EL 217', Control Structure (Partial)
7	Corridor 437, EL 239', Control Structure

APPLICABILITY: Whenever equipment protected by the spray and/or sprinkler systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required spray and/or sprinkler systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.2 Each of the above required spray and sprinkler systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months:

1. By performing a system functional test which includes simulated automatic actuation of the system, and:

a) Verifying that the automatic valves in the flow path actuate to their correct positions on a test signal, and

b) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

2. By a visual inspection of the dry pipe spray and sprinkler headers to verify their integrity, and

3. By a visual inspection of each sprinkler nozzle's spray area to verify that the spray pattern is not obstructed.

d. At least once per 3 years by performing an air or water flow test through each open head spray and sprinkler header system and verifying each open head spray nozzle and sprinkler header system is unobstructed, except the charcoal filter system spray nozzles which only need to be visually inspected and verified to be unobstructed each time the charcoal is changed.

PLANT SYSTEMS

CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.3 The following low pressure CO_2 system shall be OPERABLE:

a. Control Room Entrance, Hose Rack OHR601 and OHR602.

APPLICABILITY: Whenever equipment protected by the CO_2 system is required to be OPERABLE.

ACTION:

a. With the above required CO_2 system inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.3.1 The above required low pressure CO_2 system shall be demonstrated OPERABLE at least once per 7 days by verifying the CO_2 storage tank level to be greater than 25% and pressure to be greater than 265 psig.

4.7.6.3.2 The above required CO_2 system shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

HALON SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.4 The following Halon systems shall be OPERABLE with the storage tanks having at least 95% of full charge weight and 90% of full charge pressure:

a. Remote Shutdown Panel Area 540, EL 289' (Raised Floor), and

b. Auxiliary Equipment Room 542, EL 289' (Raised Floor).

APPLICABILITY: When equipment protected by the Halon systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required Halon systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.4 Each of the above required Halon systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

b. At least once per 6 months by verifying Halon storage tank weight and pressure.

c. At least once per 18 months by:

   1. Performance of a functional test of the general alarm circuit and associated alarm and interlock devices.

d. At least once per 24 months by:

   1. Performance of a system flow test to assure no blockage.

FIRE HOSE STATIONS

LIMITING CONDITION FOR OPERATION

3.7.6.5 The fire hose stations shown in Table 3.7.6.5-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the fire hose stations is required to be OPERABLE.

ACTION:

a. With one or more of the fire hose stations shown in Table 3.7.6.5-1 inoperable, provide gated wye(s) on the nearest OPERABLE hose station(s). One outlet of the wye shall be connected to the standard length of hose provided at the hose station. The second outlet of the wye shall be connected to a length of hose sufficient to provide coverage for the area left unprotected by the inoperable hose station. Where it can be demonstrated that the physical routing of the fire hose would result in a recognizable hazard to operating technicians, plant equipment, or the hose itself, the fire hose shall be stored in a roll at the outlet of the OPERABLE hose station. Signs shall be mounted above the gated wye(s) to identify the proper hose to use. The above ACTION shall be accomplished within 1 hour if the inoperable fire hose is the primary means of fire suppression; otherwise route the additional hose within 24 hours.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.5 Each of the fire hose stations shown in Table 3.7.6.5-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by a visual inspection of the fire hose stations accessible during plant operation to assure all required equipment is at the station.

b. At least once per 18 months by:

   1. Visual inspection of the fire hose stations not accessible during plant operation to assure all required equipment is at the station.

   2. Removing the hose for inspection and reracking, and

   3. Inspecting all gaskets and replacing any degraded gaskets in the couplings.

c. At least once per 3 years by:

   1. Partially opening each hose station valve to verify valve OPERABILITY and no flow blockage.

   2. Conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

TABLE 3.7.6.5-1

FIRE HOSE STATIONS

LOCATION		ELEVATION	HOSE RACK IDENTIFICATION
1.	Control Enclosure:		
	Stairwell	350'	1HR-141
	Stairwell, Outside SGTS Room	332'	1HR-140
	Stairwell, Outside Fan Room	304'	1HR-103
	Outside 13kV Switchgear Room	217'	2HR-116
	Stairwell, Outside Aux Equip Rm	289'	1HR-130
	Inverter Room Number 2-453	254'	2HR-250
	Wall, Outside 4kV Switchgear & Battery Rooms	239'	2HR-251
	Corridor 466, South Side of 4kV Switchgear & Battery Rooms	239'	2HR-122
	Wall, Corridor 277	200'	2HR-120
	Wall, Corridor 166	180'	2HR-121
2.	Refueling Area:		
	SE Corner Refuel Floor	352'	2HR-201
	NE Corner Refuel Floor	352'	2HR-202
	North Wall-Center	352'	2HR-203
	South Wall-Center	352'	2HR-204
3.	Reactor Enclosure Unit 2:		
	SE Corner Reactor Enclosure	331'	2HR-205
	SE Corner Reactor Enclosure (RERS Fan Area)	313'	2HR-207
	NE Corner Reactor Enclosure (Laydown Area 638)	313'	2HR-208
	SW Corner Reactor Enclosure (Near Refuel Floor Exh. Fans)	313'	2HR-209
	NW Corner Reactor Enclosure (Near Load Center)	313'	2HR-210
	SE Corner Reactor Enclosure (Corridor 580)	283'	2HR-215
	NE Corner Reactor Enclosure (Corridor 580)	283'	2HR-216

TABLE 3.7.6.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK IDENTIFICATION
3. Reactor Enclosure: (Continued)		
SW Corner Reactor Enclosure (SLC Pumps Area 574)	283'	2HR-217
NW Corner Reactor Enclosure	283'	2HR-218
SE Corner Reactor Enclosure (Area 475, Near CRD Maintenance Room)	253'	2HR-223
NE Corner Reactor Enclosure (Near Elev. & Stair No. 6)	253'	2HR-224
West Wall Reactor Enclosure (Near Unit 1/Unit 2 Airlock)	253'	2HR-225
West Wall Reactor Enclosure (Near Stair No. 2)	253'	2HR-226
SE Corner Reactor Enclosure (Near RCIC Equip Hatch)	217'	2HR-232
NE Corner Reactor Enclosure (Near Supp Pool Access Hatch)	217'	2HR-233
West Wall Reactor Enclosure (Near Personnel Airlock 366)	217'	2HR-234
NW Corner Reactor Enclosure (Near Stair No. 2)	217'	2HR-235
SE Corner Reactor Enclosure (Near Stair No. 5)	201'	2HR-240
NE Corner Reactor Enclosure (Near Elev. & Stair No. 6)	201'	2HR-241
West Wall Reactor Enclosure (Near RECW Heat Exchangers)	201'	2HR-242
NW Corner Reactor Enclosure (Near RECW Pumps)	201'	2HR-243
SE Corner Reactor Enclosure	177'	2HR-252
NE Corner Reactor Enclosure	177'	2HR-253
NW Corner Reactor Enclosure	177'	2HR-236

YARD FIRE HYDRANTS AND HOSE CART HOUSES

LIMITING CONDITION FOR OPERATION

3.7.6.6 The yard fire hydrants and hose cart houses shown in Table 3.7.6.6-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the yard fire hydrants is required to be OPERABLE.

ACTION:

a. With one or more of the yard fire hydrants or hose cart houses shown in Table 3.7.6.6-1 inoperable, within 1 hour have sufficient additional lengths of 2 1/2 inch diameter hose located in an adjacent OPERABLE hose cart house to provide service to the unprotected area(s) if the inoperable fire hydrant or hose cart house is the primary means of fire suppression; otherwise provide the additional hose within 24 hours.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.6 Each of the yard fire hydrants and hose cart houses shown in Table 3.7.6.6-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by visual inspection of the hose cart house to assure all required equipment is at the hose house.

b. At least once per 6 months, during March, April, or May and during September, October, or November, by visually inspecting each yard fire hydrant and verifying that the hydrant barrel is dry and that the hydrant is not damaged.

c. At least once per 12 months by:

   1. Conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

   2. Replacement of all degraded gaskets in couplings.

   3. Performing a flow check of each hydrant.

TABLE 3.7.6.6-1

YARD FIRE HYDRANTS AND HOSE CART HOUSES

LOCATION	HYDRANT NUMBER
East of Diesel Generator Enclosure	FH #9
South of Diesel Generator Enclosure	FH #8

LOCATION	HOSE CART HOUSE NUMBER
East of Diesel Generator Enclosure	HCH #5

3/4.7.7 FIRE RATED ASSEMBLIES

LIMITING CONDITION FOR OPERATION

3.7.7 All fire rated assemblies, including walls, floor/ceilings, cable tray enclosures and other fire barriers, separating safe shutdown fire areas or separating portions of redundant systems important to safe shutdown within a fire area, and all sealing devices in fire rated assembly penetrations, including fire doors, fire windows, fire dampers, cable, piping and ventilation duct penetration seals and ventilation seals, shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire rated assemblies and/or sealing devices inoperable, within 1 hour establish a continuous fire watch on at least one side of the affected assembly(s) and/or sealing device(s) or verify the OPERABILITY of fire detectors on at least one side of the inoperable assembly(s) and sealing device(s) and establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.7.1 Each of the above required fire rated assemblies and penetration sealing devices shall be verified OPERABLE at least once per 24 months by performing a visual inspection of:

a. The exposed surfaces of each fire rated assembly.

b. Each fire window, fire damper, and associated hardware.

c. At least 12.5% of each type of sealed penetration, except internal conduit seals. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 12.5% of each type of sealed penetration shall be made. This inspection process shall continue until a 12.5% sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration seal will be inspected at least once per 16 years.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.7.2 Each of the above required fire doors which are not electrically supervised shall be verified OPERABLE by inspecting the closing mechanism and latches at least once per 6 months, and by verifying:

a. That each locked-closed fire door is closed at least once per 7 days.

b. That each unlocked fire door without electrical supervision is closed at least once per 24 hours.

4.7.7.3 Each of the above required fire doors which are electrically supervised shall be verified OPERABLE:

a. By verifying that each lock-closed fire door is closed at least once per 7 days.

b. By verifying the OPERABILITY of the fire door supervision system for each electrically supervised fire door by performing a CHANNEL FUNCTIONAL TEST at least once per 31 days.

c. By inspecting the closing mechanism and latches at least once per 6 months.

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 Refer to Technical Specification Section 3.8.1.1 for the required Limiting Conditions for Operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION: Refer to Technical Specification Section 3.8.1.1 for the required Actions.

SURVEILLANCE REQUIREMENTS

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

e. At approved frequencies by:

1. Subjecting the diesel to an inspection utilizing procedures developed in accordance with the Limerick approved Performance Centered Maintenance template or equivalent for the Fairbanks Morse Opposed Piston Diesel Generators.

A.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 Refer to Technical Specification Section 3.8.1.2 for the required Limiting Conditions for Operation.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5, and *.

ACTION: Refer to Technical Specification Section 3.8.1.2 for the required Actions.

SURVEILLANCE REQUIREMENTS

4.8.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE per TRM Surveillance Requirement 4.8.1.1.2.e.1.

*When handling irradiated fuel in the secondary containment.

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall meet the following MAINTENANCE REQUIREMENTS:

a. Division 1, Consisting of:
   1. 125-Volt Battery 2A1 (2A1D101)
   2. 125-Volt Battery 2A2 (2A2D101)

b. Division 2, Consisting of:
   1. 125-Volt Battery 2B1 (2B1D101)
   2. 125-Volt Battery 2B2 (2B2D101)

c. Division 3, Consisting of:
   1. 125-Volt Battery 2C (2CD101)

d. Division 4, Consisting of:
   1. 125-Volt Battery 2D (2DD101)

ACTION:

Perform maintenance, if required, to restore battery per TRM MAINTENANCE REQUIREMENTS in TRM section 4.8.2.1. *For criterion in MR 4.8.2.1.b.1, if the identified damage or deterioration can be evaluated through an* engineering evaluation as not an impact to cell functionality, or has been previously evaluated, then no further actions are required.

MAINTENANCE REQUIREMENTS

4.8.2.1 Each of the required division batteries shall be demonstrated to meet the following MAINTENANCE REQUIREMENTS:

a. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 105 volts or battery overcharge with battery terminal voltage above 150 volts, by verifying that:

   1. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150×10^{-6} ohm, and

   2. Float voltage of each connected cell is $\geq$ 2.13 volts and electrolyte level > minimum level indication mark.

b. By verifying that:

   1. At least once per 18 months the cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,

   2. At least once per 18 months the cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material, and

   3. At least once per 18 months the resistance of each cell-to-cell and terminal connection is less than or equal to 150×10^{-6}ohm excluding cable intercell connections.

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ELECTRICAL POWER SYSTEMS

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.1 All primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be OPERABLE.

APPLICABILTY: OPERATIONAL CONDITIONS 1, 2, AND 3

ACTION:

a. With one or more of the above required containment penetration conductor overcurrent devices shown in Table 3.8.4.1-1 not OPERABLE:

   1. Restore the protective device(s) to OPERABLE status or deenergize the circuit(s) by tripping and locking, racking out, or removing the alternate device within 72 hours, and

   2. If unable to restore the protective device(s) to OPERABLE status within 72 hours, then:

      a. Declare the affected system or component inoperable, and

      b. Verify at least once per 7 days thereafter the alternate device is tripped and locked, racked out, or removed, or the inoperable device is racked out or removed.

