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

April 8, 2009

Mr. Timothy Rausch
Site Vice President
Oyster Creek Nuclear Generating Station
Exelon Generation Company, LLC
P.O. Box 388
Forked River, NJ 08731

SUBJECT: ISSUANCE OF RENEWED FACILITY OPERATING LICENSE NO. DPR-16 FOR OYSTER CREEK NUCLEAR GENERATING STATION

Dear Mr. Rausch:

The U.S. Nuclear Regulatory Commission (NRC) has issued the Renewed Facility Operating License No. DPR-16 for the Oyster Creek Nuclear Generating Station (Oyster Creek). The NRC issued the renewed facility operating license based on the staff's review of your application dated July 22, 2005 (ML052080185), as supplemented by letters submitted to the NRC through January 16, 2009 (documents listed in ML070890637, ML080230078 and ML090220226). Appendix A "Technical Specifications and Bases" and Appendix B "Environmental Technical Specifications" of the renewed operating license were not amended as a result of our review.

Renewed Facility Operating License No. DPR-16 expires at midnight April 9, 2029.

The NRC set forth the technical basis for issuing the renewed license in NUREG-1875, "Safety Evaluation Report Related to the License Renewal of the Oyster Creek Nuclear Generating Station," issued in March 2007 (ML070890637) and supplemented in September 2008 (ML080230078). The results of the environmental reviews related to the issuance of the renewed license appear in NUREG-1437, Supplement 28, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 28, Regarding Oyster Creek Nuclear Generating Station," issued January 2007 (ML070100234).

Enclosure 1 contains the Renewed Facility Operating License No. DPR-16 including Appendices A and B. Enclosure 2 is a copy of the related *Federal Register* notice of issuance of the renewed license. The original has been sent to the Office of the Federal Register for publication. If you have any questions regarding this renewed license, please feel free to contact me at 301-415-1906 or by e-mail at Lisa.Regner@nrc.gov.

Sincerely,

Lisa M. Regner, Senior Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-219

Enclosures:
1. Renewed Facility Operating License No. DPR-16
2. *Federal Register* Notice

cc: Distribution via Listserv

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-219

OYSTER CREEK NUCLEAR GENERATING STATION

RENEWED FACILITY OPERATING LICENSE

Renewed License No. DPR-16

1. The Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in License No. DPR-16, has now found that:

   A. The application for a Renewed Facility Operating License No. DPR-16 filed by the applicant complies 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 and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the Oyster Creek Nuclear Generating Station (Oyster Creek or the facility) has been completed in conformity with Provisional Construction Permit No. CPPR-15; the application, as amended; the provisions of the Act; and the rules and regulations of the Commission.

   C. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the term of this Renewed Facility Operating License No. DPR-16 on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1); and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by the renewed operating license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for the facility, and that any changes made to the facility's current licensing basis in order to comply with 10 CFR 54.29(a) are in accordance with the Act and the Commission's regulations;

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

E. 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 rules and regulations set forth in 10 CFR Chapter I (except as exempted from compliance in Section 2.D. below);

F. Exelon Generation Company, LLC (Exelon Generation Company) is technically qualified to engage in the activities authorized by this license in accordance with the rules and regulations of the Commission;

G. Exelon Generation Company has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

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

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

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

2. Facility Operating License No. DPR-16, dated July 2, 1991, as amended, is superseded in its entirety by Renewed Facility Operating License No. DPR-16, hereby issued to Exelon Generation Company, to read as follows:

A. This renewed license applies to the Oyster Creek Nuclear Generating Station, a boiling-water reactor and associated equipment (the facility). The facility is located in Ocean County, New Jersey, and is described in the licensee's Updated Final Safety Analysis Report, as supplemented and amended, and in the licensee's Environmental Report, as supplemented and amended.

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

(1) Pursuant to Section 104b of the Act and 10 CFR Part 50, to possess, use, and operate Oyster Creek Nuclear Generation Station at the designated location on the Oyster Creek site in Ocean County, New Jersey, in accordance with the procedures and limitations set forth in this renewed license;

(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess, and 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 Updated 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, or special nuclear materials 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, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear materials 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, source, or special nuclear materials as may be produced by the operation of the facility.

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 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 steady-state power levels not in excess of 1930 megawatts (thermal) (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 274, are hereby incorporated in the license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection

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 Safety Evaluation Report dated March 3, 1978, and supplements thereto, 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.

(4) 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: "Oyster Creek Nuclear Generating Station Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan, Revision 5." The set contains Safeguards Information protected under 10 CFR 73.21.

(5) Inspections of core spray spargers, piping and associated components will be performed in accordance with BWRVIP-18, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines," as approved by NRC staff's Final Safety Evaluation Report dated December 2, 1999.

(6) Long Range Planning Program – Deleted

(7) Reactor Vessel Integrated Surveillance Program

Exelon Generation Company is authorized to revise the Updated Final Safety Analysis Report (UFSAR) to allow implementation of the Boiling Water Reactor Vessel and Internals Project reactor pressure vessel Integrated Surveillance Program as the basis for demonstrating compliance with the requirements of Appendix H to Title 10 of the *Code of Federal Regulations* Part 50, "Reactor Vessel Material Surveillance Program Requirements," as set forth in the licensee's application dated December 20, 2002, and as supplemented on May 30, September 10, and November 3, 2003.

All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of the most recent NRC-approved version of the Boiling Water Reactor Vessel and Internals Project Integrated Surveillance Program appropriate for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC, as required by 10 CFR Part 50, Appendix H.

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

(8) 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

(9) 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.

(10) Upon implementation of Amendment No. 265 adopting TSTF-448, Revision 3, the assessment of CRE habitability as required by Specification 6.22.c.(ii), and the measurement of CRE pressure as required by Specification 6.22.d, shall be considered met. Following implementation:

(a) The first performance of the periodic assessment of CRE habitability, Specification 6.22.c.(ii), shall be within 3 years, plus the 9-month allowance of Specification 1.24.

(b) The first performance of the periodic measurement of CRE pressure, Specification 6.22.d, shall be within 24 months, plus the 180 days allowed by Specification 1.24, as measured from the date of the most recent successful pressure measurement test, or within 180 days if not performed previously.

(11) Inspection of Drywell Sand Bed Region

The licensee shall perform full scope inspections (as defined in Appendix A of the license renewal safety evaluation report dated March 20, 2007, and summarized in the Updated Final Safety Analysis Report (UFSAR)) of the drywell sand bed region every other refueling outage beginning in the refueling outage prior to April 9, 2009.

(12) Drywell Trenches

The licensee shall monitor the drywell trenches (as defined in Appendix A of the license renewal safety evaluation report dated March 20, 2007, and summarized in the UFSAR) every refueling outage to identify and eliminate the sources of water and shall receive NRC approval prior to restoring the trenches to their original design configuration.

(13) Engineering Study of Refueling Cavity Liner

The licensee shall perform an engineering study prior to April 9, 2009 to identify options to eliminate or reduce the leakage in the facility cavity liner.

(14) Three Dimensional Finite-Element Analysis of Drywell Shell

The licensee shall perform a three dimensional finite-element analysis of the drywell shell and shall provide to the NRC staff a report of the results prior to April 9, 2009.

(15) UFSAR Supplement Changes

The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be included in the next scheduled update to the UFSAR required by 10 CFR 50.71(e)(4), as modified by an exemption granted by letter dated July 7, 2004 (ADAMS Accession No. ML041340673), following the issuance of this renewed operating license. Until that update is complete, Exelon Generation Company may make changes to the programs and activities described in the supplement without prior Commission approval, provided that Exelon Generation Company evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

(16) License Renewal Commitments

The UFSAR supplement, as revised, describes certain future activities to be completed prior to April 9, 2009, and during the term of this renewed operating license No. DPR-16. Exelon Generation Company shall complete these activities in accordance with Appendix A of NUREG-1875, "Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station," dated March 2007, as supplemented on September 19, 2008, and shall notify the NRC in writing when implementation of those activities required prior to April 9, 2009 are complete and can be verified by NRC inspection.

(17) Biological Opinion

Within 30 days from the issuance date of the renewed license, Exelon Generation Company shall comply with the terms and conditions of the Incidental Take Statement associated with certain sea turtles in the Biological Opinion in effect or as subsequently issued by the National Marine Fisheries Service regarding operation of the facility.

D. The facility has been granted certain exemptions from the requirements of Section III.G of Appendix R to 10 CFR Part 50, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979."

This section relates to fire protection features for ensuring the systems and associated circuits used to achieve and maintain safe shutdown are free of fire damage. These exemptions were granted and sent to the licensee in letters dated March 24, 1986 and June 25,1990.

The facility has also been granted certain exemptions from the requirements of Section III.J of Appendix R to 10 CFR Part 50, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." This section relates to emergency lighting that shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto. This exemption was granted and sent to the licensee in a letter dated February 12, 1990.

In addition, the facility has been granted certain exemptions from Section 55.45(b)(2)(iii) and (iv) of 10 CFR Part 55, "Operators' Licenses." These sections contain requirements related to site-specific simulator certification and require that operating tests will not be administered on other than a certified or an approved simulation facility after May 26, 1991. These exemptions were granted and sent to the licensee in a letter dated March 25, 1991.

These exemptions granted pursuant to 10 CFR 50.12 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. 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.

3. Sale and License Transfer Conditions:

A. Deleted.

B. Deleted.

C. Deleted.

D. Deleted

E. Deleted

F. The decommissioning trust agreement for Oyster Creek must be in a form acceptable to the NRC.

G. With respect to the decommissioning trust fund, investments in the securities or other obligations of Exelon Corporation, Exelon Generation Company, or their affiliates, successors, or assigns shall be prohibited. Except for investments tied to market indexes or other nonnuclear sector mutual funds, investments in any entity owning one or more nuclear power plants are prohibited.

H. The decommissioning trust agreement for Oyster Creek must provide that no disbursements or payments from the trust shall be made by the trustee unless the trustee has first given the NRC 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 Director, Office of Nuclear Reactor Regulation.

I. The decommissioning trust agreement must provide that the agreement cannot be amended in any material respect without 30-days prior written notification to the Director, Office of Nuclear Reactor Regulation.

J. 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.

K. 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 the Oyster Creek license and the requirements of the Order approving the transfer, and consistent with the safety evaluation supporting such Order.

L. DELETED

M. At the time of the closing of the transfer of Oyster Creek, and the respective license from AmerGen Energy Company, LLC (AmerGen) to Exelon Generation Company, AmerGen shall transfer to Exelon Generation Company ownership and control of AmerGen Oyster Creek NQF, LLC, and AmerGen Consolidation, LLC shall be merged into Exelon Generation Consolidation, LLC. Also at the time of the closing, decommissioning funding assurance provided by Exelon Generation Company, using an additional method allowed under 10 CFR 50.75 if necessary, must be equal to or greater than the minimum amount calculated on that date pursuant to, and required by 10 CFR 50.75 for Oyster Creek. Furthermore, funds dedicated for Oyster Creek prior to closing shall remain dedicated to Oyster Creek following the closing. The name of AmerGen Oyster Creek NQF, LLC shall be changed to Exelon Generation Oyster Creek NQF, LLC at the time of the closing.

4. This license is effective as of the date of issuance and shall expire at midnight on April 9, 2029.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce S. Mallett
Deputy Executive Director for Reactor
and Preparedness Programs
Office of the Executive Director for Operations

Attachment:
Appendices A and B -
Technical Specifications

Date of Issuance: April 8, 2009

Docket No. 50-219

October 1, 1986

APPENDIX A
TO PROVISIONAL OPERATING LICENSE DPR-16*
TECHNICAL SPECIFICATIONS

AND BASES

FOR

OYSTER CREEK NUCLEAR POWER PLANT

UNIT NO. 1

OCEAN COUNTY, NEW JERSEY

AMERGEN ENERGY COMPANY, LLC

*Per Errata Sheet dated 4-6-69

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*Issued by NRC Order dated 10-24-80

SECTION I
DEFINITIONS

The following frequently used terms are defined to aid in the uniform interpretation of the specifications.

1.1 OPERABLE-OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electrical power sources, cooling of 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).

A verification of operability is an administrative check, by examination of appropriate plant records (logs, surveillance test records) to determine that a system, subsystem, train, component or device is not inoperable. Such verification does not preclude the demonstration (testing) of a given system, subsystem, train, component or device to determine operability.

1.2 OPERATING

Operating means that a system or component is performing its required function.

1.3 POWER OPERATION

Power operation is any operation when the reactor is in the startup mode or run mode except when primary containment integrity is not required.

1.4 STARTUP MODE

The reactor is in the startup mode when the reactor mode switch is in the startup mode position. In this mode, the reactor protection system scram trips initiated by condenser low vacuum and main steam line isolation valve closure are bypassed when reactor pressure is less than 600 psig; the low pressure main steamline isolation valve closure is bypassed; the IRM trips for rod block and scram are operable; and the SRM trips for rod block are operable.

1.5 RUN MODE

The reactor is in the run mode when the reactor mode switch is in the run mode position. In this mode, the reactor protection system is energized with APRM protection and the control rod withdrawal interlocks are in service.

1.6 SHUTDOWN CONDITION

The reactor is in the SHUTDOWN CONDITION when there is fuel in the reactor vessel, the reactor is subcritical, all operable control rods are fully inserted, and the mode switch is in the shutdown mode position. In this position, a control rod block is initiated.

1.7 COLD SHUTDOWN CONDITION

The reactor is in the COLD SHUTDOWN CONDITION when the reactor is in the SHUTDOWN CONDITION, and (except during REACTOR VESSEL PRESSURE TESTING), the reactor coolant system is maintained at less than 212°F and vented.

1.8 PLACE IN SHUTDOWN CONDITION

Proceed with and maintain an uninterrupted normal plant shutdown operation until the SHUTDOWN CONDITION is met.

1.9 PLACE IN COLD SHUTDOWN CONDITION

Proceed with and maintain an uninterrupted normal plant shutdown operation until the COLD SHUTDOWN CONDITION is met.

1.10 PLACE IN ISOLATED CONDITION

Proceed with and maintain an uninterrupted normal isolation of the reactor from the turbine condenser system including closure of the main steam isolation valves.

1.11 REFUEL MODE

The reactor is in the REFUEL MODE when the reactor mode switch is in the REFUEL MODE position and there is fuel in the reactor vessel. In this mode the refueling platform interlocks are in operation.

1.12 REFUELING OUTAGE

For the purpose of designating frequency of testing and surveillance, a REFUELING OUTAGE shall mean a regularly scheduled REFUELING OUTAGE. Following the first REFUELING OUTAGE, successive tests or surveillances shall be performed at least once per 24 months.

1.13 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY means that the drywell and adsorption chamber are closed and all of the following conditions are satisfied:

A. All non-automatic primary containment isolation valves which are not required to be open for plant operation are closed.
B. At least one door in the airlock is closed and sealed.
C. All automatic primary containment isolation valves are OPERABLE or the affected penetration is isolated.
D. All blind flanges and manways are closed.

1.14 SECONDARY CONTAINMENT INTEGRITY

Secondary containment integrity means that the reactor building is closed and the following conditions are met:

A. At least one door at each access opening is closed.
(Note: Momentary opening and closing of the trunnion room door does not constitute a loss of secondary containment intergrity.)

B. The standby gas treatment system is operable.

C. All automatic secondary containment isolation valves are operable or are secured in the closed position.

1.15 (DELETED)

1.16 RATED FLUX

Rated flux is the neutron flux that corresponds to a steady state power level of 1930 MW(t). Use of the term 100 percent also refers to the 1930 thermal megawatt power level.

1.17 REACTOR THERMAL POWER-TO-WATER

Reactor thermal power-to-water is the sum of (1) the instantaneous integral over the entire fuel clad outer surface of the product of heat transfer area increment and position dependent heat flux and (2) the instantaneous rate of energy deposition by neutron and gamma reactions in all the water and core components except fuel rods in the cylindrical volume defined by the active core height and the inner surface of the core shroud.

1.18 PROTECTIVE INSTRUMENTATION LOGIC DEFINITIONS

A. Instrument Channel

An instrument channel means an arrangement of a sensor and auxiliary equipment required to generate and transmit to a trip system a single trip signal related to the plant parameter monitored by that instrument channel.

B. Trip System

A trip system means an arrangement of instrument channel trip signals and auxiliary equipment required to initiate action to accomplish a protective trip function. A trip system may require one or more instrument channel trip signals related to one or more plant parameters in order to initiate trip system action. Initiation of protective action may require the tripping of a single trip system (e.g., initiation of a core spray loop, automatic depressurization, isolation of an isolation condenser, offgas system isolation, reactor building isolation, standby gas treatment and rod block) or the coincident tripping of two trip systems (e.g., initiation of scram, isolation condenser, reactor isolation, and primary containment isolation).

1.19 INSTRUMENTATION SURVEILLANCE DEFINITIONS

A. CHANNEL CHECK

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

B. CHANNEL FUNCTIONAL TEST

A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

C. CHANNEL CALIBRATION

A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an in place qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.

D. Source Check

A SOURCE CHECK is the qualitative assessment of channel response when the channel sensor is exposed to a source of radioactivity.

1.20 FDSAR

Oyster Creek Unit No. 1 Facility Description and Safety Analysis Report as amended by revised pages and figure changes contained in Amendments 14, 31 and 45* and continuing through Amendment 79.

1.21 CORE ALTERATION

A core alteration is the addition, removal, relocation or other manual movement of fuel or controls in the reactor core. Control rod movement with the control rod drive hydraulic system is not defined as a core alteration.

1.22 CRITICAL POWER RATIO

The critical power ratio is the ratio of that power in a fuel assembly which is calculated, by application of an NRC approved CPR correlation, to cause some point in that assembly to experience boiling transition divided by the actual assembly operating power.

1.23 STAGGERED TEST BASIS

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.

*Per Erata dtd. 4-9-69

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

1.24 SURVEILLANCE REQUIREMENTS

Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within the safety limits, and that the limiting conditions of operation will be met. Each surveillance requirement shall be performed within the specified time interval with a maximum allowable extension not to exceed 25% of the surveillance interval. [1]

Surveillance requirements for systems and components are applicable only during the modes of operation for which the system or components are required to be operable, unless otherwise stated in the specification.

This definition 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 a fuel cycle length surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for the surveillance that are not performed during refueling outages. The limitation of this definition is based on engineering judgement 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.

1.25 APPENDIX J TEST PRESSURE

For the purpose of conducting leak rate tests to meet 10 CFR 50 Appendix J, P_a = 35 psig.

1.26 FRACTION OF LIMITING POWER DENSITY (FLPD)

The fraction of limiting power density is the ratio of the linear heat generation rate (LHGR) existing at a given location to the design LHGR for that bundle type.

1.27 MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)

The maximum fraction of limiting power density is the highest value existing in the core of the fraction of limiting power density (FLPD).

[1] For the 10 CFR 50 Appendix J Type A test, the 25% shall not exceed 15 months.

1.28 FRACTION OF RATED POWER (FRP)

The FRACTION OF RATED POWER is the ratio of core THERMAL POWER to RATED THERMAL POWER.

1.29 TOP OF ACTIVE FUEL (TAF) - 353.3 inches above vessel zero.

1.30 REPORTABLE EVENT

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

1.31 IDENTIFIED LEAKAGE

IDENTIFIED LEAKAGE is that leakage which is collected in the primary containment equipment drain tank and eventually transferred to radwaste for processing.

1.32 UNIDENTIFIED LEAKAGE

UNIDENTIFIED LEAKAGE is all measured leakage that is other than identified leakage.

1.33 PROCESS CONTROL PLAN

The PROCESS CONTROL PLAN shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61 and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

1.34 AUGMENTED OFFGAS SYSTEM (AOG)

The AUGMENTED OFFGAS SYSTEM is a system designed and installed to holdup and/or process radioactive gases from the main condenser offgas system for the purpose of reducing the radioactive material content of the gases before release to the environs.

1.35 MEMBER OF THE PUBLIC

A MEMBER OF THE PUBLIC is a person who is not occupationally associated with Exelon Generation Company, LLC and who does not normally frequent the Oyster Creek Nuclear Generating Station site. The category does not include contractors, contractor employees, vendors, or persons who enter the site to make deliveries, to service equipment, work on the site, or for other purposes associated with plant functions.

1.36 OFFSITE DOSE CALCULATION MANUAL (ODCM)

The OFFSITE DOSE CALCULATION MANUAL shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluent, in the calculation of gaseous and liquid effluent monitoring Alarm/trip Setpoints, and in the conduct of the Environmental Radiological 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 Radioactive Effluent Release Report AND Annual Radiological Environmental Operating Report required by Specifications 6.9.1.d and 6.9.1.e, respectively.

1.37 PURGE

PURGE OR PURGING is the controlled process of discharging air or gas from a confinement and replacing it with air or gas.

1.38 SITE BOUNDARY

The SITE BOUNDARY is the perimeter line around the OCNGS beyond which the land is neither owned, leased nor otherwise subject to control by Exelon Generation Company, LLC (ref. ODCM). The area outside the SITE BOUNDARY is termed OFFSITE or UNRESTRICTED AREA.

1.39 REACTOR VESSEL PRESSURE TESTING

System pressure testing required by ASME Code Section XI, Article IWA-5000, including system leakage and hydrostatic test, with reactor vessel completely water solid, core not critical and section 3.2.A satisfied.

1.40 SUBSTANTIVE CHANGES

SUBSTANTIVE CHANGES are those which affect the activities associated with a document or the document's meaning or intent. Example of non-substantive changes are: (1) correcting spelling, (2) adding (but not deleting) sign-off spaces, (3) blocking in notes, cautions, etc, (4) changes in corporate and personnel titles which do not reassign responsibilities and which are not referenced in the Appendix A Technical Specifications, and (5) changes in nomenclature or editorial changes which clearly do not change function, meaning or intent.

1.41 DOSE EQUIVALENT I-131

DOSE EQUIVALENT I-131 shall be that concentration of I-131 microcuries per gram which alone would produce the same thyroid dose as the quantity and isotopic mixture of I131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table E-7 or Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluences for the Purpose of Evaluating Compliance with 10 CFR Par 40 Appendix I."

1.42 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) shall be applicable to a specific planar height and is equal to the sum of the heat generation rate per unit length of fuel rod for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle at that height.

1.43 CORE OPERATING LIMITS REPORT

The Oyster Creek CORE OPERATING LIMITS REPORT (COLR) is the document that provides 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 Specification 6.9.1.f. Plant operation within these operating limits is addressed in individual specifications.

1.44 LOCAL LINEAR HEAT GENERATION RATE

The LOCAL LINEAR HEAT GENERATION RATE (LLHGR) shall be applicable to a specific planar height and is equal to the AVERAGE PLANAR LINEAR GENERATION RATE (APLHGR) at the specified height multiplied by the local peaking factor at that height.

1.45 SHUTDOWN MARGIN (SDM)

SHUTDOWN MARGIN is the amount of reactivity by which the reactor would be subcritical when the control rod with the highest reactivity worth is fully withdrawn, all other operable control rods are fully inserted, all inoperable control rods are at their current position, reactor water temperature is 68§F, and the reactor fuel is xenon free. Determination of the control rod with the highest reactivity worth includes consideration of any inoperable control rods which are not fully inserted.

1.46 IDLE RECIRCULATION LOOP

A recirculation loop is idle when its discharge valve is in the closed position and its discharge bypass valve and suction valve are in the open position.

1.47 ISOLATED RECIRCULATION LOOP

A recirculation loop is fully isolated when the suction valve, discharge valve and discharge bypass valve are in the closed position.

1.48 OPERATIONAL CONDITION

The reactor plant operational status as to criticality, reactor mode switch position, reactor coolant temperature, and/or specific system status. These conditions consist of POWER OPERATION, STARTUP MODE, SHUTDOWN CONDITION, COLD SHUTDOWN CONDITION, and REFUEL MODE. A change or entry into an operating condition is signified by movement of the reactor mode switch or a change in reactor coolant temperature from <212°F to ≥212°F.

1.49 RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1930 MWt.

1.50 THERMAL POWER

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

1.51 PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.23.

SECTION 2

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMIT - FUEL CLADDING INTEGRITY

Applicability: Applies to the interrelated variables associated with fuel thermal behavior.

Objective: To establish limits on the important thermal hydraulic variables to assure the integrity of the fuel cladding.

Specifications:

A. When the reactor pressure is greater than or equal to 800 psia and the core flow is greater than or equal to 10% of rated, the existence of a minimum CRITICAL POWER RATIO (MCPR) less than 1.10 for both four or five loop operation and 1.12 for three loop operation shall constitute violation of the fuel cladding integrity safety limit.

B. When the reactor pressure is less than 800 psia or the core flow is less than 10% of rated, the core THERMAL POWER shall not exceed 25% of RATED THERMAL POWER.

C. In the event that reactor parameters exceed the limiting safety system settings in Specification 2.3 and a reactor scram is not initiated by the associated protective instrumentation, the reactor shall be brought to, and remain in, the COLD SHUTDOWN CONDITION until an analysis is performed to determine whether the safety limit established in Specification 2.1.A and 2.1.B was exceeded.

D. During all modes of reactor operation with irradiated fuel in the reactor vessel, the water level shall not be less than 4'8" above the TOP OF ACTIVE FUEL.

Bases:

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 procedure 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 CRITICAL POWER RATIO 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(1) is determined using the General Electric Thermal Analysis Basis, GETAB(2), which is a statistical model that combines all of the uncertainties in operating parameters and the procedures used to calculate critical power. The power distribution uncertainty is treated in accordance with a NRC approved method(3)(4). The revised analysis results in lower SLMCPR values primarily due to an improved treatment of the power distribution uncertainty that reduces the conservatism of the GETAB method of power allocation. All other uncertainties are consistent with the GETAB basis. The probability of the occurrence of boiling transition is determined using the General Electric Critical Quality (X) - Boiling Length (L), GEXL, correlation.

The use of the GEXL correlation is not valid for the critical power calculations at pressures below 800 psia or core flows less than 10% of rated. Therefore, the fuel cladding integrity safety limit is protected by limiting the core THERMAL POWER.

At pressures below 800 psia, the core elevation pressure drop (0 power, 0 flow) is greater than 4.56 psi. At low power and all flows this pressure differential is maintained in the bypass region of the core. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and all flows will always be greater than 4.56 psi. Analyses show that with a flow of 28×10^3 lbs/hr bundle flow, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, bundle flow with a 4.56 psi driving head will be greater than 28×10^3 lbs/hr irrespective of total core flow and independent of bundle power for the range of bundle powers of concern. 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 core THERMAL POWER of more than 50%. Thus, a core THERMAL POWER limit of 25% for reactor pressures below 800 psi or core flow less than 10% is conservative.

Plant safety analyses have shown that the scrams caused by exceeding any safety setting will assure that the Safety Limit of Specification 2.1.A or 2.1.B will not be exceeded. Scram times are checked periodically to assure the insertion times are adequate. The THERMAL POWER transient resulting when a scram is accomplished other than by the expected scram signal (e.g., scram from neutron flux following closure of the main turbine stop valves) does not necessarily cause fuel damage. Specification 2.1.C requires that appropriate analysis be performed to verify that backup protective instrumentation has prevented exceeding the fuel cladding integrity safety limit prior to resumption of POWER OPERATION. The concept of not approaching a Safety Limit provided scram signals are OPERABLE is supported by the extensive plant safety analysis.

If reactor water level should drop below the TOP OF ACTIVE FUEL, the ability to cool the core is reduced. This reduction in core cooling capability could lead to elevated cladding temperatures and clad perforation. With a water level above the TOP OF ACTIVE FUEL, adequate cooling is maintained and the decay heat can easily be accommodated. It should be noted that during power generation there is no clearly defined water level inside the shroud and what actually exists is a mixture level. This mixture begins within the active fuel region and extends up through the moisture separators. For the purpose of this specification water level is defined to include mixture level during power operations.

The lowest point at which the water level can presently be monitored is 4'8" above the TOP OF ACTIVE FUEL. Although the lowest reactor water level limit which ensures adequate core cooling is the TOP OF ACTIVE FUEL, the safety limit has been conservatively established at 4'8" above the TOP OF ACTIVE FUEL.

<u>REFERENCES</u>

(1) NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel (GESTAR II) (latest approved version as specified in the COLR)

(2) General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application, NEDO-10958-A, January 1977.

(3) NEDC-32694P-A, Power Distribution Uncertainties for Safety Limit MCPR Evaluations.

(4) NEDC-32601P-A, Methodology and Uncertainties for Safety Limit MCPR Evaluations.

2.2 SAFETY LIMIT - REACTOR COOLANT SYSTEM PRESSURE

Applicability: Applies to the limit on reactor coolant system pressure.

Objective: Preserve the integrity of the reactor coolant system.

Specification: The reactor coolant system pressure shall not exceed 1375 psig whenever irradiated fuel is in the reactor vessel.

Bases:

The reactor coolant system(1) represents an important barrier in the prevention of the uncontrolled release of fission products. It is essential that the integrity of this system be protected by establishing a pressure limit to be observed whenever there is irradiated fuel in the reactor vessel.

The pressure safety limit of 1375 psig was derived from the design pressures of the reactor pressure vessel, coolant piping, and isolation condenser. The respective design pressures are 1250 psig at 575°F, 1200 psig at 570°F and 1250 psig at 575°F. The pressure safety limit was chosen as the lower of the pressure transients permitted by the applicable design codes: ASME Boiler and Pressure Vessel Code Section I for the pressure vessel, ASME Boiler and Pressure Vessel Code Section III for the isolation condenser and the ASA Piping Code Section B31.1 for the reactor coolant system piping. The ASME Code permits pressure transients up to 10% over the design pressure (110% x 1250 = 1375 psig) and the ASA Code permits pressure transients up to 15% over the design pressure (115% x 1200 = 1380 psig).

The design basis for the reactor pressure vessel makes evident the substantial margin of protection against failure at the safety pressure limit of 1375 psig. The vessel has been designed for a general membrane stress no greater than 20,000 psi at an internal pressure of 1250 psig and temperature of 575°F; this is more than a factor of 2 below the yield strength of 42,300 psi at this temperature. At the pressure limit of 1375 psig, the general membrane stress increases to 22,000 psi, still almost a factor of 2 below the yield strength. The reactor coolant system piping provides a comparable margin of protection at the established pressure safety limit.

The normal operating pressure of the reactor coolant system is 1020 psig. An overpressurization analysis (2) is performed each cycle to assure that the pressure safety limit is not exceeded. The reactor fuel cladding can withstand pressures up to the safety limit, 1375 psig, without collapsing. (3) Finally, reactor system pressure is continuously monitored in the control room during reactor operation.

REFERENCES

(1) FDSAR, Volume I, Section IV.
(2) NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel (GESTAR II) (latest approved version as specified in the COLR).
(3) FDSAR, Volume I, Section III-2.3.3

2.3 LIMITING SAFETY SYSTEM SETTINGS

Applicability: Applies to trip settings on automatic protective devices related to variables on which safety limits have been placed.

Objective: To provide automatic corrective action to prevent the safety limits from being exceeded.

Specification: Limiting safety system settings shall be as follows:

FUNCTION	LIMITING SAFETY SYSTEM SETTINGS
A. Neutron Flux, Scram	
A.1 APRM	When the reactor mode switch is in the Run position, the APRM flux scram setting shall be the minimum of:

For $W \geq 0.0 \times 10^6$ lb / hr:

$$S \leq \left[\left(0.90 \times 10^{-6}\right) W + 65.1\right] \frac{FRP}{MFLPD} \quad ; \text{ or}$$

The applicable stability protection settings, as defined in the COLR,

with a maximum setpoint of 120.0% for core flow equal to 61×10^6 lb/hr and greater,

where:

S = setting in percent of rated power
W = recirculation flow (lb/hr)

FRP = fraction of RATED THERMAL POWER is the ratio of core THERMAL POWER to RATED THERMAL POWER

MFLPD = maximum fraction of limiting power density where the limiting power density for each bundle is the design linear heat generation rate for that bundle.

The ratio of FRP/MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0 in which case the actual operating value will be used.

This adjustment may be accomplished by increasing the APRM gain and thus reducing the flow reference APRM High Flux Scram Curve by the reciprocal of the APRM gain change.

A.2 IRM	≤ 38.4 percent of rated neutron flux
A.3 APRM Downscale	≥ 2% RATED THERMAL POWER coincident with IRM Upscale (high-high) or Inoperative

	FUNCTION	LIMITING SAFETY SYSTEM SETTINGS
B.	Neutron Flux, Control Rod Block	The Rod Block setting shall be the minimum of: For $W \geq 0.0 \times 10^6 lb/hr$: $S \leq \left[(0.90 \times 10^{-6}) W + 60.1\right] \frac{FRP}{MFLPD}$; or The applicable stability protection settings, as defined in the COLR, with a maximum setpoint of 115.0% for core flow equal to 61×10^6 lb/hr and greater. The definitions of S, W, FRP and MFLPD used above for the APRM scram trip apply. The ratio of FRP to MFLPD shall be set equal to 1.0 unless the actual operating value is less than 1.0, in which case the actual operating value will be used. This adjustment may be accomplished by increasing the APRM gain and thus reducing the flow referenced APRM rod block curve by the reciprocal of the APRM gain change.
C.	Reactor High Pressure, Scram	≤1060 psig
D.	Reactor High Pressure, Relief Valves Initiation	2 @ ≤ 1085 psig 3 @ ≤ 1105 psig
E.	Reactor High Pressure, Isolation Condenser Initiation	≤ 1060 psig with time delay ≤ 3 seconds
F.	Reactor High Pressure, Safety Valve Initiation	4 @ 1212 psig ± 36 psi 5 @ 1221 psig ± 36 psi
G.	Low Pressure Main Steam MSIV Closure	≥ 825 psig (initiated in IRM Line, range 10)
H.	Main Steam Line Isolation Valve Closure, Scram	≤10% Valve Closure from full open

FUNCTION			LIMITING SAFETY SYSTEM SETTINGS
I.	Reactor Low Water Level, Scram		≥11'5" above the top of the active fuel as indicated under normal operating conditions
J.	Reactor Low-Low Water Level, Main Steam Line Isolation Valve Closure		≥7'2" above the top of the active fuel as indicated under normal operating conditions
K.	Reactor Low-Low Water Level, Core Spray Initiation		≥7'2" above the top of the active fuel
L.	Reactor Low-Low Water Level, Isolation Condenser Initiation		≥7'2" above the top of the active Fuel with time delay ≤3 seconds
M.	Turbine Trip, Scram		10 percent turbine stop valve(s) closure from full open
N.	Generator Load Rejection, Scram		Initiate upon loss of oil pressure from turbine acceleration relay
O.	DELETED		
P.	Loss of Power		
	1)	4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	0 volts with 3 seconds ± 0.5 seconds time delay
	2)	4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	3840 (+20V, -40V) volts 10 ± 10% (1.0) second time delay

2.3 LIMITING SAFETY SYSTEM SETTINGS

Bases:

Safety limits have been established in Specifications 2.1 and 2.2 to protect the integrity of the fuel cladding and reactor coolant system barriers, respectively. Automatic protective devices have been provided in the plant design for corrective actions to prevent the safety limits from being exceeded in normal operation or operational transients caused by reasonably expected single operator error or equipment malfunction. This Specification establishes the trip settings for these automatic protection devices.

The Average Power Range Monitor, APRM[1], trip setting has been established to assure never reaching the fuel cladding integrity safety limit. The APRM system responds to changes in neutron flux. However, near the RATED THERMAL POWER, the APRM is calibrated using a plant heat balance, so that the neutron flux that is sensed is read out as percent of the RATED THERMAL POWER. For slow maneuvers, such as those where core THERMAL POWER, surface heat flux, and the power transferred to the water follow the neutron flux, the APRM will read reactor THERMAL POWER. For fast transients, the neutron flux will lead the power transferred from the cladding to the water due to the effect of the fuel time constant. Therefore, when the neutron flux increases to the scram setting, the percent increase in heat flux and power transferred to the water will be less than the percent increase in neutron flux.

The APRM trip setting will be varied automatically with recirculation flow, with the trip setting at the rated flow of 61.0 x 10^6 lb/hr or greater being 120.0% of rated neutron flux. Based on a complete evaluation of the reactor dynamic performance during normal operation as well as expected maneuvers and the various mechanical failures, it was concluded that sufficient protection is provided by the simple fixed scram setting (2,3). However, in response to expressed beliefs (4) that variation of APRM flux scram with recirculation flow is a prudent measure to ensure safe plant operation, the scram setting will be varied with recirculation flow.

An increase in the APRM scram trip setting would decrease the margin present before the fuel cladding integrity safety limit is reached. The APRM scram trip setting was determined by an analysis of margins required to provide a reasonable range for maneuvering during operation. Reducing this operating margin would increase the frequency of spurious scrams, which could have an adverse effect on reactor safety because of the resulting thermal stresses and the unnecessary challenge to the operators. Thus, the APRM scram trip setting was selected because it provides adequate margin for the fuel cladding integrity safety limit and yet allows operating margin that reduces the possibility of unnecessary scrams.

The scram trip setting must be adjusted to ensure that the LHGR transient peak is not increased for any combination of maximum fraction of limiting power density (MFLPD) and reactor core THERMAL POWER. The scram setting is adjusted in accordance with the formula in Specification 2.3.A, when the MFLPD is greater than the fraction of the rated power (FRP). The adjustment may be accomplished by increasing the APRM gain and thus reducing the flow referenced APRM High Flux Scram Curve by the reciprocal of the APRM gain change.

The low pressure isolation of the main steam line at 825 psig was provided to give protection against fast reactor depressurization and the resulting rapid cool-down of the vessel. The low-pressure isolation protection is enabled with entry into IRM range 10 or the RUN mode. In addition, a scram on 10% main steam isolation valve (MSIV) closure anticipates the pressure and flux transients which occur during normal or inadvertent isolation valve closure. Bypass of the MSIV closure scram function below 600 psig is permitted to provide sealing steam and allow the establishment of condenser vacuum. Advantage is taken of the MSIV scram feature to provide protection for the low-pressure portion of the fuel cladding integrity safety limit. To continue operation beyond 12% of rated power, the IRM's must be transferred into range 10. Reactor pressure must be above 825 psig to successfully transfer the IRM's into range 10. Entry into range 10 at less than 825 psig will result in main steam line isolation valve closure and MSIV closure scram. This provides automatic scram protection for the fuel cladding integrity safety limit which allows a maximum power of 25% of rated at pressures below 800 psia. Below 600 psig, when the MSIV closure scram is bypassed, scram protection is provided by the IRMs.

Operation of the reactor at pressure lower than 825 psig requires that the mode switch be in the STARTUP position and the IRMs be in range 9 or lower. The protection for the fuel clad integrity safety limit is provided by the IRM high neutron flux scram in each IRM range. The IRM range 9 high flux scram setting at 12% of rated power provides adequate thermal margin to the safety limit of 25% of rated power. There are few possible significant sources of rapid reactivity input to the system through IRM range 9:effects of increasing pressure at zero and low void content are minor; reactivity excursions from colder makeup water, will cause an IRM high flux trip; and the control rod sequences are constrained by operating procedures backed up by the rod worth minimizer. In the unlikely event of a rapid or uncontrolled increase in reactivity, the IRM system would be more than adequate to ensure a scram before power could exceed the safety limit. Furthermore, a mechanical stop on the IRM range switch requires an operator to pull up on the switch handle to pass through the stop and enter range 10. This provides protection against an inadvertent entry into range 10 at low pressures. The IRM scram remains active until the mode switch is placed in the RUN position at which time the trip becomes a coincident IRM upscale, APRM downscale scram.