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

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices which have the inoperable device racked out or removed or, which have the alternate device tripped, racked out, or removed.

SURVEILLANCE REQUIREMENTS

4.8.4.1 Each of the primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be demonstrated OPERABLE:

a. 4.16 KV circuit breakers

   1. Verify OPERABILITY every 60 months, with a maximum allowable extension not to exceed 25% of the specified interval, by selecting, on a rotating basis, approximately half of the breakers every refueling cycle and performing:

      a) A CHANNEL CALIBRATION of the associated protective relays, and

      b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed, and

      c) An inspection and preventive maintenance.

SURVEILLANCE REQUIREMENTS (Continued)

b. 480-Volt molded case breakers

   1. Verify OPERABILITY every 72 months, with a maximum allowable extension not to exceed 25% of the specified interval, by selecting, on a rotating basis, approximately 33% of the breakers every refueling cycle and performing:

      a) A functional test, and

      b) An inspection and preventive maintenance.

c. Circuit breakers found inoperable during testing shall be restored to an operable status prior to being returned to service and energizing the associated circuit.

TABLE 3.8.4.1-1

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

1. 4160-VOLT CIRCUIT BREAKERS

CIRCUIT BREAKER NO.	LOCATION	SYSTEMS OR EQUIPMENT POWERED
152-20101	20A201	2A Reactor Recirc Pump 'A' RPT Breaker
152-20102	20A201	2A Reactor Recirc Pump 'B' RPT Breaker
152-20201	20A202	2B Reactor Recirc Pump 'A' RPT Breaker
152-20202	20A202	2B Reactor Recirc Pump 'B' RPT Breaker

2. 480-VOLT MOLDED CASE BREAKERS*

*Primary and backup breakers have the same device numbers and are located in the same Motor Control Center cubicle.

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
52-21108	D214-R-G	IM HFB100 TM HFB100	2A1 Drywell Area Unit Cooler 2A1V212
52-21109	D214-R-G	IM HFB100 TM HFB100	2E1 Drywell Area Unit Cooler 2E1V212
52-21110	D214-R-G	IM HFB100 TM HFB100	2C1 Drywell Area Unit Cooler 2C1V212
52-21111	D214-R-G	IM HFB100 TM HFB100	2G1 Drywell Area Unit Cooler 2G1V212
52-21124	D214-R-G	IM HFB25 TM HFB100	RHR S/D Clg. Suction Inbrd Isol Vlv HV-51-2F009
52-21126	D214-R-G	TM HFB100 TM HFB100	RWCU Inbrd Isol Vlv HV-44-2F001
52-21138	D214-R-G	IM HFB25 TM HFB40	Mn Stm Line Drain Inbrd Isol Vlv HV-41-2F016
52-21141	D214-R-G	IM HFB25 TM HFB40	Inst Gas Compr Suct Line Inbrd Isol Vlv HV-59-201

TABLE 3.8.4.1-1
(Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
52-21208	D224-R-G	IM HFB100 TM HFB100	2B1 Drywell Area Unit Cooler 2B1V212
52-21209	D224-R-G	IM HFB100 TM HFB100	2F1 Drywell Area Unit Cooler 2F1V212
52-21210	D224-R-G	IM HFB100 TM HFB100	2D1 Drywell Area Unit Cooler 2D1V212
52-21211	D224-R-G	IM HFB100 TM HFB100	2H1 Drywell Area Unit Cooler 2H1V212
52-21216	D224-R-G	IM HFB25 TM HFB100	2B Reactor Recirc Pump Suction Vlv HV-43-2F023B
52-21309	D214-R-C	IM HFB50 TM HFB150	Feedwater Line 'A' Inbrd Maint Vlv HV-41-2F011A
52-21331	D214-R-C	TM HFB40 TM HFB40	RCIC Mn Stm Supply Inbrd Isol Vlv HV-49-2F007 Emergency Power
52-21707	D234-R-H	IM HFB100 TM HFB100	2C2 Drywell Area Unit Cooler 2C2V212
52-21708	D234-R-H	IM HFB100 TM HFB100	2G2 Drywell Area Unit Cooler 2G2V212
52-21807	D244-R-H	IM HFB100 TM HFB100	2D2 Drywell Area Unit Cooler 2D2V212
52-21808	D244-R-H	IM HFB100 TM HFB100	2F2 Drywell Area Unit Cooler 2F2V212
52-22310	D234-R-E	IM HFB100 TM HFB100	2A2 Drywell Area Unit Cooler 2A2V212
52-22311	D234-R-E	IM HFB100 TM HFB100	2E2 Drywell Area Unit Cooler 2E2V212
52-22313	D234-R-E	TM HFB40 TM HFB40	RCIC Mn Stm Supply Inbrd Isol Vlv HV-49-2F007
52-22314	D234-R-E	IM HFB50 TM HFB100	Feedwater Line 'B' Inbrd Maint Vlv HV-41-2F011B

TABLE 3.8.4.1-1
(Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
52-22410	D244-R-E	IM HFB100 TM HFB100	2B2 Drywell Area Unit Cooler 2B2V212
52-22411	D244-R-E	IM HFB100 TM HFB100	2H2 Drywell Area Unit Cooler 2H2V212
52-22418	D244-R-E	TM HFB100 TM HFB100	HPCI Mn Stm Supply Inbrd Isol Vlv HV-55-2F002
52-22516	214B-R-C	IM HFB25 TM HFB100	2A Reac Recirc Pump Suction VLV HV-43-2F023A
52-22518	214B-R-C	IM HFB25 TM HFB100	2A Reac Recirc Pump Discharge VLV HV-43-2F031A
52-22520	214B-R-C	IM HFB25 TM HFB40	Reactor Bottom Head Drain VLV HV-44-2F100
52-22536	214B-R-C	IM HFB25 TM HFB40	RWCU Flow Control Vlv HV-44-2F105
52-22534	214B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-2F001
52-22535	214B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-2F005
52-22537	214B-R-C	TM HFB15 TM HFB20	Disposal Cask Removal Cart Hoist 20H236
52-22538	214B-R-C	TM HFB15 TM HFB20	Control Rod Drive Platform Hoist 20H229
52-22608	224B-R-C	TM HFB25 TM HFB100	CRD Equipment Handling Platform 20N22608
52-22618	224B-R-C	IM HFB25 TM HFB100	2B Reac. Recirc. Pump Discharge VLV HV-43-2F031B
***52-22622	224B-R-C	TM HFB125	Permanent Plant In-Containment Welding System 20NW201

TABLE 3.8.4.1-1
(Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
*52-22626 2L36 (Main Breaker)	224B-R-C 2L36	TM HFB50 EB3090**	Unit 2 Reactor Enclosure Lighting XFMR 2X28
*52-22630	224B-R-C	TM HFB20 TM HFB20	2A Reac. Recirc. Pump Motor Hoist 2AH203
*52-22631	224B-R-C	TM HFB20 TM HFB20	2B Reac. Recirc. Pump Motor Hoist 2BH203
52-22634	224B-R-C	IM HFB25 TM HFB40	Reactor Vessel Head Vent HV-41-2F002
*52-22707	214C-R-A	TM HFB15 TM HFB15	Mn Stm Relief Vlv Removal Hoist 20H232
*52-22708	214C-R-A	TM HFB15 TM HFB15	Mn Stm Relief Vlv Removal Hoist 20H230

* These circuits are not normally required during reactor operations, and may be administratively maintained open, or verified operable and closed.

** 208 VAC circuit breaker

*** This breaker shall be administratively maintained open during reactor operations.

ABBREVIATIONS:

TM Thermal Magnetic
IM Instantaneous Magnetic

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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3/4.0 APPLICABILITY

BASES

The discussion in TS Bases Sections 3.0.1, 3.0.2, 3.0.3, 3.0.4, 4.0.1, 4.0.2, 4.0.3, and 4.0.4 are applicable to the TRM. Refer to the TS Section for the actual requirements.

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3/4.3.7 MONITORING INSTRUMENTATION

3/4 3.7.2 SEISMIC MONITORING INSTRUMENTATION

The OPERABILITY of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit. The information in this TRM Section is also contained in UFSAR Section 3.7.4.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

Hydrogen and Oxygen Monitors

The hydrogen and oxygen monitoring instrumentation are required to ensure that sufficient information is available to monitor and assess the degree of core damage during a beyond design basis accident (DBA) and confirm the status of the containment atmosphere. If an explosive mixture that could threaten containment integrity exists during a beyond DBA, then the hydrogen and oxygen monitors are needed to implement severe accident management strategies such as purging and /or venting.

However, both the drywell and suppression pool atmospheres are required to be capable of being monitored. The instrumentation must be maintained capable of diagnosing beyond DBAs shortly after an event and must be included within the Emergency and Operating procedures and the Maintenance program. Hydrogen and Oxygen Instrument OPERABILITY is demonstrated by routine CHANNEL CHECKS and periodic CHANNEL CALIBRATIONS. The information in this TRM section is also contained in UFSAR section 6.2.5.

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 (four of the five TIP detectors) ensures that the measurements obtained from use of this equipment accurately represent the spatial neutron flux distribution of the reactor core. The effect of having one TIP machine out of service is relatively small, because the 3D MONICORE methodology is not strongly dependent on incore data and is able to simulate the power distribution in the locations where data is missing. The overall nodal power uncertainty associated with one TIP machine out of service remains less than the 8.7% requirement for the basis of the MCPR Safety Limit.

The TIP system OPERABILITY is demonstrated by normalizing all OPERABLE probes (i.e., detectors) during the performance of a LPRM calibration procedure or when updating TIP data (OD-1). Monitoring core thermal limits may involve utilizing individual detectors to monitor selected areas of the reactor core, thus all detectors may not be required to be OPERABLE. The OPERABILITY of individual detectors to be used for monitoring is demonstrated by verifying expected performance during TIP operation.

3/4.3.7.9 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the detection instrumentation ensures that both adequate warning capability is available for prompt detection of fires and that fire suppression systems, that are actuated by fire detectors, will discharge extinguishing agent in a timely manner. Prompt detection and suppression of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program.

Fire detectors that are used to actuate fire suppression systems represent a more critically important component of a plant's fire protection program than detectors that are installed solely for early fire warning and notification. Consequently, the minimum number of OPERABLE fire detectors must be greater.

3/4.3.7.9 FIRE PROTECTION INSTRUMENTATION (Continued)

The loss of detection capability for fire suppression systems, actuated by fire detectors, represents a significant degradation of fire protection for any area. As a result, the establishment of a fire watch patrol must be initiated at an earlier stage than would be warranted for the loss of detectors that provide only early fire warning. The establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

The surveillance requirements for demonstrating the OPERABILITY of the fire detectors are based on the recommendations of NFPA 72E - 1990 Edition. The surveillance frequency for the fire detectors is determined by performance based evaluation.

Fire watch patrols should be scheduled to inspect designated areas within 1 hour of the previously documented inspection. TRM Section 4.0.2 permits a 15 minute (i.e., 25% grace) extension for this inspection time period to allow for minor variations in the inspection patrols.

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

This specification is provided to ensure that the turbine overspeed protection system instrumentation and the turbine speed control valves are OPERABLE and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety related components, equipment or structures. This information in this TRM Section is also contained in UFSAR Section 10.2.2.6.1.

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3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.2 OPERATIONAL LEAKAGE

Reactor Coolant System Pressure Isolation Valves

Reactor Coolant System (RCS) Pressure Isolation Valves (PIVs) are defined as any two normally closed valves in series within the Reactor Coolant Pressure Boundary (RCPB) that separate the high pressure RCS from an attached low pressure system. During normal and emergency conditions, it is necessary for PIVs to keep low pressure systems properly isolated in order to avoid damage by overpressurization, loss of integrity of the low pressure system and possible radioactive releases. PIV functions support compliance with General Design Criteria (GDC) 14, "RCPB;" GDC 15, "RCS Design;" and GDC 55, "RCPB Penetrating Containment." The ACTION requirements for PIVs are used in conjunction with the system specifications for which PIVs are listed in the TRM and with Primary Containment Isolation Valve requirements to ensure that plant operation is appropriately limited.

Surveillance Requirements for the RCS PIVs provide added assurance of valve integrity, thereby reducing the probability of gross failure and consequent intersystem LOCA. Leakage from the RCS PIVs is not included in any other allowable operational leakage specified in Section 3.4.3.2.

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3/4.4.4 CHEMISTRY

The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel. The effect of chloride is not as great when the oxygen concentration in the coolant is low, thus the 0.2 ppm limit on chlorides is permitted during POWER OPERATION. During shutdown and refueling operations, the temperature necessary for stress corrosion to occur is not present so a 0.5 ppm concentration of chlorides is not considered harmful during these periods.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. When the conductivity is within limits, chlorides and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

The surveillance requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

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3/4.5.4 LONG TERM GAS SUPPLY SYSTEM TO THE ADS VALVES

The long term gas supply system to the ADS valves is provided to assure that the reactor core can be adequately cooled by low pressure ECCS for the long term following a loss of coolant accident and to provide an alternate method of decay heat removal following a loss of RHR shutdown cooling event. Each long term gas supply bottle bank contains an adequate gas volume to assure that the required ADS valves can be actuated 100 times during a seven day period, when the sum of individual bottle pressures in the bottle bank is ≥ 2400 psig. The minimum required pressure of 800 psig per bottle ensures that the 2400 psig limit is maintained with the three bottles in the bank and that depleting bottles are replaced in a timely manner. An external connection is provided on each subsystem to allow for continuing to supply gas to the ADS valves beyond the initial seven days. The functional test of the swap over ensures that the flow path to the ADS valves is OPERABLE.

With one subsystem inoperable, the redundant subsystem will provide the required volume for long term actuation of the ADS valves for the initial seven days. With both subsystems inoperable, the external connections are available to facilitate the connection of an alternate gas supply for operation for the initial seven days and beyond.

The low pressure instrumentation on the long term gas supply header provides indication that the gas supply header is below the normal system operating pressure. With the low pressure instrumentation inoperable, direct pressure measurement will ensure that the required gas supply is maintained above the minimum required valve actuation pressure of 25 psi above atmosphere. The surveillance requirements provide adequate assurance that the long term gas supply system will be OPERABLE when required.

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3/4 7.6 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located. The fire suppression system consists of the water system, spray and/or sprinkler systems, CO_2 systems, Halon systems, and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety-related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

The surveillance requirements provide assurances that the minimum OPERABILITY requirements of the fire suppression systems are met. An allowance is made for ensuring a sufficient volume of Halon in the Halon storage tanks by verifying the weight and pressure of the tanks.

Each of the Halon systems consists of two bottles or two banks of bottles. Each bottle or bank has sufficient capacity to meet design requirements (20% concentration for 20 minutes). A manual selector switch (main or reserve) is used to designate which bank will discharge automatically.

The Halon systems for the Remote Shutdown Panel Area and for the Aux. Equipment Room are considered operable with one of the two banks/bottles operable and lined up for automatic injection.

When maintenance is required on one of the redundant trains, that train may be taken out of service by appropriate positioning of the selector switch. If there is an inadvertent operation of one of the redundant trains, the system may be considered operable if the reserve train is functional.

The source of water for the fire protection system is two cooling tower basins that have a capacity of 7,200,000 gallons each, for a total capacity of 14,400,000 gallons. For a system pumping capacity of 5000 gpm, this allows continuous operation of both fire pumps for 48 hours. If one cooling tower basin or supply line is not available, the remaining water source provides both fire pumps with a 24-hour supply of water. Water for the fire pumps is taken from either Unit 1 or Unit 2 cooling tower water basins through connections to the circulating water lines. One cooling tower will be out of service for up to 30 days each refueling outage on each unit, to remove the accumulated mud deposits.

The minimum contained volume is 311,000 gallons. CMEB BTP 9.5-1 requires 500 gpm for manual hose streams plus the largest design demand of any sprinkler or deluge system for a period of 2 hours in a safety related area or a minimum of 300,000 gallons.

The minimum fuel supply of 330 gallons for the diesel driven fire pump is based on providing fuel for 24 hours of full load operation.

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant.

The following provides clarification of what action is to be taken for each possible scenario of operability of the fire pumps and their associated water sources.

3/4 7.6 FIRE SUPPRESSION SYSTEMS (Continued)

Action a states that "With one fire pump and/or one water supply inoperable, restore the inoperable equipment to operable status within 7 days or provide an alternate pump or supply. The provisions of TRM Section 3.0.3 are not applicable." With the Diesel Driven Fire Pump (00-P511) or the Motor Driven Fire Pump (00-P512) or one of the cooling tower water supplies inoperable Action a is met by placing the Backup Diesel Driven Fire Pump (10-P402) and its water supply (10-T402) in service within 7 days.

Should the backup fire system be unavailable, then another alternate pump or supply would need to be provided in order to meet the requirements of Action a. Failure to do so within 7 days would impose no further TRM action because the requirements of 3.0.3 are not applicable to Action a. However, a CR would be required for non-compliance with TRM Action a.

If the backup fire system is placed in service to comply with Action a and it subsequently becomes inoperable, then the backup fire system must be returned or an alternate pump and supply must be placed in service within 7 days or a CR would be required for non-compliance with TRM Action a. The loss of the backup fire system, while in Action a does not make the fire suppression water system "otherwise inoperable" as referred to in Action b which states "With the fire suppression water system otherwise inoperable establish a backup fire suppression water system within 24 hours." However, compliance with Action a is no longer being met. In this case, compliance with Action a should be achieved within 7 days. Again, failure to comply would not require additional actions even if the 7 day allowance were to be exceeded because the requirements of 3.0.3 are not applicable. A CR would be required as addressed above.

Action b states that "With the fire suppression water system otherwise inoperable establish a backup fire suppression water system within 24 hours." Action a defines the requirements when one primary pump and/or one primary water supply is inoperable. Action b defines the requirements when the fire suppression water system is "otherwise inoperable." "Otherwise inoperable" is therefore a condition other than one pump and/or one water supply which necessitates the following definition. "Otherwise inoperable" is a condition where two primary pumps (00P511 & 00P512) and/or two water supplies are inoperable. The provisions of TRM Section 3.0.3 do apply to Action b, therefore, if the primary fire suppression water system is unable to provide any water for fire suppression then a backup fire system must be put in service within 24 hours or both units would be required to commence shutdown in accordance with the requirements of 3.0.3. A 24 hour notification to the NRC and a 30 day report is required per License Conditions 2.C.3 and 2.E.

The following chart summarizes and addresses all the various combinations of fire pump and water supply inoperability with the corresponding TRM requirements. If while in Action a the backup fire system fails, then within 7 days it must be restored or an alternate put in service or a CR must be generated. Do not enter Action b unless none of the primary means can supply water.

ACTION A: Place a backup fire suppression system (ie. FWST and BUFP) in service within 7 days or generate a PEP. (A symbol indicates operable.)

1		M	D
	2	M	D
1	2		D
1	2	M	
1		M	
1			D
	2	M	
	2		D

ACTION B: Place a backup fire suppression system (ie. FWST and BUFP) in service within 24 hours or commence shutdown of operating units. (A symbol indicates operable.)

		M	D
		M	
			D
1	2		
	2		
1			

KEY:

1 = UNIT 1 COOLING TOWER

2 = UNIT 2 COOLING TOWER

M = MOTOR DRIVEN FIRE PUMP (00-P512)

D = DIESEL DRIVEN FIRE PUMP (00-P511)

FWST = FIRE WATER STORAGE TANK (10-T402)
BUFP = BACKUP DIESEL DRIVEN FIRE PUMP (10-P402)

3/4 7.6 FIRE SUPPRESSION SYSTEMS (Continued)

Fire watch patrols should be scheduled to inspect designated areas within 1 hour of the previously documented inspection. TRM Section 4.0.2 permits a 15 minute (i.e., 25% grace) extension for this inspection time period to allow for minor variations in the inspection patrols.

3/4.7.7 FIRE RATED ASSEMBLIES

The OPERABILITY of the fire barriers and barrier penetrations ensure that fire damage will be limited. These design features minimize the possibility of a single fire involving more than one fire area prior to detection and extinguishment. The fire barriers, fire barrier penetrations for conduits, cable trays and piping, fire windows, fire dampers, and fire doors are periodically inspected to verify their OPERABILITY.

Fire watch patrols should be scheduled to inspect designated areas within 1 hour of the previously documented inspection. TRM Section 4.0.2 permits a 15 minute (i.e., 25% grace) extension for this inspection time period to allow for minor variations in the inspection patrols.

3/4.8.2 D.C. SOURCES

The CONDITION FOR OPERATION for the DC Sources as noted describes requirements to perform preventive maintenance activities on the listed safeguard batteries as noted in TSTF-360 (Tech Spec Task Force) and to relocate those requirements in licensee-controlled programs, in this case being the TRM. These requirements are based on recommendations of IEEE Standard 450-1995. The license amendment request states that failure to meet the requirements relocated to the TRM does not necessarily mean that the equipment is not capable of performing its safety function, and the corrective action is generally a routine or preventative maintenance activity. Operability determinations of equipment identified in the TRM section should be determined by compliance with the current Technical Specification Requirements for DC Sources. Since there is no limit on the CONDITION FOR OPERATION, this terminology was used. In addition, since the maintenance activities are not surveillance requirements, they have been renamed MAINTENANCE REQUIREMENTS that denote maintenance activities governed by the TRM. Failure to meet the MAINTENANCE REQUIREMENTS does not affect the Technical Specification LCO nor does non-compliance render any equipment inoperable. Failure to meet the MAINTENANCE REQUIREMENTS may be indicative of potential degrading performance.

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3/4.8.4 PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

The overcurrent protective devices (e.g., circuit breakers) for primary containment electrical penetration conductors, which are design requirements to satisfy compliance with Regulatory Guide 1.63, are listed in Table 3.8.4.1-1. Circuits which are not normally required (e.g., drywell lighting, maintenance hoists, and welding outlets) during reactor operations (i.e., power operations, start up or hot shutdown) are identified in Table 3.8.4.1-1 and may be administratively maintained open during reactor operations, in lieu of demonstrating those breakers operable. The remaining breakers in Table 3.8.4.1-1 shall be OPERABLE during reactor operations or the associated circuit de-energized.

To provide assurance of breaker reliability, OPERABILTY is demonstrated by performing a calibration check of protective relays (4-KV breakers only), a breaker functional test, and an inspection and preventive maintenance in accordance with procedures prepared in conjunction with the manufacturer's recommendations. The OPERABILITY of both the primary and backup overcurrent protective circuit breakers shall be routinely demonstrated for those circuits which are normally required during reactor operations. Circuits not normally required during reactor operations, such as drywell lights, which may on occasion be needed, shall have breaker(s) operability demonstrated prior to energizing the associated circuit.

480-Volt molded case circuit breakers are functionally tested by injecting a current with a value equal to 300% of the pickup value of the time delay trip element (not applicable to instantaneous magnetic only breakers) and verifying that the circuit breaker operates within the time delay bandwidth for that current specified by the manufacturer. The instantaneous element is tested by injecting a current equal to -20%/+40% of the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay.

The backup overcurrent protective device for the drywell lighting circuit (Breaker No. 1-L36) is a 208 VAC circuit breaker, located on the secondary side of the 1-X028 lighting transformer. The manufacturer does not recommend any routine inspection, testing, or preventive maintenance for this type circuit breaker used in this application.

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SECTION 6.0

ADMINISTRATIVE CONTROLS

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6.2.2 UNIT STAFF

e. A site fire brigade of at least five members shall be maintained on site at all times*. The fire brigade shall not include the Shift Manager, the Shift Technical Advisor, nor the two other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency.

* The fire brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required positions.

CORE OPERATING LIMITS REPORT

FOR

LIMERICK GENERATING STATION UNIT 2

RELOAD 10, CYCLE 11

(This is a complete rewrite)

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Station Qualified Reviewed By: RC Potter Date: 3/22/09
Robert Potter
Station Qualified Reviewer

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List of Tables

1.0 Terms And Definitions

ARTS	APRM, RBM, and Technical Specification Improvement Program
BASE CASE	A case analyzed with Turbine Bypass System in service and Recirculation Pump Trip in service and Feedwater Temperature Reduction allowed (FFWTR includes feedwater heater OOS or final feedwater temperature reduction) at any point during the cycle in Dual Loop mode.
DTSP	Rod Block Monitor Downscale Trip Setpoint
EOOS	Equipment Out of Service
EOR	End of Rated, the cycle exposure at which reactor power is equal to 3458 MWth with recirculation system flow equal to 100%, all control rods fully withdrawn, all feedwater heating in service and equilibrium Xenon.
FFWTR	Final Feedwater Temperature Reduction
FWHOOS	Feedwater Heaters Out of Service
HTSP	Rod Block Monitor High Trip Setpoint
ICF	Increased Core Flow
ITSP	Rod Block Monitor Intermediate Trip Setpoint
LHGR	Linear Heat Generation Rate
LHGRFAC(F)	ARTS LHGR thermal limit flow dependent multipliers
LHGRFAC(P)	ARTS LHGR thermal limit power dependent multipliers
LTSP	Rod Block Monitor Low Trip Setpoint
MAPLHGR	Maximum Average Planar Linear Heat Generation Rate
MCPR	Minimum Critical Power Ratio
MCPR(F)	ARTS MCPR flow dependent thermal limit
MCPR(P)	ARTS MCPR power dependent thermal limit
MELLLA	Maximum Extended Load Line Limit Analysis
OLMCPR	Operating Limit Minimum Critical Power Ratio
OPRM PBDA	Oscillation Power Range Monitor Period Based Detection Algorithm
RPTIS	Recirculation Pump Trip In Service

RPTOOS	Recirculation Pump Trip Out of Service
SLMCPR	Safety Limit Minimum Critical Power Ratio
SLO	Single Loop Operation
TBVIS	Turbine Bypass Valves In Service
TBVOOS	Turbine Bypass Valves Out of Service

2.0 General Information

This report provides the following cycle-specific parameter limits for Limerick Generating Station Unit 2 Cycle 11:

- Maximum Average Planar Linear Heat Generation Rate (MAPLHGR)
- Minimum Critical Power Ratio (MCPR)
- Single Loop Operation (SLO) MCPR adjustment
- ARTS MCPR thermal limit adjustments and multipliers (MCPR(P) or MCPR(F))
- ARTS LHGR thermal limit multipliers (LHGRFAC(P) or LHGRFAC(F))
- Rod Block Monitor (RBM) setpoints
- MAPLHGR single loop operation reduction factor
- LHGR single loop operation reduction factor
- Linear Heat Generation Rate (LHGR)
- Turbine Bypass Valve parameters
- Reactor Coolant System Recirculation Flow Upscale Trips
- Oscillation Power Range Monitor Period Based Detection Algorithm Trip Setpoints

These values have been determined using NRC-approved methodology (Reference 6), and are established such that all applicable limits of the plant safety analysis are met.