The adequacy of the IRM scram was determined by comparing the scram level on the IRM range 10 to the scram level on the APRMs at 30% of rated flow. The IRM scram is at 38.4% of rated power while the APRM scram is at 59.3% of rated power. The minimum flow for Oyster Creek is at 30% of rated flow and this would be the lowest APRM scram point. The increased recirculation flow to 65% of flow will provide additional margin to CPR Limits. The APRM scram at 65% of rated flow is 100.8% of rated power, while the IRM range 10 scram remains at 38.4% of rated power. Therefore, transients requiring a scram based on flux excursion will be terminated sooner with a IRM range 10 scram than with an APRM scram. The transients requiring a scram by nuclear instrumentation are the loss of feedwater heating and the improper startup of an idle recirculation loop. The loss of feedwater heating transient is not affected by the range 10 IRM since the feedwater heaters will not be put into service until after the LPRM downscales have cleared, thus insuring the operability of the APRM system. This will be administratively controlled. The improper startup of an idle recirculation loop becomes less severe at lower power level and the IRM scram would be adequate to terminate the flux excursion.

The Rod Worth Minimizer is not required beyond 10% of rated power. The ability of the IRMs to terminate a rod withdrawal transient is limited due to the number and location of IRM detectors. An evaluation was performed that showed by maintaining a minimum recirculation flow of 39.65×10^6 lb/hr in range 10 a complete rod withdrawal initiated at 35% of rated power or less would not result in violating the fuel cladding safety limit. Therefore, a rod block on the IRMs at less than 35% of rated power would be adequate protection against a rod withdrawal transient.

Reactor power level may be varied by moving control rods or by varying the recirculation flow rate. The APRM system provides a control rod block to prevent gross rod withdrawal at constant recirculation flow rate to protect against grossly exceeding the MCPR Fuel Cladding Integrity Safety Limit. This rod block trip setting, which is automatically varied with recirculation loop flow rate, prevents an increase in the reactor power level to excessive values due to control rod withdrawal. The flow variable trip setting provides substantial margin from fuel damage, assuming a steady-state operation at the trip setting, over the entire recirculation flow range. The margin to the safety limit increases as the flow decreases for the specified trip setting versus flow relationship. Therefore, the worst-case MCPR, which could occur during steady-state operation, is at 115% of the RATED THERMAL POWER because of the APRM rod block trip setting. The actual power distribution in the core is established by specified control rod sequences and is monitored continuously by the incore LPRM system. As with APRM scram trip setting, the APRM rod block trip setting is adjusted downward if the maximum fraction of limiting power density exceeds the fraction of the rated power, thus preserving the APRM rod block safety margin. As with the scram setting, this may be accomplished by adjusting the APRM gains.

The settings on the reactor high pressure scram, anticipatory scrams, reactor coolant system relief valves and isolation condenser have been established to assure never reaching the reactor coolant system pressure safety limit as well as assuring the system pressure does not exceed the range of the fuel cladding integrity safety limit. In addition, the APRM neutron flux scram and the turbine bypass system also provide protection for these safety limits, e.g., turbine trip and loss of electrical load transients (5). In addition to preventing power operation above 1060 psig, the pressure scram backs up the other scrams for these transients and other steam line isolation type transients. Actuation of the isolation condenser during these transients removes the reactor decay heat without further loss of reactor coolant thus protecting the reactor water level safety limit.

The reactor coolant system safety valves offer yet another protective feature for the reactor coolant system pressure safety limit since these valves are sized assuming no credit for other pressure relieving devices. In compliance with Section I of the ASME Boiler and Pressure Vessel Code, the safety valve must be set to open at a pressure no higher than 103% of design pressure, and they must limit the reactor pressure to no more than 110% of design pressure. The safety valves are sized according to the Code for a condition of main steam isolation valve closure while operating at 1930 MWt, followed by (1) a reactor scram on high neutron flux, (2) failure of the recirculation pump trip on high pressure, (3) failure of the turbine bypass valves to open, and (4) failure of the isolation condensers and relief valves to operate. Under these conditions, a total of 9 safety valves are required to turn the pressure transient. The ASME B&PV Code allows an as-found ± 3% of setpoint pressure variation in the lift point of the valves. The as-left Safety Valve setpoint tolerance requirement will remain ± 1% per GE NEDC-31753P (approval letter dated March 8, 1993) recommendation. This variation is recognized in Specification 4.3.

The low level water level trip setting of 11'5" above the top of the active fuel has been established to assure that the reactor is not operated at a water level below that for which the fuel cladding integrity safety limit is applicable. With the scram set at this point, the generation of steam, and thus the loss of inventory is stopped. For example, for a loss of feedwater flow a reactor scram at the value indicated and isolation valve closure at the low-low water level set point results in more than 4 feet of water remaining above the core after isolation (6). The TAF definition of 353.3 inches from vessel zero is based on a fuel length of 144 inches and it is applicable to the current fuel length of 145.24 inches. The difference in fuel length does not result in changes to any analyses or set points.

During periods when the reactor is shut down, decay heat is present and adequate water level must be maintained to provide core cooling. Thus, the low-low level trip point of 7'2" above the core is provided to actuate the core spray system (when the core spray system is required as identified in Section 3.4) to provide cooling water should the level drop to this point.*

The turbine stop valve(s) scram is provided to anticipate the pressure, neutron flux, and heat flux increase caused by the rapid closure of the turbine stop valve(s) and failure of the turbine bypass system.

The generator load rejection scram is provided to anticipate the rapid increase in pressure and neutron flux resulting from fast closure of the turbine control valves to a load rejection and failure of the turbine bypass system. This scram is initiated by the loss of turbine acceleration relay oil pressure. The timing for this scram is almost identical to the turbine trip.

The undervoltage protection system includes a 2 out of 3 coincident logic relay designed to shift emergency buses to on-site power should normal power be degraded to an unacceptable level. There is a separate relay system designed to shift emergency buses C and D to on-site power should normal power be lost. The trip points and time delay settings have been selected to assure an adequate power source to emergency safeguards systems in the event of a total loss of normal power or degraded conditions which would adversely affect the functioning of engineered safety features connected to the plant emergency power distribution system.

The APRM downscale signal insures that there is adequate Neutron Monitoring System protection if the reactor mode switch is placed in the run position prior to APRMs coming on scale. With the reactor mode switch in run, an APRM downscale signal coincident with an associate IRM Upscale (High-High) or Inoperative signal generates a trip signal. This function is not specifically credited in the accident analyses but it is retained for overall redundancy and diversity of the RPS.

<u>References</u>

(1) FDSAR, Volume 1, Section VII-4.2.4.2

(2) FDSAR, Amendment 28, Item III.A-12

(3) FDSAR, Amendment 32, Question 13

(4) Letters, Peter A. Morris, Director, Division of Reaction Licensing, USAEC, to John E. Logan, Vice President, Jersey Central Power and Light Company

(5) FDSAR, Amendment 65, Section B.XI

(6) FDSAR, Amendment 65, Section B.IX

SECTION 3

LIMITING CONDITIONS FOR OPERATION

3.0 LIMITING CONDITIONS FOR OPERATION (GENERAL)

Applicability: Applies to all Limiting Conditions for Operation.

Objective: To preserve the single failure criterion for safety systems.

Specifications:

A. In the event Limiting Conditions for Operation (LCOs) and/or associated action requirements cannot be satisfied because of circumstances in excess of those addressed in the specification, the unit shall be placed in COLD SHUTDOWN within the following 30 hours unless corrective measures are completed that permit operation under the permissible action statements for the specified time interval as measured from initial discovery or until the reactor is placed in a condition in which the specification is not applicable. Exceptions to the requirements shall be stated in the individual specifications.

B. When a system, subsystem, train, component or device is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered OPERABLE for the purpose of satisfying the requirements of applicable LCOs., provided (1) its corresponding normal or emergency power source is OPERABLE; and (2) all of its redundant system(s), subsystem(s), train(s), component(s) and device(s) are OPERABLE, or likewise satisfy the requirements of this specification. Unless both conditions (1) and (2) are satisfied, the unit shall be placed in COLD SHUTDOWN within the following 30 hours or within the time specified in the applicable specification. This specification is not applicable in COLD SHUTDOWN or the REFUEL MODE.

C. When an LCO is not met, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability shall only be made:

1. When the associated LCO requirements permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time; or

2. 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 the establishment of risk management actions, if appropriate; exceptions to this specification are stated in the individual Specifications, or

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

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

Bases:

Specification 3.0.A delineates the action to be taken for circumstances not directly provided for in the system LCOs and whose occurrence would violate the intent of the specification.

Specification 3.0.B delineates what additional conditions must be satisfied to permit operation to continue, consistent with the specifications for power sources, when a normal or emergency power source is not operable. It allows operation to be governed by the time limits of the specifications associated with the LCOs for the normal or emergency power source, not the individual specifications for each system, subsystem, train, component or device that is determined to be inoperable solely because of the inoperability of its normal or emergency power source. In addition, it specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a safety subsystem, train, component, or device in another division is inoperable for another reason.

Specification 3.0.C establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when an LCO is not met. It allows placing the plant in an OPERATIONAL CONDITION or other specified condition stated in the Applicability (e.g., the Applicability desired to be entered) when plant conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.C.1, LCO 3.0.C.2, or LCO 3.0.C.3.

LCO 3.0.C.1 allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the requirements of the LCO met that permit continued operation in the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time. Compliance with LCO conditions that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition in the Applicability provides an acceptable level of safety for continued operation. This is without regard for the status of the unit before or after the change in OPERATIONAL CONDITION. 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 LCO conditions.

LCO 3.0.C.2 allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the requirements of the LCO 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 LCO 3.0.C.2 , 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 the 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 change in OPERATIONAL CONDITION 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 specified allowable time interval requiring action to exit the LCO.

LCO 3.0.C.2 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.C.2 risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in the RUN MODE 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.C.2 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.C.2 allowance is prohibited. The Limiting Condition for Operations governing these systems and components contain Notes prohibiting the use of Specification 3.0.C.2 by stating that Specification 3.0.C.2 is not applicable.

Specification 3.0.C.3 allows entry into an 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.C.3 is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated LCO requirements 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 LCO conditions or to a specific requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.C.2 usually only consider systems and components. For this reason, Specification 3.0.C.3 is typically applied to Specifications which describe values and parameters, 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.C shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with LCO requirements. In addition, the provisions of Specification 3.0.C 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 POWER OPERATION to STARTUP MODE, STARTUP MODE to SHUTDOWN CONDITION, and SHUTDOWN CONDITION to COLD SHUTDOWN CONDITION.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.A requires entry into the LCO 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.C is not a violation of Specification 4.0.1 or Specification 4.0.3 for any Surveillances that have not been performed on inoperable equipment. However, Surveillance Requirements 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.

3.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the operating status of plant instrumentation which performs a protective function.

Objective: To assure the OPERABILITY of protective instrumentation.

Specifications:

A. The following operating requirements for plant protective instrumentation are given in Table 3.1.1:

1. The reactor mode in which a specified function must be OPERABLE including allowable bypass conditions.

2. The minimum number of OPERABLE instrument channels per OPERABLE trip system.

3. The trip settings which initiate automatic protective action.

4. The action required when the limiting conditions for operation are not satisfied.

B. 1. Failure of four chambers assigned to any one APRM shall make the APRM inoperable.

2. Failure of two chambers from one radial core location in any one APRM shall make that APRM inoperable.

C. 1. Any two (2) LPRM assemblies which are input to the APRM system and are separated in distance by less than three (3) times the control rod pitch may not contain a combination of more than three (3) inoperable detectors (i.e., APRM channel failed or bypassed, or LPRM detectors failed or bypassed) out of the four (4) detectors located in either the A and B, or the C and D levels.

2. A Travelling In-Core Probe (TIP) chamber may be used as an APRM input to meet the criteria of 3.1.B and 3.1.C.1, provided the TIP is positioned in close proximity to one of the failed LPRM's. If the criteria of 3.1.B.2 or 3.1.C.1 cannot be met, POWER OPERATION may continue at up to rated power level provided a control rod withdrawal block is OPERATING or at power levels less than 61% of rated power until the TIP can be connected, positioned and satisfactorily tested, as long as Specification 3.1.B.1 and Table 3.1.1 are satisfied.

Bases: The plant protection system automatically initiates protective functions to prevent exceeding established limits. In addition, other protective instrumentation is provided to initiate action which mitigates the consequences of accidents or terminates operator control. This specification provides the limiting conditions for operation necessary to preserve the effectiveness of these instrument systems.

Table 3.1.1 defines, for each function, the minimum number of OPERABLE instrument channels for an OPERABLE trip system for the various functions specified. There are usually two trip systems required or available for each function. The specified limiting conditions for operation apply for the indicated modes of operation. When the specified limiting condition cannot be met, the specified Actions Required shall be undertaken promptly to modify plant operation to the condition indicated in a normal manner. Conditions under which the specified plant instrumentation may be out-of-service are also defined in Table 3.1.1.

Except as noted in Table 3.1.1 an inoperable trip system will be placed in the tripped condition. A tripped trip system is considered OPERATING since by virtue of being tripped it is performing its required function. All sensors in the untripped trip system must be OPERABLE, except as follows:

1. The high temperature sensor system in the main steam line tunnel has eight sensors in each protection logic channel. This multiplicity of sensors serving a duplicate function permits this system to operate for twenty month nominal intervals without calibration. Thus, if one of the temperature sensors causes a trip in one of the two trip systems, there are several cross checks that would verify if this were a real one. If not, this sensor could be removed from service. However, a minimum of two of eight are required to be OPERABLE and only one of the two is required to accomplish a trip in a single trip system.

2. One APRM of the four in each trip system may be bypassed without tripping the trip system if core protection is maintained. Core protection is maintained by the remaining three APRM's in each trip system as discussed in Section 7.5.1.8.7 of the Updated FSAR.

3. One IRM channel in each of the two trip systems may be bypassed without compromising the effectiveness of the system. There are few possible sources of rapid reactivity input to the system in the low power low flow condition. Effects of increasing pressure at zero or low void content are minor, 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 to be uniform by operating procedures backed up by the rod worth minimizer. Worth of individual rods is very low in a uniform rod pattern. Thus, of all possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power rise. 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 percentage of rated, 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 scram level, the rate of power rise is no more than five percent of rated per minute, and three OPERABLE IRM instruments in each trip system would be more than adequate to assure a scram before the power could exceed the safety limit. In many cases, if properly located, a single OPERABLE IRM channel in each trip system would suffice.

4. When required for surveillance testing, a channel is made inoperable. In order to be able to test its trip function to the final actuating device of its trip system, the trip system cannot already be tripped by some other means such as a mode switch, interlock, or manual trip. Therefore, there will be times during the test that the channel is inoperable but not tripped. For a two channel trip system, this means that full reliance is being placed on the channel that is not being tested. 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.

5. Allowed outage times (AOT) to permit restoration of inoperable instrumentation to OPERABLE status are provided in Table 3.1.1. AOTs vary depending on type of function and the number of inoperable channels per function. If an inoperable channel cannot be restored to OPERABLE status within the AOT, 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) conservatively compensates for the inoperability and allows operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram) the Action Required must be taken.

AOTs discussed in 4 (6 hours for surveillance) and 5 (repair AOTs in Table 3.1.1, Notes nn, oo and pp) above have been determined in accordance with References 1 through 6 except for instrumentation in Table 3.1.1, Sections M and N. Note kk has been provided to specify a 2 hour surveillance AOT for those instruments.

Bypasses of inputs to a trip system other than the IRM and APRM bypasses are provided for meeting operational requirements listed in the notes in Table 3.1.1. Note 'a' allows the "high water level in scram discharge volume" scram trip to be bypassed in the refuel mode. In order to reset the safety system after a scram condition, it is necessary to drain the scram discharge volume to clear this scram input condition. (This condition usually follows any scram, no matter what the initial cause might have been.) In order to do this, this particular scram function can be bypassed only in the refuel position. Since all of the control rods are completely inserted following a scram, it is permissible to bypass this condition because a control rod block prevents withdrawal as long as the switch is in the bypass condition for this function.

The manual scram associated with moving the mode switch to shutdown is used merely to provide a mechanism whereby the reactor protection system scram logic channels and the reactor manual control system can be energized. The ability to reset a scram twenty (20) seconds after going into the SHUTDOWN MODE provides the beneficial function of relieving scram pressure from the control rod drives which will increase their expected lifetime.

To permit plant operation to generate adequate steam and pressure to establish turbine seals and condenser vacuum at relatively low reactor power, the main condenser vacuum trip is bypassed until 600 psig. This bypass also applies to the main steam isolation valves for the same reason.

The action required when the minimum instrument logic conditions are not met is chosen so as to bring plant operation promptly to such a condition that the particular protection instrument is not required; or the plant is placed in the protection or safe condition that the instrument initiates. This is accomplished in a normal manner without subjecting the plant to abnormal operations conditions. The action and out-of-service requirements apply to all instrumentation within a particular function, e.g., if the requirements on any one of the ten scram functions cannot be met then control rods shall be inserted.

The trip level settings not specified in Specification 2.3 have been included in this specification. The bases for these settings are discussed below.

The high drywell pressure trip setting is $\leq$ 3.5 psig. This trip will scram the reactor, initiate core spray, initiate primary containment isolation, initiate automatic depressurization in conjunction with low-low-low-reactor water level, initiate the standby gas treatment system and isolate the reactor building. The scram function shuts the core down during the loss-of-coolant accidents. A steam leak of about 15 gpm and a liquid leak of about 35 gpm from the primary system will cause drywell pressure to reach the scram point; and, therefore, the scram provides protection for breaks greater than the above.

High drywell pressure provides a second means of initiating the core spray to mitigate the consequences of loss-of-coolant accident. Its trip setting of ≤3.5 psig initiates the core spray in time to provide adequate core cooling. The break size coverage of high drywell pressure was discussed above. Low-low water level and high drywell pressure in addition to initiating core spray also causes isolation valve closure. These settings are adequate to cause isolation to minimize the offsite dose within required limits.

It is permissible to make the drywell pressure instrument channels inoperable during performance of the integrated primary containment leakage rate test provided the reactor is in the COLD SHUTDOWN condition. The reason for this is that the Engineered Safety Features, which are effective in case of a LOCA under these conditions, will still be effective because they will be activated (when the Engineered Safety Features system is required as identified in the technical specification of the system) by low-low reactor water level.*

The scram discharge volume has two separate instrument volumes utilized to detect water accumulation. The high water level is based on the design that the water in the SDIV's, as detected by either set of level instruments, shall not be allowed to exceed 29.0 gallons; thereby, permitting 137 control rods to scram. To provide further margin, an accumulation of not more than 14.0 gallons of water, as detected by either instrument volume, will result in a rod block and an alarm. The accumulation of not more than 7.0 gallons of water, as detected in either instrument volume will result in an alarm.

Detailed analyses of transients have shown that sufficient protection is provided by other scrams below 45% power to permit bypassing of the turbine trip and generator load rejection scrams. However, for operational convenience, 40% of rated reactor THERMAL POWER has been chosen as the setpoint below which these trips are bypassed. This setpoint is coincident with bypass valve capacity.

A low condenser vacuum scram trip of 20 inches Hg has been provided to protect the main condenser in the event that vacuum is lost. A loss of condenser vacuum would cause the turbine stop valves to close, resulting in a turbine trip transient.

The low condenser vacuum trip provides a reliable backup to the turbine trip. Thus, if there is a failure of the turbine trip on low vacuum, the reactor would automatically scram at 20 inches Hg. The condenser is capable of receiving bypass steam until 7 inches Hg vacuum thereby mitigating the transient and providing a margin.

The settings to isolate the isolation condenser in the event of a break in the steam or condensate lines are based on the predicted maximum flows that these systems would experience during operation, thus permitting operation while affording protection in the event of a break. The settings correspond to a flow rate of less than three times the normal flow rate of 3.2×10^5 lb/hr. Upon initiation of the alternate shutdown panel, this function is bypassed to prevent spurious isolation due to fire induced circuit faults.

*Correction 11/30/87

The setting of ten times the stack release limit for isolation of the air-ejector offgas line is to permit the operator to perform normal, immediate remedial action if the stack limit is exceeded. The time necessary for this action would be extremely short when considering the annual averaging which is allowed under 10 CFR 20.106, and, therefore, would produce insignificant effects on doses to the public.

Four radiation monitors are provided which initiate isolation of the reactor building and operation of the standby gas treatment system. Two monitors are located in the ventilation ducts, one is located in the area of the refueling pool and one is located in the reactor vessel head storage area. The trip logic is basically a 1 out of 4 system. Any upscale trip will cause the desired action. Trip settings of 17 mr/hr in the duct and 100 mr/hr on the refueling floor are based upon initiating standby gas treatment system so as not to exceed allowed dose rates of 10 CFR 20 at the nearest site boundary.

The SRM upscale of $5X10^5$ CPS initiates a rod block so that the chamber can be relocated to a lower flux area to maintain SRM capability as power is increased to the IRM range. Full scale reading is 1×10^6 CPS. This rod block is bypassed in IRM Ranges 8 and higher since a level of 5×10^5 CPS is reached and the SRM chamber is at its fully withdrawn position.

The SRM downscale rod block of 100 CPS prevents the instrument chamber from being withdrawn too far from the core during the period that it is required to monitor the neutron flux. This downscale rod block is also bypassed in IRM Ranges 8 and higher. It is not required at this power level since good indication exists in the Intermediate Range and the SRM will be reading approximately 5×10^5 CPS when using IRM Ranges 8 and higher.

The IRM downscale rod block in conjunction with the chamber full-in position and range switch setting, provides a rod block to assure that the IRM is in its most sensitive condition before startup. If the two latter conditions are satisfied, control rod withdrawal may commence even if the IRM is not reading at least 5%. However, after a substantial neutron flux is obtained, the rod block setting prevents the chamber from being withdrawn to an insensitive area of the core.

The APRM downscale setting of $\geq 2/150$ full scale is provided in the RUN MODE to prevent control rod withdrawal without adequate neutron monitoring.

High flow in the main steamline is set at 120% of rated flow. At this setting the isolation valves close and in the event of a steam line break limit the loss of inventory so that fuel clad perforation does not occur. The 120% flow would correspond to the THERMAL POWER so this would either indicate a line break or too high a power.

Temperature sensors are provided in the steam line tunnel to provide for closure of the main steamline isolation valves should a break or leak occur in this area of the plant. The trip is set at 50°F above ambient temperature at rated power. This setting will cause isolation to occur for main steamline breaks which result in a flow of a few pounds per minute or greater. Isolation occurs soon enough to meet the criterion of no clad perforation.

The low-low-low water level trip point is set at 4'8" above the top of the active fuel and will prevent spurious operation of the automatic relief system. The trip point established will initiate the automatic depressurization system in time to provide adequate core cooling.

Specification 3.1.B.1 defines the minimum number of APRM channel inputs required to permit accurate average core power monitoring. Specifications 3.1.B.2 and 3.1.C.1 further define the distribution of the OPERABLE chambers to provide monitoring of local power changes that might be caused by a single rod withdrawal. Any nearby, OPERABLE LPRM chamber can provide the required input for average core monitoring. A Travelling Incore Probe or Probes can be used temporarily to provide APRM input(s) until LPRM replacement is possible. Since APRM rod block protection is not required below 61% of rated power, operation may continue below 61% as long as Specification 3.1.B.1 and the requirements of Table 3.1.1 are met. For operation along the flow control line and at power levels less than 61% of rated, the inadvertent withdrawal of a single control rod does not result in MCPR less than the Fuel Cladding Integrity Safety Limit, even assuming there is no control rod block action. In order to maintain reliability of core monitoring in that quadrant where an APRM is inoperable, it is permitted to remove the OPERABLE APRM from service for calibration and/or test provided that the same core protection is maintained by alternate means.

In the rare event that Travelling In-core Probes (TIPs) are used to meet the requirements 3.1.B or 3.1.C, the licensee may perform an analysis of substitute LPRM inputs to the APRM system using spare (non-APRM input) LPRM detectors and change the APRM system as permitted by 10 CFR 50.59.

Under assumed loss-of-coolant accident conditions and certain loss of offsite power conditions with no assumed loss-of-coolant accident, it is inadvisable to allow the simultaneous starting of emergency core cooling and heavy load auxiliary systems in order to minimize the voltage drop across the emergency buses and to protect against a potential diesel generator overload. The diesel generator load sequence time delay relays provide this protective function and are set accordingly. The repetitive accuracy rating of the timer mechanism as well as parametric analyses to evaluate the maximum acceptable tolerances for the diesel loading sequence timers were considered in the establishment of the appropriate load sequencing.

Manual actuation can be accomplished by the operator and is considered appropriate only when the automatic load sequencing has been completed. This will prevent simultaneous starting of heavy load auxiliary systems and protect against the potential for diesel generator overload.

Also, the Reactor Building Closed Cooling Water and Service Water pump circuit breakers will trip whenever a loss-of-coolant accident condition exists with a concurrent loss of offsite power. This is justified by Amendment 42 of the Licensing Application which determined that these pumps were not required during this accident condition.

The drywell high radiation setpoint will ensure a timely closure of the large vent and purge isolation valves to prevent releases from exceeding ten percent of the dose guideline values allowed by 10 CFR 100. The containment vent and purge isolation function is provided in response to NUREG 0737 Item II E.4.2.7.

Temperature switches are provided at the entrance of the RWCU Pump Room to detect a line break downstream of the RWCU isolation valves. A line break will raise room temperature. Before the room temperature exceeds 180°F, the switches will trip and close the RWCU isolation valves. This ensures that a high energy line break will automatically be detected and isolated, even if an RWCU System isolation is not initiated by a LO-LO reactor water level signal. System isolation at this temperature will minimize the impact on off-site releases and the environmental qualification profiles for the Reactor Building.

References:

(1) NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System."

(2) NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2.

(3) NEDC-30851P-A, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation."

(4) NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation."

(5) NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation."

(6) GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications."

PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in Which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
A. Scram								
1. Manual Scram		X	X	X	X	2	1	Insert control rods
2. High Reactor Pressure	**		X(s)	X(ll)	X	2	2(nn)	
3. High Drywell Pressure	≤ 3.5 psig		X(u)	X(u)	X	2	2(nn)	
4. Low Reactor Water Level	**		X	X	X	2	2(nn)	
5. a. High Water Level in Scram Discharge Volume North Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2(nn)	
b. High Water Level in Scram Discharge Volume South Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2(nn)	
6. Low Condenser Vacuum	≥ 20 in. hg.			X(b)	X	1	3(mm)(nn)	
7. DELETED								

TABLE 3.1.1
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PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in Which Function Must Be Operable: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
8. Average Power Range Monitor (APRM)	**		X(c,s)	X(c)	X(c)	2	3(nn)	
9. Intermediate Range Monitor (IRM)	**		X(d)	X(d)		2	3(nn)	
10. Main Steamline Isolation Valve Closure	**		X(b,s)	X(b)	X	2	4(nn)	
11. Turbine Trip Scram	**				X(j)	2	4(nn)	
12. Generator Load Rejection Scram	**				X(j)	2	2(nn)	
13. APRM Downscale/IRM Upscale	**				X(c)	2	3(nn)	
B. Reactor Isolation								
1. Low-Low Reactor Water Level	**	X	X	X	X	2	2(oo)	Close Main Steam Isolation Valves and Close Isolation Condenser Vent Valve or,
2. High Flow in Main Steamline A	≤120% rated	X(s)	X(s)	X	X	2	2(oo)	PLACE IN COLD SHUTDOWN

TABLE 3.1.1
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PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
3. High Flow in Main Steam-line B	≤120% rated	X(s)	X(s)	X	X	2	2(oo)	
4. High Temperature in Main Steamline Tunnel	≤Ambient at Power + 50°F	X(s)	X(s)	X	X	2	2(oo)	
5. Low Pressure in Main Steamline	**			X(cc)	X	2	2(oo)	
6. DELETED								
C. Isolation Condenser Initiation								
1. High Reactor Pressure	**	X(s)	X(s)	X(ll)	X	2	2(pp)	PLACE IN COLD
2. Low-Low Reactor Water Level	≥7'2" above TOP of ACTIVE FUEL	X(s)	X(s)	X	X	2	2(pp)	SHUTDOWN CONDITION
D. Core Spray								
1. Low-Low Reactor Water Level	**	X(t)	X(t)	X(t)	X	2	2(pp)	Consider the respective core spray loop
2. High Drywell Pressure	≤ 3.5 psig	X(t)	X(t)	X(t)	X	2(k)	2(k)(pp)	inoperable and comply with
3. Low Reactor Pressure (valve permissive)	≥ 285 psig	X(t)	X(t)	X(t)	X	2	2(pp)	Spec 3.4

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
E. Containment Spray								
Comply with Technical Specification 3.4								
F. Primary Containment Isolation								
1. High Drywell Pressure	≤ 3.5 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)(oo)	Isolate containment or PLACE IN COLD SHUTDOWN CONDITION
2. Low-Low Reactor Water Level	≥ 7'2" above TOP of ACTIVE FUEL	X(u)	X(u)	X(u)	X	2	2(oo)	
G. Automatic Depressurization								
1. High Drywell Pressure	≤ 3.5 psig	X(v)	X(v)	X(v)	X	2(k)	2(k)	See note h
2. Low-Low-Low Reactor Water Level	≥ 4'8" above TOP of ACTIVE FUEL	X(v)	X(v)	X(v)	X	2	2	See note h
3. Core Spray Booster Pump d/p Permissive	> 21.2 psid	X(v)	X(v)	X(v)	X	Note i	Note i	See note i
H. Isolation Condenser Isolation (See Note hh)								
1. High Flow Steam Line	≤ 20 psig P	X(s)	X(s)	X	X	2	2(oo)	Isolate affected Isolation Condenser comply with Spec 3.8. See note dd
2. High Flow Condensate Line	≤ 27" P H_2O	X(s)	X(s)	X	X	2	2(oo)	

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
I. Offgas System Isolation								
1. High Radiation In Offgas Line (e)	≤ 2000 mRem/hr	X(s)	X(s)	X	X	1 (ii)	2(ii)	See note jj
J. Reactor Building Isolation and Standby Gas Treatment System Initiation								
1. High Radiation Reactor Building Operating Floor	≤ 100 mR/hr	X(w)	X(w)	X	X	1	1	Isolate Reactor Building and Initiate Standby Gas Treatment System or Manual Surveillance for not more than 24 Hours (Total for all instruments under J) in any 30-day period.
2. Reactor Building Ventilation Exhaust	≤ 17 mR/hr	X(w)	X(w)	X	X	1	1	
3. High Drywell Pressure	≤ 3.5 psig	X(u)	X(u)	X	X	1(k)	2(k)	
4. Low-Low Reactor Water Level	≥ 7'2" above TOP of ACTIVE FUEL	X	X	X	X	1	2	
K. Rod Block								
1. SRM Upscale	≤ $5x10^5$ cps		X	X(l)		1	2	No control rod withdrawals permitted
2. SRM Downscale	≥ 100cps(f)		X	X(l)		1	2	
3. IRM Downscale	≥ 5/125 fullscale (g)		X	X		2	3	

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS
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Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
K. Rod Block (Cont'd.)								
4. APRM Upscale	*		X(s)	X	X	2	3(c)	
5. APRM Downscale	≥ 2/150 fullscale				X	2	3 (c)	
6. IRM Upscale	≤ 108/125 fullscale		X	X		2	3	
7. a) Water Level High Scram Discharge Volume North	≤ 14 gallons		X(z)	X(z)	X(z)	1	1 per Instrument Volume	
b) Water Level High Scram Discharge Volume South	≤ 14 gallons		X(z)	X(z)	X(z)	1	1 per Instrument Volume	
L. Condenser Vacuum Pump Isolation								
Deleted								
M. Diesel Generator Load Sequence Timers	Time Delay after energization of relay							
1. CRD Pump	60 sec ± 15%	X	X	X	X	2(m)	1(n)(kk)	Consider the pump inoperable and comply with Spec 3.4.D (See note q)

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Minimum Number of OPERABLE or OPERATING [tripped] Trip Systems	Minimum Number of Instrument Channels Per OPERABLE Trip System	Action Required*
M. Diesel Generator Load Sequence Timers (Cont'd.)								
2. Service Water Pump (aa)	120 sec ± 15% (SK1A) (SK2A) 10 sec. ± 15% (SK7A) (SK8A)	X	X	X	X	2(o)	2(p)(kk)	Consider the pump inoperable and comply within 7 days (See note q)
3. Reactor Building Closed Cooling Water Pump (bb)	166 sec ± 15%	X	X	X	X	2(m)	1(n)(kk)	Consider the pump inoperable and comply within 7 days (See note q)
N. Loss of Power								
a. 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	1(kk)	
b. 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	3(kk)	See note cc
O. Containment Vent and Purge Isolation								
1. Drywell High Radiation	≤ 74.6 R/hr	X(u)	X(u)	X(u)	X	1	1	Isolate vent & Purge pathways or PLACE IN COLD SHUTDOWN CONDITION
P. RWCU HELB Isolation								
1. RWCU Pump Room High Temperature	≤ 180°F	X(s)	X(s)	X	X	2	2(oo)	Close isolation valves V-16-1, V-16-2, V-16-14, & V-16-61.

* Action required when minimum conditions for operation are not satisfied. Also permissible to trip inoperable trip system. A channel may be placed in an inoperable status for up to six hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE instrument channel in the same trip system is monitoring that parameter.

** See Specification 2.3 for Limiting Safety System Settings.

Notes:

a. Permissible to bypass, with control rod block, for reactor protection system reset in REFUEL MODE.

b. Permissible to bypass below 600 psig in REFUEL and STARTUP MODES.

c. One (1) APRM in each OPERABLE trip system may be bypassed or inoperable provided the requirements of Specification 3.1.C and 3.10.C are satisfied. Two APRM's in the same quadrant shall not be concurrently bypassed except as noted below or permitted by note.

Any one APRM may be removed from service for up to six hours for test or calibration without inserting trips in its trip system only if the remaining OPERABLE APRM's meet the requirements of Specification 3.1.B.1 and no control rods are moved outward during the calibration or test. During this short period, the requirements of Specifications 3.1.B.2, 3.1.C and 3.10.C need not be met.

d. The IRMs shall be inserted and OPERABLE until the APRMs are OPERABLE and reading at least 2/150 full scale.

e. Offgas system isolation trip set at ≤2,000 mRem/hr. Air ejector isolation valve closure time delay shall not exceed 15 minutes.

f. Unless SRM chambers are fully inserted.

g. Not applicable when IRM on lowest range.

h. With one or more instrument channel(s) inoperable in one ADS trip system, place the relay contact(s) for the inoperable initiation signal in the tripped condition within 4 days, or declare ADS inoperable and take the action required by Specification 3.4.B.3.

With one or more instrument channel(s) inoperable in both ADS trip systems, restore ADS initiation capability in at least one trip system within 1 hour, or declare ADS inoperable and take the action required by Specification 3.4.B.3.

Individual electromatic relief valve control switches shall not be placed in the "Off" position for more than 8 hours (total time for all control switches) in any 30-day period and only one relief valve control switch may be placed in the "Off" position at a time.

i. With two core spray systems OPERABLE:

1. A maximum of two core spray booster pump differential pressure (d/p) switches may be inoperable provided that the switches are in opposing ADS trip system [i.e., only: either RV-40 A&D or RV-40 B&C]. Place the relay contacts associated with the inoperable d/p switch(es) in the de-energized position, within 24 hours. Restore the inoperable d/p switch(es) within 8 days, or declare ADS inoperable and take the action required by Specification 3.4.B.3;

or,

2. If two inoperable d/p switches are in the same ADS trip system [i.e., RV-40 A&B or RV-40 C&D], place the relay contacts associated with the inoperable d/p switch(es) in the de-energized position, within 24 hours. Restore the inoperable d/p switches within 4 days, or declare ADS inoperable and take the action required by Specification 3.4.B.3.

With only one core spray system OPERABLE:

If one or more d/p switches become inoperable in the OPERABLE core spray system, declare ADS inoperable and take the action required by Specification 3.4.B.3.

j. Not required below 40% of rated reactor THERMAL POWER.

k. All four (4) drywell pressure instrument channels may be made inoperable during the integrated primary containment leakage rate test (See Specification 4.5), provided that the plant is in the COLD SHUTDOWN condition and that no work is performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the TOP OF THE ACTIVE FUEL.

l. Bypass in IRM Ranges 8, 9, and 10.

m. There is one time delay relay associated with each of two pumps.

n. One time delay relay per pump must be OPERABLE.

o. There are two time delay relays associated with each of two pumps. One timer per pump is for sequence starting (SK1A, SK2A) and one timer per pump is for tripping the pump circuit breaker (SK7A, SK8A).

p. Two time delay relays per pump must be OPERABLE.

q. Manual initiation of affected component can be accomplished after the automatic load sequencing is completed.

r. Time delay starts after closing of containment spray pump circuit breaker.

s. These functions not required to be OPERABLE with the reactor temperature less than 212°F and the vessel head removed or vented or during REACTOR VESSEL PRESSURE TESTING.

t. These functions may be inoperable or bypassed when corresponding portions in the same core spray system logic train are inoperable per Specification 3.4.A.

u. These functions not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required to be maintained.

v. These functions not required to be OPERABLE when the ADS is not required to be OPERABLE.

w. These functions must be OPERABLE only when irradiated fuel is in the fuel pool or reactor vessel and SECONDARY CONTAINMENT INTEGRITY is required per Specification 3.5.B.

y. Deleted.

z. The bypass function to permit scram reset in the SHUTDOWN or REFUEL MODE with control rod block must be OPERABLE in this mode.

aa. Pump circuit breakers will be tripped in 10 seconds ± 15% during a LOCA with a concurrent Loss of Offsite Power (LOOP) by relays SK7A and SK8A.

bb. Pump circuit breakers will trip instantaneously during a LOCA with a concurrent Loss of Offsite Power (LOOP).

cc. Only applicable during STARTUP MODE while OPERATING in IRM range 10.

dd. If any isolation condenser inlet (steam side) isolation valve becomes or is made inoperable in the open position during the RUN MODE comply with Specification 3.8.E. If an AC motor-operated outlet (condensate return) isolation valve becomes or is made inoperable in the open position during the RUN MODE comply with Specification 3.8.F.

ee. With the number of OPERABLE channels one less than the Minimum Number of OPERABLE Instrument Channels per OPERABLE Trip System, operation may proceed until performance of the next required CHANNEL FUNCTIONAL TEST provided the inoperable channel is placed in the tripped condition within 1 hour.

ff. This function is not required to be OPERABLE when the associated safety bus is not required to be energized or fully OPERABLE as per applicable sections of these Technical Specifications.

gg. Deleted

hh. The high flow trip function for "B" Isolation Condenser is bypassed upon initiation of the alternate shutdown panel. This prevents a spurious trip of the Isolation Condenser in the event of fire induced circuit damage.

ii. Instrument shall be OPERABLE during main condenser air ejector operation except that a channel may be taken out-of-service for the purpose of a check, calibration, test, or maintenance without declaring it inoperable.

jj. With no channel OPERABLE, main condenser offgas may be released to the environment for as long as 72 hours provided the stack radioactive noble gas monitor is OPERABLE. Otherwise, be in at least SHUTDOWN CONDITION within 24 hours.

kk. One channel may be placed in an inoperable status for up to two hours for required surveillance without placing the trip system in the tripped condition.

ll. This function not required to be OPERABLE with the reactor vessel head removed or unbolted.

mm. "Instrument Channel" in this case refers to the bellows which sense vacuum in each of the three condensers (A, B, and C), and "Trip System" refers to vacuum trip systems 1 and 2.

nn. With one required channel inoperable in one Trip System, within 12 hours, restore the inoperable channel or place the inoperable channel and/or that Trip System in the tripped▲ condition.

With two or more required channels inoperable:

1. Within one hour, verify sufficient channels remain OPERABLE or tripped▲ to maintain trip capability, and

2. Within 6 hours, place the inoperable channel(s) in one Trip System and/or that Trip System▲▲ in the tripped condition▲, and

3. Within 12 hours, restore the inoperable channels in the other Trip System to an OPERABLE status or tripped▲.

Otherwise, take the Action Required.

▲ An inoperable channel or Trip System need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, if the inoperable channel is not restored to OPERABLE status within the required time, the Action Required shall be taken.

▲▲ This action applies to that Trip System with the most inoperable channels; if both Trip Systems have the same number of inoperable channels, the action can be applied to either Trip System.

oo. With one required channel inoperable in <u>one</u> Trip System, either

1. Place the inoperable channel in the tripped condition within

   a. 12 hours for parameters common to Scram Instrumentation, and
   b. 24 hours for parameters not common to Scram Instrumentation.

or

2. Take the Action Required.

TABLE 3.1.1 (CONT'D)
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With one required channel inoperable in both Trip Systems,

1. Place the inoperable channel in one Trip System in the tripped condition within one hour, and

2. a. Place the inoperable channel in the remaining Trip System in the tripped condition within

   (1) 12 hours for parameters common to Scram Instrumentation, and
   (2) 24 hours for parameters not common to Scram Instrumentation.

   or

   b. Take the Action Required.

pp. With one or more required channels inoperable per Trip System:

1. For one channel inoperable, within 24 hours place the inoperable channel in the tripped condition or take the Action Required.

2. With more than one channel inoperable, take the Action Required.

3.2 REACTIVITY CONTROL

Applicability: Applies to core reactivity and the operating status of the reactivity control systems for the reactor.

Objective: To assure reactivity control capability of the reactor.

Specification:

A. Core Reactivity

1. The SHUTDOWN MARGIN (SDM) under all operational conditions shall be equal to or greater than:

   (a) 0.38% delta k/k, with the highest worth control rod analytically determined; or

   (b) 0.28% delta k/k, with the highest worth control rod determined by test.

2. If one or more control rods are determined to be inoperable as defined in Specification 3.2.B.4 while in the STARTUP MODE or the RUN MODE, then a determination of whether Specification 3.2 A. is met must be made within 6 hours. If a determination cannot be made within the specified time period, then assume Specification 3.2 A.1 is not met.

3. If Specification 3.2.A.1 is not met while in the STARTUP Mode or the RUN MODE, meet Specification 3.2.A.1 within 6 hours or be in the SHUTDOWN CONDITION within the following 12 hours.

4. If Specification 3.2.A.1 is not met while in the SHUTDOWN CONDITION, or the COLD SHUTDOWN CONDITION, then:

   (a) Fully insert all insertable control rods within 1 hour, AND

   (b) Comply with the requirements of Specifications 3.2.C and 3.5.B.

5. If Specification 3.2.A.1 is not met while in the REFUEL MODE, then:

   (a) Immediately suspend CORE ALTERATIONS except for fuel assembly removal, AND

   (b) Immediately initiate action to fully insert all insertable control rods in control cells containing one or more fuel assemblies, AND

   (c) Comply with the requirements of Specifications 3.2.C and 3.5.B.

B. Control Rod System

1. The control rod drive housing support shall be in place during power operation and when the reactor coolant system is pressurized above atmospheric pressure with fuel in the reactor vessel, unless all control rods are fully inserted and Specification 3.2.A is met.

2. The Rod Worth Minimizer (RWM) shall be operable during each reactor startup until reactor power reaches 10% of rated power except as follows:

   (a) Should the RWM become inoperable after the first 12 rods have been withdrawn, the startup may continue provided that a second licensed operator verifies that the licensed operator at the reactor console is following the rod program.

   (b) Should the RWM be inoperable before a startup is commenced or before the first twelve rods are withdrawn, one startup during each calendar year may be performed without the RWM provided that the second licensed operator verifies that the licensed operator at the reactor console is following the rod program and provided that a reactor engineer from the Core Engineering Group also verifies that the rod program is being followed. A startup without the RWM as described in this subsection shall be reported in a special report to the Nuclear Regulatory Commission (NRC) within 30 days of the startup stating the reason for the failure of the RWM, the action taken to repair it and the schedule for completion of the repairs.

   Control rod withdrawal sequences shall be established with a banked position withdrawal sequence so that the rod drop accident design limit of 280 cal/gm is not exceeded. For control rod withdrawal sequences not in strict compliance to BPWS, the maximum in sequence rod worth shall be $\leq 1.0\% \Delta K$.

3. The average of the scram insertion times of all operable control rods shall be no greater than:

Rod Length Inserted (%)	Insertion Time (Seconds)
5	0.375
20	0.900
50	2.00
90	5.00

The average of the scram insertion times for the three fastest control rods of all groups of four control rods in a two-by-two array shall be no greater than:

Rod Length Inserted (%)	Insertion Time (Seconds)
5	0.398
20	0.954
50	2.120
90	5.300

Any four rod group may contain a control rod which is valved out of service provided the above requirements and Specification 3.2.A are met. Time zero shall be taken as the de-energization of the pilot scram valve solenoids.

4. In service control rods which cannot be moved with control rod drive pressure shall be considered inoperable. If a partially or fully withdrawn control rod drive cannot be moved with drive or scram pressure, the reactor shall be brought to a shutdown condition within 48 hours unless investigation demonstrates that the cause of the failure is not due to a failed control rod drive mechanism collet housing. Inoperable control rods shall be valved out of service, in such positions that Specification 3.2.A is met. In no case shall the number of inoperable control rods valved out of service be greater than six during the power operation. If this specification is not met, the reactor shall be placed in the shutdown condition.

5. Control Rods shall not be withdrawn for approach to criticality unless at least two source range channels have an observed count rate equal to or greater than 3 counts per second.

C. Standby Liquid Control System

1. The standby liquid control system shall be operable at all times under the following conditions:

   (a) when the reactor is not shut down by the control rods such that Specification 3.2.A is met, except as provided in Specification 3.2.C.3, and

   (b) when the reactor is >212°F, except during REACTOR VESSEL PRESSURE TESTING.

2. The standby liquid control solution shall have a Boron-10 isotopic enrichment equal to or greater than 35 atom %, be maintained within the cross-hatched volume-concentration requirement area in Figure 3.2-1 and at a temperature not less than the temperature presented in Figure 3.2-2 at all times when the standby liquid control system is required to be operable.

3. (a) If one standby liquid control system pumping circuit becomes inoperable during the RUN mode and Specification 3.2.A is met, the reactor may remain in operation for a period not to exceed 7 days, provided the pump in the other circuit is verified daily to be operable, otherwise be in the Shutdown condition within 24 hours.

(b) If the solution is outside the cross-hatched volume-concentration area but within the shaded volume-concentration area of Figure 3.2-1, return the solution to the cross-hatched area within 7 days. If, after this time period, the requirement is still not met, submit a report to the NRC within 7 days advising them of plans to return the solution to the cross-hatched volume-concentration area.

(c) If the solution is outside the cross-hatched volume concentration area and outside the shaded volume-concentration area of Figure 3.2-1, return the solution to within the shaded volume-concentration area of Figure 3.2-1 or be in the Shutdown condition within 24 hours.

(d) If the solution temperature is less than the minimum shown in Figure 3.2-2, increase the temperature to greater than the minimum and verify the solution is within the shaded volume-concentration area of Figure 3.2-1 or be in the Shutdown condition within 24 hours.

(e) If the enrichment requirement of 3.2.C.2 is not met:

(1) Return the Boron-10 isotopic enrichment to greater than or equal to 35 atom % within 7 days of the receipt of the enrichment report. If, after this time period, the enrichment requirement is still not met, submit a report to the NRC within 7 days advising them of the plans to return the solution to greater than or equal to 35 atom % Boron-10 isotopic enrichment.

(2) A check shall be made to ensure that the sodium pentaborate solution meets the original design criteria by comparing the enrichment, concentration and volume to established criteria (Boron-10 equal to or greater than 82 pounds). If the sodium pentaborate solution does not meet the original criteria, be in the Shutdown condition within 24 hours.

D. <u>Reactivity Anomalies</u>

The difference between an observed and predicted control rod inventory shall not exceed the equivalent of one percent in reactivity. If this limit is exceeded and the discrepancy cannot be explained, the reactor shall be brought to the cold shutdown condition by normal orderly shutdown procedure. Operation shall not be permitted until the cause has been evaluated and appropriate corrective action has been completed. The NRC shall be notified within 24 hours of this situation in accordance with Specification 6.6.

Bases:

Limiting conditions of operation on core reactivity and the reactivity control systems are required to assure that the excess reactivity of the reactor core is controlled at all times. The conditions specified herein assure the capability to provide reactor shutdown from steady state and transient conditions and assure the capability of limiting reactivity insertion rates under accident conditions to values which do not jeopardize the reactor coolant system integrity or operability of required safety features.

The core reactivity limitation is required to assure the reactor can be shut down at any time when fuel is in the core. It is a restriction that must be incorporated into the design of the core fuel; it must be applied to the conditions resulting from core alterations; and it must be applied in determining the required operability of the core reactivity control devices. The basic criterion is that the core at any point in its operation be capable of being made subcritical in the cold, xenon-free condition with the operable control rod of highest worth fully withdrawn and all other operable rods fully inserted. At most times in core life, more than one control rod drive could fail mechanically and this criterion would still be met.

The SDM limit specified in Section 3.2.A.1 accounts for the uncertainty in the demonstration of SDM by testing. Separate SDM limits are provided for testing where the highest worth control rod is determined analytically or by measurement (Ref. 11). This is due to the reduced uncertainty in the SDM test when the highest worth control rod is determined by measurement. When SDM is demonstrated by calculations not associated with a test, additional margin must be added to the specified SDM limit to account for uncertainties in the calculation. To ensure adequate SDM during the design process, a design margin of 1.0% delta k is included to account for uncertainties in the design calculations (Ref. 11).

Inability to meet SDM limits in the STARTUP MODE or RUN MODE is most probably due to inoperable control rods. Reduced SDM is not considered an immediate threat to nuclear safety, therefore time is allowed for analysis to insure Specification 3.2 A. is met, and for repair before requiring the plant to undergo a transient to achieve the SHUTDOWN CONDITION. The allowed times of 6 hours for analysis and an additional 6 hours for repair, if 3.2.A.1 is not met, are considered reasonable while limiting the potential for further reduction in SDM or the occurrence of a transient.

If SDM cannot be restored, shutdown is required to minimize the potential for, and consequences of, an accident or malfunction of equipment important to safety. The allowed completion time of 12 hours is considered reasonable to achieve the SHUTDOWN CONDITION from full power in an orderly manner and without challenging plant systems.

Inability to meet SDM limits in the SHUTDOWN CONDITION or COLD SHUTDOWN CONDITION could be due to inoperable control rods, discovery of errors in the SDM analysis, or discovery of errors in previous CORE ALTERATIONS. Inserting control rods maximizes SDM and, since all operable control rods are required to be fully inserted in these conditions, should be able to be completed in 1 hour. The Standby Liquid Control System is allowed to be inoperable and Secondary Containment Integrity is allowed to be relaxed in these conditions when SDM limits are met. Therefore, they may not be available when the inability to meet SDM limits is recognized. The Standby Liquid Control System is needed to provide negative reactivity if control rods are not adequate to maintain the reactor subcritical. Secondary Containment Integrity is needed to provide means for control of potential radioactive releases.

Inability to meet SDM limits in the REFUEL MODE is most probably due to CORE ALTERATION errors. CORE ALTERATIONs are suspended to prevent further reduction in SDM. Fuel assembly removal and control rod insertion reduce total reactivity and are allowed in order to recover SDM. Control rods in control cells which do not contain fuel do not affect the reactivity of the core and therefore do not have to be inserted. The Standby Liquid Control System is allowed to be inoperable in this mode when SDM limits are met and, therefore, may not be available when the inability to meet SDM limits is recognized. The Standby Liquid Control System is needed to provide negative reactivity if control rods are not adequate to maintain the reactor subcritical. Secondary Containment Integrity is needed to provide means for control of potential radioactive releases.

Fuel bundles containing gadolinia as a burnable neutron absorber results in a core reactivity characteristic which increases with exposure, goes through a maximum and then decreases. Thus, it is possible that a core could be more reactive later in the cycle than at the beginning. Satisfaction of the above criterion can be demonstrated conveniently only at the time of refueling since it requires the core to be cold and xenon-free. The demonstration is designed to be done at these times and is such that if it is successful, the criterion is satisfied for the entire subsequent fuel cycle. The criterion will be satisfied by demonstrating Specification 4.2.A at the beginning of each fuel cycle with the core in the cold, xenon-free condition. This demonstration will include consideration for the calculated reactivity characteristic during the following operating cycle and the uncertainty in this calculation.

The control rod drive housing support restricts the outward movement of a control rod to less than 3 inches in the extremely remote event of a housing failure (2). The amount of reactivity which could be added by this small amount of rod withdrawal, which is less than a normal single withdrawal increment, will not contribute to any damage to the reactor coolant system. The support is not required when no fuel is in the core since no nuclear consequences could occur in the absence of fuel.

The support is not required if the reactor coolant system is at atmospheric pressure since there would then be no driving force to rapidly eject a drive housing. The support is not required if all control rods are fully inserted since the reactor would remain subcritical even in the event of complete ejection of the strongest control rod (3).

The Rod Worth Minimizer (4) provides automatic supervision of conformance to the specified control rod patterns. It serves as a back-up to procedural control of control rod worth. In the event that the RWM is out of service when required, a licensed operator can manually fulfill the control rod pattern conformance functions of the RWM in which case the normal procedural controls are backed up by independent procedural controls to assure conformance during control rod withdrawal. This allowance to perform a startup without the RWM is limited to once each calendar year to assure a high operability of the RWM which is preferred over procedural controls.

Control rod drop accident (RDA) results for plants using banked position withdrawal sequences (BPWS) show that in all cases the peak fuel enthalpy in an RDA would be much less than the 280 cal/gm design limit even with the maximum incremental rod worth. The BPWS is developed prior to initial operation of the unit following any refueling outage and the requirement that the operator follow the BPWS is supervised by the RWM or a second licensed operator. If it is necessary to deviate slightly from the BPWS sequence (i.e., due to an inoperable control rod) no further analysis is needed if the maximum incremental rod worth in the modified sequence is equal to or less than 1.0% delta K. An incremental control rod worth of less than or equal to 1.0% delta K will not result in a peak fuel enthalpy above the design limit of 280 cal/gm as documented in reference 10.

The BPWS limits the reactivity worths of control rods and together with the integral rod velocity limiters and the action of the control rod drive system limits potential reactivity insertion such that the results of a control rod drop accident will not exceed a maximum fuel energy content of 280 cal/gm. Method and basis for the rod drop accident analyses are documented in Reference 5.

The control rod system is designed to bring the reactor subcritical from a scram signal at a rate fast enough to prevent fuel damage. Scram reactivity curve for the transient analyses is calculated and evaluated with each reload core. In the analytical treatment of the transients, 290 milliseconds are allowed between a neutron sensor reaching the scram point and the start of motion of the control rods. This is adequate and conservative when compared to the typical time delay of about 210 milliseconds estimated from scram test results. Approximately the first 90 milliseconds of each of these time intervals result from the sensor and circuit delays when the pilot scram solenoid de-energizes. Approximately 120 milliseconds later, the control rod motion is estimated to actually begin.

However, 200 milliseconds is conservatively assumed for this time interval in the transient analyses and this is also included in the allowable scram insertion times of Specification 3.2.B.3. The specified limits provide sufficient scram capability to accommodate failure to scram of any one operable rod. This failure is in addition to any inoperable rods that exist in the core, provided that those inoperable rods met the core reactivity Specification 3.2.A.

Control rods (6) which cannot be moved with control rod drive pressure are clearly indicative of an abnormal operating condition on the affected rods and are, therefore, considered to be inoperable. Inoperable rods are valved out of service to fix their position in the core and assure predictable behavior. If the rod is fully inserted and then valved out of service, it is in a safe position of maximum contribution to shutdown reactivity. If it is valved out of service in a non-fully inserted position, that position is required to be consistent with the shutdown reactivity limitation stated in Specification 3.2.A, which assures the core can be shutdown at all times with control rods. Before a rod is valved out of service in a non-fully inserted position, an analysis is performed to insure Specification 3.2.A is met.

The number of inoperable control rods permitted to be valved out of service could be many more than six allowed by the specification, particularly late in the operating cycle; however, the occurrence of more than six could be indicative of a generic problem and the reactor will be shut down. Operable rods that have been taken out of service at the fully inserted position to perform HCU maintenance are not to be counted as inoperable control rods. Also, if damage within the control rod drive mechanism and in particular, cracks in drive internal housings, cannot be ruled out, then a generic problem affecting a number of drives cannot be ruled out. Circumferential cracks resulting from stress assisted intergranular corrosion have occurred in the collet housing of drives at several BWRs. This type of cracking could occur in a number of drives and if the cracks propagated until severance of the collet housing occurred, scram could be prevented in the affected rods. Limiting the period of operation with a potentially severed collet housing and requiring increased surveillance after detecting one stuck rod will assure that the reactor will not be operated with a large number of rods with failed collet housings. Placing the reactor in the shutdown condition inserts the control rods and accomplishes the objective of the specifications on control rod operability. This operation is normally expected to be accomplished within eight hours.

The source range monitor (SRM) system (7) performs no automatic safety function. It does provide the operator with a visual indication of neutron level which is needed for knowledgeable and efficient reactor startup at low neutron levels. The results of the reactivity accidents are functions of the neutron flux. The requirement of at least 3 cps assures that any transient begins at or above the initial value of 10^{-8} of rated power used in the analyses of transients from cold conditions. One operable SRM channel would be adequate to monitor the approach to critical using homogeneous patterns of scattered control rods.

The standby liquid control system is designed to bring the reactor to a cold shutdown condition from the full power steady state operating condition at any time in core life independent of the control rod system capabilities (8). If the reactor is shutdown by the control rod system and would be subcritical in its most reactive condition as required in Specification 3.2.A, there is no requirement for operability of this system. To bring the reactor from full power to cold shutdown, sufficient liquid control must be inserted to give a negative reactivity worth equal to the combined effects of rated coolant voids, fuel Doppler, xenon, samarium, and temperature change plus shutdown margin. This requires a Boron-10 concentration of 110 ppm in the reactor. An additional 25% Boron-10, which results in an average Boron-10 concentration in the reactor of 138 ppm, is inserted to provide margin for mixing uncertainties in the reactor. An amount of Boron-10 equal to or greater than 82 pounds will bring the reactor to cold shutdown.

The standby liquid control system is also required to meet 10 CFR 50.62 (Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants). The standby liquid control system must have the equivalent control capacity (injection rate) of 86 gpm at 13% by wt. natural sodium pentaborate for a 251" diameter reactor pressure vessel in order to satisfy 10 CFR 0.62 requirements. The equivalency requirement is fulfilled by a combination of concentration, Boron-10 enrichment and flow rate of sodium pentaborate solution. A minimum of 15.0 wt.% solution and 35 atom % Boron-10 enrichment at a 30 gpm pump flow rate satisfies the ATWS Rule (10 CFR 50.62) equivalency requirement and assures that the reactor is shutdown before unacceptable containment conditions develop.

The standby liquid control system is required to insert the solution within 120 minutes in order to override the rate of reactivity insertion due to cooldown of the reactor following the xenon peak, the 3737 gallons 5 wt. % point represents the allowable maximum volume-minimum concentration values which satisfy this requirement. Compliance with 10 CFR 50.62 (use of enriched boron) results in the cold shutdown B-10 concentration in the reactor, at the maximum concentration - minimum volume points chosen 19.6 wt. % 913 gallons, being injected in approximately 26 minutes. Thus, the system will insert the solution in the time interval of between 26-120 minutes.

The shaded area of Figure 3.2-1 represents the acceptable values of liquid control tank volume and solution concentration which assure that, with one 30 gpm liquid control pump, the reactor can be brought to the cold shutdown condition from a full power steady state operating condition at any time in core life independent of the control rod system capabilities. The cross-hatched area of Figure 3.2-1 represents the acceptable values of liquid control tank volume and solution concentration which assure that the equivalency requirements of 10 CFR 50.62 are satisfied. The maximum volume of 4213 gal is established by the tank capacity. The tank volume requirements include consideration for 137 gal of solution which is contained below the point where the pump takes suction from the tank and, therefore, cannot be inserted into the reactor.

The solution saturation temperature varies with the concentration of sodium pentaborate. The solution will be maintained at least 5°F above the saturation temperature to guard against precipitation. The 5°F margin is included in Figure 3.2-2. Temperature and liquid level alarms for the system are annunciated in the control room.

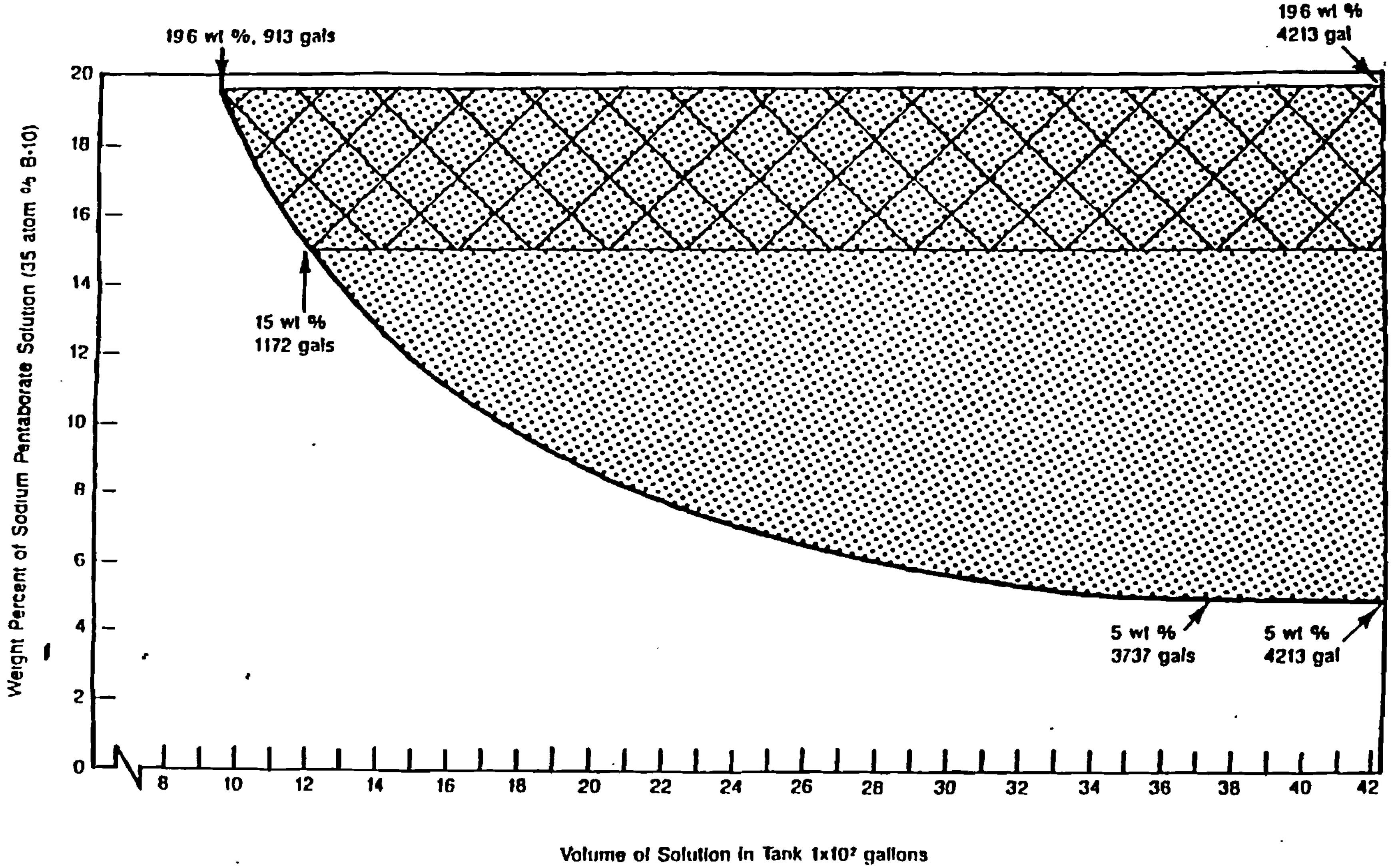
The acceptable time out of service for a standby liquid control system pumping circuit as well as other safety features is determined to be 10 days. However, the allotted time out of service for a standby liquid control system pumping circuit is conservatively set at 7 days in the specification. Systems are designed with redundancy to increase their availability and to provide backup if one of the components is temporarily out of service.

The standby liquid control system also has a post-LOCA safety function to buffer suppression pool pH in order to maintain bulk pH above 7.0. This function is necessary to prevent iodine re-evolution to satisfy the methodology for Alternate Source Term. Manual initiation is used, and the minimum amount of total boron required for suppression pool pH buffering is 1460 lbm. A single pump can satisfy the post-LOCA function which applies to POWER OPERATION and SHUTDOWN CONDITION.

During each fuel cycle, excess operating reactivity varies as fuel depletes and as any burnable poison in supplementary control is burned. The magnitude of this excess reactivity is indicated by the integrated worth of control rods inserted into the core, referred to as the control rod inventory in the core. As fuel burnup progresses, anomalous behavior in the excess reactivity may be detected by comparison of actual rod inventory with expected inventory based on appropriately corrected past data. Experience at Oyster Creek and other operating BWR's indicates that the control rod inventory should be predictable to the equivalent of one percent in reactivity. Deviations beyond this magnitude would not be expected and would require thorough evaluation. One percent reactivity limit is considered safe since an insertion of this reactivity into the core would not lead to transients exceeding design conditions of the reactor system.

References:
(1) FDSAR, Volume I, Section III-5.3.1
(2) FDSAR, Volume I, Section VI-3
(3) FDSAR, Volume I, Section III-5.2.1
(4) FDSAR, Volume I, Section VII-9
(5) NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel (GESTAR II) (latest approved version as specified in the COLR).
(6) FDSAR, Volume I, Section III-5 and Volume II, Appendix B
(7) FDSAR, Volume I, Sections VII-4.2.2 and VII-4.3.1
(8) FDSAR, Volume I, Section VI-4
(9) FDSAR, Amendment No. 55, Section 2
(10) C. J. Paone, Banked Position Withdrawal Sequence, January 1988 (NEDO-21231)
(11) UFSAR, Volume 4, Section 4.3.2.4.1

Fig. 3.2-1 Sodium Pentaborate Solution Volume - Concentration Requirement



Amendment No. 124, 178
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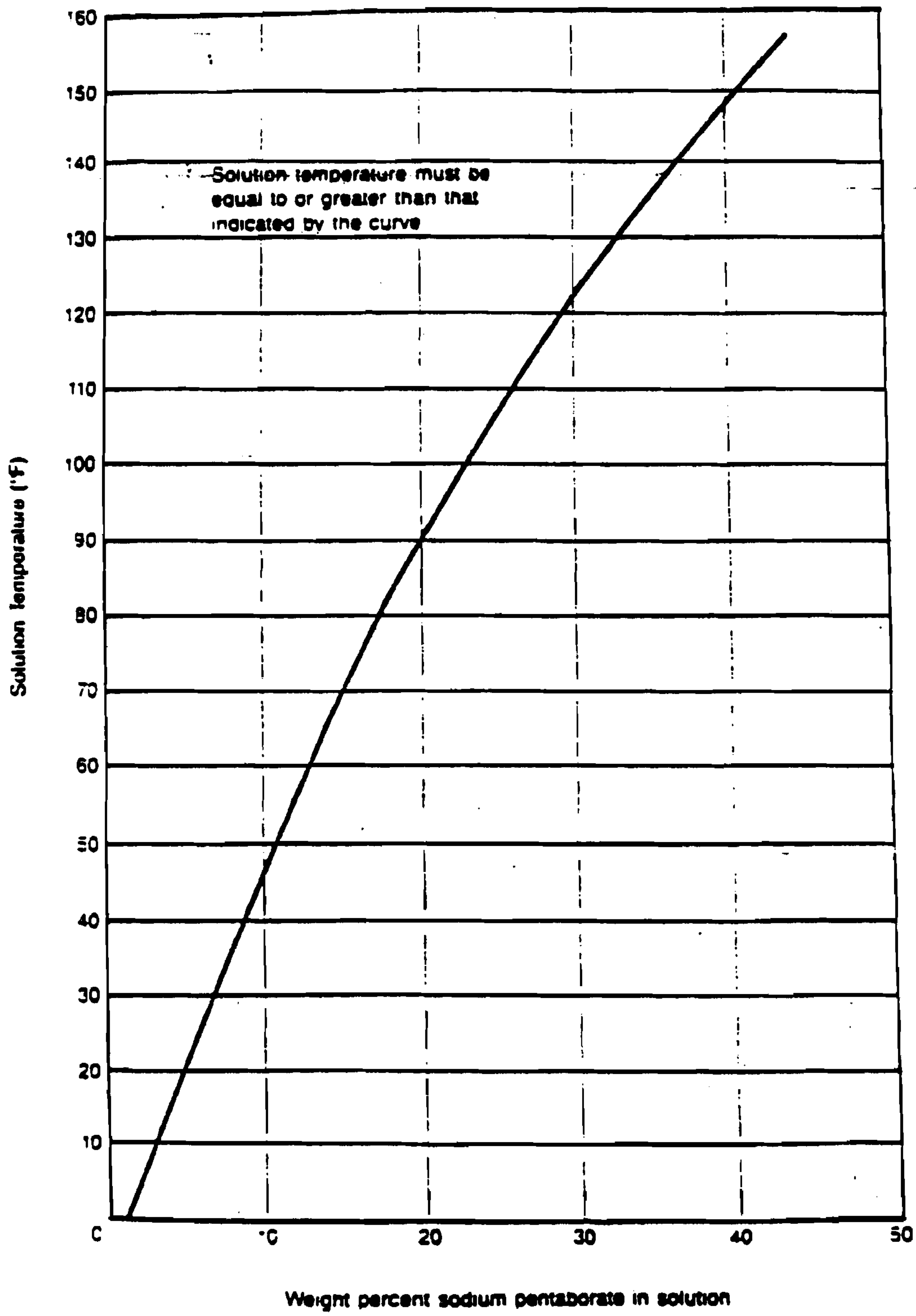
FIGURE 3.2.2 - Sodium Pentaborate Solution Temperature Requirements



3.3 REACTOR COOLANT

Applicability: Applies to the operating status of the reactor coolant system.

Objective: To assure the structure integrity of the reactor coolant system.

Specification: A. Pressure Temperature Relationships

(i) Reactor Vessel Pressure Tests - the minimum reactor vessel temperature at a given pressure shall be in excess of that indicated by the curves in the Pressure and Temperature Limits Report (PTLR).

(ii) Heatup and Cooldown Operations: Reactor noncritical -- the minimum reactor vessel temperature for heatup and cooldown operations at a given pressure when the reactor is not critical shall be in excess of that indicated by the curves in the Pressure and Temperature Limits Report (PTLR).

(iii) Power operations -- the minimum reactor vessel temperature for power operations at a given pressure shall be in excess of that indicated by the curves in the Pressure and Temperature Limits Report (PTLR).

(iv) Deleted

B. Reactor Vessel Closure Head Boltdown: The reactor vessel closure head studs may be elongated .020" (1/3 design preload) with no restrictions on reactor vessel temperature as long as the reactor vessel is at atmospheric pressure. Full tensioning of the studs is not permitted unless the temperature of the reactor vessel flange and closure head flange is in excess of the values specified in the Pressure and Temperature Limits Report (PTLR).

C. Thermal Transients

1. The average rate of reactor coolant temperature change during normal heatup and cooldown shall not exceed the values specified in the Pressure and Temperature Limits Report (PTLR).
2. The pump in an idle recirculation loop shall not be started unless the temperature of the coolant within the idle recirculation loop is within 50°F of the reactor coolant temperature.

D. Reactor Coolant System Leakage

1. Reactor coolant system leakage shall be limited to:

   a. 5 gpm unidentified leakage
   b. 25 gpm total (identified and unidentified)
   c. 2 gpm increase in unidentified leakage rate within any 24 hour period while operating at steady state power

2. With the reactor coolant system leakage greater than the limits in 3.3.D.1.a or b above, reduce the leakage rate to within the acceptable limits within 8 hours, or place the reactor in the shutdown condition within the next 12 hours and be in the cold shutdown condition within the following 24 hours.

3. With any reactor coolant leakage greater than the limit in 3.3.D.1.c above, identify the source of leakage within 4 hours, or be in the shutdown condition within the next 12 hours and be in the cold shutdown condition within the following 24 hours.

4. For determination of unidentified leakage, the primary containment sump flow monitoring system shall be operable except as specified below:

   a. With the primary containment sump flow integrator inoperable:

      1. Restore it to operable status within 7 days.
      2. Calculate the unidentified leakage rate utilizing an acceptable alternate means as specified in plant procedures.

   b. If Specification 3.3.D.4a cannot be met, place the reactor in the shutdown condition within the next 12 hours.

5. For determination of identified leakage, the primary containment equipment drain tank monitoring system shall be operable except as specified below:

   a. With the primary containment equipment drain tank monitoring system inoperable:

      1. Restore it to operable status within 7 days. and
      2. Calculate the identified leakage rate utilizing an acceptable alternate means as specified in plant procedures.

   b. If Specification 3.3.D.5.a cannot be met, place the reactor in the shutdown condition within the next 12 hours.

E. Reactor Coolant Quality

1. The reactor coolant quality during power operation with steaming rates to the turbine-condenser of less than 100,000 pounds per hour shall be limited to:

conductivity	2 us/cm[s=mhos at 25°C (77°F]
chloride ion	0.1 ppm

2. When the conductivity and chloride concentration limits given in 3.3.E.1 are exceeded, an orderly shutdown shall be initiated immediately, and the reactor coolant temperature shall be reduced to less than 212°F within 24 hours.

3. The reactor coolant quality during power operation with steaming rates to the turbine-condenser of greater than or equal to 100,000 pounds per hour shall be limited to:

conductivity	10 uS/cm	[S=mhos at 25°C (77°F)]
chloride ion	0.5 ppm	

4. When the maximum conductivity or chloride concentration limits given in 3.3.E.3 are exceeded, an orderly shutdown shall be initiated immediately, and the reactor coolant temperature shall be reduced to less than 212°F within 24 hours.

5. During power operation with steaming rates on the turbine-condenser of greater than or equal to 100,000 pounds per hour, the time limit above 1.0 uS/cm at 25°C (77°F) and 0.2 ppm chloride shall not exceed 72 hours for any single incident.

6. When the time limits for 3.3.E.5 are exceeded, an orderly shutdown shall be initiated within 4 hours.

F. Recirculation Loop Operability

1. During POWER OPERATION, all five recirculation loops shall be OPERATING except as specified in Specification 3.3.F.2.

2. POWER OPERATION with a maximum of two IDLE RECIRCULATION LOOPS or one IDLE RECIRCULATION LOOP and one ISOLATED RECIRCULATION LOOP is permitted. The reactor shall not operate with two ISOLATED RECIRCULATION LOOPS.

   a. With one ISOLATED LOOP the following conditions shall be met:

      1. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) as a function of average planar exposure, at any axial location shall not exceed 98% of the limits specified in 3.10.A. The action to bring the core to 98% of the APHLGR limits shall be completed prior to isolating the recirculation loop.

2. The circuit breaker of the recirculation pump motor generator set associated with an ISOLATED RECIRCULATION LOOP shall be open and defeated from operation.

3. An ISOLATED RECIRCULATION LOOP shall not be returned to service unless the reactor is in the COLD SHUTDOWN condition.

b. When there are two inoperable recirculation loops (either two IDLE RECIRCULATION LOOPS or one IDLE RECIRCULATION LOOP and one ISOLATED RECIRCULATION LOOP) the reactor core THERMAL POWER shall not exceed 90% of rated power.

3. If Specifications 3.3.F.1 and 3.3.F.2 are not met, an orderly shutdown shall be initiated immediately until all operable control rods are fully inserted and the reactor is in either the REFUEL MODE or SHUTDOWN CONDITION within 12 hours.

4. With reactor coolant temperature greater than 212°F and irradiated fuel in the reactor vessel, at least one recirculation loop discharge valve and its associated suction valve shall be in the full open position.

5. If Specification 3.3.F.4 is not met, immediately open one recirculation loop discharge valve and its associated suction valve.

6. With reactor coolant temperature less than 212°F and irradiated fuel in the reactor vessel, at least one recirculation loop discharge valve and its associated suction valve shall be in the full open position unless the reactor vessel is flooded to a level above 185 inches TAF or unless the steam separator and dryer are removed.

G. Primary Coolant System Pressure Isolation Valves

Applicability:

Operational conditions - Startup and Run Modes; applies to the operational status of the primary coolant system pressure isolation valves.

Objective:

To increase the reliability of primary coolant system pressure isolation valves thereby reducing the potential of an inter-system loss of coolant accident.

Specification:

1. During reactor power operating conditions, the integrity of all pressure isolation valves listed in Table 3.3.1 shall be demonstrated. Valve leakage shall not exceed the amounts indicated.

2. If Specification 1 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

H. Required Minimum Recirculation Flow Rate for Operation in IRM Range 10

1. During STARTUP mode operation, a minimum recirculation flow rate is required before operating in IRM range 10 to ensure that technical specification transient MCPR limits for operation are not exceeded. This minimum flow rate is no longer required once the reactor is in the RUN mode.

2. 39.65×10^6 lb/hr is the minimum recirculation flow rate necessary for operation in IRM range 10 at this time. This flow rate leaves sufficient margin between the minimum flow required by the RWE analysis performed and the minimum flow used while operating in IRM range 10.