This report is prepared in accordance with Technical Specification 6.9.1.9 of Reference 1. Preparation of this report was performed in accordance with Exelon Nuclear, Nuclear Fuels T&RM NF-AB-120-3600.

The data presented in this report is valid for all licensed operating domains on the operating map, including:

- Maximum Extended Load Line Limit down to 81% of rated core flow during full power operation
- Increased Core Flow (ICF) up to 110% of rated core flow
- Final Feedwater Temperature Reduction (FFWTR) up to 105°F during cycle extension operation
- Feedwater Heater Out of Service (FWHOOS) up to 60°F feedwater temperature reduction at any time during the cycle prior to cycle extension.

Further information on the cycle specific analyses for Limerick 2 Cycle 11 and the associated operating domains discussed above is available in Reference 2.

3.0 MAPLHGR Limits

3.1 Technical Specification

Section 3.2.1

3.2 Description

The limiting MAPLHGR value for the most limiting lattice (excluding natural uranium) of each fuel type as a function of average planar exposure is given in Table 3-1 (Reference 2). The limiting MAPLHGR value is the same for all fuel types in the Limerick Unit 2 Cycle 11 core. For single loop operation, a reduction factor is used which is shown in Table 3-2 (Reference 2). MAPFAC(P) and MAPFAC(F) are 1.0 for all power and flow conditions. The power and flow dependent multipliers for MAPLHGR have been removed and replaced with LHGRFAC(P) and LHGRFAC(F) (See Reference 3). LHGRFAC(P) and LHGRFAC(F) are addressed in Section 5.0.

TABLE 3-1
MAPLHGR Versus Average Planar Exposure
All Fuel Types
(Reference 2)

Average Planar Exposure (GWD/ST)	MAPLHGR Limit (kW/ft)
0.0	12.82
14.51	12.82
19.13	12.82
57.61	8.00
63.50	5.00

TABLE 3-2
MAPLHGR Single Loop Operation (SLO) Reduction Factor
(Reference 2)

SLO Reduction Factor	**0.80**

4.0 MCPR Limits

4.1 Technical Specification

Section 3.2.3

4.2 Description

Table 4-1 is derived from the Reference 2 analyses and is valid for all Cycle 11 fuel types and operating domains. Table 4-1 includes treatment of these MCPR limits for SLO. Bounding MCPR values are also provided for RPTOOS or TBVOOS. These two options represent the Equipment Out of Service conditions. The cycle exposure that represents EOR is given in the latest verified and approved Cycle Management Report or an associated Engineering Change Request.

ARTS provides for power and flow dependent thermal limit adjustments and multipliers, which allow for a more reliable administration of the MCPR thermal limit. The flow-dependent adjustment MCPR(F) is sufficiently generic to apply to all fuel types and operating domains (Reference 2). In addition, there are four sets of power-dependent MCPR multipliers for use with the TBVIS, TBVOOS, RPTIS and RPTOOS conditions (References 2, 3 and 9). Section 7.0 contains the conditions for Turbine Bypass Valve Operability. These adjustments are provided in Table 4-2 and 4-3. The OLMCPR is determined for a given power and flow condition by evaluating the power-dependent MCPR and the flow-dependent MCPR and selecting the greater of the two. The MCPR(P) values are independent of recirculation pump trip operability (Reference 3).

TABLE 4-1
Operating Limit Minimum Critical Power Ratio (OLMCPR)[1]
(Reference 2)

EOOS Combination	SCRAM Time Option[2]	Cycle Exposure < EOR – 2700 MWd/ST	Cycle Exposure ≥ EOR – 2700 MWd/ST
BASE	B	1.34	1.39
	A	1.37	1.42
BASE SLO	B	1.44[(3)]	1.44[(3)]
	A	1.44[(3)]	1.44
TBVOOS	B	1.37	1.43
	A	1.40	1.46
TBVOOS SLO	B	1.44[(3)]	1.45
	A	1.44[(3)]	1.48
RPTOOS	B	1.40	1.47
	A	1.51	1.64
RPTOOS SLO	B	1.44[(3)]	1.49
	A	1.53	1.66

[1] This table is valid for all Cycle 11 fuel types.
[2] When Tau does not equal 0 or 1, determine OLMCPR via linear interpolation.
[3] OLMCPR limit set by the Single Loop Operation Recirculation Pump Seizure (Reference 2)

TABLE 4-2
Power Dependent MCPR Limit Adjustments And Multipliers
(References 2, 3 and 9)

EOOS Combination	Core Flow (% of rated)	Core Thermal Power (% of Rated) 0	25	< 30	≥ 30	45	60	100
		MCPR(P)			Operating Limit MCPR Multiplier, Kp			
Base	≤ 60	2.66	2.66	2.44	1.481	1.280	1.150	1.000
	> 60	3.39	3.39	2.93				
Base SLO	≤ 60	2.68	2.68	2.46	1.481	1.280	1.150	1.000
	> 60	3.41	3.41	2.95				
RPTOOS	≤ 60	2.66	2.66	2.44	1.481	1.280	1.150	1.000
	> 60	3.39	3.39	2.93				
RPTOOS SLO	≤ 60	2.68	2.68	2.46	1.481	1.280	1.150	1.000
	> 60	3.41	3.41	2.95				
TBVOOS	≤ 60	3.07	3.07	2.63	1.481	1.280	1.150	1.000
	> 60	4.54	4.54	3.77				
TBVOOS SLO	≤ 60	3.09	3.09	2.65	1.481	1.280	1.150	1.000
	> 60	4.56	4.56	3.79				

TABLE 4-3
Flow Dependent MCPR Limits MCPR(F)
(Reference 2)

Flow (% rated)	MCPR(F) Limit
30.0	1.53
79.0	1.25
110.0	1.25

5.0 Linear Heat Generation Rate Limits

5.1 Technical Specification

Section 3.2.4

5.2 Description

The LHGR is an exposure dependent value. Due to the proprietary nature of these values only the maximum UO_2 LHGR for each fuel type is listed in Table 5-1. For single loop operation, a reduction factor is used which is shown in Table 5-2 (Reference 2).

ARTS provides for power- and flow-dependent thermal limit multipliers, which allow for a more reliable administration of the LHGR thermal limits. There are two sets of flow-dependent LGHR multipliers for dual-loop and single-loop operation (References 2 and 5). In addition, there are four sets of power-dependent LHGR multipliers for use with the TBVIS, TBVOOS, RPTIS and RPTOOS conditions (References 2, 3 and 9). Section 7.0 contains the conditions for Turbine Bypass Valve Operability. The LHGR multipliers are shown in Tables 5-3 through 5-4.

Thermal limit monitoring must be performed with the more limiting LHGR limit resulting from the power- and flow-biased calculation. The LHGRFAC(P) values are independent of recirculation pump trip operability (Reference 3).

TABLE 5-1
Linear Heat Generation Rate Limits
(Reference 8)

FUEL TYPE	MAXIMUM VALUE
GE14	13.4 kW/ft

TABLE 5-2
LHGR Single Loop Operation (SLO) Reduction Factor
(Reference 2)

SLO Reduction Factor[1]	0.80

[1] Applied through Table 5-4

TABLE 5-3
Power Dependent LHGR Multiplier LHGRFAC(P)
(References 2, 3 and 9)

<table>
<tr><th rowspan="3">EOOS Combination</th><th rowspan="3">Core Flow (% of rated)</th><th colspan="5">Core Thermal Power (% of rated)</th></tr>
<tr><th>0</th><th>25</th><th>< 30</th><th>≥ 30</th><th>100</th></tr>
<tr><th colspan="5">LHGRFAC(P) Multiplier</th></tr>
<tr><td rowspan="2">Base</td><td>≤ 60</td><td>0.485</td><td>0.485</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.434</td><td>0.434</td><td>0.473</td></tr>
<tr><td rowspan="2">Base SLO</td><td>≤ 60</td><td>0.485</td><td>0.485</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.434</td><td>0.434</td><td>0.473</td></tr>
<tr><td rowspan="2">RPTOOS</td><td>≤ 60</td><td>0.485</td><td>0.485</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.434</td><td>0.434</td><td>0.473</td></tr>
<tr><td rowspan="2">RPTOOS SLO</td><td>≤ 60</td><td>0.485</td><td>0.485</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.434</td><td>0.434</td><td>0.473</td></tr>
<tr><td rowspan="2">TBVOOS</td><td>≤ 60</td><td>0.463</td><td>0.463</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.352</td><td>0.352</td><td>0.386</td></tr>
<tr><td rowspan="2">TBVOOS SLO</td><td>≤ 60</td><td>0.463</td><td>0.463</td><td>0.490</td><td rowspan="2">0.634</td><td rowspan="2">1.000</td></tr>
<tr><td>> 60</td><td>0.352</td><td>0.352</td><td>0.386</td></tr>
</table>

TABLE 5-4
Flow Dependent LHGR Multiplier LHGRFAC(F)
(References 2, 3 and 5)

EOOS Combination	Core Flow (% of rated)				
	0	44.07	70	80	110
	LHGRFAC(F) Multiplier				
Dual Loop	0.5055		0.9732	1.00	1.00
Single Loop	0.5055	0.80	0.80	0.80	0.80

6.0 Control Rod Block Setpoints

6.1 Technical Specification

Section 3.3.6

6.2 Description

Technical Specification 3.3.6 states control rod block instrumentation channels shall be OPERABLE with their trip setpoints consistent with the values shown in the Trip Setpoint column of Technical Specification Table 3.3.6-2. The Reactor Coolant System Recirculation Flow Upscale Trip is a cycle-specific value and as such is found in Table 6-2 of this COLR. Table 6-2 lists the Nominal Trip Setpoint and Allowable Value. These setpoints are set high enough to allow full utilization of the enhanced ICF domain up to 110% of rated core flow. Additionally, the ARTS Rod Block Monitor provides for power-dependent RBM trips. The trip setpoints/allowable values and applicable RBM signal filter time constant data are shown in Table 6-1. These values are for use with Technical Specification 3.3.6.

TABLE 6-1
Rod Block Monitor Setpoints[1]
(References 2 and 7)

	Nominal Trip Setpoint	Allowable Value
LTSP	121.5%	121.5%
ITSP	116.5%	116.5%
HTSP	111.0%	111.7%
DTSP	5.0%	2.0%

TABLE 6-2
Reactor Coolant System Recirculation Flow Upscale Trip
(Reference 7)

Nominal Trip Setpoint	113.4%
Allowable Value	115.6%

[1] These setpoints (with Rod Block Monitor filter time constant between 0.1 seconds and 0.55 seconds) are based on a cycle-specific rated RWE MCPR limit of 1.30, which is less than or equal to the minimum cycle OLMCPR (see COLR References 2 and 7).

7.0 Turbine Bypass Valve Parameters

7.1 Technical Specification

Section 3.7.8 and 4.7.8.C

7.2 Description

The operability requirements for the steam bypass system for use in Technical Specifications 3.7.8 and 4.7.8.C are found in Tables 7-1 and 7-2. If these requirements cannot be met, the MCPR, MCPR(P) and LHGRFAC(P) limits for inoperable Steam Bypass System, known as Turbine Bypass Valve Out Of Service, must be used.

TABLE 7-1
Turbine Bypass System Response Time
(Reference 4)

Maximum delay time before start of bypass valve opening following generation of the turbine bypass valve flow signal	0.11 sec
Maximum time after generation of a turbine bypass valve flow signal for bypass valve position to reach 80% of full flow (includes the above delay time)	0.31 sec

TABLE 7-2
Minimum Required Bypass Valves To Maintain System Operability
(Reference 4)

Reactor Power	No. of Valves in Service
$P \geq 25\%$	7

8.0 Stability Protection Setpoints

8.1 Technical Specification

Section 2.2.1.2.F

8.2 Description

The Limerick 2 Cycle 11 OPRM Period Based Detection Algorithm (PBDA) Trip Setpoints for the OPRM System for use in Technical Specification 2.2.1 are found in Table 8-1. These values are based on the cycle specific analysis documented in Reference 2. The setpoints provided in Table 8-1 are bounding for all modes of operation shown in Table 9-1.

TABLE 8-1
OPRM PBDA Trip Setpoints[1]
(Reference 2)

PBDA Trip Amplitude	Corresponding Maximum Confirmation Count Trip Setting
≤ 1.14	≤ 16

9.0 Modes Of Operation

TABLE 9-1
Modes Of Operation
(References 2, 3 and 5)

EOOS Options	Operating Region[2]
Base, Option A or B	Yes
Base SLO, Option A or B	Yes
TBVOOS, Option A or B	Yes
TBVOOS SLO, Option A or B	Yes
RPTOOS, Option A or B	Yes
RPTOOS SLO, Option A or B	Yes
TBVOOS and RPTOOS, Option A or B	No
TBVOOS and RPTOOS SLO, Option A or B	No

[1] The station has conservatively decided to maintain the PDBA Trip Amplitude at 1.12 with a Corresponding Maximum Count Trip Setting of 14 until such time where these changes do not introduce a Unit difference at Limerick. This decision was agreed upon by Operations and Site Engineering.

[2] Operating Region refers to operation on the Power to Flow map with or without FFWTR.

10.0 Methodology

The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

1. "General Electric Standard Application for Reactor Fuel", GNF Document, NEDE-24011-P-A-16, October 2007 and U.S. Supplement NEDE-24011-P-A-16-US, Revision 16, October 2007.

2. "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications", GENE Document, NEDO-32465-A, Rev. 0, August 1996.

11.0 References

1. "Technical Specifications and Bases for Limerick Generating Station Unit 2", Docket No. 50-353, License No. NPF-85, Exelon Document.

2. "Supplemental Reload Licensing Report for Limerick Generating Station Unit 2 Reload 10 Cycle 11", Global Nuclear Fuel Document No. 0000-0087-4784-SRLR, Revision 0, February 2009.

3. "GE14 Fuel Design Cycle-Independent Analyses for Limerick Generating Station Units 1 and 2", GENE Document, GE-NE-L12-00884-00-01P Revision 0, March 2001.

4. "OPL-3 Parameters for Limerick 2 Cycle 11", TODI: ES0800031 Rev. 0, November 2008, Exelon Document.

5. "ARTS Flow-Dependent Limits with TBVOOS for Peach Bottom Atomic Power Station and Limerick Generating Station", GENE Document NEDC-32847P, June 1998.

6. "General Electric Standard Application for Reactor Fuel", GNF Document, NEDE-24011-P-A-16, October 2007 and U.S. Supplement NEDE-24011-P-A-16-US, Revision 16, October 2007.

7. "Power Range Neutron Monitoring System Setpoint Calculations Limerick Generating Station, Units 1 & 2 Mod. No. P00224", LE-0107, Rev. 0 (including minor revision 00C), April 2008, Exelon Document.

8. "Fuel Bundle Information Report for Limerick Generating Station Unit 2 Reload 10 Cycle 11", Global Nuclear Fuel Document No. 0000-0087-4784-FBIR, Revision 0, February 2009.

9. "Limerick Units 1 and 2 Off-Rated Analysis Below PLU Power Level With Credit for Backup Trip", GENE Document, GE-NE-0000-0053-9467-R1, August 2006.

LIMERICK GENERATING STATION, UNIT 2
SURVEILLANCE FREQUENCY CONTROL PROGRAM
LIST OF SURVEILLANCE FREQUENCIES

This document provides the list of surveillance frequencies within the Limerick Generating Station (LGS), Unit 2, Surveillance Frequency Control Program (SFCP) as required by Technical Specification (TS) Section 6.8.4.j. This is not an all inclusive list of TS surveillance frequencies. This list only includes fixed periodic surveillance frequencies; event driven surveillance frequencies remain in TS. Each surveillance frequency specified in the list is associated with a corresponding TS Surveillance Requirement (SR) identified by TS SR number in the list. Any change to the type or scope of testing, e.g., Channel Check, Channel Functional Test, or Channel Calibration, or acceptance criteria specified in the associated TS SR requires prior NRC approval through a license amendment request. As part of the SFCP, this list is intended to be used in conjunction with TS by Operations and other station personnel to ensure that SRs specified in TS are performed at intervals sufficient to assure that associated TS Limiting Conditions for Operation (LCOs) are met.

Changes to this list may occur for one of two reasons, either: (1) addition, deletion, or modification of the associated TS SR through a license amendment processed in accordance with LS-AA-101 and issued by the NRC, or (2) station pursuit of a change to an individual surveillance frequency in the list. Changes to individual surveillance frequencies in the list, other than those approved by an NRC license amendment, are evaluated using NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 0, as required by TS Section 6.8.4.j. The process for making changes to individual frequencies is controlled by ER-LG-450. The responsibility for the administrative control of this list is assigned to site Regulatory Assurance. Administrative control of this list is governed by LS-LG-1000.

The Description section of the list is a summary description of the referenced TS SR which is provided for information purposes only and is not intended to be a substitute for the actual TS requirements. Refer to the TS for the specific action required by each respective SR identified in the list.

The SFCP Tables within this document may contain certain information other than the specific surveillance frequencies which is a duplicate of information specified in the corresponding TS Tables, e.g., footnotes, operational conditions for which the surveillance is required, etc. Any proposed changes to information other than the frequencies in the SFCP Tables must be reviewed against the corresponding TS Table and TS SR to ensure that information required by the associated TS Table or TS SR is not inadvertently modified or deleted. A change to information in a SFCP Table which is a duplicate of information in the TS Table or TS SR would require prior NRC approval of a change to the information in the TS Table or TS SR through a license amendment request.

In accordance with TS Section 6.8.4.j, the provisions of TS SRs 4.0.2 and 4.0.3 are applicable to the frequencies within the SFCP. TS SR 4.0.2 allows a maximum extension of up to 25% of the specified surveillance frequency. TS SR 4.0.3, for missed surveillances, allows a delay in declaring the associated LCO not met for up to 24 hours, or up to the limit of the specified surveillance frequency, whichever is greater, based on performance of a risk evaluation.

Noncompliance with the frequencies specified in the SFCP, i.e., missed surveillances, requires generation of a Condition Report (CR) in accordance with LS-AA-125. Based on the guidance provided in NUREG-1022, "Event Reporting Guidelines, 10 CFR 50.72 and 50.73," Rev. 2, missed surveillances are not reportable as a condition prohibited by TS unless the surveillance, once performed, indicates that the equipment was not capable of performing its specified safety function(s) for a period of time longer than allowed by TS.

LIMERICK GENERATING STATION, UNIT 2
SURVEILLANCE FREQUENCY CONTROL PROGRAM
LIST OF SURVEILLANCE FREQUENCIES
PAGE REVISION LIST

Page	Revision No. and Date
SFCP-i	Rev. 0, November 20, 2006
SFCP-ii	Rev. 11, March 27 , 2009
SFCP-1	Rev. 5, December 12, 2007
SFCP-2	Rev. 11, March 27, 2009
SFCP-3	Rev. 3, October 1, 2007
SFCP-4	Rev. 3, October 1, 2007
SFCP-5	Rev. 3, October 1, 2007
SFCP-6	Rev. 0, November 20, 2006
SFCP-7	Rev. 11, March 27, 2009
SFCP-8	Rev. 10, November 5, 2008
SFCP-9	Rev. 10, November 5, 2008
SFCP-10	Rev. 8, April 23, 2008
SFCP-11	Rev. 6, January 2, 2008
SFCP-12	Rev. 0, November 20, 2006
SFCP-13	Rev. 0, November 20, 2006
SFCP-14	Rev. 11, March 27, 2009
SFCP-15	Rev. 0, November 20, 2006
SFCP-16	Rev. 0, November 20, 2006
SFCP-T-i	Rev. 0, November 20, 2006
SFCP-T-1-9	Rev. 0, November 20, 2006
SFCP-T-1-10	Rev. 0, November 20, 2006
SFCP-T-3/4 3-7	Rev. 7, April 4, 2008
SFCP-T-3/4 3-8	Rev. 0, November 20, 2006
SFCP-T-3/4 3-27	Rev. 0, November 20, 2006
SFCP-T-3/4 3-28	Rev. 0, November 20, 2006
SFCP-T-3/4 3-29	Rev. 0, November 20, 2006
SFCP-T-3/4 3-30	Rev. 0, November 20, 2006
SFCP-T-3/4 3-31	Rev. 0, November 20, 2006
SFCP-T-3/4 3-40	Rev. 0, November 20, 2006
SFCP-T-3/4 3-41	Rev. 0, November 20, 2006
SFCP-T-3/4 3-45	Rev. 3, October 1, 2007
SFCP-T-3/4 3-51	Rev. 0, November 20, 2006
SFCP-T-3/4 3-56	Rev. 0, November 20, 2006
SFCP-T-3/4 3-61	Rev. 5, December 12, 2007
SFCP-T-3/4 3-62	Rev. 0, November 20, 2006
SFCP-T-3/4 3-66	Rev. 0, November 20, 2006
SFCP-T-3/4 3-67	Rev. 0, November 20, 2006
SFCP-T-3/4 3-83	Rev. 0, November 20, 2006
SFCP-T-3/4 3-87	Rev. 9, July 8, 2008
SFCP-T-3/4 3-107	Rev. 0, November 20, 2006
SFCP-T-3/4 3-108	Rev. 0, November 20, 2006
SFCP-T-3/4 3-115	Rev. 0, November 20, 2006
SFCP-T-3/4 4-17	Rev. 0, November 20, 2006
SFCP-T-3/4 8-8	Rev. 6, January 2, 2008

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
TS Section 3/4.1		
4.1.3.1.1.a	Scram discharge volume drain and vent valves - each valve is open	31 days
4.1.3.1.1.b	Scram discharge volume drain and vent valves - each valve cycles full travel	92 days
4.1.3.1.2.a	All withdrawn control rods operable - one notch test	31 days
4.1.3.1.4.a	Scram discharge volume drain and vent valves: 1. Close on scram signal 2. Open on scram reset	24 months
4.1.3.1.4.b	Channel functional test - scram discharge volume scram and control rod block level instrumentation	184 days
4.1.3.2.c	Maximum scram insertion time	120 days of power operation
4.1.3.5.a	Control rod scram accumulator - indicated pressure ≥ limit	7 days
4.1.3.7.a	Control rod position indication	24 hours
4.1.4.3.a	Rod Block Monitor - Channel Functional Test and Channel Calibration	SFCP Table 4.3.6-1 unless otherwise noted in TS Table 4.3.6-1
4.1.5.a	Standby Liquid Control System within limits: 1. Temperature of sodium pentaborate solution 2. Volume of sodium pentaborate solution 3. Temperature of pump suction piping	24 hours
4.1.5.b	Standby Liquid Control System: 1. Continuity of explosive charge 2. Available weight of Boron10 ≥ limit; concentration of sodium pentaborate in solution ≤ limit 3. Each valve in flow path is in correct position	31 days
4.1.5.d	Standby Liquid Control System - during shutdown: 1. Initiate at least one SLCS loop - verify flow path 2. Heat-treated piping is unblocked	24 months
TS Section 3/4.2		
4.2.1.a	APLHGR ≤ limiting value	24 hours
4.2.1.c	APLHGR ≤ limiting value - when reactor is operating with a Limiting Control Rod Pattern for APLHGR	12 hours
4.2.3.a	MCPR ≥ applicable MCPR limit	24 hours
4.2.3.c	MCPR ≥ applicable MCPR limit - when reactor is operating with a Limiting Control Rod Pattern for MCPR	12 hours
4.2.4.a	LHGRs ≤ limit	24 hours
4.2.4.c	LHGRs ≤ limit - when reactor is operating with a Limiting Control Rod Pattern for LHGR	12 hours

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
TS Section 3/4.3		
4.3.1.1	Reactor Protection System - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.1.1-1 unless otherwise noted in TS Table 4.3.1.1-1
4.3.1.2	Reactor Protection System - Logic System Functional Test (LSFT), except TS Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, and 2.f (LSFT is not required for these exceptions)	24 months
4.3.1.3	Reactor Protection System - Response Time: – Each reactor trip functional unit (at least one channel per trip system) demonstrated within limit – All channels tested	 24 months Once every N times 24 months (N is total number of redundant channels in a specific trip system)
4.3.2.1	Isolation actuation instrumentation channels - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.2.1-1 unless otherwise noted in TS Table 4.3.2.1-1
4.3.2.2	Isolation actuation instrumentation channels - Logic System Functional Test (except as noted below) Actuation instrumentation associated with the following valves: HV-013-206, HV-013-207, HV-013-208, HV-013-211, HV-087-220A(B), HV-087-221A(B), HV-087-228, HV-087-229, HV-087-222, HV-087-223, HV-051-2F008, HV-051-2F009, HV-051-2F015A(B), HV-051-251A(B).	24 months 48 months
4.3.2.3	Isolation System - Response Time: – Each isolation trip function (at least one channel per trip system) demonstrated within limit – All channels tested	 24 months Once every N times 24 months (N is total number of redundant channels in a specific trip system)
4.3.3.1	ECCS actuation instrumentation channels - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.3.1-1 unless otherwise noted in TS Table 4.3.3.1-1
4.3.3.2	ECCS actuation instrumentation channels - Logic System Functional Test	24 months
4.3.3.3	ECCS - Response Time: – Each ECCS trip function (at least one channel per trip system) demonstrated within limit – All channels tested	 24 months Once every N times 24 months (N is total number of redundant channels in a specific trip system)
4.3.4.1.1	ATWS recirculation pump trip actuation instrumentation - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.4.1-1