NRC Order Dated April 20, 1981

Correction letter of 8-7-2000

Section 3.3

Bases:

The reactor coolant system(1) is a primary barrier against the release of fission products to the environs. In order to provide assurance that this barrier is maintained at a high degree of integrity, restrictions have been placed on the operating conditions to which it can be subjected.

The Oyster Creek reactor vessel was designed and manufactured in accordance with General Electric Specification 21A1105 and ASME Section I as discussed in Reference 13. The original operating limitations were based upon the requirement that the minimum temperature for pressurization be at least 60°F greater than the nil ductility transformation temperature. The minimum temperature for pressurization at any time in life has to account for the toughness properties in the most limiting regions of the reactor vessel, as well as the effects of fast neutron embrittlement.

Pressure and temperature curves are generated in accordance with Reference 15 and are contained in the Pressure and Temperature Limits Report (PTLR).

Stud tensioning is considered significant from the standpoint of brittle fracture only when the preload exceed approximately 1/3 of the final design value. No vessel or closure stud minimum temperature requirements are considered necessary for preload values below 1/3 of the design preload with the vessel depressurized since preloads below 1/3 of the design preload result in vessel closure and average bolt stresses which are less than 20% of the yield strengths of the vessel and bolting materials. Extensive service experience with these materials has confirmed that the probability of brittle fracture is extremely remote at these low stress levels, irrespective of the metal temperature.

The reactor vessel head flange and the vessel flange in combination with the double "O" ring type seal are designed to provide a leak tight seal when bolted together. When the vessel head is placed on the reactor vessel, only that portion of the head flange near the inside of the vessel rests on the vessel flange. As the head bolts are replaced and tensioned, the vessel head is flexed slightly to bring together the entire contact surface adjacent to the "O" rings of the head and vessel flange.

Detailed stress analyses(4) were made on the reactor vessel for both steady state and transient conditions with respect to material fatigue. The results of these analyses are presented and compared to allowable stress limits in Reference (4). The specific conditions analyzed currently include 240 cycles (17) of normal startup and shutdown with a heating and cooling rate of 100°F per hour applied continuously over a temperature range of 100°F to 546°F and for 10 cycles of emergency cooldown at a rate of 300°F per hour applied over the same range. A review of the original analysis shows that the components with the highest fatigue usage factor are the reactor vessel studs and reactor vessel basin seal skirt. These components have the potential to exceed the allowable fatigue usage factor if the number of thermal cycles (i.e., heatup/cooldown) exceed design assumptions. The number of heatup and cooldown cycles was reanalyzed, as documented by Reference (17), for a higher number of cycles (240) than expected in the original analysis (120). The reanalysis confirmed that the original fatigue usage factor limit of 0.8 is maintained. All other components have relatively low usage factors and are not expected to exceed fatigue usage factor limit of 0.8 for the original design life of 40 years. Subsequently, the method for the determination of Fatigue Cumulative Usage Factor (CUF) was changed to incorporate the NRC-approved methodology of ASME B&PV code. The limit used with this method was changed from 0.8 to 1.0 (Reference 18). Thermal stresses from this analysis combined with the primary load stresses fall within ASME Code Section III allowable stress intensities. Although the Oyster Creek Unit I reactor vessel was built in accordance with Section I of the ASME Code, the design criteria included in the reactor vessel specifications were in essential agreement with the criteria subsequently incorporated into Section III of the Code.(6)

The expected number of normal heatup and cooldown cycles to which the vessel will be subjected is 80(7). Although no heatup or cooldown rates of 300°F per hour are expected over the life the vessel and the vessel design did not consider such events(6), stress analyses have been made which showed the allowable number of such events is 22,000 on the basis of ASME Section III alternating stress limits.

During reactor operation, the temperature of the coolant in an idle recirculation loop is expected to remain at reactor coolant temperature unless it is valved out of service. Requiring the coolant temperature in an idle loop to be within 50°F of the reactor coolant temperature before the sump is started assures that the change in coolant temperature at the reactor vessel nozzles and bottom head region are within the conditions analyzed for the reactor vessel as discussed above.

Allowable leakage rates of coolant from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes and on the ability to makeup coolant system leakage in the event of loss of offsite AC power. The normally expected background leakage due to equipment design and the detection capability for determining coolant system leakage were also considered in establishing the limits. The behavior of cracks in piping systems has been experimentally and analytically investigated as part of the USAEC sponsored Reactor Primary Coolant System Rupture Study (the Pipe Rupture Study). Work (8) utilizing the data obtained in this study indicates that leakage from a crack can be detected before the crack grows to a dangerous or critical size by mechanically or thermally induced cyclic loading, or stress corrosion cracking or some other mechanism characterized by gradual crack growth. This evidence suggests that for leakage somewhat greater than the limit specified for unidentified leakage, the probability is small that imperfections or cracks associated with such leakage would grow rapidly. However, the establishment of allowable unidentified leakage greater than that given in the 3.3-D on the basis of the data presently available would be premature because of uncertainties associated with the data. For leakage of the order of 5 gpm as specified in 3.3-D, the experimental and analytical data suggest a reasonable margin of safety that such leakage magnitude would not result from a crack approaching the critical size for rapid propagation. Leakage of the magnitude specified can be detected reasonably in a matter of a few hours utilizing the available leakage detection schemes, and if the origin cannot be determined in a reasonably short time, the plant should be shut down to allow further investigation and corrective action.

The drywell floor drain sump and equipment drain tank provide the primary means of leak detection(9,10). Identified leakage is that from valves and pumps in the reactor system and from the reactor vessel head flange gasket. Leakage through the seals of this equipment is piped to the drywell equipment drain tank. Leakage from other sources is classified as unidentified leakage and is collected in the drywell floor drain sump. Leakage which does not flash in a vapor will drain in the sump. The vapor will be condensed in the drywell ventilation system and routed to the sump.

Condensate cannot leave the sump or the drywell equipment drain tank unless the respective pumps are running. The sump and the drain tank are provided with two pumps each. Alarms are provided for the sump that will actuate on a predetermined pumpout rate(10) and will be set to actuate at a leakage that is less than the unidentified leakage limit of 5 gpm.

Additional qualitative information(10) is available to the operator via the monitored drywell atmospheric condition. However, this information is not quantitative since fluctuation in atmospheric conditions are normally expected, and quantitative measurements are not possible. The temperature of the closed cooling water which serves as coolant for the drywell ventilation system is monitored and also provides information which can be related to reactor coolant system leakage(9). Additional protection is provided by the drywell high pressure scram which would be expected to be reached within 30 minutes of a steam leak of about 12 gpm(10).

During a loss of offsite AC power, the control rod drive hydraulic pumps, which are powered by the diesels, each can supply 110 gpm water makeup to the reactor vessel. A 25 gpm limit for total leakage, identified and unidentified, was established to be less than the 110 gpm makeup of a single rod drive hydraulic pump to avoid the use of the emergency core cooling system in the event of a loss of normal AC power.

Materials in the primary system are primarily 304 stainless steel and zircaloy fuel cladding. The reactor water chemistry limits are placed upon conductivity and chloride concentration since conductivity is measured continuously and gives an indication of abnormal conditions or the presence of unusual materials in the coolant, while chloride limits are specified to prevent stress corrosion cracking of stainless steel.

Chlorides are known to (1) promote intergranular stress corrosion cracking of sensitized steels, (2) induce transgranular cracking of non-sensitized stainless steels, (3) promote pitting and (4) promote crevice attack in most RCS materials (BWR Water Chemistry Guidelines, EPRI, April 1, 1984). The higher the concentration, the faster the attack. Therefore, the level of chloride in the reactor water should be kept as low as is practically achievable. The limits are therefore set to be consistent with Regulatory Guide 1.56 (Rev. 1).

In the case of BWR's where no additives are used in the primary coolant, and where neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. When the conductivity is within its proper normal range, pH, chloride, and other impurities affecting conductivity and water quality must also be within their normal ranges. Significant changes in conductivity provide the operator with a warning mechanism so that he can investigate and remedy the conditions causing the change.

Measurements of pH, chloride, and other chemical parameters are made to determine the cause of the unusual conductivity and instigate proper corrective action. These can be done before limiting conditions, with respect to variables affecting the boundaries of the reactor coolant, are exceeded. Several techniques are available to correct off-standard reactor water quality conditions including removal of impurities from reactor water by the cleanup system, reducing input of impurities causing off-standard conditions by reducing power and reducing the reactor coolant temperature to less than 212°F. The major benefit of reducing the reactor coolant temperature to less than 212°F is to reduce the temperature dependent corrosion rates and thereby provide time for the cleanup system to re-establish proper water quality.

Specifications 3.3.F.1 and 3.3.F.2 provide the OPERABILITY requirements for recirculation loops including acceptable valve alignments for OPERATION with less than five OPERABLE loops.

The IDLE loop configuration allows back flow through the loop discharge bypass valve and the loop temperature can be maintained within 50°F of the reactor coolant inlet temperature. An idle loop can be restarted since the restart of the loop will not result in a cold water addition transient causing a concern from either reactivity addition or reactor nozzle thermal stresses.

The ISOLATED RECIRCULATION LOOP will experience a cooling of the loop temperatures greater than 50°F and restart of an isolated loop could result in a cold water addition transient. Therefore, restart of an ISOLATED loop is not permitted and the circuit breakers for the motor generator set are open and defeated from operation to prevent an inadvertent startup of an ISOLATED RECIRCULATION LOOP. The ISOLATED LOOP can only be returned to service when the reactor is in COLD SHUTDOWN. When a recirculation loop is ISOLATED, the coolant between the suction and discharge and discharge bypass valves is no longer available during a loss of coolant accident (LOCA). This lose of inventory requires a reduction to 98% of the MAPLHGR limits in the Core Operating Limits Report.

During three-loop operation reactor power is limited to 90% of rated power. This is a physical restriction, since it is unlikely that the plant could operate at 90% of rated power with three operating recirculation pumps; and it is the maximum power analyzed for three-loop operation. No more than one recirculation loop can be ISOLATED. This restriction is required since the loss of inventory from a second ISOLATED REICRCULATION LOOP has not been analyzed. Operation with two IDLE or one IDLE and one ISOLATED RECIRCULTION LOOPS is permissible.

A non-operating recirculation loop may not be configured with both the suction valve and discharge valve in the open position since the back flow through the loop would result in non-conservative instrument readings for recirculation flow. Therefore, the reactor would be shutdown according to Specification 3.3.F.3 if a recirculation loop cannot be placed into an IDLE or ISOLATED configuration.

Specifications 3.3.F.4 and 3.3.F.6 assure that an adequate flow path exists from the annular space, between the pressure vessel wall and the core shroud, to the core region. This provides sufficient hydraulic communication between these areas, thus assuring that reactor water instrument readings are indicative of the level in the core region. For the bounding loss of feedwater transient[2], a single fully open recirculation loop transfers coolant from the annulus to the core region at approximately five times the boiloff rate with no forced circulation[3]. With the reactor vessel flooded to a level above 185 inches TAF or when the steam separator and dryer are removed, the core region and all recirculation loops can therefore be isolated. When the steam separator and dryer are removed, safety limit 2.1.D ensures water level is maintained above the core shroud.

References:

1. FDSAR, Volume 1, Section IV-2

2. Letter to NRC dated May 19, 1979, "Transient of May 2, 1979"

3. General Electric Co. Letter G-EN-9-55, "Revised Natural Circulation Flow Calculation", dated May 29, 1979

4. Licensing Application Amendment 16, Design Requirements Section

5. (Deleted)

6. FDSAR, Volume 1, Section IV-2.3.3 and Volume 11, Appendix H

7. FDSAR, Volume 1, Table IV-2-1

8. Licensing Application Amendment 34, Question 14

9. Licensing Application Amendment 28, Item III-B-2

10. Licensing Application Amendment 32, Question 15

11. (Deleted)

12. (Deleted)

13. Licensing Application Amendment 16, Page 1

14. (Deleted)

15. SIR-05-044-A, "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," April 2007

16. (Deleted)

17. GPUN Safety Evaluation, SE-000221-004, "Reactor Vessel Thermal Cycles"

18. 50.59 Evaluation, OC-2006-E-001, Revised Method For The Determination of Fatigue Cumulative Usage Factor for ECR 06-00046

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TABLE 3.3.1

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES

System	Valve No.	Maximum[a] Allowable Leakage
Core Spray System 1	NZ02A	5.0 GPM
	NZ02C	5.0 GPM
Core Spray System 2	NZ02B	5.0 GPM
	NZ02D	5.0 GPM

Footnote:

(a) 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5. Test differential pressure shall not be less than 150 psid.

3.4 EMERGENCY COOLING

Applicability: Applies to the operating status of the emergency cooling systems.

Objective: To assure operability of the emergency cooling systems.

Specifications:

A. Core Spray System

NOTE: LCO 3.0.C.2 is not applicable to the Core Spray System

1. The Core Spray System shall be OPERABLE at all times with irradiated fuel in the reactor vessel with an absorption chamber water volume of at least 82,000 ft^3 except as specified in Table 3.4.1, or as noted below.

2. If Specification 3.4.A.1 is not met the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION and no work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8"above TOP OF ACTIVE FUEL.

Table 3.4.1

Run or Startup Mode (except for low power physics testing)		
Condition	Requirement	Provided:
Any active loop component becomes inoperable. -OR- Two or more active loop components in the same loop (System 1 or System 2) are inoperable provided no two components are redundant.	The Reactor may remain in operation for a period not to exceed 15 Days.	Both Emergency Diesel Generators are OPERABLE. The Redundant active loop components within the same loop as the inoperable components are verified OPERABLE on a daily basis. Specification 3.4.A.3 is met unless only a core spray booster pump is inoperable.
One Emergency Diesel Generator is inoperable.	The Reactor may remain in operation for a period not to exceed 7 Days. (Refer to Section 3.7.C.2)	All core spray equipment connected to the OPERABLE emergency diesel generator is OPERABLE.

Run or Startup Mode (except for low power physics testing)		
Condition	**Requirement**	**Provided:**
One core spray loop (System 1 or System 2) or its core spray header delta-P instrumentation becomes inoperable. -OR- Both of the redundant components in a loop (System 1 or System 2) are inoperable.	The Reactor may remain in operation for a period not to exceed 7 Days.	Both Emergency Diesel Generators are OPERABLE. The remaining loop (System 1 or System 2) has no inoperable components and is verified daily to be OPERABLE. Specification 3.4.A.3 is met.
Two of the four redundant active loop components in the core spray system not in the same loop (System 1 or System 2) are inoperable. -OR- Two or more non-redundant active loop components are inoperable in both loops (System 1 and System 2).	The Reactor may remain in operation for a period not to exceed 7 Days.	Both Emergency Diesel Generators are OPERABLE. The Redundant active loop components within the same loop as the inoperable components are verified OPERABLE on a daily basis. Specification 3.4.A.3 is met.

Shutdown or Refuel Mode		
Condition	**Requirement**	**Provided:**
Maintenance or modifications of core spray systems, their power supplies, or water supplies.	Maintain reduced core spray system availability as follows: 1.At least one core spray pump, and system components necessary to deliver rated core spray to the reactor vessel, must remain OPERABLE to the extent the pump and any necessary valves can be started or operated from the control room or from local control stations. 2.The Fire protection system is OPERABLE to the extent that one diesel driven fire pump is capable of providing water to the core spray system. 3.Verify the systems in 1 & 2 above are OPERABLE on a weekly basis.	The Reactor is maintained in the COLD SHUTDOWN CONDITION or in the REFUEL MODE with the reactor coolant system maintained at less than 212°F and vented. -AND- No work is performed on the reactor vessel and connected systems that could result in lowering the reactor water level to less than 4'8" above the TOP OF ACTIVE FUEL.

Shutdown or Refuel Mode		
Condition	Requirement	Provided:
Maintenance or modifications of core spray systems, their power supplies, or water supplies while work is in progress having the potential to lower reactor water level below 4'8" TAF. -OR- The Reactor is in the startup mode for low power physics testing.	Maintain reduced core spray system availability as follows: 1.At least one core spray pump in each loop, and system components necessary to deliver rated core spray to the reactor vessel, must remain OPERABLE to the extent that the pump and any necessary valves in each loop can be started or operated from the control room or from local control stations. 2.Fire protection system is OPERABLE to the extent that one diesel driven fire pump is capable of providing water to the core spray system. 3.Verify the systems in 1 & 2 above are OPERABLE every 72 hours.	The Reactor is: In the REFUEL MODE with the reactor coolant system maintained at less than 212°F. -OR- In the STARTUP MODE for the purpose of low power physics testing.
The requirements for maintenance or modification can not be met.	Initiate work to meet the requirements.	Specification 3.4.A.2 is met.

3. In the event of inoperable active loop components the APLHGR of all the rods in any fuel assembly, as a function of average planar exposure, at any axial location shall not exceed 90% of the limits given in Specification 3.10.A. The action to bring the core to 90% of the APLHGR Limits must be completed within two hours after the component has been determined to be inoperable.

4. The core spray system is not required to be operable when the following conditions are met:

   a. The reactor mode switch is locked in the "Refuel" or "Shutdown" position.

   b. (1) There is an operable flow path capable of taking suction from the condensate storage tank and transferring water to the reactor vessel, and

      (2) The fire protection system is OPERABLE to the extent that one diesel driven fire pump is capable of providing water to the core spray system, and

      (3) These systems are verified to be OPERABLE on a weekly basis.

c. The reactor coolant system is maintained at less than 212 °F and vented (except during reactor vessel pressure testing).

d. At least one core spray pump, and system components necessary to deliver rated core spray flow to the reactor vessel, must remain operable to the extent that the pump and any necessary valves can be started or operated from the control room or from local control stations, and the torus is mechanically intact. Verify the pump and components are OPERABLE, as described, on a weekly basis.

e. (1) No work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the TOP OF the ACTIVE FUEL and there is a minimum of 360,000 gallons of water available between the torus and condensate storage tank water inventories. At least two redundant core spray systems including core spray pumps and system components must remain operable as defined in d. above. At least one recirculation loop discharge valve and its associated suction valve shall be in the full open position. Verify the pumps and components are OPERABLE, as described, on a weekly basis.

OR

(2) The reactor vessel head, fuel pool gate, and separator-dryer pool gates are removed and the water level is above elevation 117 feet. When filling or draining the reactor cavity, a sufficient water inventory (between the condensate storage tank and the reactor cavity) to complete the flooding operation shall be maintained. The 360,000 gallons of water minimum requirement in (1) above does not apply during the filling and draining operation provided there is a sufficient amount of water to complete the flooding operation.

B. Automatic Depressurization System

1. Five electromatic relief valves, which provide the automatic depressurization and pressure relief functions, shall be operable when the reactor water temperature is greater than 212°F and pressurized above 110 psig, except as specified in 3.4.B.2 and during Reactor Vessel Pressure Testing consistent with Specifications 1.39 and 3.3.A.(i).

2. If at any time there are only four operable electromatic relief valves, the reactor may remain in operation for a period not to exceed 3 days provided the motor operated isolation and condensate makeup valves in both isolation condensers are verified daily to be operable.

3. If Specifications 3.4.B.1 and 3.4.B.2 are not met; reactor pressure shall be reduced to 110 psig or less, within 24 hours.

4. The time delay set point for initiation after coincidence of low-low-low reactor water level and high drywell pressure shall be set not to exceed two minutes.

C. Containment Spray System and Emergency Service Water System

NOTE: LCO 3.0.C.2 is not applicable to the Containment Spray System and Emergency Service Water System

1. The containment spray system and the emergency service water system shall be operable at all times with irradiated fuel in the reactor vessel, except as specified in Specifications 3.4.C.3, 3.4.C.4, 3.4.C.6 and 3.4.C.8.

2. The absorption chamber water volume shall not be less than 82,000 ft^3 in order for the containment spray and emergency service water system to be considered operable.

3. If one emergency service water system loop becomes inoperable, its associated containment spray system loop shall be considered inoperable. If one containment spray system loop and/or its associated emergency service water system loop becomes inoperable during the run mode, the reactor may remain in operation for a period not to exceed 7 days provided the remaining containment spray system loop and its associated emergency service water system loop each have no inoperable components and are verified daily to be operable.

4. If a pump in the containment spray system or emergency service water system becomes inoperable, the reactor may remain in operation for a period not to exceed 15 days provided the other similar pump is verified daily to be operable. A maximum of two pumps may be inoperable provided the two pumps are not in the same loop. If more than two pumps become inoperable, the limits of Specification 3.4.C.3 shall apply.

5. During the period when one diesel is inoperable, the containment spray loop and emergency service water system loop connected to the operable diesel shall have no inoperable components.

6. If primary containment integrity is not required (see Specification 3.5.A), the containment spray system may be made inoperable.

7. If Specifications 3.4.C.3, 3.4.C.4, 3.4.C.5 or 3.4.C.6 are not met, the reactor shall be placed in cold shutdown condition. If the containment spray system or the emergency service water system becomes inoperable, the reactor shall be placed in the cold shutdown condition and no work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the top of the active fuel.

8. The containment spray system may be made inoperable during the integrated primary containment leakage rate test required by Specification 4.5, provided that the reactor is maintained in the cold shutdown condition and that no work is performed on the reactor or its connected systems which could result in lowering the reactor level to less than 4'8" above the top of the active fuel.

D. Control Rod Drive Hydraulic System

1. The control rod drive (CRD) hydraulic system shall be operable when the reactor water temperature is above 212°F except as specified in 3.4.D.2 and 3.4.D.3 below.

2. If one CRD hydraulic pump becomes inoperable when the reactor water temperature is above 212°F, the reactor may remain in operation for a period not to exceed 7 days provided the second CRD hydraulic pump is operating and is checked at least once every 8 hours. If this condition cannot be met, the reactor water temperature shall be reduced to less than 212°F.

3. During reactor vessel pressure testing, at least one CRD pump shall be operable.

E. Core Spray and Containment Spray Pump Compartments Doors

The core spray and containment spray pump compartments doors shall be closed at all times except during passage in order to consider the core spray system and the containment spray system operable.

F. Fire Protection System

1. The fire protection system shall be operable at all times with fuel in the reactor vessel except as specified in Specification 3.4.F.2.

2. If the fire protection system becomes inoperable during the run mode, the reactor may remain in operation provided both core spray system loops are operable with no inoperable components.

Bases:

This specification assures operability of the emergency core cooling system to provide adequate core cooling. The Oyster Creek ECCS has two core spray loops (system 1 and system 2); each containing a core spray sparger and redundant active loop components consisting of two main pumps, two booster pumps, two parallel isolation valves (outside the drywell) and two check valves in parallel (inside the drywell). Specification 3.4.A.1 insures the availability of core cooling to meet the ECCS acceptance criteria in 10 CFR 50.46 utilizing the MAPLHGR limits provided in Section 3.10. These limits are from calculations(1) that include models and procedures which are specified in 10 CFR 50 Appendix K. A core spray flow of at least 3400 gpm (1 main and 1 booster pump) from 1 loop plus 2200 gpm (1 main pump) from the other loop at a vessel pressure of 110 psig is used in the calculation. Core spray loop 2 would be required to deliver 3640 gpm if loop 2 is relied upon as the two pump contributor and 2360 gpm if loop 2 is the single pump contributor, since loop 2 has flow losses through cracks in the core spray sparger.

Table 3.4.1 allows continued operation with one core spray loop inoperable for a limited period of time. An evaluation of data presented in Reference 5 shows that flow from a single core spray sparger, main and booster pumps delivering 3400 gpm (3640 gpm for loop 2) at a vessel pressure of 110 psig, will meet 10 CFR 50.46 criteria with a 10% reduction in MAPLHGR Limits specified in Section 3.10. At 90% of the APLHGR, each core spray system is capable of supplying the required minimum bundle flow rate to ensure core cooling (References 6 and 7). Two hours is allowed for a reduction in the APLHGR limit which is consistent with two hours provided by Specification 3.10.A.3 to return an exceeded APLHGR to within the prescribed limit.

Under the APLHGR operational constraints of specification 3.4.A.3 the operable core spray loop meets all Appendix K requirements except for the case of a core spray line break inside the drywell in the operable loop. As a result, reactor operation is permitted for a period not to exceed seven days. The allowed time out of service for the redundant core spray loop is justified based on the low probability of the event, the direct operator indication of a Core Spray System pipe break, and emergency procedures which provide for additional cooling water through the fire system.

The probability of a pipe break between the reactor vessel and the core spray check valve in the operable core spray loop (approx. 28 feet of 6 inch pipe) compared to the total pipe in the reactor coolant pressure boundary is very small. The probability of a core spray line break in conjunction with the other core spray loop out of service, which in itself is a low probability, is so small that it does not constitute an unacceptable risk. In the extremely unlikely event that this LOCA scenario were to occur, the operators are provided with a specific visual and audible alarm alerting them of a "Core Spray System I (II) Pipe Break" (one for each core spray loop). These alarms are initiated by differential pressure detectors on each core spray loop. In such a case the core spray line break would occur above the top of the active fuel allowing the core to be re-flooded from the fire protection system through the intact core spray loop.

In addition, a small break LOCA in the operable core spray loop prior to a larger break will be detected by the drywell unidentified leakage system (drywell sump) even before it is detected by the core spray alarm system. This will provide the operators with additional time to respond.

Therefore, the out-of-service time for one of the two core spray loops, as evaluated as per the guidelines in Reference 8, has been conservatively selected to be 7 days.

Table 3.4.1 allows continued operation with one redundant active loop component inoperable for a limited period of time. Each core spray loop contains redundant active components based upon Reference 1 or 5, as appropriate. Therefore, with the loss of one of these components, the system as a whole (both loops) can tolerate an additional single failure of one of its active components and still perform the intended function and meet 10 CFR 50.46 criteria. If a redundant active loop component fails, a fifteen day period is allowed for repairs, based on 1 out of 4 components being required. The 1 out of 4 requirement is maintained by assuring no two inoperable components are redundant.

Table 3.4.1 ensures that if one diesel is out of service for repair, the core spray components fed by the other diesel must be OPERABLE. Since each diesel will provide power to components for both core spray loops, the required flow specified in the bases for Specification 3.4.A.1 will be met.

When the reactor is in the shutdown or refueling mode and the reactor coolant system is less than 212°F and vented and no work is being performed that could result in lowering the water level to less than 4'8" above the core, the likelihood of a leak or rupture leading to uncovering of the core is very low. The only source of energy that must be removed is decay heat and one day after shutdown this heat generation rate is conservatively calculated to be not more than 0.6% of rated power. Sufficient core spray flow to cool the core can be supplied by one core spray pump or one of the two fire protection system pumps under these conditions. When it is necessary to perform repairs on the core spray system components, power supplies or water sources, Table 3.4.1 permits reduced cooling system capability to that which could provide sufficient core spray flow from two independent sources. Manual initiation of these systems is adequate since it can be easily accomplished within 15 minutes during which time the temperature rise in the reactor fuel cladding will not reach 2200°F.

In order to allow for certain primary system maintenance, which will include control rod drive repair, LPRM removal/installation, reactor leak test, etc., (all performed according to approved procedure), Table 3.4.1 requires the availability of an additional core spray pump in an independent loop, while this maintenance is being performed. The likelihood of the core being uncovered is still considered to be very low, however, the requirement of a second core spray pump capable of full rated flow and the 72 hour OPERABILITY verification of both core spray pumps is specified.

Specification 3.4.A.4 allows the core spray system to be inoperable in the cold shutdown or refuel modes if the reactor cavity is flooded and the spent fuel pool gates are removed and a source of water supply to the reactor vessel is available as specified in 3.4.A.4.b.1 which may include the core spray pump, a condensate pump through the feedwater system, or other defined path from the condensate storage tank capable of providing the required makeup capability. Water would then be available to keep the core flooded.

The requirement in Specification 3.4.A.4.e(1) to maintain at least one recirculation loop discharge valve and its associated suction valve in the full open position assures that an adequate flow path exists from the annular space, between the pressure vessel wall and the core shroud, to the core region.

The relief valves of the automatic depressurization system enable the core spray system to provide protection against the small break in the event the feedwater system is not active.

The containment spray system is provided to remove heat energy from the containment in the event of a loss-of-coolant accident. Actuation of the containment spray system in accordance with plant emergency operating procedures ensures that containment and torus pressure and temperature conditions are within the design basis for containment integrity, EQ, and core spray NPSH requirements. The flow from one pump in either loop is more than ample to provide the required heat removal capability (2). The emergency service water system provides cooling to the containment spray heat exchangers and, therefore, is required to provide the ultimate heat sink for the energy release in the event of a loss-of-coolant accident. The emergency service water pumping requirements are those which correspond to containment cooling heat exchanger performance implicit in the containment cooling description. Since the loss-of-coolant accident while in the cold shutdown condition would not require containment spray, the system may be deactivated to permit integrated leak rate testing of the primary containment while the reactor is in the cold shutdown condition.

The core spray main pump compartments and containment spray pump compartments were provided with water-tight doors(4). Specification 3.4.E ensures that the doors are in place to perform their intended function.

Similarly, since a loss-of-coolant accident when primary containment integrity is not required would not result in pressure build-up in the drywell or torus, the containment spray system may be made inoperable under these conditions.

<u>References</u>

1. NEDC-31462P, "Oyster Creek Nuclear Generating Station SAFER/CORECOOL/GESTR-LOCA Loss-of-Coolant Accident Analysis," August 1987.

2. Licensing Application, Amendment 32, Question 3

3. (Deleted)

4. Licensing Application, Amendment 18, Question 4

5. GPUN Topical Report 053, "Thermal Limits with One Core Spray Sparger" December 1988.

6. NEDE-30010A, "Performance Evaluation of the Oyster Creek Core Spray Sparger", January 1984.

7. Letter and enclosed Safety Evaluation, Walter A. Paulson (NRC) to P. B. Fiedler (GPUN), July 20, 1984.

8. APED-5736, "Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards", April 1969.

3.5 CONTAINMENT

Applicability: Applies to the operating status of the primary and secondary containment systems.

Objective: To assure the integrity of the primary and secondary containment systems.

Specification: A. Primary Containment

1. At any time that the nuclear system is pressurized above atmospheric or work is being done which has the potential to drain the vessel and irradiated fuel is in the vessel, the suppression pool water volume and temperature shall be maintained within the following limits.

    a. Maximum water volume - 92,000 ft^3
    b. Minimum water volume - 82,000 ft^3
    c. Maximum water temperature

        (1) During normal POWER OPERATION - 95°F

        (2) During testing which adds heat to the suppression pool, the water temperature shall not exceed 10°F above the normal POWER OPERATION limit specified in (1) above. In connection with such testing, the pool temperature must be reduced to below the normal POWER OPERATION limit specified in (1) above within 24 hours.

        (3) The reactor shall be scrammed from any operating condition if the pool temperature reaches 110°F. POWER OPERATION shall not be resumed until the pool temperature is reduced below the normal POWER OPERATION limit specified in (1) above.

        (4) During reactor isolation conditions, the reactor pressure vessel shall be depressurized to less than 180 psig at normal cooldown rates if the pool temperature reaches 120°F.

    d. If the limits of Specification 3.5.A.1.a, b or c(1) are exceeded, the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION within 24 hours.

2. Maintenance and repair, including draining of the suppression pool, may be performed provided that the following conditions are satisfied:

   a. The reactor mode switch is locked in the refuel or shutdown position.

   b. (1) There is an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring water to the reactor vessel, and

      (2) The fire protection system is OPERABLE to the extent that one diesel driven fire pump is capable of providing water to the core spray system, and

      (3) These systems are verified to be OPERABLE on a weekly basis.

   c. The reactor coolant system is maintained at less than 212°F and vented.

   d. At least one core spray pump, and system components necessary to deliver rated core spray flow to the reactor vessel, must remain OPERABLE to the extent that the pump and any necessary valves can be started or operated from the control room or from local control stations, and the torus is mechanically intact. Verify the pump and components are operable, as described, on a weekly basis.

   e. (1) No work shall be performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the TOP OF the ACTIVE FUEL and there is a minimum of 360,000 gallons of water available between the torus and condensate storage tank water inventories. At least two redundant core spray systems including core spray pumps and system components must remain operable as defined in d. above. At least one recirculation loop discharge valve and its associated suction valve shall be in the full open position. Verify the pumps and components are operable, as described, on a weekly basis.

      or

      (2) The reactor vessel head, fuel pool gate, and separator-dryer pool gates are removed and the water level is above elevation 117 feet. When filling or draining the reactor cavity, a sufficient water inventory (between the condensate storage tank and the reactor cavity) to complete the flooding operation shall be maintained. The 360,000 gallons of water minimum requirement in (1) above does not apply during the filling and draining operation provided there is a sufficient amount of water to complete the flooding operation.

3. PRIMARY CONTAINMENT INTEGRITY shall be maintained at all times when the reactor is critical or when the reactor water temperature is above 212°F and fuel is in the reactor vessel except while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 Mwt or during REACTOR VESSEL PRESSURE TESTING.

a. With one or more of the automatic containment isolation valves inoperable:

(1) Maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours (48 hours for the traversing in-core probe system) either;

(a) Restore the inoperable valve(s) to OPERABLE status or

(b) Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolation position, or

(c) Isolate each affected penetration by use of at least one closed manual valve or blind flange.

(2) If Specification 3.5.A.3 or the provisions of Specifications 3.5.A.3.a.(1)(a), (b) or (c) can not be met, the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION within 24 hours.

(3) An inoperable containment isolation valve of the shutdown cooling system may be opened with a reactor water temperature equal to or less than 350°F in order to PLACE the reactor IN the COLD SHUTDOWN CONDITION. The inoperable valve shall be returned to the OPERABLE status prior to placing the reactor in a condition where PRIMARY CONTAINMENT INTEGRITY is required.

b. If the primary containment air lock is inoperable, per Specification 4.5.C.2, restore the inoperable air lock to OPERABLE status within the 24 hours or be in at least a SHUTDOWN CONDITION within the next 12 hours and in cold shutdown within the following 24 hours.

4. Reactor Building to Suppression Chamber Vacuum Breaker System

a. Except as specified in Specification 3.5.A.4.b below, two reactor building to suppression chamber vacuum breakers in each line shall be OPERABLE at all times when PRIMARY CONTAINMENT INTEGRITY is required. The set point of the differential pressure instrumentation which actuates the air-operated vacuum breakers shall not exceed 0.5 psid. The vacuum breakers shall move from closed to fully open when subjected to a force equivalent of not greater than 0.5 psid acting on the vacuum breaker disc.

b. From the time that one of the reactor building to suppression chamber vacuum breakers is made or found to be inoperable, the vacuum breaker shall be locked closed and reactor operation is permissible only during the succeeding seven days unless such vacuum breaker is made OPERABLE sooner, provided that the procedure does not violate PRIMARY CONTAINMENT INTEGRITY.

c. If the limits of Specification 3.5.A.4.a are exceeded, reactor shutdown shall be initiated and the reactor shall be in a COLD SHUTDOWN CONDITION within 24 hours.

5. Pressure Suppression Chamber - Drywell Vacuum Breakers

a. When primary containment is required, all suppression chamber-drywell vacuum breakers shall be OPERABLE except during testing and as stated in Specification 3.5.A.5.b and c, below. Suppression chamber - drywell vacuum breakers shall be considered OPERABLE if

(1) The valve is demonstrated to open from closed to fully open with the applied force at all valve positions not exceeding that equivalent to 0.5 psi acting on the suppression chamber face of the valve disk.

(2) The valve disk will close by gravity to within not greater than 0.10 inch of any point on the seal surface of the disk when released after being opened by remote or manual means.

(3) The position alarm system will annunciate in the control room if the valve is open more than 0.10 inch at any point along the seal surface of the disk.

b. Five of the fourteen suppression chamber - drywell vacuum breakers may be inoperable provided that they are secured in the closed position. With one of the nine required suppression chamber-drywell vacuum breakers inoperable, restore one vacuum breaker to OPERABLE status within 72 hours.

c. One position alarm circuit for each OPERABLE vacuum breaker may be inoperable, provided that each OPERABLE suppression chamber – drywell vacuum breaker with one defective alarm circuit, and associated remaining position alarm circuit are verified to be OPERABLE immediately, and monthly in accordance with 4.5.F.5.a. Additionally, a daily verification using the OPERABLE position alarm circuit that the affected vacuum breaker is closed shall be performed.

d. If Specifications 3.5.A.5(a), (b) or (c) can not be met, the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION within 24 hours.

6. The primary containment oxygen concentration shall be less than 4.0 volume percent while in the RUN MODE, except as specified in 3.5.A.6.a and 3.5.A.6.b below.

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to,

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to the next scheduled reactor shutdown.

c. If the primary containment oxygen concentration is greater than or equal to 4.0 volume percent while in the RUN MODE, except as specified in 3.5.A.6.a or 3.5.A.6.b above, restore oxygen concentration to < 4.0 volume percent within 24 hours, otherwise reduce THERMAL POWER to ≤ 15% RTP within the next 8 hours.

7. Deleted.

8. Shock Suppressors (Snubbers)

a. All safety related snubbers are required to be operable whenever the systems they protect are required to be operable except as noted in 3.5.A.8.b and c below.

b. With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to operable status.

c. If the requirements of 3.5.A.8.a and 3.5.A.8.b cannot be met, declare the protected system inoperable and follow the appropriate action statement for that system.

d. An engineering evaluation shall be performed to determine if the components protected by the snubber(s) were adversely affected by the inoperability of the snubber prior to returning the system to operable status.

B. Secondary Containment

1. Secondary containment integrity shall be maintained at all times unless all of the following conditions are met:

a. The reactor is subcritical and Specification 3.2.A is met.

b. The reactor is in the cold shutdown condition.

c. The reactor vessel head or the drywell head are in place.

d. No work is being performed on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive material.

e. No operations are being performed in, above, or around the spent fuel storage pool that could cause release of radioactive materials.

2. Upon the accidental loss of SECONDARY CONTAINMENT INTEGRITY, restore, SECONDARY CONTAINMENT INTEGRITY within 4 hours, except as provided in specification 3.5.B.3.

3. With one or more of the automatic secondary containment isolation valves inoperable:

   a. Maintain at least one automatic secondary containment isolation valve in each affected penetration OPERABLE.

   b. Within 8 hours restore the inoperable automatic secondary containment isolation valve(s) to OPERABLE status or isolate each affected penetration with at least one valve secured in the closed position.

4. If Specifications 3.5.B.2 or 3.5.B.3 cannot be met:

   a. During Power Operation:

      (1) Have the reactor mode switch in the shutdown mode position within the following 24 hours.

      (2) Cease all work on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive materials.

      (3) Cease all operations in, above or around the Spent Fuel Storage Pool that could cause release of radioactive materials.

   b. During refueling:

      (1) Cease fuel handling operations or activities which could reduce the shutdown margin (excluding reactor coolant temperature changes).

      (2) Cease all work on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive materials.

      (3) Cease all operations in, above or around the Spent Fuel Storage Pool that could cause release of radioactive materials.

5. Two separate and independent standby gas treatment system circuits shall be operable when secondary containment is required except as specified by Specification 3.5.B.6.

6. With one standby gas treatment system circuit inoperable:

   a. During Power Operation:

      (1) Verify the operability of the other standby gas treatment system circuit within 2 hours. If testing is required to demonstrate operability and significant painting, fire, or chemical release has taken place in the reactor building within the previous 12 hours, then demonstration by testing shall take place within 1 hour of the expiration of the 12 hour period, and

      (2) Continue to verify the operability of the standby gas treatment system circuit once per 24 hours until the inoperable standby gas treatment circuit is returned to operable status.

      (3) Restore the inoperable standby gas treatment circuit to operable status within 7 days.

   b. During Refueling:

      (1) Verify the operability of the other standby gas treatment system within 2 hours. If testing is required to demonstrate operability and significant painting, fire, or chemical release has taken place in the reactor building within the previous 12 hours, then demonstration by testing shall take place within 1 hour of the expiration of the 12 hour period, and

      (2) Continue to verify the operability of the redundant standby gas treatment system once per 7 days until the inoperable system is returned to operable status.

      (3) Restore the inoperable standby gas treatment system to operable status within 30 days or cease all spent fuel handling, core alterations or operation that could reduce the shutdown margin (excluding reactor coolant temperature changes,

7. If Specifications 3.5.B.5 and 3.5.B.6 are not met, reactor shutdown shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours and the condition of Specification 3.5.B.1 shall be met.

Bases:

Specifications are placed on the operating status of the containment systems to assure their availability to control the release of any radioactive materials from irradiated fuel in the event of an accident condition. The primary containment system[1] provides a barrier against uncontrolled release of fission products to the environs in the event of a break in the reactor coolant systems.

Whenever the reactor coolant water temperature is above 212°F, failure of the reactor coolant system would cause rapid expulsion of the coolant from the reactor with an associated pressure rise in the primary containment. Primary containment is required, therefore, to contain the thermal energy of the expelled coolant and fission products which could be released from any fuel failures resulting from the accident. If the reactor coolant is not above 212°F, there would be no pressure rise in the containment. In addition, the coolant cannot be expelled at a rate which could cause fuel failure to occur before the core spray system restores cooling to the core. Primary containment is not needed while performing low power physics tests since procedures and the Rod Worth Minimizer would limit rod worth such that a rod drop would not result in any fuel damage. In addition, in the unlikely event that an excursion did occur, the reactor building and standby gas treatment system, which shall be operational during this time, offer a sufficient barrier to keep off-site doses well below 10 CFR 100 limits.

The absorption chamber water volume provides the heat sink for the reactor coolant system energy released following the loss-of-coolant accident. The core spray pumps and containment spray pumps are located in the corner rooms and due to their proximity to the torus, the ambient temperature in those rooms could rise during the design basis accident. Calculations[7] made, assuming an initial torus water temperature of 100°F and a minimum water volume of 82,000 ft.^{3}, indicate that the corner room ambient temperature would not exceed the core spray and containment spray pump motor operating temperature limits and, therefore, would not adversely affect the long-term core cooling capability. The maximum water volume limit allows for an operating range without significantly affecting accident analyses with respect to free air volume in the absorption chamber. For example, the containment capability[8] with a maximum water volume of 92,000 ft.^{3} is reduced by not more than 5.5% metal-water reaction below the capability with 82,000 ft.^{3}.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak temperature of the suppression pool is maintained below 160°F during any period of relief valve operation with sonic conditions at the discharge exit. 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.

The technical specifications allow for torus repair work or inspections that might require draining of the suppression pool when all irradiated fuel is removed or when the potential for draining the reactor vessel has been minimized. This specification also provides assurance that the irradiated fuel has an adequate cooling water supply for normal and emergency conditions with the reactor mode switch in shutdown or refuel whenever the suppression pool is drained for inspection or repair.

The function of the primary containment isolation valves (PCIVs), in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary 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 DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment function assumed in the safety analyses will be maintained. These isolation devices are either passive or active (automatic). Manual valves, deactivated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

The opening of locked or sealed closed containment isolation valves on an intermittent basis will be performed under administrative control including the following considerations: 1) an operator, who is in constant communication with the control room, will be stationed at the valve controls; 2) that operator will be instructed to close those valves in an accident situation; and, 3) it will be assured that environmental conditions will not preclude access to close those valves and that this action will prevent the release of radioactivity outside the containment.

The purpose of the vacuum relief valves is to equalize the pressure between the drywell and suppression chamber, and suppression chamber and reactor building so that the containment external design pressure limits are not exceeded.

The vacuum relief system from the reactor building to the pressure suppression chamber consists of two 100% vacuum relief breaker subsystems (2 parallel sets of 2 valves in series). Operation of either subsystem will maintain the containment external pressure less than the 2 psi external design pressure of the drywell; the external design pressure of the suppression chamber is 1 psi (FDSAR Amendment 15, Section 11).

The capacity of the 14 suppression chamber to drywell vacuum relief valves is sized to limit the external pressure of the drywell during post-accident drywell cooling operations to the design limit of 2 psi. They are sized on the basis of the Bodega Bay pressure suppression tests[9][10]. A calculation[15] was performed in accordance with NE DE-24802[16] to determine the required number of vacuum breakers by using a mass and energy balance to determine vacuum breaker flow area. The results of the calculation indicate that 8 vacuum breakers are required to proivde vacuum relief capability. An aditional vacuum breaker is included for single failure criteria, bringing the total required to 9.

Each suppression chamber drywell vacuum breaker is fitted with a redundant pair of limit switches to provide fail safe signals to panel mounted indicators in the reactor building and alarms in the control room when the disks are open more than 0.1" at any point along the seal surface of the disk. These switches are capable of transmitting the disk closed-to-open signal with 0.01" movement of the switch plunger. Continued reactor operation with failed components is justified because of the redundancy of components and circuits and, most importantly, the accessibility of the valve lever arm and position reference external to the valve. The fail-safe feature of the alarm circuits assures operator attention if a line fault occurs.

Conservative estimates of the hydrogen produced, consistent with the core cooling system provided, show that the hydrogen air mixture resulting from a loss-of-coolant accident is considerably below the flammability limit and hence it cannot burn, and inerting would not be needed. However, inerting of the primary containment was included in the proposed design and operation. The 5% oxygen limit is the oxygen concentration limit stated by the American Gas Association for hydrogen-oxygen mixtures below which combustion will not occur.[4] The 4% oxygen limit was established by analysis of the Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containments.[12]

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. An event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. The primary containment oxygen concentration must be within the specified limit when the primary containment is inerted, except as allowed by Specifications 3.5.A.6.a or 3.5.A.6.b during startups and shutdowns. The primary containment must be inert when reactor power is greater than or equal to 15% RTP, since this is the condition with the highest probability of an event that could produce hydrogen. Specification 3.5.A.6.a requires that primary containment be inerted within 24 hours of exceeding 15 percent RTP during startup. Specification 3.5.A.6.b allows de-inerting to commence 24 hours prior to reaching 15 percent RTP during the shutdown sequence.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as power is less than 15 percent RTP, the potential for an event that generates significant hydrogen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup or within the las 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24-hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient, while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is, therefore, required that all snubbers required to protect the primary coolant system or any other safety system or component be OPERABLE whenever the systems they protect are required to be OPERABLE.

The purpose of an engineering evaluation is to determine if the components protected by the snubber were adversely affected by the inoperability of the snubber. This ensures that the protected component remains capable of meeting the designed service. A documented visual inspection will usually be sufficient to determine system OPERABILITY.

Because snubber protection is required only during low probability events, a period of 72 hours is allowed for repairs or replacements.

Secondary containment[5] is designed to minimize any ground level release of radioactive materials which might result from a serious accident. The reactor building provides secondary containment during reactor operation when the drywell is sealed and in service and provides primary containment when the reactor is shutdown and the drywell is open, as during refueling. Because the secondary containment is an integral part of the overall containment system, it is required at all times that primary containment is required. Moreover, secondary containment is required during fuel handling operations and whenever work is being performed on the reactor or its connected systems in the reactor building since their operation could result in inadvertent release of radioactive material.

When secondary containment is not maintained, the additional restrictions on operation and maintenance give assurance that the probability of inadvertent releases of radioactive material will be minimized. Maintenance will not be performed on systems which connect to the reactor vessel lower than the top of the active fuel unless the system is isolated by at least one locked closed isolation valve.

The trunnion room door is not an access opening for the passage of personnel and equipment into the reactor building. During all modes of operation, the trunnion room is a low traffic area and momentary openings of the door would be limited and administratively controlled and have little effect on SGTS and HVAC.

The standby gas treatment system[6] filters and exhausts the reactor building atmosphere to the stack during secondary containment isolation conditions, with a minimum release of radioactive materials from the reactor building to the environs.

In Section 3.5.B.5 and 3.5.B.6 of the Technical Specification, the use of the word "Circuits" actually means "Trains" as the word trains is used in the following paragraph.

Two separate filter trains are provided, each having 100% capacity[6]. There is a section of ductwork upstream and downstream that is common to both filter trains. If one filter train becomes inoperable, there is no immediate threat to secondary containment and reactor operation may continue while repairs are being made. Since the test interval for this system is one month (Specification 4.5), the time out-of-service allowance of 7 days is based on considerations presented in the Bases in Specification 3.2 for a one-out-of-two system.

There is also only one vital power supply to the SGTS automatic initiation controls and for the operation of the heating coils for both filter trains.

Therefore, the SGTS is not mechanically nor electrically single failure proof. However, manual actuation of the SGTS is not vulnerable to single failures and is an acceptable backup to automatic initiation.

Two automatic secondary containment isolation valves are installed in each reactor building ventilation system supply and exhaust duct penetration. Both isolation valves for each supply duct penetration are located inside the secondary containment boundary, and the two exhaust duct penetration isolation valves are located outside of the secondary containment boundary. Removal of an inboard supply or exhaust valve (closest to the boundary) is permitted only when secondary containment is not required. The outboard isolation supply or exhaust valve can be removed when secondary containment is required as long as the inboard valve is secured in the closed position.

References:

(1) FDSAR, Volume I, Section V-1
(2) FDSAR, Volume I, Section V-1.4.1
(3) FDSAR, Volume I, Section V-1.7
(4) Licensing Application, Amendment 11, Question III-25
(5) FDSAR, Volume I, Section V-2
(6) FDSAR, Volume I, Section V-2.4
(7) Licensing Application, Amendment 42
(8) Licensing Application, Amendment 32, Question 3
(9) Robbins, C. H., "Tests on a Full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment, "GEAP-3596, November 17, 1960.
(10) Bodega Bay Preliminary Hazards Summary Report, Appendix I, Docket 50-205, December 28, 1962.
(11) Report H. R. Erickson, Bergen-Paterson To K. R. Goller, NRC, October 7, 1974. Subject: Hydraulic Shock Sway Arrestors.
(12) General Electric NEDO-22155 "Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containment" June 1982.
(13) Oyster Creek Nuclear Generating Station, Mark I Containment Long-Term Program, Plant Unique Analysis Report, Suppression Chamber and Vent System, MPR-733; August, 1982.

(14) Oyster Creek Nuclear Generating Station, Mark I Containment Long-Term Program, Plant Unique Analysis Report, Torus Attached Piping, MPR-734; August, 1982.
(15) AmerGen Calculation C-1302-243-E170-087, "Wetwell-to-Drywell Vacuum Breaker Sizing."
(16) General Electric NEDE-24802, "Mark I Containment Program Mark I Wetwell-to-Drywell Vacuum Breaker Functional Requirements, Task 9.4.3," April, 1980.

3.6 Radioactive Effluents

Applicability: Applies to the radioactive effluents of the facility.

Objective: To assure that radioactive material is not released to the environment in an uncontrolled manner and to assure that the radioactive concentrations of any material released is kept as low as is reasonably achievable and, in any event, within the limits of 10 CFR part 20.1301 and 40 CFR Part 190.10(a).

Specification:

3.6.A. Reactor Coolant Radioactivity

The specific activity of the primary coolant except during REFUEL MODE shall be limited to: Less than or equal to 0.2 microcuries per gram DOSE EQUIVALENT (D.E.) I-131.

Limiting Condition for Operation

1. Whenever an isotopic analysis shows reactor coolant activity exceeds 0.2 uCi/gram DOSE EQUIVALENT (D.E.) I-131, operation may continue for up to 48 hours. Additional analyses shall be done at least once per 4 hours until the specific activity of the primary coolant is restored to within its limit. The provisions of Specification 3.0.C.3 are applicable.

2. If the reactor coolant activity is greater than 0.2 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 D.E. I-131, be in at least SHUTDOWN CONDITION within 12 hours. The provisions of Specification 3.0.C.3 are applicable.

3. Annual Reporting Requirement

   The results of specific activity analyses in which the reactor coolant exceeded the limits of Specification 3.6.A shall be reported on an annual basis. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded until after the radioiodine activity is reduced to less than the limit; (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 radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded until after the radioiodine activity is reduce to less than the limit; (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 specific activity of the primary coolant exceeded the radioiodine limit.

4. With the reactor mode switch in Run or Startup position, with:

   1. Thermal power changed by more than 15% of rated thermal power in one hour*, or

   2. The off-gas level, at the SJAE, increased by more than 10,000 microcuries per second in one 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 one hour during steady state operation at release rates greater than 75,000 microcuries per second,

   take sample and analyze at least one sample, between 2 and 6 hours following the change in thermal power or off-gas level and at least once per four hours thereafter, until the specific activity of the primary coolant is restored to within limits.

3.6.B <u>Liquid Radwaste Treatment</u> - RELOCATED TO THE ODCM

3.6.C <u>Radioactive Liquid Storage</u>

Applicability: Applies at all times to specified outdoor tanks used to store radioactive liquids.

1. The quantity of radioactive material, excluding tritium, noble gases, and radionuclides having half-lives shorter than three days, contained in any of the following outdoor tanks shall not exceed 10.0 curies:

   a. Waste Surge Tank, HP-T-3

   b. Condensate Storage Tank

2. In the event the quantity of radioactive material in any of the tanks named exceeds 10.0 curies, begin treatment as soon as reasonably achievable, continue it until the total quantity of radioactive material in the tank is 10 curies or less, and describe the reason for exceeding the limit in the next Annual Effluent Release Report.

3. Specification 3.0.A and 3.0.B do not apply.

3.6.D <u>Condenser Offgas Treatment</u> - RELOCATED TO THE ODCM

3.6.E <u>Main Condenser Offgas Radioactivity</u>

1. The gross radioactivity in noble gases discharged from the main condenser air ejector shall not exceed 0.21/E Ci/sec after the holdup line where E is the average gamma energy (Mev per atomic transformation).

2. In the event Specification 3.6.E.1 is exceeded, reduce the discharge rate below the limit within 72 hours or be in at least SHUTDOWN CONDITION within the following 12 hours.

* If there are <u>consecutive</u> thermal power changes by more than 15% per hour, take sample and analyze at least <u>one</u> sample between 2 and 6 hours following the change and at least once per four hours thereafter, until the specific activity of the primary coolant is restored to within limits.

3.6.F **Condenser Offgas Hydrogen Concentration**

1. The concentration of hydrogen in the Augmented Offgas System (AOG) downstream of the recombiner during AOG operation shall not exceed 4 percent by volume.

2. In the event the hydrogen concentration downstream of a recombiner exceeds 4 percent by volume, the concentration shall be reduced to less than 4 percent within 48 hours.

3. In the event the hydrogen concentration is not reduced to ≤4 percent within 48 hours, be in at least SHUTDOWN CONDITION or within the limit within the following 24 hours.

3.6.G Not used.

3.6.H Not used.

3.6.I **Radioactivity Concentration in Liquid Effluent**

RELOCATED TO THE ODCM

3.6.J **Limit on Dose Due to Liquid Effluent**

RELOCATED TO THE ODCM

3.6.K **Dose Rate Due to Gaseous Effluent**

RELOCATED TO THE ODCM

3.6.L **Air Dose Due to Noble Gas in Gaseous Effluent**

RELOCATED TO THE ODCM

3.6.M **Dose Due to Radioiodine and Particulates in Gaseous Effluent**

RELOCATED TO THE ODCM

3.6.N **Annual Total Dose Due to Radioactive Effluents**

RELOCATED TO THE ODCM

Basis:

3.6.A 10 CFR 100, as implemented by SRP Section 15.6.4, requires that the radiological consequences of failure of a main steam line outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100. During Systematic Evaluation Program (SEP) for Oyster Creek, an independent assessment of the radiological consequences of a main steam line failure outside containment (SEP Topic XV-18) was performed by the NRC staff. The assessment determined that if the existing Oyster Creek Technical Specification limit for primary coolant iodine activity (8.0 uCi total iodine per gram) is used, the potential offsite doses would exceed the applicable dose limit. The staff recommended that Oyster Creek maintain the primary coolant radioiodine activity within the General Electric Standard Technical Specification (NUREG-0123) limit (0.2 uCi/gram DOSE EQUIVALENT I-131), which would meet the acceptance criteria.

However, the Staff's analyses for Oyster Creek showed that small-line failures are more limiting than the main steam line failure. 10 CFR 100, as implemented by SRP Section 15.6.2, requires that the radiological consequences of failure of small lines carrying primary coolant outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100. During the evaluation of SEP Topic XV-16 "Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment" the Staff determined that Oyster Creek does not comply with current acceptance criteria. The Staff recommended that the General Electric Standard Technical Specification (NUREG-0123) limit (0.2 uCi/gram DOSE EQUIVALENT I-131) for reactor coolant radioiodine activity be adopted in order to ensure that the radiological consequences to the environment from a failure of small lines are acceptably low.

The LCO statement permitting power operation to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131, but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. The reporting of cumulative operating time with greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 will allow sufficient time for Commission to evaluate the circumstances.

Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analysis following power changes may be permissible if justified by the data obtained.

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.

3.6.B RELOCATED TO THE ODCM

3.6.C Restricting the quantity of radioactive material contained in the specific tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20.1001-20.2402, Appendix B, Table 2, Column 2 in the canal at the Route 9 bridge.

Retaining radioactive liquids on-site in order to permit systematic and appropriate processing is consistent with maintaining radioactive discharges to the environment as low as practicable. Limiting the contents of each outside tank to 10 curies or less assures that even if the contents of a tank were released onto the ground and drained into the discharge canal, the potential dose to a member of the public is estimated to be less than 1 percent of the 500 mrem/year limit to the total body of a member of the public and only 1 percent of the corresponding 1500 mrem/year standard for a single organ.

In the highly unlikely event that every outside tank named in Specification 3.6.C were to contain 10 curies and the contents of all were to spill into the discharge canal, the potential dose to a member of the public is estimated to be only about 2 percent of the 500 mrem/year limit to the total body and about 6 percent of the corresponding 1500 mrem/year standard.

3.6.D RELOCATED TO THE ODCM

3.6.E Some radioactive materials are released from the plant under controlled conditions as part of the normal operation of the facility. Other radioactive material not normally intended for release could be inadvertently released in the event of an accident. Therefore, limits in 10 CFR Part 20 apply to releases during normal operation and limits in 10 CFR Part 100 apply to accidental releases.

Radioactive gases from the reactor pass through the steam lines to the turbine and then to the main condenser where they are extracted by the air ejector, passed through holdup piping and released via the plant stack preferably after treatment in the Augmented Offgas System. Radioactive materials release limits for the plant stack have been calculated using meteorological data from a 400 ft. tower at the plant site. The analysis of these on-site meteorological data shows that a release of radioactive gases after holdup in the offgas system, would not result in a whole body radiation dose exceeding the 10 CFR 20 value of 0.1 rem per year.

Whole body dose was calculated to determine the offgas system isolation trip setpoints for the Steam Jet Air Ejector (SJAE) radiation monitor using RAC Code from gamma dose due to cloud passage over the receptor and not cloud submersion in which beta dose could be additive. The Holland plume rise model with no correction factor was used in the calculation of the effect of momentum and buoyancy of a continuously emitted plume. The source terms for this calculation assumes historical (i.e., 1989-1990) offgas isotopic composition, site specific meteorological conditions, plant specific offgas flow rates and takes credit for AOG operation 60 percent of the time.

These calculations have established that a dose rate of ≤ 2,000 mRem/hr at the SJAE Offgas Radiation Monitor is within 10 CFR 20.1301(a)(1) limits, i.e., less than 100 mRem in a year.

3.6.F The purpose of Specification 3.6.F is to require that the concentration of potentially explosive gas mixtures in the Augmented Offgas System be maintained below the flammability limit of hydrogen in air, although the AOG is designed to withstand a hydrogen explosion. Specification 3.6.F applies to the hydrogen concentration downstream of a recombiner during AOG operation. The AOG has redundant recombiners so that the recombiner in use can be isolated and purged with air in the event hydrogen in it exceeds the specified limit.

3.6.G NOT USED

3.6.H NOT USED

3.6.I RELOCATED TO THE ODCM

3.6.J RELOCATED TO THE ODCM

3.6.K RELOCATED TO THE ODCM

3.6.L RELOCATED TO THE ODCM

3.6.M RELOCATED TO THE ODCM

3.6.N RELOCATED TO THE ODCM

3.7 AUXILIARY ELECTRICAL POWER

Applicability: Applies to the OPERATING status of the auxiliary electrical power supply.

Objective: To assure the OPERABILITY of the auxiliary electrical power supply.

Specification:

NOTE: LCO 3.0.C.2 is not applicable to Auxiliary Electrical Power.

A. The reactor shall not be made critical unless all of the following requirements are satisfied:

1. The following buses or panels energized.

   a. 4160 volt buses 1C and 1D in the Turbine Building Switchgear Room.

   b. 460 volt buses:

      USS 1A2, USS 1B2, MCC 1A21, MCC 1B21, Vital MCC 1A2, and Vital MCC 1B2 in the Reactor Building 480 V Switchgear Room.

      USS 1A3 and USS 1B3 in the Intake Structure.

      MCC 1A21A, MCC 1A21B, MCC 1B21A, MCC 1B21B, and Vital MCC 1AB2 on Reactor Building Elevation 23' 6".

      MCC 1A24 and 1B24 in the Boiler House.

   c. 208/120 volt panels CIP-3, IP-4, IP-4A, IP-4B, IP-4C and VACP-1 in the Reactor Building Switchgear Room.

   d. 120 volt protection panels PSP-1 and PSP-2 in the Lower Cable Spreading Room.

   e. 125 VDC Distribution Centers DC-B and DC-C.
      125 VDC Power Panels DC-D and DC-F.
      125 VDC MCCs DC-1 and DC-2

   f. 24 volt DC power panels DC-A and DC-B in the Lower Cable Spreading Room.

2. One 230 KV line (N-line or O-line) is fully operational and switch gear and both startup transformers are energized to carry power to the station 4160 volt AC buses and carry power to or away from the plant.

3. An additional source of power consisting of one of the following is in service connected to feed the appropriate plant 4160 V bus or buses:

   a. 230 KV S-line fully operational.
   b. A 34.5 KV line fully operational.

4. Station batteries B and C and an associated battery charger are OPERABLE. Switchgear control power for 4160 volt bus 1D and 460 volt buses 1B2 and 1B3 is provided by 125 VDC Distribution Center DC-B. Switchgear control power for 4160 volt bus 1C and 460 volt buses 1A2 and 1A3 is provided by 125 VDC Distribution Center DC-C.

5. Bus tie breakers ED and EC are in the open position.

B. The reactor shall be PLACED IN the COLD SHUTDOWN CONDITION if the availability of power falls below that required by Specification A above, except that

1. The reactor may remain in operation for a period not to exceed 7 days if a startup transformer is out of service. None of the engineered safety feature equipment fed by the remaining transformer may be out of service.

2. The reactor may remain in operation for a period not to exceed 7 days if 125 VDC Motor Control Center DC-2 is out of service, provided the requirements of Specification 3.8 are met.

3. The reactor may remain in operation provided the requirements of Specification 3.7.D are met.

C. Standby Diesel Generators

1. The reactor shall not be made critical unless both diesel generators are operable and capable of feeding their designated 4160 volt buses.

2. If one diesel generator becomes inoperable during power operation, repairs shall be initiated immediately and the other diesel shall be operated at least one hour every 24 hours at greater than 80% rated load until repairs are completed. The reactor may remain in operation for a period not to exceed 7 days if a diesel generator is out of service. During the repair period none of the engineered safety features normally fed by the operational diesel generator may be out of service or the reactor shall be placed in the cold shutdown condition. If a diesel is made inoperable for biennial inspection, the testing and engineered safety feature requirements described above must be met.

3. If both diesel generators become inoperable during power operation, the reactor shall be placed in the cold shutdown condition.

4. For the diesel generators to be considered operable:

A) There shall be a minimum of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank,

OR

B) To facilitate inspection, repair, or replacement of equipment which would require full or partial draining of the standby diesel generator fuel tank, the following conditions must be met:

1) There shall be a minimum of 14,000 gallons of fuel oil contained in temporary tanker trucks, connected and aligned to the diesel generator fill station.

-AND-

2) The reactor cavity shall be flooded above elevation 117 feet with the spent fuel pool gates removed, or all reactor fuel shall be contained in the spent fuel pool with spent fuel pool gates installed.

AND

3) The plant shall be placed in a configuration in which the core spray system is not required to be OPERABLE.

D. Station Batteries and Associated Battery Chargers

1. With one required station battery B or C charger inoperable:

   a. Restore associated station battery terminal voltage to greater than or equal to the minimum established float voltage within 2 hours,

   b. Verify affected station battery float current ≤ 2 amps once per 12 hours, and

   c. Restore station battery charger to OPERABLE status within 7 days.

2. With one or more station B and C batteries inoperable due to:

   a. One station battery B or C having one or more battery cells float voltage < 2.07 volts, perform 4.7.C.1.a and 4.7.C.1.b for the affected battery within 2 hours and restore affected cell(s) voltage ≥ 2.07 volts within 24 hours.

   b. One station battery B or C float current > 2 amps, perform 4.7.C.1.a for the affected battery within 2 hours and restore affected battery float current to within limits within 12 hours.

   c. One station battery B or C having 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.

   d. One station battery B or C having 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.

(*) 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.

e. Both station batteries B and C inoperable due to entering one or more Actions 3.7.D.2.a through 3.7.D.2.d, restore battery parameters for one battery to within limits within 2 hours.

f. Station battery B or C not meeting any Action 3.7.D.2.a through 3.7.D.2.e, meet the Action(s) within 2 hours or the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION.

g. One station battery B or C having:

(i) One or more battery cells float voltage < 2.07 volts (Action 3.7.D.2.a)

<u>AND</u>

(ii) Float current > 2 amps (Action 3.7.D.2.b)

Restore one battery parameter to within limits within 2 hours or the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION.

3. With one station battery inoperable for reasons other than allowed in 3.7.D.2.a through 3.7.D.2.g, restore the battery to OPERABLE status within 2 hours or the reactor shall be PLACED IN the COLD SHUTDOWN CONDITION.

Bases:

The general objective is to assure an adequate supply of power with at least one active and one standby source of power available for operation of equipment required for a safe plant shutdown, to maintain the plant in a safe shutdown condition and to operate the required engineered safety feature equipment following an accident.

AC power for shutdown and operation of engineered safety feature equipment can be provided by any of three active (one or two 230 KV lines: N-line or O-line, the 230 KV S-line, and one of two 34.5 KV lines is active) and either of two standby (two diesel generators) sources of power. In applying the minimum requirement of one active and one standby source of AC power, since two 230 KV lines are on the same set of towers, either one or both of the 230 KV lines (N-line or O-Line) are considered as a single active source. Normally all six sources are available. However, to provide for maintenance and repair of equipment and still have redundancy of power sources the requirement of one active and one standby source of power was established. The plant's main generator is not given credit as a source since it is not available during shutdown.

The plant 125V DC system consists of three batteries and associated distribution system. Batteries B and C are designated as the safety related subsystems while battery A is designated as a non-safety related subsystem. Safety related loads are supplied by batteries B and C, each with two associated full capacity chargers. One charger on each battery is in service at all times with the second charger available in the event of charger failure. These chargers are active sources and supply the normal 125V DC requirements with the batteries and standby sources. (1)

Action 3.7.D.1 is for one required safety related battery B or battery C charger (i.e., no station battery charger operable for the associated battery) inoperable (e.g., the battery float voltage limit of 4.7.C.1.a is not maintained for battery B or battery C). These 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 3.7.D.1.a 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 12 hours, the associated battery will be restored to its fully charged condition (as verified by Action 3.7.D.1.b) 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 12 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.

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 12 hours (Action 3.7.D.1.b).

Action 3.7.D.1.b requires that the affected station battery float current be verified ≤ 2 amps. 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 12 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action 3.7.D.1.c 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 or the standby charger in the event it was inoperable but continued to supply minimum established float voltage). 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 station battery < 2.07 V, the battery cell(s) is degraded. Per Action 3.7.D.2.a, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.7.C.1.a) and of the overall battery state of charge by monitoring the battery float charge current (4.7.C.1.b). 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.

One safety related station battery float current > 2 amps 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 3.7.D.2.b, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions 3.7.D.2.a and 3.7.D.2.b only specify "perform," a failure of 4.7.C.1.a or 4.7.C.1.b 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 failure(s), is also entered.

If the Action 3.7.D.2.b 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 12 hours is a reasonable time prior to declaring the battery inoperable.

With one station battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Per Action 3.7.D.2.c, within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action 3.7.D.2.c addresses this potential (as well as provisions in Specification 6.8.5, "Station 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 6.8.5 item to initiate action to equalize and test in accordance with manufacturers' 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 3.7.D.2.d, with one station battery 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 3.7.D.2.e, with both station batteries 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 both safety related station batteries are involved. With both safety related station batteries 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 safety related battery not within limits are therefore not appropriate, and the parameters must be restored to within limits on one required station battery within 2 hours.

Per Action 3.7.D.2.f, when any battery parameter is outside the allowances of Actions 3.7.D.2.a, b, c, d, or e, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, per Action 3.7.D.2.g, discovering one or both station batteries 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 or the reactor placed in the COLD SHUTDOWN CONDITION.

Action 3.7.D.3 imposes a 2-hour restoration time for one station battery that is inoperable for reasons other than addressed by the parameter degradation Actions provided. With one station battery inoperable, the battery charger is supplying the DC bus. The 2-hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Actions 3.7.D.2 together with additional specific completion times. Failing to correct this inoperability within 2 hours would require the plant to proceed to cold shutdown.

The probability analysis in Appendix "L" of the FDSAR was based on one diesel and shows that even with only one diesel the probability of requiring engineered safety features at the same time as the second diesel fails is quite small. The analysis used information on peaking diesels when synchronization was required which is not the case for Oyster Creek. Also the daily test of the second diesel when one is temporarily out of service tends to improve the reliability as does the fact that synchronization is not required.

There are numerous sources of diesel fuel which can be obtained within 6 to 12 hours and the heating boiler fuel in a 75,000 gallon tank on the site could also be used.

If makeup Fuel to the Diesel Fuel Oil Tank is not available, the loading on the EDGs can be managed so that they can provide their Design Basis function without makeup to the Fuel Oil Tank for three days. Calculation C-1302-862-5360-002 provides scenarios that will ensure that the Diesels will be available for three days without makeup fuel oil.

During plant cold shutdown or refueling, it may be necessary to inspect, repair and replace the 15,150 gallon standby diesel generator fuel storage tank. This would require tank partial or full drain down. An alternate fuel supply configuration may be established which consists of temporary tanker trucks capable of containing 14,000 gallons. This configuration is capable of supporting continuous operation of both diesels for at least 3 days.

The temporary configuration is acceptable since a minimal power load would be required during and following a design basis condition of a loss of offsite power while the plant is in cold shutdown or refueling. Analysis shows that in the event of a tornado or seismic event which may cause a loss of offsite power and a temporary loss of the temporary EDG fuel oil supply, power can be restored before the consequences of previously analyzed conditions are exceeded.

References:

(1) Letter, Ivan R. Finfrock, Jr. to the Director of Nuclear Reactor Regulation dated April 4, 1978.

3.8 ISOLATION CONDENSER

Applicability: Applies to operating status of the isolation condenser.

Objective: To assure heat removal capability under conditions of reactor vessel isolation from its normal heat sink.

Specification:

NOTE: LCO 3.0.C.2 is not applicable to the Isolation Condenser.

A. The two isolation condenser loops shall be operable during power operations and whenever the reactor coolant temperature is greater than 212°F except as specified in C, below or during reactor vessel pressure testing.

B. The shell side of each condenser shall contain a minimum water volume of 22,730 gallons. If the minimum volume cannot be maintained or if a source of makeup water is not available to the condenser, the condenser shall be considered inoperable.

C. If one isolation condenser becomes inoperable during the run mode the reactor may remain in operation for a period not to exceed 7 days provided the motor operated isolation and condensate makeup valves in the operable isolation condenser are verified daily to be operable.

D. If Specification 3.8.A and 3.8.B are not met, or if an inoperable isolation condenser cannot be repaired within 7 days, the reactor shall be placed in the cold shutdown condition.

E. If an isolation condenser inlet (steam side) isolation valve (V-14-30, 31, 32 or 33) becomes or is made inoperable, in the open position during the run mode, the redundant inlet isolation valve shall be verified operable. If the inoperable valve is not returned to service within 4 hours declare the affected isolation condenser inoperable, isolate it and comply with Specification 3.8.C.

F. If an AC motor-operated isolation condenser outlet (condensate return) isolation valve (V-14-36 or 37) becomes or is made inoperable in the open position in the run mode, return the valve to service within 4 hours or declare the affected isolation condenser inoperable, isolate it and comply with Specification 3.8.C.

Basis: The purpose of the isolation condenser is to depressurize the reactor and to remove reactor decay heat in the event that the turbine generator and main condenser is unavailable as a heat sink[1] Since the shell side of the isolation condensers operate at atmospheric pressure, they can accomplish their purpose when the reactor temperature is sufficiently above 212°F to provide for the heat transfer corresponding to reactor decay heat. The tube side of the isolation condensers form a closed loop with the reactor vessel and can operate without reducing the reactor coolant water inventory.

Each condenser containing a minimum total water volume of 22,730 gallons provides 11,060 gallons above the condensing tubes. Based on scram from a reactor power level of 1950 MWt (the design basis power level for the isolation condensers) the condenser system can accommodate the reactor decay heat[2,3] (corrected for U-239 and NP-239) for 1 hour and 40 minutes without need for makeup water. One condenser with a minimum water volume of 22,730 gallons can accommodate the reactor decay heat for 45 minutes after scram from 1950 MWt before makeup water is required. In order to accommodate a scram from 1950 MWt and cooldown, a total of 107,500 gallons of makeup water would be required either from the condensate storage tank or from the fire protection system. Since the rated reactor power is 1930 MWt, the above calculations represent conservative estimates of the isolation condenser system capability.

The vent lines from each of the isolation condenser loops to the main steam lines downstream of the main steam lines isolation valves are provided with isolation valves which close automatically on isolation condenser actuation or on signals which close the main steam isolation valves. High temperature sensors in the isolation condenser and pipe areas cause alarm in the control room to alert the operator of a piping leak in these areas.

Specification 3.8.E allows reduction in redundancy of isolation capability for isolation condenser inlet (steam side) isolation valves. Reasonable assurance of isolation capability is provided by testing the operability of the redundant valve. Specification 3.8.F allows short term inoperability of the AC motor-operated isolation condenser outlet (condensate return) valve. It is not necessary to test the redundant DC motor-operated valve as this valve is normally in the closed position. These specifications permit troubleshooting and repair as well as routine maintenance, such as valve stem packing addition or replacement, to be performed during reactor operation without reducing the redundancy of the isolation condenser heat sink function. The out of service time of 4 hours is consistent with that permitted for primary containment isolation valves.[5]

Either of the two isolation condensers can accomplish the purpose of the system. If one condenser is found to be inoperable, there is no immediate threat to the heat removal capability for the reactor and reactor operation may continue while repairs are being made. Therefore, the time out of service for one of the condensers is based on considerations for a one out of two system.[4] The test interval for operability of the valves required to place the isolation condenser in operation is once/3 months (Specification 4.8). The allotted out of service time for an isolation condenser is conservatively set at seven days. However, if at the time the failure is discovered and the repair time is longer than 7 days, the reactor will be placed in the cold shutdown condition. If the repair time is not more than 7 days the reactor may continue in operation, but as an added factor of conservatism, the motor operated isolation condenser and condensate makeup valves on the operable isolation condenser are tested daily. Expiration of the 7 day period or inability to meet the other specifications requires that the reactor be placed in the cold shutdown condition which is normally expected to take no more than 18 hours. The out of service allowance when the system is required is limited to the run mode in order to require system availability, including redundancy, at startup.

References:

1. FDSAR, Volume I, Section IV-3
2. K. Shure and D. J. Dudziak, "Calculating Energy Release by Fission Products," U.S. AEC Report, WAPD-T-1309, March 1961.
3. K. Shure, "Fission Product Decay Heat," in U.S. AEC Report, WAPD-BT-24, December 1961.
4. Specification 3.2, Bases.
5. Specification 3.5.3.a.1.

3.9 REFUELING

Applicability: Applies to fuel handling operations during refueling.

Objective: To assure that criticality does not occur during refueling.

Specification:

A. Fuel shall not be loaded into a reactor core cell unless the control rod in that core cell is fully inserted.

B. During CORE ALTERATIONS the reactor mode switch shall be locked in the refuel position.

C. The refueling interlocks shall be OPERABLE with the fuel grapple hoist loaded switch set at ≤485 lb. during the fuel handling operations with the head off the reactor vessel. If the frame-mounted auxiliary hoist, the trolley-mounted auxiliary hoist or the service platform hoist is to be used for handling fuel with the head off the reactor vessel the load limit switch on the hoist to be used shall be set at ≤400 lb.

Fuel Handling operations with the head off the reactor vessel can be performed with the refueling interlocks inoperable provided all the following specifications are satisfied:

1. All control rods are verified to be fully inserted.

2. Control rod withdrawal has been disabled.

D. During CORE ALTERATIONS at least two (2) source range monitor (SRM) channels shall be OPERABLE and inserted to the normal operating level. One of the OPERABLE SRM channel detectors shall be located in the core quadrant where CORE ALTERATIONS are being performed, and another shall be located in an adjacent quadrant.

E. Removal of one control rod or rod drive mechanism may be performed provided that all the following specifications are satisfied.

1. The reactor mode switch is locked in the refuel position.

2. At least two (2) sources range monitor (SRM) channels shall be OPERABLE and inserted to the normal operation level. One of the OPERABLE SRM channel detectors shall be located in the core quadrant where the control rod is being removed and one shall be located in an adjacent quadrant.

F. Removal of any number of control rods or rod drive mechanisms may be performed provided all the following specifications are satisfied:

1. The reactor mode switch is locked in the refuel position and all refueling interlocks are OPERABLE as required in Specification 3.9.C. The refueling interlocks associated with the control rods being withdrawn may be bypassed as required after the fuel assemblies have been removed from the core cell surrounding the control rods as specified in 4, below.

2. At least two (2) source range monitor (SRM) channels shall be OPERABLE and inserted to the normal operation level. One of the OPERABLE SRM channel detectors shall be located in the core quadrant where a control rod is

being removed and one shall be located in an adjacent quadrant.