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.3.4.1.2	ATWS recirculation pump trip actuation instrumentation - Logic System Functional Test	24 months
4.3.4.2.1	End-of-Cycle Recirculation Pump Trip System - Channel Functional Test and Channel Calibration	SFCP Table 4.3.4.2.1-1
4.3.4.2.2	End-of-Cycle Recirculation Pump Trip System - Logic System Functional Test	24 months
4.3.4.2.3	End-of-Cycle Recirculation Pump Trip System - Response Time: – Each trip function - one type channel input (TCV fast closure or TSV closure) demonstrated within limit – both types of channel inputs tested	 24 months 48 months
4.3.4.2.4	Recirculation pump circuit breaker trip coil - breaker arc suppression time interval	60 months
4.3.5.1	RCIC system actuation instrumentation - Channel Check, Channel Functional Test, and Channel Calibration (Channel Check and Channel Calibration are not required for manual initiation)	SFCP Table 4.3.5.1-1
4.3.5.2	RCIC system actuation instrumentation - Logic System Functional Test	24 months
4.3.6	Control rod block trip systems and instrumentation - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.6-1 unless otherwise noted in TS Table 4.3.6-1.
4.3.7.1	Radiation monitoring instrumentation - Channel Check, Channel Functional Test, and Channel Calibration	SFCP Table 4.3.7.1-1 unless otherwise noted in TS Table 4.3.7.1-1
4.3.7.4.1	Remote shutdown monitoring instrumentation - Channel Check and Channel Calibration	SFCP Table 4.3.7.4-1
4.3.7.4.2	Remote shutdown control switches and control circuits - verify capability to perform intended functions	24 months
4.3.7.5	Accident monitoring instrumentation - Channel Check and Channel Calibration	SFCP Table 4.3.7.5-1 unless otherwise noted in TS Table 4.3.7.5-1
4.3.7.6.a.1	Source range monitor channels - Channel Check: a. OPCON 2 (with IRMs on range 2 or below) b. OPCON 3 or 4	 12 hours 24 hours
4.3.7.6.a.2	Source range monitor channels - Channel Calibration (Neutron detectors may be excluded)	24 months
4.3.7.6.b	Source range monitor channels - Channel Functional Test	31 days
4.3.7.8.1	Chlorine detection system subsystems: a. Channel Check b. Channel Functional Test c. Channel Calibration	 12 hours 92 days 24 months

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.3.7.8.2	Toxic gas detection system subsystems a. Channel Check b. Channel Functional Test c. Channel Calibration	 12 hours 31 days 24 months
4.3.7.12	Offgas monitoring instrumentation - Channel Check, Source Check, Channel Calibration and Channel Functional Test	SFCP Table 4.3.7.12-1 unless otherwise noted in TS Table 4.3.7.12-1
4.3.9.1	Feedwater/main turbine trip system actuation instrumentation - Channel Check, Channel Functional Test and Channel Calibration	SFCP Table 4.3.9.1-1
4.3.9.2	Feedwater/main turbine trip system actuation instrumentation - Logic System Functional Test	24 months
Section 3/4.4		
4.4.1.1.4	One reactor coolant system recirculation loop not in operation, verify: a. Reactor Thermal Power ≤ limit b. Recirculation flow control system in Local Manual c. Operating Recirc pump speed ≤ limit	12 hours
4.4.1.2.a	Jet pumps - two recirculation loop operation (while greater than 25% of rated thermal power)	24 hours
4.4.1.2.b	Jet pumps- single recirculation loop operation	24 hours
4.4.1.3	Recirculation loop flow mismatch verified within limit	24 hours
4.4.2.2	Safety relief valves - removed, set pressure tested and reinstalled or replaced with spares: – 1/2 of the SRVs – All 14 SRVs	 24 months 54 months
4.4.3.1.a	RCS leakage detection systems - Channel Check of the primary containment atmosphere gaseous radioactivity monitoring system	12 hours
4.4.3.1.b	RCS leakage detection instrumentation - Channel Functional Test	31 days
4.4.3.1.c	RCS leakage detection instrumentation - Channel Calibration	24 months
4.4.3.1.d	Monitor primary containment: – pressure – temperature	 12 hours 24 hours
4.4.3.2.1.a	RCS leakage within limits - primary containment atmospheric gaseous radioactivity	12 hours
4.4.3.2.1.b	RCS leakage within limits - drywell floor drain sump and drywell equipment drain tank flow rate	8 hours
4.4.3.2.1.c	RCS leakage within limits - drywell unit coolers condensate flow rate	12 hours
4.4.3.2.1.d	RCS leakage within limits - primary containment pressure	12 hours

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.4.3.2.1.e	RCS leakage within limits - reactor vessel head flange leak detection system	24 hours
4.4.3.2.1.f	RCS leakage within limits - primary containment temperature	24 hours
4.4.3.2.2.a	RCS pressure isolation valves - leak testing and leakage within limits	24 months
4.4.3.2.3	High/low pressure interface valve leakage pressure monitors: a. Channel Functional Test b. Channel Calibration	 31 days 24 months
4.4.5	Reactor coolant specific activity sampling and analysis program	SFCP Table 4.4.5-1 unless otherwise noted in TS Table 4.4.5-1
4.4.6.1.1	RCS temperature and pressure within heatup and cooldown limits, and to the right of the limit lines of TS Figure 3.4.6.1-1, during RCS heatup, cooldown, and inservice leak and hydrostatic testing operations	30 minutes
4.4.6.1.2	RCS temperature and pressure to the right of the criticality limit line of TS Figure 3.4.6.1-1 during RCS heatup	30 minutes
4.4.6.1.5.a	Reactor vessel flange and head flange temperature $\geq$ limit in Operational Condition 4: 1. RCS temperature $\leq 100^{\circ}F$ 2. RCS temperature $\leq 90^{\circ}F$	 12 hours 30 minutes
4.4.6.1.5.b	Reactor vessel flange and head flange temperature $\geq$ limit during tensioning of the reactor vessel head bolting studs.	30 minutes
4.4.6.2	Reactor steam dome pressure less than limit	12 hours
4.4.9.1	RHR Hot Shutdown - One independent RHR shutdown cooling subsystem or alternate method in operation and circulating reactor coolant	12 hours
4.4.9.2	RHR Cold Shutdown - One RHR shutdown cooling subsystem or recirculation pump operating or alternate method in operation and circulating reactor coolant	12 hours
Section 3/4.5		
4.5.1.a	ECCS operability: 1. CSS, LPCI and HPCI a. System piping filled with water b. Each valve in flow path is in correct position 2. LPCI system cross-tie valves are closed 3. HPCI pump flow controller in correct position 4. Channel Functional Test of CSS and LPCI injection header ΔP instrumentation	31 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.5.1.c	ECCS operability: 1. CSS, LPCI and HPCI system functional test 2. HPCI system: a. System flow rate b. Suction auto transfer from condensate storage tank to suppression chamber 3. Channel Calibration of CSS, LPCI and HPCI system discharge line "keep filled" alarm instrumentation 4. Channel Calibration of CSS header ΔP instrumentation 5. Channel Calibration of LPCI header ΔP instrumentation	24 months
4.5.1.d.1	ADS accumulator gas supply header pressure ≥ limit	31 days
4.5.1.d.2	ADS: a. System functional test b. Each valve is capable of being opened	24 months
4.5.2.2	Core spray system - condensate storage tank volume	12 hours
4.5.3.1	Suppression chamber water level ≥ limit: a. 22' 0" b. 16' 0"	 24 hours 12 hours
4.5.3.2	Suppression chamber level less than required limit or drained in Operational Condition 4 or 5* a. verify required conditions of Specification 3.5.3.b to be satisfied b. verify footnote conditions * to be satisfied	12 hours
Section 3/4.6		
4.6.1.1.b	Primary Containment Integrity - primary containment penetrations not capable of being closed by automatic isolation valves are closed	31 days
4.6.1.3.c	Verify only one door in the air lock can be opened at a time	6 months
4.6.1.6	Drywell and suppression chamber internal pressure is within limits	12 hours
4.6.1.7	Drywell average air temperature is within limit	24 hours
4.6.1.8	Each primary containment purge valve is closed	31 days
4.6.2.1.a	Suppression chamber water volume within limits	24 hours
4.6.2.1.b	Suppression chamber average water temperature ≤ limit	24 hours (see exceptions for more frequent testing specified in TS Section 4.6.2.1.b)

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.6.2.1.c	8 suppression pool water temperature indicators in at least 8 locations operable: 1. Channel Check 2. Channel Functional Test 3. Channel Calibration	 24 hours 31 days 24 months
4.6.2.1.d	Two suppression chamber water level indicators operable: 1. Channel Check 2. Channel Functional Test 3. Channel Calibration * * Channel Calibration for level transmitters LT-55-2N062B and LT-55-2N062F	 24 hours 92 days 24 months 18 months
4.6.2.2.a	RHR system suppression pool spray mode - each valve in flow path is in correct position	31 days
4.6.2.3.a	RHR system suppression pool cooling mode - each valve in flow path is in correct position	31 days
4.6.3.2	Primary containment automatic isolation valve - each automatic isolation valve actuates on a containment isolation test signal (except as noted below) Isoaltion instrumentation associated with the following valves: HV-013-206, HV-013-207, HV-013-208, HV-013-211, HV-087-220A(B), HV-087-221A(B), HV-087-228, HV-087-229, HV-087-222, HV-087-223, HV-051-2F008, HV-051-2F009, HV-051-2F015A(B), HV-051-251A(B).	24 months 48 months
4.6.3.4	Reactor instrumentation line excess flow check valves check flow: – Representative sample – Each valve	 24 months 120 months
4.6.3.5.a	Traversing in-core probe explosive isolation valve - explosive charge continuity	31 days
4.6.3.5.b	Traversing in-core probe explosive isolation valve - removing and initiating the explosive squib: – Representative sample – Each squib in each valve	 24 months 120 months
4.6.4.1.a	Suppression chamber - drywell vacuum breaker - verified closed	7 days
4.6.4.1.b.1	Suppression chamber - drywell vacuum breaker - cycling each vacuum breaker through one complete cycle	31 days
4.6.4.1.b.2	Suppression chamber - drywell vacuum breaker - verifying position indication	31 days
4.6.4.1.b.3	Suppression chamber - drywell vacuum breaker a. Each valve's opening setpoint b. Channel Calibration of both position indicators c. Each valve's position indicator is capable of detecting disk displacement	24 months
4.6.5.1.1.a	Reactor enclosure (RE) secondary containment pressure ≥ limit	24 hours