3. All other control rods are fully inserted with the exception of one rod which may be partially withdrawn not more than two notches to perform refueling interlock surveillance.

4. The four fuel assemblies are removed from the core cell surrounding each control rod or rod drive mechanism to be removed.

5. The SHUTDOWN MARGIN requirements of Specification 3.2.A are met.

6. An evaluation will be conducted for each refuel/reload to ensure that actual core criticality of the proposed order of defueling and refueling is bounded by previous analysis performed to support such defueling and refueling activities, otherwise a new analysis shall be performed.

   The new analysis must show that sufficient conservatism exists for the proposed order of defueling and refueling before such operation shall be allowed to proceed.

G. With any of the above requirements not met, cease CORE ALTERATIONS or control rod removal as appropriate, and initiate action to satisfy the above requirements.

Basis: During refueling operations, the reactivity potential of the core is being altered. It is necessary to require certain interlocks and restrict certain refueling procedures such that there is assurance that inadvertent criticality does not occur.

Addition of large amounts of reactivity to the core is prevented by operating procedures, which are in turn backed up by refueling interlocks (1) on rod withdrawal and movement of the refueling platform. When the mode switch is in the "Refuel" position, interlocks prevent the refueling platform from being moved over the core if a control rod is withdrawn and fuel is on a hoist. Likewise, if the refueling platform is over the core with fuel on a hoist control rod motion is blocked by the interlocks. With the mode switch in the refuel position only one control rod can be withdrawn (1, 2).

The one rod withdrawal interlock may be bypassed in order to allow multiple control rod removal for repair, modifications, or core unloading. The requirements for simultaneous removal of more than one control rod are more stringent than the requirements for removal of a single control rod, since in the latter case Specification 3.2.A assures that the core will remain subcritical.

The refueling interlocks may be inoperable provided that all 137 control rods are verified to be fully inserted and control rod withdrawal has been disabled prior to commencing or recommencing fuel handling operations with the head off the reactor vessel. This will ensure that all control rods remain fully inserted during fuel handling operations with the head off the reactor vessel. Therefore, Specification 3.2.A is met and the core will remain subcritical during fuel handling operations.

It is not the intent of the alternative option in Specification 3.9.C to eliminate the first performance of Technical Specification Surveillance 4.9.A prior to in-vessel fuel movement. It is expected that the refueling interlocks would be operable during fuel moves except for equipment failures or during maintenance that would otherwise result in false indications of rod withdrawal during which all rods will be verified as fully inserted and rod withdrawal prevented.

Fuel handling is normally conducted with the fuel grapple hoist. The total load on this hoist when the interlock is required consists of the weight of the fuel grapple and the fuel assembly. This total is approximately 773 lbs. in the extended position in comparison to the load limit of 485 lbs. Provisions have also been made to allow fuel handling with either of the three auxiliary hoists and still maintain the refueling interlocks. The 400 lb load trip setting on these hoists is adequate to trip the interlock when one of the more than 600 lb. fuel bundles is being handled.

The source range monitors provide neutron flux monitoring capabilities with the reactor in the refueling and shutdown modes (3). Specifications 3.9.D, 3.9.E and 3.9.F require the OPERABILITY of at least two source range monitors during CORE ALTERATIONS and when control rods are to be removed. This requirement ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

REFERENCES:

(1) FDSAR, Volume I, Section VII-7.2.5
(2) FDSAR, Volume I, Section XIII-2.2
(3) FDSAR, Volume I, Section VII-4.2.2 and VII-4.3.1

3.10 CORE LIMITS

Applicability: Applies to core conditions required to meet the Final Acceptance Criteria for Emergency Core Cooling Performance.

Objective: To assure conformance to the peak clad temperature limitations during a postulated loss-of-coolant accident as specified in 10 CFR 50.46 (January 4, 1974) and to assure conformance to the operating limits for LOCAL LINEAR HEAT GENERATION RATE and minimum CRITICAL POWER RATIO.

Specification:

A. AVERAGE PLANAR LHGR

During POWER OPERATION the maximum AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for each fuel type as a function of exposure shall not exceed the limits specified in the CORE OPERATING LIMITS REPORT (COLR).

If at any time during POWER OPERATION it is determined by normal surveillance that the limiting value for APLHGR is being exceeded, action shall be initiated to restore operation to within the prescribed limits. If the APLHGR is not returned to within the prescribed limits within two (2) hours, action shall be initiated to bring the reactor to the COLD SHUTDOWN CONDITION within 36 hours. During this period surveillance and corresponding action shall continue until reactor operation is within the prescribed limits at which time POWER OPERATION may be continued.

B. LOCAL LHGR

During POWER OPERATION, the LOCAL LINEAR HEAT GENERATION RATE (LHGR) of any rod in any fuel assembly, at any axial location shall not exceed the maximum allowable LHGR limits specified in the COLR.

If at any time during operation it is determined by normal surveillance that the limiting value of LHGR is being exceeded, action shall be initiated to restore operation to within the prescribed limits. If the LHGR is not returned to within the prescribed limits within two (2) hours, action shall be initiated to bring the reactor to the COLD SHUTDOWN CONDITION within 36 hours. During this period, surveillance and corresponding action shall continue until reactor operation is within the prescribed limits at which time POWER OPERATION may be continued.

C. Minimum CRITICAL POWER RATIO (MCPR)

During steady state POWER OPERATION the minimum CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit as specified in the COLR.

When APRM status changes due to instrument failure (APRM or LPRM input failure), the MCPR requirement for the degraded condition shall be met within a time interval of eight (8) hours, provided that the control rod block is placed in operation during this interval.

For core flows other than rated, the nominal value for MCPR shall be increased by a factor of k_f, where k_f is as shown in the COLR.

If at any time during POWER OPERATION it is determined by normal surveillance that the limiting value for MCPR is being exceeded for reasons other than instrument failure, action shall be initiated to restore operation to within the prescribed limits. If the steady state MCPR is not returned to within the prescribed limits within two [2] hours, action shall be initiated to bring the reactor to the COLD SHUTDOWN CONDITION within 36 hours. During this period, surveillance and corresponding action shall continue until reactor operation is within the prescribed limit at which time POWER OPERATION may be continued.

Bases:

The Specification for AVERAGE PLANAR LHGR assures that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46. The analytical methods and assumptions used in evaluating the fuel design limits are presented in FSAR Chapter 4.

LOCA analyses are performed for each fuel design at selected exposure points to determine APLHGR limits that meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using GE calculational models which are consistent with the requirements of 10 CFR 50, Appendix K.

The PCT following a postulated LOCA is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. Since expected location variations in power distribution within a fuel assembly affect the calculated peak clad temperature by less than ± 20°F relative to the peak temperature for a typical fuel design, the limit on the average linear heat generation rate is sufficient to assure that calculated temperatures are below the limits specified in 10 CFR 50.46.

The maximum AVERAGE PLANAR LHGR limits for the various fuel types currently being used are provided in the COLR. The COLR includes MAPLHGR limits for five loop operation. Additional limits on MAPLHGR for operations with less than five loops are given in Specification 3.3.F.2.

Fuel design evaluations are performed to demonstrate that the cladding 1% plastic strain and other fuel design limits are not exceeded during anticipated operational occurrences for operation with LHGRs up to the operating limit LHGR.

The analytical methods and assumptions used in evaluating the anticipated operational occurrences to establish the operating limit MCPR are presented in the FSAR, Chapters 4, 6 and 15 and in Technical Specification 6.9.1.f. To assure that the Safety Limit MCPR is not exceeded during any moderate frequency transient event, limiting transients have been analyzed to determine the largest reduction in CRITICAL POWER RATIO (CPR). The types of transients evaluated are pressurization, positive reactivity insertion and coolant temperature decrease. The operational MCPR limit is selected to provide margin to accommodate transients and uncertainties in monitoring the core operating state, manufacturing, and in the critical power correlation itself. This limit is derived by addition of the CPR for the most limiting transient to the safety limit MCPR designated in Specification 2.1.

The APRM response is used to predict when the rod block occurs in the analysis of the rod withdrawal error transient. The transient rod position at the rod block and corresponding MCPR can be determined. The MCPR has been evaluated for different APRM responses which would result from changes in the APRM status as a consequence of bypassed APRM channel and/or failed/bypassed LPRM inputs. The steady state MCPR required to protect the minimum transient CPR for the worst case APRM status condition (APRM Status 1) is determined in the rod withdrawal error transient analysis. The steady state MCPR values for APRM status conditions 1, 2, and 3 will be evaluated each cycle. For those cycles where the rod withdrawal error transient is not the most severe transient the MCPR value for APRM status conditions 1, 2, and 3 will be the same and be equal to the limiting transient MCPR value.

The time interval of Eight (8) hours to adjust the steady state of MCPR to account for a degradation in the APRM status is justified on the basis of instituting a control rod block which precludes the possibility of experiencing a rod withdrawal error transient since rod withdrawal is physically prevented. This time interval is adequate to allow the operator to either increase the MCPR to the appropriate value or to upgrade the status of the APRM system while in a condition which prevents the possibility of this transient occurring.

Transients analyzed each fuel cycle will be evaluated with respect to the operational MCPR limit specified in the COLR.

The purpose of the k_f factor is to define operating limits at other than rated flow conditions. At less than 100% flow the required MCPR is the product of the operating limit MCPR and the k_f factor. Specifically, the k_f factor provides the required thermal margin to protect against a flow increase transient.

The k_f factor curves, as shown in the COLR, were developed generically using the flow control line corresponding to RATED THERMAL POWER at rated core flow. For the manual flow control mode, the k_f factors were calculated such that at the maximum flow state (as limited by the pump scoop tube set point) and the corresponding core power (along the rated flow control line), the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPR's were calculated at different points along the rated flow control line corresponding to different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR determines the value of k_f.

The k_f factor also provides the required thermal margin to protect against reactor thermal hydraulic instability. The k_f factor establishes the required MCPR at low flow conditions such that if a reactor thermal hydraulic instability were to occur, the MCPR Safety Limit would not be exceeded.

3.11

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3.12 Alternate Shutdown Monitoring Instrumentation

Applicability: Applies to the operating status of alternate shutdown monitoring instrumentation.

Objective: To assure the operability of the alternate shutdown monitoring instrumentation.

Specification:

A. The alternate shutdown monitoring instruments listed in Table 3.12-1 shall be operable during reactor power operations and when reactor coolant temperature exceeds 212°F.

B. With less than the minimum number of operable channels specified in Table 3.12-1, either restore the inoperable channel 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.

Basis:

The operability of the alternate shutdown monitoring instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of hot shutdown of the plant from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with Appendix R and General Design Criteria 19 of 10 CFR 50.

TABLE 3.12-1 ALTERNATE SHUTDOWN

MONITORING INSTRUMENTATION

Functional Unit	Readout Location	Min. Channels Operable
Reactor Pressure	RSP	1
Reactor Water Level (fuel zone)	RSP	1
Condensate Storage Tank Level	Local	1
Service Water Pump Discharge Pressure	Local	1
Control Rod Drive System Flowmeter	Rx 23' near V-15-30	1
Shutdown Cooling System Flowmeter	Local	1
Isolation Condenser "B" Shell Water Level	RSP	1
Reactor Building Closed Cooling Water Pump Discharge Pressure	Local	1

RSP - Remote Shutdown Panel

3.13 ACCIDENT MONITORING INSTRUMENTATION

Applicability: Applies to the operating status of accident monitoring instrumentation.

Objective: To assure operability of accident monitoring instrumentation.

Specification: A. Relief Valve Position Indicators

1. The accident monitoring instrumentation channels shown in Table 3.13.1 shall be OPERABLE when the mode switch is in the Startup or Run positions.

2. With no accident monitoring instrumentation operable for a relief valve as specified in Table 3.13.1, either restore any inoperable channel to operable status within 7 days, or place the reactor in the SHUTDOWN condition within the next 24 hours. If only the primary* detector or the backup** indicator on a relief valve becomes inoperable, no action is required. The provisions of 3.0.A do not apply.

B. Safety Valve Position Indicators

1. During POWER OPERATION, both primary* and backup** safety valve monitoring instruments are required to be OPERABLE except as provided in 3.13.B.2.

2. If the primary* accident monitoring instrument on a safety valve becomes inoperable, the primary* accident monitoring instruments on an adjacent valve, if OPERABLE, must have its set point appropriately reduced. When a reduced setpoint causes an alarm condition due to background noise, the setpoint may be returned to normal. If the backup** accident monitoring instrument on a safety valve becomes inoperable, no action is required. The provisions of Specification 3.0.A do not apply.

* Acoustic Monitor
** Thermocouple

C. In the event that any of these monitoring channels become inoperable, they shall be made OPERABLE prior to startup following the next COLD SHUTDOWN.

D. Wide Range Torus Water Level Monitor

1. Two wide range torus water level monitor channels shall be continuously indicated in the control room during POWER OPERATION.

2. With the number of OPERABLE accident monitoring channels less than the total Number of Channels shown in Table 3.13.1, restore the inoperable channel(s) to OPERABLE status within 7 days or place the reactor in the SHUTDOWN CONDITION within the next 24 hours.

3. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels operable requirements of Table 3.13.1, restore the inoperable channel(s) to OPERABLE status within 48 hours or place the reactor in the SHUTDOWN CONDITION within the next 24 hours.

E. Wide Range Drywell Pressure Monitor

1. Two Wide Range Drywell Pressure monitor channels shall be continuously indicated in the control room during POWER OPERATION.

2. With the number of OPERABLE accident monitoring channels less than the total Number of Channels shown in Table 3.13.1, restore the inoperable channel(s) to OPERABLE status within 7 days or place the reactor in the SHUTDOWN CONDITION within the next 24 hours.

3. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels operable requirements of 3.13.1, restore the inoperable channel(s) to OPERABLE status within 48 hours or place the reactor in the SHUTDOWN CONDITION within the next 24 hours.

F. DELETED

G. Containment High-Range Radiation Monitor

1. Two containment high-range radiation monitors shall be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is required.

2. With the number of OPERABLE monitors less than 2:

   a. Take appropriate action to restore the inoperable monitor(s) to OPERABLE status as soon as possible.

   b. Perform any actions required by Table 3.1.1.

   c. Restore the inoperable monitor(s) to OPERABLE status within 7 days of the failure or prepare and submit a Special Report within 14 days following the failure outlining the cause of inoperability, actions taken, and the planned schedule for restoring the monitors to OPERABLE status.

3. With the number of OPERABLE monitors less than 1, in addition to the actions of 3.13.G.2 above. restore at least 1 monitor to OPERABLE status within 7 days of the failure or have available a preplanned alternate method capable of being implemented to provide an estimate of the radioactive material in containment under accident conditions.

H. High-Range Radioactive Noble Gas Effluent Monitor

1. The high range radioactive noble gas effluent monitors listed in Table 3.13.1 shall be OPERABLE during POWER OPERATION.

2. With the number of OPERABLE channels less than required by the minimum channels OPERABLE requirements. restore the inoperable channel(s) to OPERABLE status within 7 days of the event or prepare and submit a Special Report within 30 days following the event outlining the action taken. the cause of the inoperability and the plans and schedule for restoring the equipment to OPERABLE status.

BASES

The purpose of the safety/relief valve accident monitoring instrumentation is to alert the operator to a stuck open safety/relief valve which could result in an inventory threatening event.

As the safety valves present distinctly different concerns than those related to relief valves, the technical specifications are separated as to the actions taken upon inoperability. Clearly, the actuation of a safety valve will be immediately detectable by observed increase in drywell pressure. Further confirmation can be gained by observing reactor pressure and water level. Operator action in response to these symptoms would be taken regardless of the acoustic monitoring system status. Acoustic monitors act only to confirm the reseating of the safety valve. In actuality, the operator actions in response to the lifting of a safety valve will not change whether or not the safety valve reseats. Therefore, the actions taken for inoperable acoustic monitors on safety valves are significantly less stringent than that taken for those monitors associated with relief valves.

Should an acoustic monitor on a safety valve become inoperable, the setpoint on an adjacent monitor, if operable, will be reduced to assure alarm actuation should the safety valve lift. When a reduced setpoint results in having the acoustic monitor on an adjacent valve in an alarm condition due to background noise, the setpoint may be returned to normal. This will ensure that the adjacent valve's acoustic monitor remains operable. Analyses, using very conservative blowdown forces and attenuation factors, show that reducing the alarm setpoint on adjacent monitors to less than 1.4g will assure alarm actuation should the adjacent safety valve lift. Minimum blowdown force considered was 30g with a maximum attenuation of 27dB. In actuality, a safety valve lift would result in considerably larger blowdown force. The maximum attenuation of 27dB was determined based on actual testing of a similar monitoring system installed in a similar configuration.

The operability of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. The capability is consistent with NUREGs 0578 and 0737.

The capability is provided to detect and measure concentrations of noble gas fission products in (1) plant gaseous effluents and (2) in containment during and following an accident. For the plant gaseous effluent capability, two Radioactive Gaseous Effluent Monitoring Systems (RAGEMS) are installed at Oyster Creek. One system monitors releases at the main stack (RAGEMS I) and the other monitors the turbine building vents (RAGEMS II). For the in containment post-accident capability, two high range radiation monitors are installed in the drywell. These monitors augment the capabilities provided by the Offsite Thermoluminescent Dosimeter Program (Emergency Plan Section 7.5.2.2b).

TABLE 3.13.1

ACCIDENT MONITORING INSTRUMENTATION

	INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
1.	Relief Valve Position Indicator (Primary Detector*)	1/valve	
	Relief Valve Position Indicator (Backup Indications**)	1/valve	
2.	Wide Range Drywell Pressure Monitor (PT/PR-53 & 54)	2	1
3.	Wide Range Torus Water Level (LT/LR-37 & 38)	2	1
4.	DELETED		
5.	Containment High Range Radiation	2	1
6.	High Range Radioactive Noble Gas Effluent Monitor		
	a. Main Stack	1	1
	b. Turbine Building Vents	1	1

* Acoustic Monitor

** Thermocouple

Thermocouple TE 65A can be substituted for thermocouple TE210-43V, W, or X
Thermocouple TE 65B can be substituted for thermocouple TE210-43Y or Z

3.14 <u>Solid Radioactive Waste</u> - DELETED

3.15 Explosive Gas Monitoring Instrumentation

Objective: The explosive gas monitoring instrumentation channels shown in Table 3.15.2 shall be OPERABLE with Alarm/Trip setpoints set to ensure that the limits of Specification 3.6.F are not exceeded.

Applicability: As shown in Table 3.15.2

Specification

A. Explosive Gas Instrumentation

1. With an explosive gas monitoring instrumentation channel Alarm/Trip setpoint less conservative than required by the Objective above declare the channel inoperable and take ACTION shown in Table 3.15.2.

2. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.15.2. Restore the inoperable instrumentation to OPERABLE status within 30 days and, if unsuccessful, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.3.

3. The provisions of Specifications 3.0 and 3.1 are not applicable.

Basis:

A. The explosive gas monitoring instrumentation in Table 3.15.2 is provided for monitoring hydrogen below the explosive level in the Offgas System downstream from the recombiner. The operability and use of this instrumentation is consistent with the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR 50. The offgas hydrogen monitor has an alarm which reports in the reactor Control Room. The offgas hydrogen monitor initiates a bypass of the Augmented Offgas System in the event the setpoint is exceeded.

TABLE 3.15.2

EXPLOSIVE MONITORING INSTRUMENTATION

	Instrument	Minimum (a) Channels Operable	Essential Function	Applicability	Action
1.	Main Condenser Offgas Treatment System Recombiner Effluent Hydrogen Monitor	2(d)	Monitor hydrogen concentration	(c)	125

TABLE 3.15.2 NOTATIONS

(a) Channels shall be OPERABLE and in service as indicated except that a channel may be taken out of service for the purpose of a check, calibration, test, maintenance or sample media change without declaring the channel to be inoperable.

(b) NOT USED

(c) During Augmented Offgas Treatment System operation.

(d) One hydrogen and one temperature sensor.

ACTION 125 With one channel OPERABLE, operation of the main condenser offgas treatment system may continue provided a recombiner temperature sensing instrument is operable. When only one of the types of instruments, i.e., hydrogen monitor or temperature monitor, is operable, the offgas treatment system may be operated provided a gas sample is collected at least once per day and is analyzed for hydrogen within four hours. In the event neither a hydrogen monitor nor a recombiner temperature sensing instrument is operable when required, the Offgas Treatment System may be operated provided a gas sample is collected at least once per 8 hours and analyzed within the following 4 hours.

3.17 Control Room Heating, Ventilating, and Air-Conditioning System

Applicability: Applies to the operability of the control room heating, ventilating, and air conditioning (HVAC) system and Control Room Envelope (CRE) boundary.

--NOTE--
The CRE boundary may be opened intermittently under administrative control.

Objective: To assure the capability of the control room HVAC system and CRE boundary to minimize the amount of radioactivity, hazardous chemicals, or smoke from entering the control room in the event of an accident.

Specifications:

A. The control room HVAC system shall be operable during all modes of plant operation.

B. With one control room HVAC system determined inoperable for reasons other than specification D:

1. Verify once per 24 hours the partial recirculation mode of operation for the operable system, or place the operable system in the partial recirculation mode; and

2. Restore the inoperable system within 7 days, or prepare and submit a special report to the Commission in lieu of any other report required by Section 6.9, within the next 14 days, outlining the action taken, the cause of the inoperability and the plans/schedule for restoring the HVAC system to operable status.

C. With both control room HVAC systems determined inoperable for reasons other than specification D:

1. During Power Operation: place the reactor in the cold shutdown condition within 30 hours

2. During Refueling:

(a) Cease irradiated fuel handling operations; and

(b) Cease all work on the reactor or its connected systems in the reactor building which could result in inadvertent releases of radioactive materials.

D. When one or both control room HVAC systems are determined inoperable due to an inoperable CRE boundary:

1. During Power Operation: actions to implement mitigating actions shall be performed immediately, verification that the mitigating actions are in place shall be performed within 24 hours, and the CRE boundary shall be restored to operable status within 90 days.

2. During movement of irradiated fuel assemblies in the containment or during operations with a potential for draining the reactor vessel:

(a) Immediately suspend movement of irradiated fuel assemblies in the containment; and

(b) Immediately initiate action to suspend operations with the potential to drain the reactor vessel.

Basis:

The operability of the control room HVAC system ensures that the control room will remain habitable for operations personnel during a postulated design basis accident. The 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 may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to protect the CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

Since control room HVAC systems A and B do not have HEPA filters or charcoal absorbers, the supply fan and dampers for each system minimize the beta and gamma doses to the operators by providing positive pressurization and limiting the makeup and infiltration air into the control room envelope. For the supply of 100% outside unfiltered air to the control room envelope, the most limiting design basis accident radiation exposure to personnel occupying the control room is limited to less than a 30-day integrated dose of 5 rem TEDE.

The control room HVAC system with the use of Self Contained Breathing Apparatus (SCBA) provides protection from smoke and hazardous chemicals for 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).

A periodic offsite chemical survey, and procedures for controlling onsite chemicals, are essential elements of CRE protection against hazardous chemicals. The system design is based on low probability of offsite sources of toxic gas, based on a chemical survey of the surrounding areas. The offsite chemical survey is conducted periodically to determine any change of condition that may need to be addressed. The onsite chemicals are controlled procedurally such that they do not affect CRE habitability adversely.

The control room envelope (CRE) boundary may be opened intermittently under administrative control. This 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 control room. 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.

In order for the Control Room HVAC System 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 the CRE occupants are protected from hazardous chemicals and smoke.

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 a 30-day integrated dose of 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 INOPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated 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.

REFERENCES:

(1) UFSAR Section 6.4
(2) UFSAR Section 9.5

4.0 Surveillance Requirement Applicability

4.0.1 Surveillance requirements shall be met during the modes or other specified conditions in the applicability for individual LCOs, unless otherwise stated in the surveillance requirements. 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 LCO. Failure to perform a surveillance within the specified frequency shall be failure to meet the LCO except as provided in 4.0.2. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 If it is discovered that a surveillance was not performed within its specified frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified frequency, 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 LCO must immediately be declared not met, and the applicable condition(s) must be entered.

When the surveillance is performed within the delay period and the surveillance is not met, the LCO must immediately be declared not met, and the applicable condition(s) must be entered.

4.0.3 Entry into an OPERATIONAL CONDITION or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified frequency, except as provided by 4.0.2. When an LCO is not met due to surveillances not having been met, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.C.

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

BASES: Surveillance Requirement 4.0.1 establishes the requirement that surveillance requirements must be met during the modes or other specified conditions in the applicability for which the requirements of the LCO apply, unless otherwise specified in the individual surveillance requirements. 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 frequency constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated surveillance requirements 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 surveillance requirements; 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 a mode or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified.

Surveillances, including surveillances invoked by required actions, 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 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. Post maintenance testing may not be possible in the current mode 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 a mode or other specified condition where other necessary post maintenance tests can be completed.

Surveillance Requirement 4.0.2 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 frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the surveillance has not been performed in accordance with surveillance requirement 4.0.2 and not at the time that the specified frequency 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 required actions 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 frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g. prior to entering power operation after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, Surveillance Requirement 4.0.2 allows for the full delay period of up to the specified frequency to perform the surveillance. However, since there is not a time interval specified, the missed surveillance should be performed at the first reasonable opportunity. Surveillance requirement 4.0.2 provides a time limit for, and allowances for the performance of, surveillances that become applicable as a consequence of mode changes imposed by required actions.

Failure to comply with specified surveillance frequencies is expected to be an infrequent occurrence. Use of the delay period established by Surveillance Requirement 4.0.2 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 frequency 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 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 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 licensee's 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 completion times of the required actions for the applicable LCO conditions begin immediately upon expiration of the delay period. If a surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits 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 completion time of the actions, restores compliance with Surveillance Requirement 4.0.1.

Specification 4.0.3 establishes the requirement that all applicable Surveillance Requirements (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.C.

However, in certain circumstances, failing to meet a Surveillance Requirement will not result in Specification 4.0.3 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 4.0.3 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 4.0.3 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.C will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.3 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 4.0.2.

The provisions of Specification 4.0.3 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with LCO requirements. In addition, the provisions of Specification 4.0.3 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 POWER OPERATION to STARTUP MODE, STARTUP MODE to SHUTDOWN CONDITION, and SHUTDOWN CONDITION to COLD SHUTDOWN CONDITION.

SECTION 4

SUREVEILLANCE REQUIREMENTS

4.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the surveillance of the instrumentation that performs a safety function.

Objective: To specify the minimum frequency and type of surveillance to be applied to the safety instrumentation.

Specification: Instrumentation shall be checked, tested, and calibrated as indicated in Tables 4.1.1 and 4.1.2 using the definitions given in Section 1.

4.1 PROTECTIVE INSTRUMENTATION

Bases:

Surveillance intervals are based on reliability analyses and have been determined in accordance with General Electric Licensing Topical Reports given in References 1 through 5.

The functions listed in Table 4.1.1 logically divide into three groups:

a. On-off sensors that provide a scram function or some other equally important function.

b. Analog devices coupled with a bi-stable trip that provides a scram function or some other vitally important function.

c. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed only at shutdown.

Group (b) devices utilize an analog sensor followed by an amplifier and bi-stable trip circuit. The sensor and amplifier are active components and a failure would generally result in an upscale signal, a downscale signal, or no signal. These conditions are alarmed so a failure would not go undetected. The bi-stable portion does need to be tested in order to prove that it will assume its tripped state when required.

Group (c) devices are active only during a given portion of the operational cycle. For example, the IRM is inactive during full-power operation and active during startup. Thus, the only test that is significant is the one performed just prior to shutdown and startup. The condenser Low Vacuum trip can only be tested during shutdown, and although it is connected into the reactor protection system, it is not required to protect the reactor. Testing at each REFUELING OUTAGE is adequate. The switches for the high temperature main steamline tunnel are not accessible during normal operation because of their location above the main steam lines. Therefore, after initial calibration and in-place OPERABILITY checks, they will not be tested between refueling shutdowns. Considering the physical arrangement of the piping which would allow a steam leak at any of the four sensing locations to affect the other locations, it is considered that the function is not jeopardized by limiting calibration and testing to refueling outages.

The CHANNEL FUNCTIONAL TEST verifies instrument channel operability. A successful test of the required contact(s) of a channel relay may be performed by the verification of a change in state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST or CHANNEL CALIBRATION of a relay. This is acceptable because all the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests.

The logic of the instrument safety systems in Table 4.1.1 is such that testing the instrument channels trips the trip system to verify that it is OPERABLE. The testing may be performed by means of any series of sequential, overlapping, or total channel steps. However, certain systems require coincident instrument channel trips to completely test their trip systems. Therefore, Table 4.1.2 specifies the minimum trip system test frequency for these tripped systems. This assures that all trip systems for protective instrumentation are adequately tested, from sensors through the trip system.

IRM calibration is to be performed during reactor startup. The calibration of the IRMs during startup will be significant since the IRMs will be relied on for neutron monitoring and reactor protection up to 38.4% of rated power during a reactor startup.

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. Limiting Safety System Settings (LSSS) 2.3.A.1 allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the absolute difference between the APRM channels and the calculated power to indicate within 2% RTP is modified to include any gain adjustments required by LSSS 2.3.A.1.

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

General Electric Licensing Topical Report NEDC-30851P-A (Reference 1), Section 5.7 indicates that the major contributor to reactor protection system unavailability is common cause failure of the automatic scram contactors. Analysis showed a weekly test interval to be optimum for scram contactors. The test of the automatic scram contactors can be performed as part of the CHANNEL CALIBRATION or CHANNEL FUNCTIONAL TEST of Scram Functions or by use of the subchannel test switches.

References:

(1) NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System."

(2) NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2.

(3) NEDC-30851P-A, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation."

(4) NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation."

(5) NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation."

TABLE 4.1.1
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MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test & Calibration)
1. High Reactor Pressure	1/d	Note 3	1/3 mo.	
2. High Drywell Pressure (Scram)	N/A	1/3 mo.	1/3 mo.	By application of test pressure
3. Low Reactor Water Level	1/d	Note 3	1/3 mo.	
4. Low-Low Water Level	1/d	Note 3	1/3 mo.	
5. High Water Level in Scram Discharge Volume				
a. Digital	N/A	1/3 mo.	1/3 mo.	By varying level in sensor columns
b. Analog	N/A	Note 3	1/3 mo.	
6. Low-Low-Low Water Level	N/A	1/3 mo.	1/3 mo.	By application of test pressure
7. High Flow in Main Steamline	1/d	1/3 mo.	1/3 mo.	By application of test pressure
8. Low Pressure in Main Steamline	N/A	1/3 mo.	1/3 mo.	By application of test pressure
9. High Drywell Pressure (Core Cooling)	1/d	1/3 mo.	1/3 mo.	By application of test pressure
10. Main Steam Isolation Valve (Scram)	N/A	N/A	1/3 mo.	By exercising valve

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel		Check	Calibrate	Test	Remarks (Applies to Test & Calibration)
11.	APRM Level	N/A	1/3d	N/A	Verify the absolute difference between the APRM channels and the calculated power is ≤ 2% rated thermal power [plus any gains required by LSSS 2.3.A.1].
	APRM Scram Trips • Flow biased neutron flux - high • Fixed neutron flux - high or inop • Downscale	Note 2	1/3 mo.	1/3 mo.	Using built-in calibration equipment during POWER OPERATION
12.	APRM Rod Blocks	Note 2	1/3 mo.	1/3 mo.	Upscale and downscale
13.	DELETED				
14.	High Radiation in Reactor Building				
	Operating Floor	1/s	1/3 mo.	1/3 mo.	Using gamma source for calibration
	Ventilation Exhaust	1/s	1/3 mo.	1/3 mo.	
15.	High Radiation on Air Ejector Off-Gas		1/3 mo.	1/3 mo.	Using built-in calibration equipment
		1/s			Channel Check
		1/mo.			Source check
			1/24 mo.		Calibration according to established station calibration procedures
				1/24 mo.	Note a

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel		Check	Calibrate	Test	Remarks (Applies to Test & Calibration)
16.	IRM Level	N/A	Each startup	N/A	
	IRM Scram	*	*	*	Using built-in calibration equipment
17.	IRM Blocks	N/A	Prior to startup and shutdown	Prior to startup and shutdown	Upscale and downscale
18.	Condenser Low Vacuum	N/A	1/24 mo.	1/24 mo.	
19.	Manual Scram Buttons	N/A	N/A	1/3 mo.	
20.	High Temperature Main Steamline Tunnel	N/A	1/24 mo.	Each refueling outage	Using heat source box
21.	SRM	*	*	*	Using built-in calibration equipment
22.	Isolation Condenser High Flow ΔP (Steam & Water)	N/A	1/3 mo.	1/3 mo.	By application of test pressure
23.	Turbine Trip Scram	N/A	N/A	1/3 mo.	
24.	Generator Load Rejection Scram	N/A	1/3 mo.	1/3 mo.	
25.	Recirculation Loop Flow	N/A	1/24 mo.	N/A	By application of test pressure
26.	Low Reactor Pressure Core Spray Valve Permissive	N/A	1/3 mo.	1/3 mo.	By application of test pressure

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test & Calibration)
27. Scram Discharge Volume (Rod Block)				
a) Water level high	N/A	Each refueling outage	1/3 mo.	Calibrate by varying level in sensor column
b) Scram Trip bypass	N/A	N/A	Each refueling outage	
28. Loss of Power				
a) 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	1/d	1/24 mo.	1/mo.	
b) 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	1/d	1/24 mo.	1/mo.	
29. Drywell High Radiation	N/A	Each refueling outage	Each refueling outage	
30. Automatic Scram Contactors	N/A	N/A	1/wk	Note 1
31. Core Spray Booster Pump Differential Pressure	N/A	1/3 mo.	1/3 mo.	By application of a test pressure

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test & Calibration)
32. LPRM Level				
a) Electronics	N/A	1/12 mo.	1/12 mo.	
b) Detectors	N/A	Note 4	N/A	
33. RWCU HELB High Temperature	N/A	Each refueling outage	1/3 mo.	Perform Channel Tests using the test switches.

* Calibrate prior to startup and normal shutdown and thereafter check 1/s and test 1/wk until no longer required.

Legend:
N/A = Not Applicable
1/s = Once per shift
1/d = Once per day
1/3d = Once per 3 days;
1/wk = Once per week
1/mo. = Once per month
1/3 mo. = Once every 3 months;
1/12 mo. = Once every 12 months
1/24 mo. = Once every 24 months

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

NOTE 1: Each automatic scram contactor is required to be tested at least once per week. When not tested by other means, the weekly test can be performed by using the subchannel test switches.

NOTE 2: At least daily during reactor POWER OPERATION, the reactor neutron flux peaking factor shall be estimated and flow-referenced APRM scram and rod block settings shall be adjusted, if necessary, as specified in Section 2.3 Specifications A.1 and A.2.

NOTE 3: Calibrate electronic bistable trips by injection of an external test current once per 3 months. Calibrate transmitters by application of test pressure once per 12 months.

NOTE 4: Perform LPRM detectors calibration every 1000 MWD/MT Average Core Exposure

The following notes are only for Item 15 of Table 4.1.1:

A channel may be taken out of service for the purpose of a check, calibration, test or maintenance without declaring the channel to be inoperable.

a. 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 setpoint.
2) Instrument indicates a downscale failure.
3) Instrument controls not set in operate mode.
4) Instrument electrical power loss.

TABLE 4.1.2

MINIMUM TEST FREQUENCIES FOR TRIP SYSTEMS

Trip System	Minimum Test Frequency
1) Dual Channel (Scram)	Same as for respective instrumentation in Table 4.1.1
2) Rod Block	Same as for respective instrumentation in Table 4.1.1
3) DELETED	DELETED
4) Automatic Depressurization each trip system, one at a time	Each refueling outage
5) MSIV Closure each closure logic circuit independently (1 valve at a time)	Each refueling outage
6) Core Spray each trip system, one at a time	1/3 mo. and each refueling outage
7) Primary Containment Isolation each trip circuit independently (1 valve at a time)	Each refueling outage
8) Refueling Interlocks	Prior to each refueling operation
9) Isolation Condenser Actuation and Isolation each trip circuit independently (1 valve at a time)	Each refueling outage
10) Reactor Building Isolation and SGTS Initiation	Same as for respective instrumentation in Table 4.1.1
11) DELETED	DELETED
12) Air Ejector Offgas Line Isolation	Each refueling outage
13) Containment Vent and Purge Isolation	1/24 mo.

4.2 REACTIVITY CONTROL

Applicability: Applies to the surveillance requirements for reactivity control.

Objective: To verify the capability for controlling reactivity.

Specification:

A. SDM shall be verified:
   1. Prior to each CORE ALTERATION, and
   2. Once within 4 hours following the first criticality following any CORE ALTERATION.

B. The control rod drive housing support system shall be inspected after reassembly.

C. 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:

   1. For all control rods prior to THERMAL POWER exceeding 40% power with reactor coolant pressure greater than 800 psig, following core alterations or after a reactor shutdown that is greater than 120 days.

   2. 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 "a" or "b" as follows:

      a.1 Specifically affected individual control rods shall be scram time tested with the reactor depressurized and the scram insertion time from the fully withdrawn position to 90% insertion shall not exceed 2.2 seconds, and

      a.2 Specifically affected individual control rods shall be scram time tested at greater than 800 psig reactor coolant pressure prior to exceeding 40% power.

      b. Specifically affected individual control rods shall be scram time tested at greater than 800 psig reactor coolant pressure.

   3. On a frequency of less than or equal to once per 180 days of cumulative power operation, for at least 20 control rods, on a rotating basis, with reactor coolant pressure greater than 800 psig.

D. Each partially or fully withdrawn control rod shall be exercised at least once each week. This test shall be performed within 24 hours in the event power operation is continuing with two or more inoperable control rods or in the event power operation is continuing with one fully or partially withdrawn rod which cannot be moved and for which control rod drive mechanism damage has not been ruled out. The surveillance need not be completed within 24 hours if the number of inoperable rods has been reduced to less than two and if it has been demonstrated that control rod drive mechanism collet housing failure is not the cause of an immovable control rod.

E. Surveillance of the standby liquid control system shall be as follows:

1. Pump operability	Once/3 months
2. Boron concentration determination	Once/month
3. Functional test	Once every 24 months
4. Solution volume and temperature check	Once/day
5. Solution Boron-10 Enrichment	Once every 24 months. Enrichment analyses shall be received no later than 30 days after sampling. If not received within 30 days, notify NRC (within 7 days) of plans to obtain test results.

F. At specific power operation conditions, the actual control rod configuration will be compared with the expected configuration based upon appropriately corrected past data. This comparison shall be made every equivalent full power month. The initial rod inventory measurement performed with equilibrium conditions are established after a refueling or major core alteration will be used as base data for reactivity monitoring during subsequent power operation throughout the fuel cycle.

G. The scram discharge volume drain and vent valves shall be verified open at least once per 31 days, except in shutdown mode*, and shall be cycled at least one complete cycle of full travel at least quarterly.