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.6.5.1.1.b	RE secondary containment integrity: 1. RE secondary containment equipment hatches and blowout panels are closed and sealed 2. One door in each access to RE secondary containment is closed 3. All RE secondary containment penetrations not capable of being closed by automatic isolation dampers/valves are closed	31 days
4.6.5.1.1.c	RE secondary containment integrity: 1. One Standby Gas Treatment System (SGTS) subsystem - RE secondary containment draw down time ≤ limit with RERS in service 2. One SGTS subsystem operating for one hour - maintain RE secondary containment ≥ limit	24 months
4.6.5.1.2.a	Refueling (RF) area secondary containment pressure ≥ limit	24 hours
4.6.5.1.2.b	RF area secondary containment integrity: 1. RF area secondary containment equipment hatches and blowout panels are closed and sealed 2. One door in each access to RF area secondary containment is closed 3. All RF area secondary containment penetrations not capable of being closed by automatic isolation dampers/valves are closed	31 days
4.6.5.1.2.c	One SGTS subsystem operating for one hour - maintain RF area secondary containment ≥ limit	24 months
4.6.5.2.1.b	RE secondary containment ventilation system automatic isolation valves - each isolation valve actuates on a containment isolation test signal	24 months
4.6.5.2.1.c	RE secondary containment ventilation system automatic isolation valves - isolation time is within limit	92 days
4.6.5.2.2.b	RF area secondary containment ventilation system automatic isolation valves - each isolation valve actuates on a containment isolation test signal	24 months
4.6.5.2.2.c	RF area secondary containment ventilation system automatic isolation valves - isolation time is within limit	92 days
4.6.5.3.a	SGTS - verify system operates with flow through the HEPA filters and charcoal adsorbers with heaters operable	92 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.6.5.3.b	SGTS operability: 1. In-place penetration and bypass leakage < limit and system flow rate = limit 2. Within 31 days after removal, laboratory analysis of carbon sample shows methyl iodide penetration < limit 3. When fan is running, subsystem flowrate from each reactor enclosure and from refuel area = limits 4. Pressure drop across the refueling area to SGTS prefilter is < limit	24 months (surveillance frequency is an exception to RG 1.52, Rev. 2, March 1978)
4.6.5.3.d	SGTS operability: 1. Pressure drop across the combined HEPA filters and charcoal adsorber banks < limit 2. Fan starts and isolation valves open on each of the identified test signals 3. Temperature differential across each heater ≥ limit	24 months
4.6.5.4.a	RERS - verify system operates with flow through the HEPA filters and charcoal adsorbers	92 days
4.6.5.4.b	RERS operability: 1. In-place penetration and bypass leakage < limit and system flow rate = limit 2. Within 31 days after removal, laboratory analysis of carbon sample shows methyl iodide penetration < limit 3. Flowrate = limit during subsystem operation	24 months (surveillance frequency is an exception to RG 1.52, Rev. 2, March 1978)
4.6.5.4.d	RERS operability: 1. Pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks < limit, prefilter pressure drop < limit and pressure drop across each HEPA < limit. 2. Filter train starts and isolation valves open on each of the identified test signals	24 months
4.6.6.2	Drywell unit cooler hydrogen mixing subsystem operability: a. Starting system from control room b. System operates at least 15 minutes	92 days
4.6.6.3	Drywell and suppression chamber oxygen concentration is within the limit (after Thermal Power > 15% of Rated Thermal Power).	7 days
Section 3/4.7		
4.7.1.1.a	RHRSW operability - each valve in the flow path is in its correct position	31 days
4.7.1.2.a	ESW loop operability - each valve is in its correct position	31 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.7.1.2.b	ESW loop operability: 1. Each automatic valve actuates to its correct position on appropriate ESW pump start signal 2. Each ESW pump starts when its associated EDG starts	24 months
4.7.1.3.a	Spray pond operability - pond water level > limit	24 hours
4.7.1.3.b	Spray pond operability - water surface temperature ≤ limit when spray pond temperature is: 1. ≥ 80°F 2. ≥ 85°F 3. > 32°F	 4 hours 2 hours 24 hours
4.7.2.1.a	CREFAS operability - control room air temperature ≤ limit	12 hours
4.7.2.1.b	CREFAS operability - on staggered test basis, verify system operates with flow through the HEPA filters and charcoal adsorbers with heaters operable	31 days
4.7.2.1.c	CREFAS operability: 1. In-place penetration and bypass leakage < limit and system flow rate = limit 2. Within 31 days after removal, laboratory analysis of carbon sample shows methyl iodide penetration < limit 3. Flowrate = limit during subsystem operation	24 months (surveillance frequency is an exception to RG 1.52, Rev. 2, March 1978)
4.7.2.1.e	CREFAS operability: 1. Pressure drop across the combined prefilter, upstream and downstream HEPA filters, and charcoal adsorber banks < limit, prefilter pressure drop < limit and pressure drop across each HEPA < limit. 2. On each of the chlorine isolation mode actuation test signals, the system automatically switches to the chlorine isolation mode and the isolation valves close within limit 3. On each of the radiation isolation mode actuation test signals, the system automatically switches to the radiation isolation mode.	24 months
4.7.3.a	RCIC operability: 1. System piping from the pump discharge valve to the system isolation valve is filled with water 2. Each valve is in its correct position 3. Pump flow controller is in the correct position	31 days
4.7.3.b	RCIC operability - RCIC pump develops a flow ≥ limit in the test flow path.	92 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.7.3.c	RCIC operability: 1. System functional test - each automatic valve in the flow path actuates to its correct position 2. System will develop a flow of $\geq$ limit in test flow path. 3. Suction for RCIC system is automatically transferred from the condensate storage tank to the suppression pool 4. Channel Calibration of RCIC system discharge line "keep filled" level alarm instrumentation	24 months
4.7.5.2.a	Sealed source testing - sealed sources containing radioactive material are tested	6 months
4.7.8	Main turbine bypass system operability: a. Each turbine bypass valve cycled through one complete cycle of full travel b. System functional test - each automatic valve actuates to its correct position c. Turbine bypass system response time $\leq$ to the value specified in the COLR.	 92 days 24 months 24 months
Section 3/4.8		
4.8.1.1.1.a	Independent circuits between offsite transmission network and the onsite Class 1E distribution system - correct breaker alignments and indicated power availability	7 days
4.8.1.1.1.b	Independent circuits between offsite transmission network and the onsite Class 1E distribution system - transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit	24 months
4.8.1.1.2.a	Diesel generator operability - on a staggered test basis: 1. Fuel level in day tank 2. Fuel level in fuel storage tank 3. Fuel transfer pump starts and transfers fuel from storage system to day fuel tank 4. Diesel can start and gradually accelerate to synchronous speed 5. Diesel is synchronized, gradually loaded and operates at load for at least 60 minutes 6. Diesel generator is aligned to provide standby power to associated emergency busses 7. Pressure in all diesel generator air start receivers $\geq$ limit	31 days
4.8.1.1.2.b.1	Diesel generator operability - removing accumulated water from the day tank	31 days
4.8.1.1.2.b.2	Diesel generator operability - removing accumulated water from the storage tank	31 days
4.8.1.1.2.d	Diesel generator operability - sample fuel oil from storage tanks; total particulate contamination < limit	31 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.8.1.1.2.e	Diesel generator operability: 2. Each diesel generator's capability to reject a load ≥ that of its single largest post-accident load 3. Diesel generator capability to reject a load of 2850 kW without tripping 4. Simulating loss of offsite power by itself: a. Deenergization of the emergency busses and load shedding from the emergency busses b. Diesel generator starts on the auto-start signal, energizes the emergency busses, energizes the auto-connected loads through individual load timers and operates while its generator is loaded with the shutdown loads 5. On ECCS actuation signal, without loss-of-offsite power, diesel generator starts on the auto-start signal and operates on standby 6. Simulating loss-of-offsite power in conjunction with an ECCS actuation test signal: a. Deenergization of the emergency busses and load shedding from the emergency busses b. Diesel generator starts on the auto-start signal, energizes the emergency busses, energizes the auto-connected shutdown loads through individual load timers and operates while its generator is loaded with the emergency loads 7. All automatic diesel generator trips, except engine overspeed and generator differential over-current, are automatically bypassed upon ECCS actuation signal 8. a. Diesel generator operates for at least 24 hours b. Diesel generator starts within 5 minutes of shutting down the diesel generator after the diesel generator has operated for at least 2 hours. 9. Auto-connected loads to each diesel generator do not exceed the 2000-hour rating 10. Diesel generator's capability to: a. Synchronize with the offsite power source while the generator is loaded with its emergency loads upon simulated restoration of offsite power b. Transfer its loads to the offsite power source c. Be restored to its standby status 11. With diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode 12. The automatic load sequence timers are operable with the interval between each load block within limit	24 months

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
	of its design interval 13. The following diesel generator lockout features prevent diesel generator starting only when required: a. Control room switch in pull-to-lock (with Local/Remote switch in Remote) b. Local/Remote switch in Local c. Emergency stop	
4.8.1.1.2.f	Diesel generator operability - start all four diesels simultaneously, during shutdown, and verify all four diesel generators accelerate to speed within limit.	10 years
4.8.1.1.2.g	Diesel generator operability: 1. Drain each diesel fuel oil storage tank, remove accumulated sediment and clean the tank. 2. Perform a pressure test of portions of diesel fuel oil system.	10 years
4.8.1.1.2.h	Diesel generator operability - diesel generator start and accelerate to synchronous speed within limit.	184 days
4.8.2.1.a	Battery and charger operability: 1. Each division battery float current $\leq$ limit. 2. Total battery terminal voltage for each 125-volt battery $\geq$ minimum established float voltage.	7 days
4.8.2.1.b	Battery and charger operability: 1. Battery pilot cell voltage $\geq$ limit. 2. Battery connected cell electrolyte level $\geq$ minimum established design limits 3. Pilot cell electrolyte temperature $\geq$ minimum established design limits	31 days
4.8.2.1.c	Battery and charger operability: - Battery connected cell voltage $\geq$ limit.	92 days
4.8.2.1.d	Battery and charger operability: 1. Battery chargers supply currents listed at $\geq$ minimum established float voltage. 2. Battery capacity adequate to supply and maintain required emergency loads for design duty cycle.	24 months
4.8.2.1.e	Battery and charger operability - battery capacity is at least 80% manufacturer's rating when subjected to a performance discharge test.	60 months
4.8.2.1.f.1	Battery and charger operability - performance discharge test: a. Battery shows degradation b. Battery reached 85% expected life with battery capacity < manufacturer's rating	12 months
4.8.2.1.f.2	Battery and charger operability - performance discharge test - Battery reached 85% expected life with battery capacity > manufacturer's rating	24 months

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.8.3.1	Power distribution system divisions energized - correct breaker alignment and voltage on busses/MCCs/panels.	7 days
4.8.3.2	Power distribution system divisions energized - correct breaker alignment and voltage on busses/MCCs/panels.	7 days
4.8.4.2.2	Motor-operated valves bypassed only under accident conditions - Channel Functional Test (except as noted below). Bypass associated with the following valves: HV-013-206, HV-013-207, HV-013-208, HV-013-211, HV-087-220A(B), HV-087-221A(B), HV-087-228, HV-087-229, HV-087-222, HV-087-223, HV-051-2F008, HV-051-2F009, HV-051-2F015A(B).	24 months 48 months
4.8.4.3.b	RPS electrical power monitoring - Channel Calibration of overvoltage, undervoltage, and underfrequency protective instrumentation.	24 months
Section 3/4.9		
4.9.1.1	Reactor mode switch - verified locked in Shutdown or Refuel position.	12 hours
4.9.1.2	Reactor mode switch Refuel position interlocks - Channel Functional Test during control rod withdrawal or Core Alterations	31 days
4.9.2.a	SRM channel operability: 1. Channel Check 2. Detectors inserted to normal operating level 3. During Core Alterations, detector of an operable SRM channel located in core quadrant where Core Alterations are being performed.	12 hours
4.9.2.b	SRM channel operability - Channel Functional Test	31 days
4.9.2.c	SRM channel count rate at least 3.0 cps: 2. During Core Alterations 3. All other times in OPCON 5	 12 hours 24 hours
4.9.2.d	RPS shorting links have been removed during: 1. Time any control rod is withdrawn, unless adequate shutdown margin has been demonstrated 2. Shutdown margin demonstrations	12 hours
4.9.3	All control rods verified to be inserted	12 hours
4.9.5	Direct communication between the control room and refueling floor personnel during Core Alterations	12 hours
4.9.7	Crane interlocks which prevent crane travel over fuel assemblies in the spent fuel storage pool racks demonstrated operable during crane operation	31 days
4.9.8	Reactor vessel water level at least its minimum required depth during handling of fuel assemblies or control rods within the reactor pressure vessel.	24 hours
4.9.9	Water level in spent fuel storage pool at least at its minimum required depth.	7 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.9.10.1	Control rod and/or control rod drive mechanism removed: a. Reactor mode operable b. SRM channels are operable c. Shutdown Margin requirements satisfied d. All other control rods in 5-by-5 array centered on control rod being removed are inserted and disarmed e. All other control rods are inserted.	24 hours
4.9.10.2.1	Control rod and/or control rod drive mechanism removed: a. Reactor mode operable b. SRM channels are operable c. Shutdown Margin requirements satisfied d. All other control rods either inserted or have surrounding four fuel cell assemblies removed from core cell e. Four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core are removed from the core cell.	24 hours
4.9.11.1	At least one RHR shutdown cooling subsystem, or alternate method, verified to be in operation and circulating reactor coolant.	12 hours
4.9.11.2	At least one RHR shutdown cooling subsystem, or alternate method, verified to be in operation and circulating reactor coolant.	12 hours
Section 3/4.10		
4.10.1	Thermal Power and reactor coolant temperature within limits during low power Physics Tests.	1 hour
4.10.3	During performance of shutdown margin demonstrations: a. Source range monitors operable b. Rod worth minimizer is operable c. No Core Alterations in progress.	12 hours
4.10.4.1	Suspension of requirements that recirculation loops be in operation - verify the time this requirements has been suspended to be < 24 hours during Physics Tests and the Startup Test Program.	1 hour
4.10.4.2	Thermal Power < 5% Rated Thermal Power during Physics Tests.	1 hour
4.10.5	Effective Full Power Days of operation < 120, by calculation, during the Startup Test Program.	7 days
4.10.6	Reactor vessel unpressurized and Thermal Power and reactor coolant temperature within limits during training startups.	1 hour
Section 3/4.11		
4.11.1.4	Quantity of radioactive material in outside temporary tanks within limit when radioactive materials are added to the tank.	7 days

SURVEILLANCE REQUIREMENT	DESCRIPTION	FREQUENCY
4.11.2.6.2	The rate of the sum of the activities of the specified noble gases from the recombiner after-condenser discharge within limits.	31 days.

LIMERICK GENERATING STATION, UNIT 2

SURVEILLANCE FREQUENCY CONTROL PROGRAM

LIST OF SURVEILLANCE FREQUENCIES

TABLES

SFCP TABLE 1.1

SURVEILLANCE FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 184 days.
A	At least once per 366 days.
E	At least once per 18 months (550 days).
R (Refueling Interval)	At least once per 24 months (731 days).
S/U	Prior to each reactor startup.
P	Prior to each radioactive release.
N.A.	Not applicable.

SFCP TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any temperature
2. STARTUP	Startup/Hot Standby	Any temperature
3. HOT SHUTDOWN	Shutdown# ***	> 200°F
4. COLD SHUTDOWN	Shutdown# ## ***	≤ 200°F ****
5. REFUELING*	Shutdown or Refuel** #	NA

#The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that the control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

##The reactor mode switch may be placed in the Refuel position while a single control rod drive is being removed from the reactor pressure vessel per Specification 3.9.10.1.

*Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

**See Special Test Exceptions 3.10.1 and 3.10.3.

***The reactor mode switch may be placed in the Refuel position while a single control rod is being moved provided that the one-rod-out interlock is OPERABLE.

****See Special Test Exception 3.10.8.

SFCP TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S(b)	M	R	2
	S	M(j)	R	3(i), 4(i), 5(i)
b. Inoperative	N.A.	M(j)	N.A.	2, 3(i), 4(i), 5(i)
2. Average Power Range Monitor(f):				
a. Neutron Flux - Upscale (Setdown)	D(b)	SA(l)	R	2
b. Simulated Thermal Power - Upscale	D	SA(e)	W(d), R(g)	1
c. Neutron Flux - Upscale	D	SA	W(d), R	1
d. Inoperative	N.A.	SA	N.A.	1, 2
e. 2-Out-Of-4 Voter	D	SA	N.A.	1, 2
f. OPRM Upscale	D	SA(e)	R(c)(g)	1(m)
3. Reactor Vessel Steam Dome Pressure - High	S	Q	R	1, 2(h)
4. Reactor Vessel Water Level-Low, Level 3	S	Q	R	1, 2
5. Main Steam Line Isolation Valve - Closure	N.A.	SA	R	1
6. DELETED				
7. Drywell Pressure - High	S	Q	R	1, 2
8. Scram Discharge Volume Water Level - High				
a. Level Transmitter	S	SA	R	1, 2, 5(i)
b. Float Switch	N.A.	SA	R	1, 2, 5(i)

SFCP TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Turbine Stop Valve - Closure	N.A.	Q	R	1
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	N.A.	Q	R	1
11. Reactor Mode Switch Shutdown Position	N.A.	R	N.A.	1, 2, 3, 4, 5
12. Manual Scram	N.A.	W	N.A.	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.
(c) Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 30% and for recirculation drive flow is < 60%.
(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.
(e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.
(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH).
(g) Calibration includes the flow input function.
(h) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.
(k) DELETED
(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.
(m) With THERMAL POWER ≥ 25% of RATED THERMAL POWER.

SFCP TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2	S	Q	R	1, 2, 3
2) Low, Low, Low - Level 1	S	Q	R	1, 2, 3
b. DELETED				
c. Main Steam Line Pressure - Low	S	Q	R	1
d. Main Steam Line Flow - High	S	Q	R	1, 2, 3
e. Condenser Vacuum - Low	S	Q	R	1, 2**, 3**
f. Outboard MSIV Room Temperature - High	S	Q	R	1, 2, 3
g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	S	Q	R	1, 2, 3
h. Manual Initiation	N.A.	R	N.A.	1, 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level## Low - Level 3	S	Q	R	1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	S	Q	R	1, 2, 3
c. Manual Initiation	N.A.	R	N.A.	1, 2, 3

SFCP TABLE 4.3.2.1-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High	S	Q	R	1, 2, 3
b. RWCS Area Temperature - High	S	Q	R	1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High	S	Q	R	1, 2, 3
d. SLCS Initiation	N.A.	R	N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2	S	Q	R	1, 2, 3
f. Manual Initiation	N.A.	R	N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High	S	Q	R	1, 2, 3
b. HPCI Steam Supply Pressure, Low	S	Q	R	1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High	S	Q	R	1, 2, 3
d. HPCI Equipment Room Temperature - High	S	Q	R	1, 2, 3
e. HPCI Equipment Room Δ Temperature - High	S	Q	R	1, 2, 3
f. HPCI Pipe Routing Area Temperature - High	S	Q	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. HPCI Steam Line Δ Pressure Timer	N.A.	Q	R	1, 2, 3

SFCP TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	S	Q	R	1, 2, 3
b. RCIC Steam Supply Pressure - Low	S	Q	R	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	S	Q	R	1, 2, 3
d. RCIC Equipment Room Temperature - High	S	Q	R	1, 2, 3
e. RCIC Equipment Room Δ Temperature - High	S	Q	R	1, 2, 3
f. RCIC Pipe Routing Area Temperature - High	S	Q	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. RCIC Steam Line Δ Pressure Timer	N.A.	Q	R	1, 2, 3

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2	S	Q	R	1, 2, 3
2) Low, Low, Low - Level 1	S	Q	R	1, 2, 3
b. Drywell Pressure ## - High	S	Q	R	1, 2, 3
c. North Stack Effluent Radiation - High	S	Q	R	1, 2, 3
d. Deleted				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	S	Q	R	1, 2, 3
f. Deleted				
g. Deleted				
h. Drywell Pressure - High/ Reactor Pressure - Low	S	Q	R	1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.	M	Q	1, 2, 3
j. Manual Initiation	N.A.	R	N.A.	1, 2, 3

SFCP TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2	S	Q	R	1, 2, 3
b. Drywell Pressure## - High	S	Q	R	1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	S	Q	R	*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	S	Q	R	1, 2, 3
e. Deleted				
f. Deleted				
g. Reactor Enclosure Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. Refueling Area Manual Initiation	N.A.	R	N.A.	*

*Required when (1) handling RECENTLY IRRADIATED FUEL in the secondary containment, or (2) during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.

SFCP TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	Q	R	1, 2, 3, 4*, 5*
d. Manual Initiation	N.A.	R	N.A.	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	Q	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	Q	R	1, 2, 3
d. Injection Valve Differential Pressure - Low (Permissive)	S	Q	R	1, 2, 3, 4*, 5*
e. Manual Initiation	N.A.	R	N.A.	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM***				
a. Reactor Vessel Water Level - Low Low, Level 2	S	Q	R	1, 2, 3
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. Condensate Storage Tank Level - Low	S	Q	R	1, 2, 3
d. Suppression Pool Water Level - High	S	Q	E	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	S	Q	R	1, 2, 3
f. Manual Initiation	N.A.	R	N.A.	1, 2, 3

SFCP TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	Q	R	1, 2, 3
b. Drywell Pressure - High	S	Q	R	1, 2, 3
c. ADS Timer	N.A.	Q	Q	1, 2, 3
d. Core Spray Pump Discharge Pressure - High	S	Q	R	1, 2, 3
e. RHR LPCI Mode Pump Discharge Pressure - High	S	Q	R	1, 2, 3
f. Reactor Vessel Water Level - Low, Level 3	S	Q	R	1, 2, 3
g. Manual Initiation	N.A.	R	N.A.	1, 2, 3
h. ADS Drywell Pressure Bypass Timer	N.A.	Q	Q	1, 2, 3
5. LOSS OF POWER				
a. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)##	N.A.	R	N.A.	1, 2, 3, 4**, 5**
b. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	S	M	R	1, 2, 3, 4**, 5**

* When the system is required to be OPERABLE per Specification 3.5.2.

** Required OPERABLE when ESF equipment is required to be OPERABLE.

*** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Loss of Voltage Relay 127-11X is not field setable.

SFCP TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low Low, Level 2	S	R	R
2. Reactor Vessel Pressure - High	S	R	R

SFCP TABLE 4.3.4.2.1-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve-Closure	Q*	R
2. Turbine Control Valve-Fast Closure	Q*	R

* Including trip system logic testing.

SFCP TABLE 4.3.5.1-1

REACTOR CORE ISOLATION SYSTEM ACTUATION INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNITS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
a. Reactor Vessel Water Level - Low Low, Level 2	S	Q	R
b. Reactor Vessel Water Level - High, Level 8	S	Q	R
c. Condensate Storage Tank Level - Low	S	Q	R
d. Manual Initiation	N.A.	R	N.A.

SFCP TABLE 4.3.6-1
CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	Q[c]	R	1*
b. Inoperative	N.A.	Q[c]	N.A.	1*
c. Downscale	N.A.	Q[c]	R	1*
2. APRM				
a. Simulated Thermal Power-Upscale	N.A.	SA	R	1
b. Inoperative	N.A.	SA	N.A.	1, 2
c. Neutron Flux - Downscale	N.A.	SA	R	1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.	SA	R	2
e. Recirculation Flow - Upscale	N.A.	SA	R	1
f. LPRM Low Count	N.A.	SA	R	1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	M[d][e], M[f]	N.A.	2, 5
b. Upscale	N.A.	M[d][e], M[f]	R	2, 5
c. Inoperative	N.A.	M[d][e], M[f]	N.A.	2, 5
d. Downscale	N.A.	M[d][e], M[f]	R	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.	M	N.A.	2, 5**
b. Upscale	N.A.	M	R	2, 5**
c. Inoperative	N.A.	M	N.A.	2, 5**
d. Downscale	N.A.	M	R	2, 5**
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.	SA	R	1, 2, 5**
6. DELETED				
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	R[g]	N.A.	3, 4

SFCP TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** Deleted.

(d) When in OPERATIONAL CONDITION 2.

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) When in OPERATIONAL CONDITION 5.

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

SFCP TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	S	Q	R	1, 2, 3, and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	S	M	R	(a)
b. Control Room Direct Radiation Monitor	S	M	R	At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor	S	M	R(b)	At All Times

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment or during operations with a potential for draining the reactor vessel with the vessel head removed and fuel in the vessel.

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

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

SFCP TABLE 4.3.7.4-1

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK *	CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Safety/Relief Valve Position, 3 valves	M	NA
4. Suppression Chamber Water Level	M	R
5. Suppression Chamber Water Temperature	M	R
6. Drywell Pressure	M	R
7. Drywell Temperature	M	R
8. RHR System Flow	M	R
9. RHR Service Water Pump Discharge Pressure	M	R
10. RHR Heat Exchanger Service Water Outlet Pressure	M	R
11. RCIC System Flow	M	R
12. RCIC Turbine Speed	M	R
13. Emergency Service Water Pump Discharge Pressure	M	R
14. Condensate Storage Tank Level	M	R
15. RHR Heat Exchanger Bypass Valve (HV-C-51-2F048A) Position Indication (0 - 100%)	M	R
16. RCIC Turbine Tripped Indication	M	R
17. RCIC Turbine Bearing Oil Pressure Low Indication	M	R
18. RCIC Bearing Oil Temperature High Indication	M	R
19. RHR Heat Exchanger Discharge Line High Radiation Indication	M	R

*Control is not required to be transferred to perform this CHANNEL CHECK.

SFCP 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 Chamber Water Level	M	R
4. Suppression Chamber Water Temperature	M	R
5. Deleted		
6. Primary Containment Pressure	M	R
7. Deleted		
8. Deleted		
9. Deleted		
10. Deleted		
11. Primary Containment Post LOCA Radiation Monitors	M	R**
12. North Stack Wide Range Accident Monitor***	M	R
13. Neutron Flux	M	R

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

***High range noble gas monitors.

SFCP TABLE 4.3.7.12-1

OFFGAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE IS REQUIRED
1. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N.A.	Q(3)	M	**
2. (Deleted)					
3. (Deleted)					
4. MAIN CONDENSER OFFGAS PRE-TREATMENT RADIOACTIVITY MONITOR (STEAM JET AIR EJECTOR)					
a. Noble gas activity monitor	D	M	R(2)	Q(1)	**
5. (Deleted)					

SFCP TABLE 4.3.7.12-1 (Continued)

TABLE NOTATIONS

* (Deleted)

** During operation of the main condenser steam jet air ejector and offgas treatment system.

*** (Deleted)

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.

2. Circuit failure.

3. Instrument indicates a downscale failure.

4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Institute of Standards and Technology (NIST), previously National Bureau of Standards, or using standards that have been obtained from suppliers that participate in measurement assurance activities with NIST. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(3) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. 0.0 volume percent hydrogen, balance nitrogen, and

2. 4 volume percent hydrogen, balance nitrogen.

(4) (Deleted)

SFCP TABLE 4.3.9.1-1

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Reactor Vessel Water Level-High, Level 8	D	Q	R	1*

* With Thermal Power greater than or equal to 25% of Rated Thermal Power.

SFCP TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	OPERATIONAL CONDITIONS IN WHICH SAMPLE AND ANALYSIS IS REQUIRED
1. (Deleted)		
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	At least once per 7 days	1
3. (Deleted)		
4. Isotopic Analysis for Iodine	a) Refer to TS Table 4.4.5-1, Item 4.a.	1**, 2**, 3**, 4**
	b) Refer to TS Table 4.4.5-1, Item 4.b.	1, 2
5. Isotopic Analysis of an Off-gas Sample Including Quantitative Measurements for at least Xe-133, Xe-135, and Kr-88	At least once per 31 days	1

**Until the specific activity of the primary coolant system is restored to within its limits.

SFCP TABLE 4.8.1.1.2-1

INFORMATION ON THIS PAGE HAS BEEN DELETED