H. All withdrawn control rods shall be determined OPERABLE by demonstrating the scram discharge volume drain and vent valves OPERABLE. This will be done at least once per refueling cycle by placing the mode switch in shutdown and by verifying that:

a. The drain and vent valves close within 30 seconds after receipt of a signal for control rods to scram, and

b. The scram signal can be reset and the drain and vent valves open when the scram discharge volume trip is bypassed.

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

BASIS:

Adequate SDM must be demonstrated to ensure that the reactor can be made subcritical from any initial operating condition. Adequate SDM is demonstrated by testing before or during the first startup after fuel movement, control rod replacement, or shuffling within the reactor pressure vessel. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value must be increased by an adder, "R", which is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated BOC core reactivity. If the value of R is negative (that is, BOC is the most reactive point in the cycle), no correction to the BOC measured value is required.

The SDM may be demonstrated during an in sequence control rod withdrawal, in which the highest worth control rod is analytically determined, or during local criticals. Local critical tests require the withdrawal of out of sequence control rods.

The frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and have appropriate verification.

During REFUEL MODE, adequate SDM is required to ensure that the reactor does not reach criticality during core alterations. An evaluation of each in vessel fuel movement during fuel loading (including shuffling fuel within the core) shall be performed to ensure adequate SDM is maintained during refueling. This evaluation can be a bounding analyses that demonstrate adequate SDM for the most reactive configurations during the refueling may be performed to demonstrate acceptability of the entire fuel movement sequence. For the SDM demonstrations that rely solely on calculation, additional margin must be added to the SDM limit of 0.38% delta k/k to account for uncertainties in the calculation.

The control rod drive housing support system[(2)] is not subject to deterioration during operation. However, reassembly must be assured following a partial or complete removal.

The scram insertion times for all control rods[(3)] will be determined at the time of each refueling outage. The scram times generated at each refueling outage when compared to scram times previously recorded gives a measurement of the functional effects of deterioration for each control rod drive. Scram time testing with the reactor depressurized is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing above 800 psig reactor coolant pressure is performed prior to exceeding 40% power.

The weekly control rod exercise test serves as a periodic check against deterioration of the control rod system. Experience with this control rod system has indicated that weekly tests are adequate, and that rods which move by drive pressure will scram when required as the pressure applied is much higher. The requirement to exercise the control rods within 24 hours of a condition with two or more control rods which are valved out of service or one fully or partially withdrawn control rod which can not be moved provides assurance of the reliability of the remaining control rods.

Pump operability, boron concentration, solution temperature and volume of standby liquid control system[4] are checked on a frequency consistent with instrumentation checks described in Specification 4.1. Experience with similar systems has indicated that the test frequencies are adequate. The only practical time to functionally test the liquid control system is during a refueling outage. The functional test includes the firing of explosive charges to open the shear plug valves and the pumping of demineralized water into the reactor to assure operability of the system downstream of the pumps. The test also includes recirculation of liquid control solution to and from the solution tanks.

Pump operability is demonstrated on a more frequent basis. This test consists of recirculation of demineralized water to a test tank. A continuity check of the firing circuit on the shear plug valves is provided by pilot lights in the control room. Tank level and temperature alarms are provided to alert the operator to off-normal conditions.

Figure 3.2.1 was revised to reflect the minimum and maximum weight percent of sodium pentaborate solution, and the minimum atom percent of B-10 to meet 10 CFR 50.62(c)(4). Since the weight percent of sodium pentaborate can change with water makeup or water evaporation, frequent surveillances are performed on the solution concentration, volume and temperature. The sodium pentaborate is enriched with B-10 at the chemical vendor's facility to meet the minimum atom percent. Preshipment samples of batches are analyzed for B-10 enrichment and verified by an independent laboratory prior to shipment to Oyster Creek. Since the B-10 enrichment will not change while in storage or in the SLCS tank, the surveillance for B-10 enrichment is performed on a 24 month interval. An additional requirement has been added to evaluate the solution's capability to meet the original design shutdown criteria whenever the Boron-10 enrichment requirement is not met.

The functional test and other surveillance on components, along with the monitoring instrumentation, gives a high reliability for standby liquid control system operability.

References

(1) FDSAR, Volume II, Figure III-5-11
(2) FDSAR, Volume I, Section VI-3
(3) FDSAR, Volume I, Section III-5 and Volume II, Appendix B
(4) FDSAR, Volume I, Section VI-4

4.3 REACTOR COOLANT

Applicability: Applies to the surveillance requirements for the reactor coolant system.

Objective: To determine the condition of the reactor coolant system and the operation of the safety devices related to it.

Specification:

A. Materials surveillance specimens and neutron flux monitors shall be installed in the reactor vessel adjacent to the wall at the midplane of the active core. Specimens and monitors shall be periodically removed, tested, and evaluated to determine the effects of neutron fluence on the fracture toughness of the vessel shell materials. Pressure and temperature curves are contained in the Pressure and Temperature Limits Report (PTLR).

B. Inservice inspection of ASME Code Class 1, Class 2 and Class 3 systems and 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, Section 50.55a, except where specific written relief has been granted by the NRC pursuant to 10 CFR, Section 50.55a.

C. Inservice testing of ASME Code Class 1, Class 2 and Class 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, Section 50.55a, except where specific written relief has been granted by the NRC pursuant to 10 CFR, Section 50.55a.

D. A visual examination for leaks shall be made with the reactor coolant system at pressure during each scheduled refueling outage or after major repairs have been made to the reactor coolant system in accordance with Article 5000, Section XI. The requirements of specification 3.3.A shall be met during the test.

E. Each replacement safety valve or valve that has been repaired shall be tested in accordance with Specification C above. Setpoints shall be as follows:

Number of Valves	Set Points (psig)
4	1212 ± 36
5	1221 ± 36

F. A sample of reactor coolant shall be analyzed at least every 72 hours for the purpose of determining the content of chloride ion and to check the conductivity.

* G. Primary Coolant System Pressure Isolation Valves Specification:

1. Periodic leakage testing[a] on each valve listed in Table 4.3.1 shall be accomplished prior to exceeding 600 psig reactor pressure every time the plant is placed in the cold shutdown condition for refueling, each time the plant is placed in a cold shutdown condition for 72 hours if testing has not been accomplished in the preceding 9 months, whenever the valve is moved whether by manual actuation or due to flow conditions, and after returning the valve to service after maintenance, repair or replacement work is performed.

H. Reactor Coolant System Leakage

1. Unidentified leakage rate shall be calculated at least once every 4 hours.

2. Total leakage rate (identified and unidentified) shall be calculated at least once every 8 hours.

3. A CHANNEL CALIBRATION of the primary containment sump flow integrator and the primary containment equipment drain tank flow integrator shall be conducted at least once per 24 months.

I. An inservice inspection program for piping identified in NRC Generic Letter 88-01 shall be performed in accordance with the NRC staff positions on schedule, methods, personnel, and sample expansion included in the generic letter or in accordance with alternate measures approved by the NRC staff.

Bases:

Data is available relating neutron fluence (E>1.0MeV) and the change in the Reference Nil-Ductility Transition Temperature (RT_{NDT}). Pressure and temperature curves are contained in the Pressure and Temperature Limits Report (PTLR).

The inspection program will reveal problem areas should they occur, before a leak develops. In addition, extensive visual inspection for leaks will be made on critical systems. Oyster Creek was designed and constructed prior to

[a] To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

* NRC Order dated April 20, 1981.

the existence of ASME Section XI. For this reason, the degree of access required by ASME Section XI is not generally available and will be addressed as "requests for relief" in accordance with 10 CFR 50.55a(g).

Experience in safety valve operation shows testing in accordance with the ASME Code is adequate to detect failures or deterioration. The as-found setpoint tolerance is specified in the ASME OM Code as the owner-defined tolerance or ± 3% of valve nameplate set pressure. An analysis has been performed which shows that with all safety valves set 36 psig higher, the safety limit of 1375 psig is not exceeded.

Conductivity instruments continuously monitor the reactor coolant. Experience indicates that a check of the conductivity instrumentation at least every 72 hours is adequate to ensure accurate readings. The reactor water sample will also be used to determine the chloride ion content to assure that the limits of 3.3.E are not exceeded. The chloride ion content will not change rapidly over a period of several days; therefore, the sampling frequency is adequate.

TABLE 4.3.1

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES

System	Valve No.	Maximum (a) Allowable Leakage
Core Spray System 1	NZ02A	5.0 GPM
	NZ02C	5.0 GPM
Core Spray System 2	NZ02B	5.0 GPM
	NZ02D	5.0 GPM

Footnote:

(a) 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5. Test differential pressure shall not be less than 150 psid.

NRC Order dated April 20, 1981

4.4 EMERGENCY COOLING

Applicability: Applies to surveillance requirements for the emergency cooling systems.

Objective: To verify the operability of the emergency cooling systems.

Specification: Surveillance of the emergency cooling systems shall be performed as follows:

Item	Frequency
A. Core Spray System	
1. Pump Operability	Once/3 months. Also after major maintenance and prior to startup following a refueling outage.
2. Motor operated valve operability	Once/3 months
3. Automatic actuation test	Every three months
4. Pump compartment water-tight doors closed	Once/week and after each entry
5. Core spray header ΔP instrumentation	
CHANNEL CHECK	Once/day
CHANNEL CALIBRATION	Once/3 months
CHANNEL FUNCTIONAL TEST	Once/3 months
B. Automatic Depressurization	
1. Verify each relief valve actuator strokes when manually actuated	Once every 24 months
2. Automatic actuation test	Every refueling outage
C. Containment Cooling System	
1. Pump Operability	Once/3 months. Also after major maintenance and prior to startup following a refueling outage.

Item	Frequency
C. Containment Cooling System	
2. Motor-operated valve operability	Every 3 months
3. Pump compartment water-tight doors closed	Once/week and after each entry
D. Emergency Service Water System	
1. Pump Operability	Once/3 months. Also after major maintenance and prior to startup following a refueling outage.
E. Control Rod Drive Hydraulic System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
F. Fire Protection System	
1. Pump Operability	Once/month. Also after major maintenance and prior to startup following a refueling outage.
2. Isolation valve operability	Once/3 months. Also after major maintenance and prior to startup following a refueling outage.

Bases:

It is during major maintenance or repair that a system's design intent may be violated accidentally. Therefore, a functional test is required after every major maintenance operation. During an extended outage, such as a refueling outage, major repair and maintenance may be performed on many systems. To be sure that these repairs on other systems do not encroach unintentionally on critical standby cooling systems, they should be given a functional test prior to startup.

Motor operated pumps, valves and other active devices that are normally on standby should be exercised periodically to make sure that they are free to operate. Motors on pumps should operate long enough to approach equilibrium temperature to ensure there is no overheat problem. Whenever practical, valves should be stroked full length to ensure that nothing impedes their motion. Testing of components per OC Inservice Testing Program in accordance with the ASME Code once every 3 months provides assurances of the availability of the system. The Control Rod Hydraulic pumps and Fire Protection System pumps are not part of the Inservice Test Program per the ASME Code and will continue to be tested for operability once per month. Engineering judgment based on experience and availability analyses of the type presented in Appendix L of the FDSAR indicates that testing these components more often than once a month over a long period of time does not significantly improve the system reliability. Also, at this frequency of testing wearout should not be a problem through the life of the plant.

The operability of the Electromatic Relief Valves (EMRVs) is verified by a stroke test of its relief valve actuator as specified in TS 4.4.B.1, and by the Inservice Testing Program (IST).

The EMRV actuator stroke test is performed with the pilot valve actuator mounted in its normal position. The test checks the manual actuation electrical circuitry, solenoid actuator, pilot operating lever, and pilot valve assembly. This verifies pilot valve movement. However, since this test is performed prior to establishing the reactor pressure needed to overcome the main valve closure spring force, the main valve will not stroke during the test, thereby minimizing the potential for valve leakage.

The control rod drive hydraulic system is normally in operation, thereby providing continuous indication of system operability. A check of flow rate and operability can be made during normal operation.

4.5 CONTAINMENT SYSTEM

Applicability: Applies to containment system leakage rate, continuous leak rate monitor, functional testing of valves, standby gas treatment system operability, inerting surveillance, drywell coating surveillance, instrument line flow check valve surveillance, suppression chamber surveillance, and snubber surveillance.

Objectives: To verify operability of containment systems, and that leakage from the containment system is maintained within specified values, as outlined in Appendix J of 10 CFR 50.

Specification:

A. Primary Containment Leakage Testing

A Primary Containment Leakage Rate Testing Program shall be established to implement 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 Leak Test Program," dated September 1995, as modified by the following exception:

1. The first Type A test required by this program will be performed during refueling outage 18R.

B. Type A Primary Containment Integrated Leak Rate Test (PCILRT).

PCILRT shall be performed in accordance with the Primary Containment Leakage Rate Testing Program.

C. Type B and Type C Local Leak Rate Tests (LLRT)

1. LLRT shall be performed in accordance with the Primary Containment Leakage Rate Testing Program.

2. The Drywell Airlock, Drywell Airlock electrical penetration, and Drywell Airlock barrel seal shall be local leak rate tested in accordance with the Primary Containment Leakage Rate Testing Program.

   a. When containment integrity is required, the airlock must be tested at 10 psig within 7 days after each containment access. If the airlock is opened more frequently than once every 7 days, it may be tested at 10 psig once per 30 days during this time period.

b. If the airlock is opened during a period when Primary Containment is not required, it need not be tested while Primary Containment is not required, but must be tested at P_a prior to returning the reactor to an operating mode requiring PRIMARY CONTAINMENT INTEGRITY.

D. Primary Containment Leakage Rates shall be limited to:

1. The maximum allowable Primary Containment leakage rate is 1.0 L_a. The maximum allowable Primary Containment leakage rate to allow for plant startup following a type A test is 0.75 L_a. The leakage rate acceptance criteria for the Primary Containment Leakage Rate Testing Program for Type B and Type C tests is $\leq$0.60 L_a at P_a, except as stated in Specification 4.5.D.2.

2. Verify leakage rate through each MSIV is $\leq$ 11.9 scfh when tested at $\geq$ 20 psig.

3. The leakage rate acceptance criteria for the drywell airlock shall be $\leq$ 0.05 L_a when measured or adjusted to P_a.

E. Continuous Leak Rate Monitor

1. When the primary containment is inerted, the containment shall be continuously monitored for gross leakage by review of the inerting system makeup requirements.

2. This monitoring system may be taken out of service for the purpose of maintenance or testing but shall be returned to service as soon as practical.

F. Functional Test of Valves

1. All automatic primary containment isolation valves shall be tested for automatic closure by an isolation signal during each REFUELING OUTAGE and the isolation time determined to be within its limit. The following valves are required to close in the time specified below:

   Main steam line isolation valves: $\geq$ 3 seconds and $\leq$ 10 seconds

2. Each automatic 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 by cycling the valve through at least one complete cycle of full travel and verifying the isolation time limit is met. Following maintenance, repair or replacement work on the control or power circuit for the valves, the affected component shall be tested to assure it will perform its intended function in the circuit.

3. During each COLD SHUTDOWN, each main steam isolation valve shall be closed and its closure time verified to be within the limits of Specification 4.5.F.1 above unless this test has been performed within the last 92 days.

4. Reactor Building to Suppression Chamber Vacuum Breakers

   a. The reactor building to suppression chamber vacuum breakers and associated instrumentation, including setpoint, shall be checked for proper operation every three months.

   b. During each REFUELING OUTAGE, each vacuum breaker shall be tested to determine that the force required to open the vacuum breaker from closed to fully open does not exceed the force specified in Specification 3.5.A.4.a. The air-operated vacuum breaker instrumentation shall be calibrated during each REFUELING OUTAGE.

5. Pressure Suppression Chamber - Drywell Vacuum Breakers

   a. Periodic OPERABILITY Tests

   Once every 3 months and following any release of energy which would tend to increase pressure to the suppression chamber, each OPERABLE suppression chamber - drywell vacuum breaker shall be exercised. Operation of position switches, indicators and alarms shall be verified every 3 months by operation of each OPERABLE vacuum breaker.

   b. REFUELING OUTAGE Tests

   (1) All suppression chamber - drywell vacuum breakers shall be tested to determine the force required to open each valve from fully closed to fully open.

   (2) The suppression chamber - drywell vacuum breaker position indication and alarm systems shall be calibrated and functionally tested.

(3) At least four of the suppression chamber - drywell vacuum breakers shall be inspected. If deficiencies are found, all vacuum breakers shall be inspected and deficiencies corrected such that Specification 3.5.A.5.a can be met.

(4) A drywell to suppression chamber leak rate test shall be performed once every 24 months to demonstrate that with an initial differential pressure of not less than 1.0 psi, the differential pressure decay rate shall not exceed the equivalent of air flow through a 2-inch orifice.

G. Reactor Building

1. Secondary containment capability tests shall be conducted after isolating the reactor building and placing either Standby Gas Treatment System filter train in operation.

2. The tests shall be performed at least once per operating cycle (interval not to exceed 20 months) and shall demonstrate the capability to maintain a 1/4 inch of water vacuum under calm wind conditions with a Standby Gas Treatment System Filter train flow rate of not more than 4000cfm.

3. A secondary containment capability test shall be conducted at each refueling outage prior to refueling.

4. The results of the secondary containment capability tests shall be in the subject of a summary technical report which can be included in the reports specified in Section 6.

H. Standby Gas Treatment System

1. The capability of each Standby Gas Treatment System circuit shall be demonstrated by:

a. At least once per 18 months, after every 720 hours of operation, and following significant painting, fire, or chemical release in the reactor building during operation of the Standby Gas Treatment System by verifying that:

(1) The charcoal absorbers remove $\geq$99% of a halogenated hydrocarbon refrigerant test gas and the HEPA filters remove $\geq$ 99% of the DOP in a cold DOP test when tested in accordance with ANSI N510-1975.

(2) Results of laboratory carbon sample analysis show $\geq$95% radioactive methyl iodide removal efficiency when tested in accordance with ASTM D 3803-1989 (30°C, 95% relative humidity, at least 45.72 feet per minute charcoal bed face velocity).

b. At least once per 18 months by demonstrating:

(1) That the pressure drop across a HEPA filter is equal to or less than the maximum allowable pressure drop indicated in Figure 4.5.1.

(2) The inlet heater is capable of at least 10.9 KW input.

(3) Operation with a total flow within 10% of design flow.

c. At least once per 30 days on a STAGGERED TEST BASIS by operating each circuit for a minimum of 10 hours.

d. Anytime the HEPA filter bank or the charcoal absorbers have been partially or completely replaced, the test per 4.5.H.1.a (as applicable) will be performed prior to returning the system to OPERABLE STATUS.

e. Automatic initiation of each circuit every 18 months.

I. Inerting Surveillance

When an inert atmosphere is required in the primary containment, the oxygen concentration in the primary containment shall be checked at least weekly.

J. Drywell Coating Surveillance

Carbon steel test panels coated with Firebar D shall be placed inside the drywell near the reactor core midplane level. They shall be removed for visual observation and weight loss measurements during the first, second, fourth and eighth refueling outages.

K. Instrument Line Flow Check Valves Surveillance

The capability of a representative sample of instrument line flow check valves to isolate shall be tested at least once per 24 months. In addition, each time an instrument line is returned to service after any condition which could have produced a pressure flow disturbance in that line, the open position of the flow check valve in that line shall be verified. Such conditions include:

Leakage at instrument fittings and valves
Venting an unisolated instrument or instrument line
Flushing or draining an instrument
Installation of a new instrument or instrument line

L. Suppression Chamber Surveillance

1. At least once per day the suppression chamber water level and temperature and pressure suppression system pressure shall be checked.

2. A visual inspection of the suppression chamber interior, including water line regions, shall be made at each major refueling outage.

3. Whenever heat from relief valve operation is being added to the suppression pool, the pool temperature shall be continually monitored and also observed until the heat addition is terminated.

4. Whenever operation of a relief valve is indicated and the suppression pool temperature reaches 160°F or above while the reactor primary coolant system pressure is greater than 180 psig, an external visual examination of the suppression chamber shall be made before resuming normal power operation.

M. Shock Suppressors (Snubbers)

As used in this specification, "type of snubber" shall mean snubbers of the same design and manufacturer, irrespective of capacity.

1. Each snubber shall be demonstrated OPERABLE by performance of the following inspection program:

a. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of the categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 4.5-1. The visual inspection interval for each type of snubber shall be determined based upon the criteria provided in Table 4.5-1.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify that: (1) that there are no visible indications of damage or impaired OPERABILITY; (2) attachments to the foundation or supporting structure are functional; and (3) fasteners for the attachment of the snubber to the component and to the snubber anchorage are functional.

Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified as 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 that may be generically susceptible; and (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Specification 4.5.M.d or 4.5.M.e. 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 ACTION requirements shall be met.

c. Functional Tests

At least once every 24 months, a representative sample (10% of the total of each type of snubber in use in the plant) shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria of Specification 4.5.M.d or 4.5.M.e, an additional 10% of that type of snubber shall be functionally tested. As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, mechanical or hydraulic.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle.
2. Snubbers within 5 feet of heavy equipment (valve, pump, motor, etc.).
3. Snubbers within 10 feet of the discharge from a safety relief valve.

In addition to the regular sample, snubbers which failed a previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed (if it is repaired and installed in another position) and the replacement snubber shall be retested. The results from testing of these snubbers are not included for determining additional sampling requirements.

For any snubber that fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated. If caused by manufacturer or design deficiency, actions shall be taken to ensure that all snubbers of the same design are not subject to the same defect.

d. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continuous load, the ability of the snubbers to withstand load without displacement shall be verified.

e. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The drag force to maintain movement of the snubber rod in either tension or compression is less than the specified maximum drag force.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

f. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.1.

Concurrent with the first inservice visual inspection and at least once per 24 months thereafter, the installation and maintenance records for each snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be re-evaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This re-evaluation, replacement or reconditioning shall be indicated in the records. Service life shall not at any time affect reactor operations.

N. Secondary Containment Isolation Valves

1. Each secondary 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 by cycling the valve through at least one complete cycle of full travel. Following maintenance, repair or replacement work on the control or power circuit for the valves, the affected component shall be tested to assure it will perform its intended function in the circuit.

2. At least once per refueling outage, all valves shall be tested for automatic closure by an isolation signal.

4.5 CONTAINMENT SYSTEM

Bases:

In the event of a loss-of-coolant accident, the peak drywell pressure would be 38 psig which would rapidly reduce to 20 psig within 100 seconds following the pipe break. The total time the drywell pressure would be above 35 psig is calculated to be about 7 seconds. Following the pipe break, absorption chamber pressure rises to 20 psig within 8 seconds, equalizes with drywell pressure at 25 psig within 60 seconds and thereafter rapidly decays with the drywell pressure decay [(1)]

The design pressures of the drywell and absorption chamber are 62 psig and 35 psig, respectively.[(2)] The original calculated 38 psig peak drywell pressure was subsequently reconfirmed.[(3)] A 15% margin was applied to revise the drywell design pressure to 44 psig. The design leak rate is 0.5%/day at a pressure of 35 psig. As pointed out above, the pressure response of the drywell and absorption chamber following an accident would be the same after about 60 seconds. Based on the calculated primary containment pressure response discussed above and the absorption chamber design pressure, primary containment pre-operational test pressures were chosen. Also, based on the primary containment pressure response and the fact that the drywell and absorption chamber function as a unit, the primary containment will be tested as a unit rather than testing the individual components separately.

The design basis loss-of-coolant accident was evaluated at the primary containment maximum allowable accident leak rate of 1.0%/day at 35 psig. The analysis showed that with this leak rate and a standby gas treatment system filter efficiency of 90 percent for elemental and organic iodines, 90% for particulates, and assuming the fission product release fractions stated in Regulatory Guide 1.183, the maximum dose is 1.91 rem TEDE at the site boundary considering fumigation conditions over an exposure duration of two hours. The resultant doses that would occur for the duration of the accident at the low population distance of 2 miles are lower than those stated due to the variability of meteorological conditions that would be expected to occur over a 30-day period. Thus, the doses reported are the maximum that would be expected in the unlikely event of a design basis loss-of-coolant accident. These doses are also based on the assumption of no holdup in the secondary containment resulting in a direct release of fission product from the primary containment through the filters and stack to the environs. Therefore, the specified primary containment leak rate and filter efficiency are conservative and provide margin between expected offsite doses and 10 CFR 50.67 guideline limits. The maximum dose to control room operators over the 30-day accident period is 4.63 rem TEDE.

Although the dose calculations suggest that the allowable test leak rate could be allowed to increase significantly before the guideline dose limit given in 10 CFR 50.67 would be exceeded, establishing the limit of 1.0%/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly from the containment design value to take advantage of the design leak-tightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as-built" condition is achieved by establishing the allowable operational leak rate. The operational limit is derived by multiplying the allowable test leak rate by 0.75 thereby providing a 25% margin to allow for leakage deterioration which may occur during the period between leak rate tests.

A Primary Containment Leakage Rate Testing Program has been established to implement the requirements of 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. Guidance for implementation of Option B is contained in NRC Regulatory Guide 1.163, "Performance Based Containment Leak Test Program", Revision 0, dated September 1995. Additional guidance for NRC Regulatory Guide 1.163 is contained in Nuclear Energy Institute (NEI) 94-01, "Industry Guideline for Implementing Performance Based Option of 10 CFR 50, Appendix J," Revision 0, dated July 26, 1995, and ANSI/ANS 56.8-1994, "Containment System Leakage Testing Requirements." The Primary Containment Leakage Rate Testing Program conforms with this guidance as modified by approved exemptions.

The maximum allowable leakage rate for the primary containment (L_a) is 1.0 percent by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a). As discussed below, P_a for the purpose of containment leak rate testing is 35 psig.

The penetration and air purge piping leakage test frequency, along with the containment leak rate tests, is adequate to allow detection of leakage trends. Whenever a double gasketed penetration (primary containment head equipment hatches and the absorption chamber access hatch) is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. The test pressure of 35 psig is consistent with the accident analyses and the maximum preoperational leak rate test pressure.

Monitoring the nitrogen makeup requirements of the inerting system provides a method of observing leak rate trends and would detect gross leaks in a very short time. This equipment must be periodically removed from service for test and maintenance, but this out-of-service time be kept to a practical minimum.

Automatic primary containment isolation valves are provided to maintain PRIMARY CONTAINMENT INTEGRITY following the design basis loss-of-coolant accident. Closure times for the automatic primary containment isolation valves are not critical because it is on the order of minutes before significant fission product release to the containment atmosphere for the design basis loss of coolant accident. These valves are highly reliable, see infrequent service and most of them are normally in the closed position. Therefore, a test during each REFUELING OUTAGE is sufficient.

Large lines connecting to the reactor coolant system, whose failure could result in uncovering the reactor core, are supplied with automatic isolation valves (except containment cooling). Closure times restrict coolant loss from the circumferential rupture of any of these lines outside primary containment to less than that for a main steam line break (the design basis accident for outside containment line breaks). The minimum time for main steam isolation valve (MSIV) closure of 3 seconds is based on the transient analysis that shows the pressure peak 76 psig below the lowest safety valve setting. The maximum time for MSIV closure of 10 seconds is based on the value assumed for the main steam line break dose calculations and restricts coolant loss to prevent uncovering the reactor core. Per the ASME Code, the full closure test of the MSIVs during COLD SHUTDOWNs will ensure OPERABILITY and provide assurance that the valves maintain the required closing time. The provision for a minimum of 92 days between the tests ensures that full closure testing is not too frequent. The MSIVs are partially stroked quarterly as part of reactor protection system instrument surveillance testing.

Surveillance of the suppression chamber-reactor building vacuum breaker consists of OPERABILITY checks and leakage tests (conducted as part of the containment leak-tightness tests). These vacuum breakers are normally in the closed position and open only during tests or an accident condition. As a result, a testing frequency of three months for OPERABILITY is considered justified for this equipment. Inspections and calibrations are performed during the REFUELING OUTAGEs, this frequency being based on equipment quality, experience, and engineering judgement.

The 14 suppression chamber-drywell vacuum relief valves are designed to open to the full open position (the position that curtain area is equivalent to valve bore) with a force equivalent to a 0.5 psi differential acting on the suppression chamber face of the valve disk. This opening specification assures that the design limit of 2.0 psid between the drywell and external environment is not exceeded. Once each REFUELING OUTAGE, each valve is tested to assure that it will open fully in response to a force less than that specified. Also, it is inspected to assure that it closes freely and operates properly.

The containment design has been examined to establish the allowable bypass area between the drywell and suppression chamber as 10.5 in^2 (expressed as vacuum breaker open area). This is equivalent to one vacuum breaker disk off its seat 0.371 inch; this length corresponds to an angular displacement of 1.25°. A conservative allowance of 0.10 inch has been selected as the maximum permissible valve opening. Valve closure within this limit may be determined by light indication from two independent position detection and indication systems. Either system provides a control room alarm for a non-seated valve.

At the end of each refueling cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chamber. The drywell pressure will be increased by at least 1 psi with respect to the suppression chamber pressure. The pressure transient (if any) will be monitored with a sensitive pressure gauge. If the drywell pressure cannot be increased by 1 psi over the suppression chamber pressure it would be because a significant leakage path exists: in the event, the leakage source will be identified and eliminated before POWER OPERATION is resumed. If the drywell pressure can be increased by 1 psi over the suppression chamber, the rate of change of the suppression chamber pressure must not exceed a rate equivalent to the rate of air flow from the drywell to the suppression chamber through a 2-inch orifice. In the event the rate of change of pressure exceeds this value, then the source of leakage will be identified and eliminated before POWER OPERATION is resumed.

The drywell suppression chamber vacuum breakers are exercised every 3 months and immediately following termination of discharge of steam into the suppression chamber. This monitoring of valve operability is intended to assure that valve operability and position indication system performance does not degrade between refueling inspections. When a vacuum breaker valve is exercised through an opening-closing cycle, the position indicating lights are designed to function as follows:

Full Closed (Closed to 0.10" open)	2 Green - On 2 Red - Off
Open 0. 10 " (0.10" open to full open)	2 Green - Off 2 Red - On

During each refueling outage, four suppression chamber-drywell vacuum breakers will be inspected to assure components have not deteriorated. Since valve internals are designed for a 40-year lifetime, an inspection program which cycles through all valves in about 1/10th of the design lifetime is extremely conservative. The alarm systems for the vacuum breakers will be calibrated during each refueling outage. This frequency is based on experience and engineering judgement.

Initiating reactor building isolation and operation of the standby gas treatment system to maintain a 1/4 inch of water vacuum, tests the operation of the reactor building isolation valves, leakage tightness of the reactor building and performance of the standby gas treatment system. Checking the initiating sensors and associated trip channels demonstrates the capability for automatic actuation. Performing the reactor building in leakage test prior to refueling demonstrates secondary containment capability prior to extensive fuel handling operations associated with the outage. Verifying the efficiency and operation of charcoal filters once per 18 months gives sufficient confidence of standby gas treatment system performance capability. A charcoal filter efficiency of 99% for halogen removal is adequate.

The in-place testing of charcoal filters is performed using halogenated hydrocarbon refrigerant which is injected into the system upstream of the charcoal filters. Measurement of the refrigerant concentration upstream and downstream of the charcoal filters is made using a gas chromatograph. The ratio of the inlet and outlet concentrations gives an overall indication of the leak tightness of the system. Although this is basically a leak test, since the filters have charcoal of known efficiency and holding capacity for elemental iodine and/or methyl iodide, the test also gives an indication of the relative efficiency of the installed system. The test procedure is an adaptation of test procedures developed at the Savannah River Laboratory which were described in the Ninth AEC Cleaning Conference.*

High efficiency particulate filters are installed before and after the charcoal filters to minimize potential releases of particulates to the environment and to prevent clogging of the iodine filters. An efficiency of 99% is adequate to retain particulates that may be released to the reactor building following an accident. This will be demonstrated by testing with DOP at testing medium.

The 95% methyl iodide removal efficiency is based on the formula in GL 99-02 for allowable penetration [(100% - 90% credited in DBA analysis) divided by a safety factor of 2]. If the allowable penetration is ≤ 5%, the required removal efficiency is ≥ 95%. If laboratory tests for the adsorber material in one circuit of the Standby Gas Treatment System are unacceptable, all adsorber material in that circuit shall be replaced with adsorbent qualified according to Regulatory Guide 1.52. Any HEPA filters found defective shall be replaced with those qualified with Regulatory Position C.3.d of Regulatory Guide 1.52.

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* D.R. Muhabier. "In Place Nondestructive Leak Test for Iodine Adsorbers." Proceedings of the Ninth AEC Air Cleaning Conference. USAEC Report CONF-660904. 1966

The snubber inspection frequency is based upon the number of unacceptable snubbers found during the previous inspection, the total population or category size for each snubber type, and the previous inspection interval. A snubber is considered unacceptable if it fails to satisfy the acceptance criteria of the visual inspection. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, that decision must be made and documented before any inspection and used as the basis upon which to determine the next inspection interval for that category.

If continued operation cannot be justified with an unacceptable snubber, the snubber shall be declared inoperable and the applicable action requirements met. To determine the next surveillance interval, the snubber may be reclassified as acceptable if it can be demonstrated that the snubber is operable in its as-found condition by the performance of a functional test and if it satisfies the acceptance criteria for functional testing.

The next visual inspection interval may be twice, the same, or reduced by as much as two-thirds of the previous inspection interval. This interval depends on the number of unacceptable snubbers found in proportion to the size of the population or category for each type of snubber included in the previous inspection. Table 4.5-1 establishes the length of the next visual inspection interval.

To further increase the assurance of snubber reliability, functional tests should be performed once each refueling cycle. These tests will include stroking of the snubbers to verify proper piston movement, lock-up and bleed. Ten percent represents an adequate sample for such tests. Observed failures of these samples require testing of additional units.

After the containment oxygen concentration has been reduced to meet the specification initially, the containment atmosphere is maintained above atmospheric pressure by the primary containment inerting system. This system supplies nitrogen makeup to the containment so that the very slight leakage from the containment is replaced by nitrogen, further reducing the oxygen concentration. In addition, the oxygen concentration is continuously recorded and high oxygen concentration is annunciated. Therefore, a weekly check of oxygen concentration is adequate. This system also provides the capability for determining if there is gross leakage from the containment.

The drywell exterior was coated with Firebar D prior to concrete pouring during construction. The Firebar D separated the drywell steel plate from the concrete. After installation, the drywell liner was heated and expanded to compress the Firebar D to supply a gap between the steel drywell and the concrete. The gap prevents contact of the drywell wall with the concrete which might cause excessive local stresses during drywell expansion in a loss-of-coolant accident.

The surveillance program is being conducted to demonstrate that the Firebar D will maintain its integrity and not deteriorate throughout plant life. The surveillance frequency is adequate to detect any deterioration tendency of the material.[8]

The operability of the instrument line flow check valves are demonstrated to assure isolation capability for excess flow and to assure the operability of the instrument sensor when required. The representative sample consists of an approximately equal number of EFCV's, such that each EFCV is tested at least every 10 years (nominal). The nominal 10 year interval is based on other performance-based testing programs, such as Inservice Testing (snubbers) and Option B to 10 CFR 50, Appendix J. EFCV test failures will be evaluated to determine if additional testing in that 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. (9)

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 continually monitored and also observed during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken. The requirement for an external visual examination following any event where potentially high loadings could occur provides assurance that no significant damage was encountered. Particular attention should be focused on structural discontinuities in the vicinity of the relief valve discharge since these are expected to be the points of highest stress.

References

(1) Licensing Application, Amendment 32, Question 3
(2) FDSAR, Volume I, Section V-1.1
(3) GE-NE 770-07-1090, "Oyster Creek LOCA Drywell Pressure Response," February 1991
(4) Deleted
(5) FDSAR, Volume I, Sections V-1.5 and V-1.6
(6) FDSAR, Volume I, Sections V-1.6 and XIII-3.4
(7) FDSAR, Volume I, Section XIII-2
(8) Licensing Application, Amendment 11, Question III-18
(9) GE BWROG B21-00658-01, "Excess Flow Check Valve Testing Relaxation," dated November 1998

FIGURE 4.5.1

MAXIMUM ALLOWABLE PRESSURE DROP FOR HEPA FILTERS

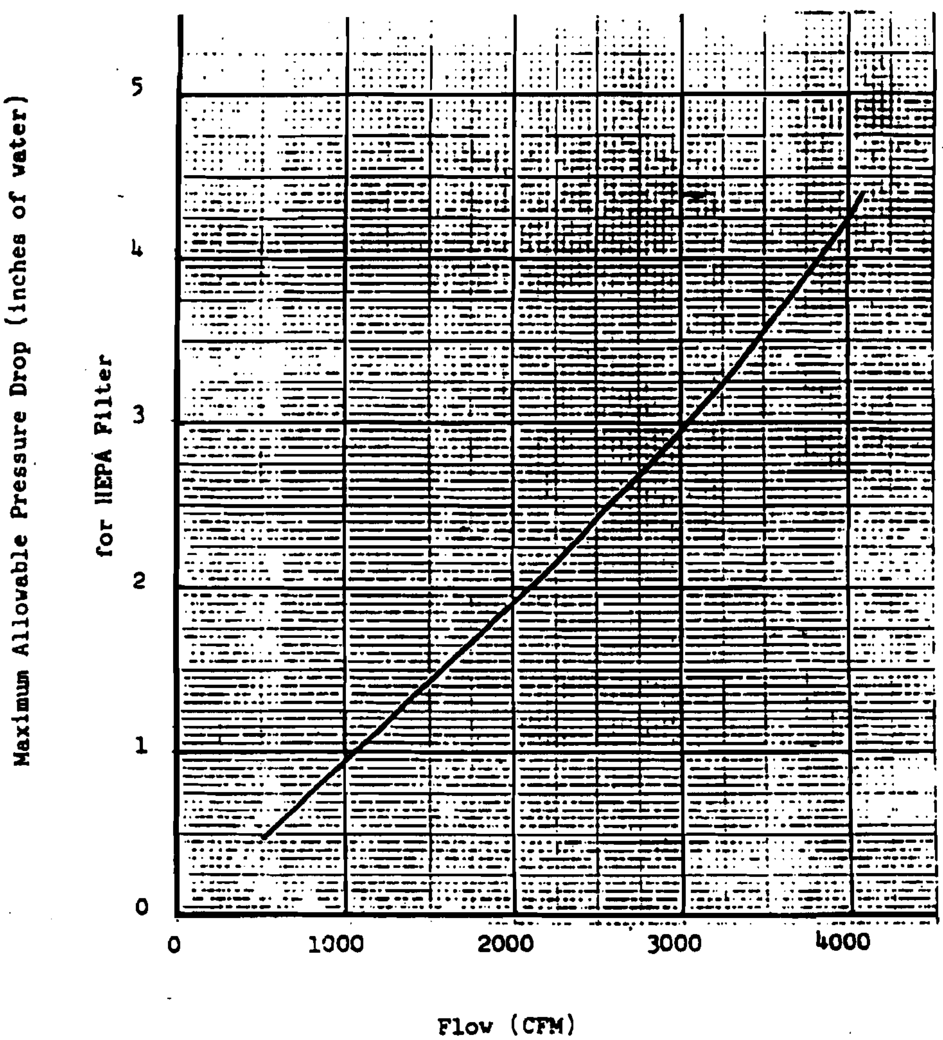

TABLE 4.5-1
SNUBBER VISUAL INSPECTION INTERVAL
Page 1 of 2

NUMBER OF UNACCEPTABLE SNUBBERS

Population or Category (Notes 1,2)	Column A Extend Interval (Notes 3,6)	Column B Repeat Interval (Notes 4,6)	Column C Reduce Interval (Notes 5,6)
1	0	0	1
80	0	0	2
100	0	1	4

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 categories may be examined separately or jointly. However, the decision on how to categorize the snubbers must be made and documented 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 permissable. 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.

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 Column B and C.

Note 6: Each inspection interval shall be subject to the limitations of Technical Specification 1.24.

4.6 RADIOACTIVE EFFLUENT

Applicability: Applies to monitoring of gaseous and liquid radioactive effluents of the Station during release of effluents via the monitored pathway(s). Each Surveillance Requirement applies whenever the corresponding Specification is applicable unless otherwise stated in an individual Surveillance Requirement. Surveillance Requirements do not have to be performed on inoperable equipment.

Objective: To measure radioactive effluents adequately to verify that radioactive effluents are as low as is reasonable achievable and within the limit of 10 CFR Part 20.

Specification:

A. Reactor Coolant

Reactor coolant shall be sampled and analyzed at least once every 72 hours for DOSE EQUIVALENT I-131 during RUN MODE, STARTUP MODE and SHUTDOWN CONDITION.

B. NOT USED.

C. Radioactive Liquid Storage

1. Liquids contained in the following tanks shall be sampled and analyzed for radioactivity at least once per 7 days when radioactive liquid is being added to the tank:

   a. Waste Surge Tank, HP-T-3;
   b. Condensate Storage Tank.

D. Main Condenser Offgas Treatment

RELOCATED TO THE ODCM.

E. Main Condenser Offgas Radioactivity

1. The gross radioactivity in fission gases discharged from the main condenser air ejector shall be measured by sampling and analyzing the gases.

   a. at least once per month, and

   b. When the reactor is operating at more than 40 percent of rated power, within 4 hours after an increase in the fission gas release via the air ejector of more than 50 percent, as indicated by the Condenser Air Ejector Offgas Radioactivity Monitor after factoring out increase(s) due to change(s) in the THERMAL POWER level.

F. Condenser Offgas Hydrogen Concentration

The concentration of hydrogen in offgases downstream of the recombiner in the Offgas System shall be monitored with hydrogen instrumentation as described in Table 3.15.2.

G. NOT USED.

H. NOT USED.

I. Radioactivity Concentration in Liquid Effluent

RELOCATED TO THE ODCM

J. Dose due to Liquid Effluent

RELOCATED TO THE ODCM

K. Dose Rate Due to Gaseous Effluent

RELOCATED TO THE ODCM

L. NOT USED.

M. Dose Due to Radioiodine and Particulates in Gaseous Effluent

RELOCATED TO THE ODCM

N. Annual Total Dose Due to Radwaste Effluent

RELOCATED TO THE ODCM.

Basis:

A. The reactor water sample will be used to assure that the limit of Specification 3.6.A is not exceeded. The total radioactive iodine activity would not be expected to change rapidly over a period of several days. In addition, the trend of the stack off-gas release rate, which is continuously monitored, is a good indicator of the trend of the iodine activity in the reactor coolant.

I. RELOCATED TO THE ODCM.

4.7 AUXILIARY ELECTRICAL POWER

Applicability: Applies to surveillance requirements of the auxiliary electrical supply.

Objective: To verify the availability of the auxiliary electrical supply.

Specification:

A. Diesel Generator

1. Each diesel generator shall be started and loaded to not less than 80% rated load every two weeks.

2. The two diesel generators shall be automatically actuated and functionally tested during each refueling outage. This shall include testing of the diesel generator load sequence timers listed in Table 3.1.1.

3. Deleted.

4. The diesel generators' fuel supply shall be checked following the above tests.

5. The diesel generators' starting batteries shall be tested and monitored per Specification 4.7.B.

B. Diesel Generator Starting Batteries

1. Weekly surveillance will be performed to verify the following:

   a. The active metallic surface of the plates shall be fully covered with electrolyte in all batteries.

   b. The designated pilot cell voltage is greater than or equal to 2.0 volts.

   c. The overall battery voltage is greater than or equal to 112 volts while the battery is on a float charge.

   d. The pilot cell specific gravity, corrected to 77°F, is greater than or equal to 1.190.

2. Quarterly surveillance will be performed to verify the specific gravity for each fourth cell is greater than or equal to 1.190 when corrected to 77°F. The specific gravity and electrolyte temperature of every fourth cell shall be recorded for surveillance review.

3. Annual surveillance will be performed to verify the specific gravity for each cell is greater than or equal to 1.190 when corrected to 77°F. The electrolyte temperature and specific gravity for every cell shall be recorded for surveillance review.

4. At least once per 12 months, the diesel generator battery capacity shall be demonstrated to be able to supply the design duty loads (diesel start) during a battery service test.

5. At least once per 24 months, the following tests will be performed (perform during plant shutdowns or during 24-month Diesel Generator inspections):

   a. Battery capacity shall be demonstrated to be at least 80% of the manufacturers' rating when subjected to a battery capacity discharge test.

   b. If a Diesel Generator Starting Battery is demonstrated to have less than 85% of manufacturers ratings during a capacity discharge test, it shall be replaced within 2 years.

C. Station Batteries

1. Weekly surveillance will be performed to verify the following:

   a. The overall battery voltage is greater than or equal to the minimum established float voltage.

   b. Each station battery float current is ≤ 2 amps when battery terminal voltage is greater than or equal to the minimum established float voltage of 4.7.C.1.a.

2. Monthly Surveillance will be performed to verify the following:

   a. The electrolyte level in each station battery is greater than or equal to minimum established design limits.

   b. The voltage of each pilot cell is greater than or equal to 2.07 volts while the respective battery is on a float charge.

   c. The electrolyte temperature of each station battery pilot cell is greater than or equal to minimum established design limits.

3. Quarterly surveillance will be performed to verify the voltage of each connected cell is greater than or equal to 2.07 volts while the respective battery is on a float charge.

4. At least once per 24 months:

   a. The station battery capacity shall be demonstrated to be able to supply the design duty cycle loads during a battery service test. The modified performance discharge test may be substituted for the service test.

   b. (i) Verify required station battery charger supplies ≥ 429 amps for the B MG Set charger, ≥ 600 amps for the A/B static charger, and ≥ 500 amps for the C charger, for ≥ 4 hours at greater than or equal to the minimum established float voltage, or

      (ii) Verify each required battery charger can recharge the battery to the fully charged state while supplying the normal steady state DC loads during station operation, after a battery discharge to the bounding design basis event discharge state.

5. The following tests will be performed to verify battery capacity (perform during plant shutdowns for Station Batteries B and C):

   a. At least once per 60 months, battery capacity shall be demonstrated to be at least 80% of the manufacturers' rating when subjected to a performance discharge test or a modified performance discharge test.

   b. Performance discharge tests or modified performance discharge tests of station battery capacity shall be given at least once per 12 months when:

      (i) The station battery shows degradation, or

      (ii) The station battery has reached 85% of expected life with battery capacity < 100% of manufacturer's rating.

   c. Performance discharge tests or modified performance discharge tests of station battery capacity shall be given at least once per 24 months when the battery has reached 85% of expected life with battery capacity ≥ 100% of manufacturer's rating.

Basis: The biweekly tests of the diesel generators are primarily to check for failures and deterioration in the system since last use. The manufacturer has recommended the two week test interval, based on experience with many of their engines. One factor in determining this test interval (besides checking whether or not the engine starts and runs) is that the lubricating oil should be circulated through the engine approximately every two weeks. The diesels should be loaded to at least 80% of rated load until engine and generator temperatures have stabilized (about one hour). The minimum 80% load will prevent soot formation in the cylinders and injection nozzles. Operation up to an equilibrium temperature ensures that there is no over-heat problem. The tests also provide an engine and generator operating history to be compared with subsequent engine-generator test data to identify and correct any mechanical or electrical deficiency before it can result in a system failure.

The test during refueling outages is more comprehensive, including procedures that are most effectively conducted at that time. These include automatic actuation and functional capability tests, to verify that the generators can start and assume load in less than 20 seconds and testing of the diesel generator load sequence timers which provide protection from a possible diesel generator overload during LOCA conditions.

The diesel generator batteries are challenged every two weeks to perform the 80% load test. This effectively performs an uninstrumented battery service test. The biweekly diesel start, when combined with the annual battery service test, provides an extensive amount of data on battery performance characteristics. This test data negates the need to lower the battery performance test interval from biennial to annually.

The diesel batteries shall be tested and monitored in accordance with the requirements of Specification 4.7.B to ensure their viability. The requirement to replace any battery in the next refueling outage or within 2 years which demonstrates less than 85% of manufacturers capacity during a capacity discharge test provides additional assurance of continued battery operability.

Verifying, per 4.7.C.1.a, 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 (2.17 V per cell average, or 130.2 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 40 years for B station battery; 20 years for C station battery). The weekly frequency is consistent with manufacturer recommendations and IEEE Standard 450-1995.

Verifying battery float current while on float charge (4.7.C.1.b) 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 Standard 450-1995. The weekly frequency is consistent with IEEE Standard 450-1995.

This Surveillance Requirement (4.7.C.1.b) provides that the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.7.C.1.a. When this float voltage is not maintained the Actions of 3.7.D.1 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.

The 4.7.C.2.a minimum established design limit for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. For the station batteries, this is the minimum level mark on the side of the battery cell. The Frequency is consistent with IEEE-450-1995.

Surveillance Requirements 4.7.C.2.b and 4.7.C.3 require verification that the cell float voltages are equal to or greater than 2.07 V. The frequencies for cell voltage verification (monthly for pilot cell, and quarterly for each connected cell) are consistent with IEEE Standard 450-1995.

Surveillance Requirement 4.7.C.2.c verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit for station battery B; 50 degrees Fahrenheit for station battery C). Cell electrolyte temperature is maintained above these temperatures 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. The Frequency is consistent with IEEE Standard 450-1995.

A battery service test, per 4.7.C.4.a, is a special test of the station battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC auxiliary electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements.

Surveillance Requirement 4.7.C.4.b verifies the design capacity of the station battery chargers. The battery charger supply is based on normal steady state DC loads during station operation and the charging capacity to restore the battery from the design minimum charge state to the fully charged state. The minimum required amperes and duration ensures that these requirements can be satisfied. The battery is recharged when the measured charging current is $\leq$ 2 amps.

Surveillance Requirement 4.7.C.4.b(i) requires that each required station battery charger (i.e., only one charger per station battery "required" for compliance with 3.7.A.4) 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 normal minimum established float voltage. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours. Alternately, 4.7.C.4.b(ii) allows that the battery charger load test be capable of recharging the battery after a service test coincident with normal steady state DC loads during station operation. This level of loading may not normally be available following the battery service test and may need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, an the exponential decay in charging current.

A battery performance discharge test (4.7.C.5) 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 4.7.C.5.b(i)) 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 4.7.C.5; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.7.C.4.a.

4.8 ISOLATION CONDENSER

Applicability: Applies to periodic testing requirements for the isolation condenser system.

Objective: To verify the operability of the isolation condenser system.

Specification: A. Surveillance of each isolation condenser loop shall be as follows:

Item	Frequency
1. Operability of motor-operated isolation valves and condensate makeup valves.	Once/3 months
2. Automatic actuation and functional test.	Each refueling outage (interval not to exceed 20 months) or following major repair.
3. Shell side water volume check	Once/day
4. Isolation valve (steam side)	
a. Visual inspection	Each refueling outage
b. External leakage check	Each primary system Leak test
c. Area temperature check	Once/shift

Basis: Motor-operated valves on the isolation condenser steam and condensate lines and on the condensate makeup line that are normally on standby should be exercised periodically to make sure that they are free to operate. The valves will be stroked full length every time they are tested to verify proper functional performance. This frequency of testing is consistent with instrumentation tests discussed in Specification 4.1. Testing of these components per the ASME Code once every 3 months provides assurance of availability of the system. Also, at this frequency of testing, wearout should not be a problem throughout the life of the plant.

The automatic actuation and functional test will demonstrate the automatic opening of the condensate return line valves and the automatic closing of the isolation valves on the vent lines to the main steam lines. Automatic closure of the isolation condenser steam and condensate lines on actuation of the condenser pipe break detectors will also be verified by the test. It is during a major maintenance or repair that a system's design intent may be violated accidentally. This makes the functional test necessary after every major repair operation.

By virtue of normal plant operation the operators daily observe the water level in the isolation condensers. In addition, isolation condenser shell side water level sensors provide control room annunciation of condenser high or low water level.

Each refueling outage the insulation will be removed from the steam side isolation valve and the external valve bodies will be inspected for signs of deterioration. Additionally, special attention is specified for these valves during primary system leakage tests and the temperature in the area of these valves is checked once each shift for temperature increases that would indicate valve leakage. The special attention given these valves in the design and during their construction[1] along with the indicated surveillance is judged to be adequate to assure that these valves will maintain their integrity when they are required for isolation of the primary containment.

<u>Reference</u>

(1) Licensing Application, Amendment 32, Question 5

4.9 REFUELING

Applicability: Applies to the periodic testing of those interlocks and instruments used during refueling.

Objective: To verify the operability of instrumentation and interlocks in use during refueling.

Specification:

A. The refueling interlocks shall be tested prior to any fuel handling with the head off the reactor vessel, at weekly intervals thereafter until no longer required and following any repair work associated with the interlocks.

B. Prior to beginning any core alterations, the source range monitors (SRMs) shall be calibrated. Thereafter, the SRM's will be checked daily, tested monthly and calibrated every 3 months until no longer required.

C. Within four (4) hours prior to the start of control rod removal pursuant to Specification 3.9.E verify:

1. That the reactor mode switch is locked in the refuel position and that the one rod out refueling interlock is operable.

2. That two (2) SRM channels, one in the core quadrant where the control rod is being removed and one in an adjacent quadrant, are operable and inserted to the normal operation level.

D. Verify within four (4) hours prior to the start of control rod removal pursuant to Specification 3.9.F and at least once per 24 hours thereafter, until replacement of all control rods or rod drive mechanisms and all control rods are fully inserted that:

1. the reactor mode switch is locked in the refuel position and the one rod out refueling interlock is operable.

2. Two (2) SRM channels, one in the core quadrant where a control rod is being removed and one in an adjacent quadrant, are operable and fully inserted.

3. All control rods not removed are fully inserted with the exception of one rod which may be partially withdrawn not more than two notches to perform refueling interlock surveillance.

4. The four fuel assemblies surrounding each control rod or rod drive mechanism being removed or maintained at the same time are removed from the core cell.

E. Verify prior to the start of removal of control rods pursuant to Specification 3.9.F that Specification 3.9.F.5 will be met.

F. Following replacement of a control rod or rod drive mechanism removed in accordance with Specification 3.9.F, prior to inserting fuel in the control cell, verify that the bypassed refueling interlocks associated with that rod have been restored and that the control rod is fully inserted.

<u>Basis:</u> The refueling interlocks[1] are required only when fuel is being handled and the head is off the reactor vessel. A test of these interlocks prior to the time when they are needed is sufficient to ensure that the interlocks are operable. The testing frequency for the refueling interlocks is based upon engineering judgment and the fact that the refueling interlocks are a backup for refueling procedures.

The SRM's[2] provide neutron monitoring capability during core alterations. A calibration using external testing equipment to calibrate the signal conditioning equipment prior to use is sufficient to ensure operability. The frequencies of testing, using internally generated test signals, and recalibration, if the SRM's are required for an extended period of time, are in agreement with other instruments of this type which are presented in Specification 4.1.

The surveillance requirements for control rod removal assure that the requirements of Specification 3.9 are met prior to initiating control rod removal and at appropriate intervals thereafter.

<u>References:</u> (1) FDSAR, Volume I, Section VII-7-2.5
(2) FDSAR, Volume I, Sections VII-4.2.2 and VII-4-5.1

4.10 ECCS RELATED CORE LIMITS

Applicability: Applies to the periodic measurement during power operation of core parameters related to ECCS performance.

Objective: To assure that the limits of Section 3.10 are not being violated.

Specification:

A. Average Planar LHGR.

The APLHGR for each type of fuel as a function of average planar exposure shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.

B. Local LHGR.

The LHGR as a function of core height shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.

C. Minimum Critical Power Ratio (MCPR).

1. MCPR shall be checked daily during reactor operation at greater than or equal to 25% rated thermal power.
2. The MCPR operating limit shall be determined within 72 hours of completing scram time testing as required in Specification 4.2.C.

Bases:

The term "daily" in Technical Specification 4.10 shall be conservatively interpreted as once per 24 hours (with normal grace allowance). This applies to Technical Specification 4.10 surveillance requirements only.

The LHGR shall be checked daily to determine whether fuel burnup or control rod movement has caused changes in power distribution. Since changes due to burnup are slow, and only a few control rods are moved daily, a daily check of power distribution is adequate.

The minimum critical power ratio (MCPR) is unlikely to change significantly during steady state power operation so that 24 hours is an acceptable frequency for surveillance. In the event of a single pump trip, 24 hours surveillance interval remains acceptable because the accompanying power reduction is much larger than the change in MAPLHGR limits for four loop operation at the corresponding lower steady state power level as compared to five loop operation. The 24 hours frequency is also acceptable for the APRM status check since neutron monitoring system failures are infrequent and a downscale failure of an APRM initiates a control rod withdrawal block, thus precluding the possibility of a control rod withdrawal error.

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. Surveillance 4.10.C.2 determines the actual scram speed distribution which is compared to the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with scram times of Specification 3.2.B.3 or actual scram times. The MCPR operating limit must be determined once within 72 hours after each set of scram time tests required by Surveillance 4.2.C because the effective scram speed distribution may change during the cycle. The 72 hour completion time is acceptable due to the relatively minor changes in scram speed expected during the operating cycle.

At core power levels less than or equal to 25% rated thermal power the reactor will be operating at or above the minimum recirculation pump speed. For all designated control rod patterns which may be employed at this point, operating plant experience and thermal hydraulic analysis indicate that the resulting APLHGR, LHGR and MCPR values all have considerable margin to the limits of Specification 3.10. Consequently, monitoring of these quantities below 25% of the rated thermal power is not required.

4.11 Sealed Source Contamination

Applicability: Applies to each licensed sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting materials or 5 microcuries of alpha emitting material.

Objective: To detect and prevent contamination from sealed source leakage.

Specification:

A. Radioactive sources shall be tested for contamination. The test shall be capable of detecting the presence of 0.005 microcuries of radioactive material on the test sample. If the test reveals the presence of 0.005 microcuries or more of removable contamination, it shall immediately be withdrawn from use, decontaminated, and repaired, or be disposed of in accordance with Commission regulations.

B. Tests for contamination shall be performed by the licensee or by other persons specifically authorized by the Commission or an agreement state as follows:

1. Each sealed source, except startup sources previously subjected to core flux, containing radioactive material, other than Hydrogen 3, with a half life greater than thirty days and in any form other than gas shall be tested for contamination at intervals not to exceed six months.

2. The periodic leak test required does not apply to sealed sources that are stored and not being used. The sources excepted from this test shall be tested prior to any use or transfer to another user unless they have been tested within six months prior to the date of use or transfer. In the absence of a certificate from a transferor indicating that a test has been made within six months prior to the transfer, sealed sources shall not be put into use until tested.

3. Startup sources shall be tested prior to and following any repair or modification and within 31 days before being subjected to core flux.

Bases:

Ingestion or inhalation of source material may give rise to total body or organ irradiation. This specification assures that leakage from radioactive material sources does not exceed allowable limits.

4.12 Alternate Shutdown Monitoring Instrumentation

<u>Applicability:</u> Applies to the surveillance requirements of the alternate shutdown monitoring instrumentation.

<u>Objective:</u> To specify the minimum frequency and type of surveillance to be applied to the alternate shutdown monitoring instrumentation.

<u>Specification:</u>

Each of the alternate shutdown monitoring channels shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.12-1.

<u>Basis:</u>

The operability of the alternate shutdown monitoring instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of hot shutdown of the plant from locations outside of the control room. The type and frequency of surveillances required in Table 4.12-1 are consistent with or more conservative than the BWR Standard Technical Specifications.

TABLE 4.12-1 ALTERNATE SHUTDOWN MONITORING INSTRUMENTATION

Functional Limit	CHANNEL CHECK	CHANNEL CALIBRATION
Reactor Pressure	M	Q
Reactor Water Level (fuel zone)	n/a	Q
Condensate Storage Tank Level	M	R
Service Water Pump Discharge Pressure	M	R
Control Rod Drive System Flowmeter	M	R
Shutdown Cooling System Flowmeter	n/a	R
Isolation Condenser "B" Shell Water Level	M	R
Reactor Building Closed Cooling Water Pump Discharge Pressure	M	R

M - Monthly

Q - Quarterly

R - Refueling Outage

4.13 ACCIDENT MONITORING INSTRUMENTATION

Applicability: Applies to surveillance requirements for the accident monitoring instrumentation.

Objective: To verify the operability of the accident monitoring instrumentation.

Specification:

A. Safety & Relief Valve Position Indicators

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.13-1.

B. Wide Range Drywell Pressure Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.13-1.

C. Wide Range Torus Water Level Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.13-1.

D. DELETED

E. Containment High-Range Radiation Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.13-1.

F. High Range Radioactive Noble Gas Effluent Monitor

Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.13-1.

Bases:

The operability of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with NUREGs 0578 and 0737.

TABLE 4.13-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Primary and Safety Valve Position Indicator (Primary Detector*)	A	B
Relief and Safety Valve Position Indicator (Backup Indications**)	A	B
Relief Valve Position Indicator (Common Header Temperature Element**)	C	B
2. Wide Range Drywell Pressure Monitor (PT/PR 53 & 54)	A	D
3. Wide Range Torus Water Level Monitor (LT/LR 37 & 38)	A	D
4. DELETED		
5. Containment High Range Radiation Monitor	A	F***
6. High Range Radioactive Noble Gas Effluent Monitor		
a. Main Stack	A	G
b. Turbine Building Vent	A	G

Legend:
A = at least once per 31 days
B = at least once per 24 months
C = at least once per 15 days until channel calibration is performed and thence at least once per 31 days
D = at least once per 6 months
E = DELETED
F = each refueling outage
G = once per 20 months

* Acoustic Monitor
** Thermocouple
*** CHANNEL CALIBRATION shall consist of electronic signal substitution of the channel, not including the detector, for all decades above 10R/hr and a one point calibration check of the detector at or below 10R/hr by means of a calibrated portable radiation source traceable to NBS.

4.14 Solid Radioactive Waste - DELETED

4.15 Explosive Gas Monitoring Instrumentation

Applicability: States surveillance requirements for OPERABILITY of explosive gas monitoring instrumentation.

Objective: To demonstrate the OPERABILITY of explosive gas monitoring instrumentation.

Specification:

Gaseous Effluent Instrumentation

Each explosive gas effluent monitoring instrument channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST at the frequencies shown in Table 4.15.2.

TABLE 4.15.2

EXPLOSIVE GAS MONITORING
INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION(f)	CHANNEL FUNCTIONAL TEST	CHANNEL SURVEILLANCE REQUIRED (a)
1. Main Condenser Offgas Treatment System Hydrogen Monitor	D	N/A	Q(g)	M	(c)

Legend: D = once per 24 hrs; M = once per 31 days; Q = once per 92 days;
N/A = Not Applicable.

TABLE 4.15.2 NOTATIONS

(a) Instrumentation shall be OPERABLE and in service except that a channel may be taken out of services for the purpose of a check, calibration, test or maintenance without declaring it to be inoperable.

(c) During main condenser offgas treatment system operation.

(f) The CHANNEL CALIBRATION shall be performed according to established station calibration procedures.

(g) A CHANNEL CALIBRATION shall include the use of at least two standard gas samples, each containing a known volume percent hydrogen in the range of the instrument, balance nitrogen.

4.16 Radiological Environmental Surveillance

RELOCATED TO THE ODCM

4.17 Control Room Heating, Ventilating, and Air-Conditioning System

Applicability: Applies to surveillance requirements for the control room heating, ventilating, and air conditioning (HVAC) systems.

Objective: To verify the capability of each control room HVAC system to minimize the amount of radioactivity from entering the control room in the event of an accident.

Specification: Surveillance of each control room HVAC system shall be as follows:

A. At least once monthly: by initiating, from the control room, the partial recirculation mode of operation, and by verifying that the system components are aligned such that the system is operating in this mode.

B. At least once every refueling outage: by verifying that in the partial recirculation mode of operation, the control room and lower cable spreading room are maintained at a positive pressure of $\geq$ 1/8 in. WG relative to the outside atmosphere.

Basis: Periodic surveillance of each control room HVAC system is required to ensure the operability of the system. The operability of the system in conjunction with control room design provisions is based upon limiting the radiation exposure to personnel occupying the control room to less than a 30-day integrated dose of 5 rem TEDE for the most limiting design basis accident.

SECTION 5

DESIGN FEATURES

5.1 SITE

A. The reactor (center line) is located 1,358 feet west of the east boundary of New Jersey State Highway Route 9 which is the minimum exclusion distance as defined in 10 CFR 100.3. The licensee will at all times retain the complete authority to determine and maintain sufficient control of all activities through ownership, easement, contract and/or other legal instruments on property which is closer to the reactor (center line) than 1,358 feet. This includes the authority to exclude or remove personnel and property within the minimum exclusion distance.

B. The reactor building, standby gas treatment system and stack shall comprise a secondary containment in such fashion to enclose the primary containment in order to provide for controlled elevated release of the reactor building atmosphere under accident conditions.

Bases:

Exclusion area means that area surrounding the reactor, in which the reactor licensee has the authority to determine all activities including exclusion or removal of personnel and property from the area. This area may be traversed by a highway, railroad, or waterway, provided these are not so close to the facility as to interfere with normal operations of the facility and provided appropriate and effective arrangements are made to control traffic on the highway, railroad, or waterway, in case of emergency, to protect the public health and safety. Residence within the exclusion area shall normally be prohibited. In any event, residents shall be subject to ready removal in case of necessity. Activities unrelated to operation of the reactor may be permitted in an exclusion area under appropriate limitations, provided that no significant hazards to the public health and safety will result.

Activities unrelated to plant operation within the exclusion area are acceptable provided:

(a) Such activities, including accidents associated with such activities, represent no hazard to the plant or have been shown to be accommodated as part of the plant design basis

(b) The licensee is aware of such activities and has made appropriate arrangements to evacuate persons engaged in such activities, in the event of an accident, and

(c) There is reasonable assurance that persons engaged in such activities can be evacuated without receiving radiation doses in excess of the guideline values given in 10 CFR Part 100.

Contract provisions for property agreements in the exclusion area must ensure that the licensee retains sufficient control of all activities in the exclusion area including the authority to exclude or remove personnel and property, thereby (1) maintaining compliance with 10 CFR Part 100 radiological limits for the exclusion area, including evacuation when necessary, and (2) ensuring that any activities, now or in the future, in the exclusion area would not negatively affect nuclear safety, safe plant operations or violate current plant design or licensing bases.

Any property transactions in the "exclusion area", as is the case for any activity which has the potential to adversely affect nuclear safety or safe plant operations, requires a specific safety evaluation and 50.59 review.

References:

(1) 10 CFR Part 100, "Reactor Site Criteria".
(2) NRC Standard Review Plan, NUREG-0800 (Formerly NUREG-75/087), Chapter 2.1.2, "Exclusion Area Authority and Control", Rev. 2, July 1981.

5.2 CONTAINMENT

A. The primary containment shall be of the pressure suppression type having a drywell and an absorption chamber constructed of steel. The drywell shall have a volume of approximately 180,000 ft^3 and conforms to the ASME Boiler and Pressure Vessel Code, Section VIII, for an internal pressure of 44 psig at 292°F and an external pressure of 2 psig at 150°F to 205°F. The absorption chamber shall have a total volume of approximately 210,000 ft^3. It is designed to conform to ASME Boiler and Pressure Vessel Code, Section VIII, for an internal pressure of 35 psig at 150°F and an external pressure of 1 psig at 150°F.

B. Penetrations added to the primary containment shall be designed in accordance with standards set forth in Section V-1.5 of the Facility Description and Safety Analysis Report. Piping passing through such penetrations shall have isolation valves in accordance with standards set forth in Section V-1.6 of the Facility Description and Safety Analysis Report.

BASIS

The drywell pressure of 44 psig is based upon a conservatively calculated peak drywell pressure of 38.1 psig plus an added 15% allowance. The calculated peak pressure results from a design basis loss of coolant accident (DBLOCA). The corresponding coincident drywell temperature of 292° F is the saturated steam temperature of the containment atmosphere for the 44 psig pressure. The specified coincident pressure and temperature condition represent the bounding case for the structural pressure/temperature design of the drywell.

5.3 AUXILIARY EQUIPMENT

5.3.1 Fuel Storage

A. The fuel storage facilities are designed and shall be maintained with a K-effective equivalent to less than or equal to 0.95 including all calculational uncertainties.

B. Deleted

C. Deleted

D. The temperature of the water in the spent fuel storage pool, measured at or near the surface, shall not exceed 125°F.

E. The maximum amount of spent fuel assemblies stored in the spent fuel storage pool shall be 3035.

BASIS

The specification of a K-effective less than or equal to 0.95 in fuel storage facilities assures an ample margin from criticality. This limit applies to unirradiated fuel in both the dry storage vault and the spent fuel racks as well as irradiated fuel in the spent fuel racks. Criticality analyses were performed on the poison racks to ensure that a K-effective of 0.95 would not be exceeded. The analyses took credit for burnable poisons in the fuel and included manufacturing tolerances and uncertainties as described in Section 9.1 of the FSAR. Calculational uncertainties described in 5.3.1.A are explicitly defined in FSAR Section 9.1.2.3.9. Any fuel stored in the fuel storage facilities shall be bounded by the analyses in these reference documents.

The effects of a dropped fuel bundle onto stored fuel in the spent fuel storage facility have been analyzed. This analysis shows that the fuel bundle drop would not cause doses resulting from ruptured fuel pins that exceed 10 CFR 100 limits (1,2,3).

Detailed structural analysis of the spent fuel pool was performed using loads resulting from the dead weight of the structural elements, the building loads, hydrostatic loads from the pool water, the weight of fuel and racks stored in the pool, seismic loads, and loads due to thermal gradients in the pool floor and the walls. Thermal gradients result in two loading conditions: normal operating and the accident conditions with the loss of spent fuel pool cooling. For the normal condition, the reactor building air temperature was assumed to vary between 65°F and 110°F while the pool water temperature varied between 85°F and 125°F. The most severe loading from the normal operating thermal gradient results with reactor building air temperatures at 65°F and the water temperature at 125°F. Air temperature measurements made during all phases of plant operation in the shutdown heat exchanger room, which is directly beneath part of the spent fuel pool floor slab, show that 65°F is the appropriate minimum air temperature. The spent fuel pool water temperature will alarm control room before the water temperature reaches 120°F.

Results of the structural analysis show that the pool structure is structurally adequate for the loadings associated with normal operation and postulated accidents (5) (6). The floor framing was also found to be capable of withstanding the steady state thermal gradient conditions with the pool water temperature at 150°F without exceeding ACI Code requirements. The walls are also capable of operation at a steady state condition with the pool water temperature at 140°F (5).

Since the cooled fuel pool water returns at the bottom of the pool and the heated water is removed from the surface, the average of the surface temperature and the fuel pool cooling return water is an appropriate estimate of the average bulk temperature; alternately the pool surface temperature could be conservatively used.

References

1. Amendment No. 78 to FDSAR (Section 7)
2. Supplement No. 1 to Amendment No. 78 to the FDSAR (Question 12)
3. Supplement No. 1 to Amendment 78 of the FDSAR (Question 40)
4. Deleted
5. Revision No. 1 to Addendum 2 to Supplement No. 1 to Amendment No. 78 of FDSAR (Questions 5 and 10)
6. FDSAR Amendment No. 79
7. Deleted
8. Holtec Report HI-981983, Revision 4

ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Vice President - Oyster Creek shall be responsible for overall facility operation. Those responsibilities delegated to the Vice President as stated in the Oyster Creek Technical Specifications may also be fulfilled by the Plant Manager. The Vice President shall delegate in writing the succession to this responsibility during his and/or the Plant Manager absence.

6.2 ORGANIZATION

6.2.1 Corporate

6.2.1.1 An onsite and offsite organization shall be established for unit operation and corporate management. The onsite and offsite organization shall include the positions for activities affecting the safety of the nuclear power plant.

6.2.1.2 Lines of authority, responsibility and communication shall be established and defined from the highest management levels through intermediate levels to and including operating organization positions. These relationships shall be documented and updated as appropriate, in the form of organizational charts. These organizational charts will be documented in the Updated FSAR and updated in accordance with 10 CFR 50.71e.

6.2.1.3 The Chief Nuclear Officer shall have corporate responsibility for overall plant nuclear safety and shall take measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support in the plant so that continued nuclear safety is assured.

6.2.2 FACILITY STAFF

6.2.2.1 The Vice President - Oyster Creek 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.

6.2.2.2 The facility organization shall meet the following:

a. Each on duty shift shall include at least the following shift staffing:

- One (1) Shift Manager (see h. below)
- Two (2) licensed Nuclear Plant Operators
- Three (3) licensed or non-licensed Nuclear Plant Operators
- One (1) Shift Technical Adviser (see h. below)

Except for the Shift Manager, shift crew composition may be one less than the minimum requirements, for a period of time not to exceed two hours, in order to accommodate unexpected absence of on-duty shift crew members. Immediate action must be taken to restore the shift crew composition to within requirements given above. This provision does not permit any shift crew position to be unmanned upon shift change due to an incoming shift crew member being late or absent.

b. At all times when there is fuel in the vessel, at least one licensed senior reactor operator shall be on site and one licensed reactor operator should be at the controls.

c. At all times when there is fuel in the vessel, except when the reactor is in COLD SHUTDOWN or REFUEL modes, two licensed senior reactor operators and two licensed reactor operators shall be on site, with at least one licensed senior reactor operator in the control room and one licensed reactor operator at the controls.

d. At least two licensed reactor operators shall be in the control room during all reactor startups, shutdowns, and other periods involving planned control rod manipulations.

e. All CORE ALTERATIONS shall be directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

f. An individual qualified in radiation protection measures shall be on site when fuel is in the reactor.

g. (deleted)

h. Each on duty shift shall include a Shift Technical Advisor except that the Shift Technical Advisors position need not be filled if the reactor is in the refuel or shutdown mode and the reactor is less than 212 F. The Shift Technical Advisor position may be filled by an on-shift Senior Reactor Operator (dual-role SRO/STA) provided the individual meets the requirements of 6.3.3.

i. (deleted)

j. The Senior Manager - Operations or an Operations Manager, and the Shift Manager require Senior Reactor Operators licenses. The licensed Nuclear Plant Operators require a Reactor Operators license.

6.2.2.3 Individuals who train the operating staff and those who carry out the health physics and quality assurance function shall have sufficient organizational freedom to be independent of operational pressures, however, they may report to the appropriate manager on site.

6.3 Facility Staff Qualifications

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1 of 1978 for comparable positions unless otherwise noted in the Technical Specifications, with the following exceptions: 1) the education and experience eligibility requirements for operator license applicants (described in Exelon letter RS-07-078, dated July 19, 2007), and changes thereto, shall be approved by the NRC and described in an applicable station training procedure, and 2) technicians and maintenance personnel who do not meet ANSI/ANS 3.1 of 1978, Section 4.5, are permitted to perform work for which qualification has been demonstrated.

6.3.2 The management position responsible for radiological controls shall meet or exceed the qualifications of Regulatory Guide 1.8 (Rev. 1-R, 9/75). Each other member of the radiation protection organization for which there is a comparable position described in ANSI N18.1-1971 shall meet or exceed the minimum qualifications specified therein, or in the case of radiation protection technicians, they shall have at least one year's continuous experience in applied radiation protection work in a nuclear facility dealing with radiological problems similar to those encountered in nuclear power stations and shall have been certified by the management position responsible for radiological controls as qualified to perform assigned functions. This certification must be based on an NRC approved, documented program consisting of classroom training with appropriate examinations and documented positive findings by responsible supervision that the individual has demonstrated his ability to perform each specified procedure and assigned function with an understanding of its basis and purpose.

6.3.3 The Shift Technical Advisors shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design, response and analysis of the plant for transients and accidents.

6.4 DELETED

6.5 DELETED

(Pages 6-4 through 6-8 deleted)

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 reported to the cognizant manager and the cognizant department director and the Vice President – Oyster Creek. The functionally cognizant department staff shall prepare a Licensee Event Report (LER) in accordance with the guidance outlined in 10 CFR 50.73(b). Copies of all such reports shall be submitted to the functionally cognizant department director and the Vice President - Oyster Creek.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. If any Safety Limit is exceeded, the reactor shall be shut down immediately until the Commission authorizes the resumption of operation.

b. The Safety Limit violation shall be reported to the Commission and the Vice President-Oyster Creek.

c. A Safety Limit Violation Report shall be prepared. The report shall be submitted to the Vice President-Oyster Creek. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components systems or structures, (3) corrective action taken to prevent recurrence.

d. The Safety Limit Violation Report shall be submitted to the Commission within ten days of the violation.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the items referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33 as referenced in the QATR.

b. Surveillance and test activities of equipment that affects nuclear safety and radioactive waste management equipment.

c. Refueling Operations.

d. Security Plan Implementation.

e. Fire Protection Program Implementation.

f. Emergency Plan Implementation.

g. Process Control Plan Implementation.

h. Offsite Dose Calculation Manual Implementation.

i. Quality Assurance Program for effluent and environmental monitoring using the guidance in Regulatory Guide 4.15, Revision 1.

j. Plant Staff Overtime pursuant to Technical Specification 6.2.2.2(i), above.

6.8.2 Each procedure required by 6.8.1 above, and substantive changes thereto, shall be reviewed and approved prior to implementation and shall be reviewed periodically as set forth in administrative procedures.

6.8.3 Temporary changes to procedures of 6.8.1, above, may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the licensee's management staff knowledgeable in the area affected by the procedure. For changes which may affect the operational status of unit systems or equipment, at least one of these individuals shall be a member of unit management or supervision holding a Senior Reactor Operator's License on the unit.

c. The change is documented, reviewed and approved within 14 days of implementation.

6.8.4 The following programs shall be established, implemented and maintained:

a. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluent and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluent 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 the surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2. Limitations on the concentrations of radioactive material released in liquid effluent to the UNRESTRICTED AREA conforming to less than the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001-20.2402.

3. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluent in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM.

4. Limitations on the annual and quarterly doses and dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluent released to the UNRESTRICTED AREA conforming to Appendix I of 10 CFR 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 the 31 day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR 50,

7. Limitations on the dose rate resulting from radioactive materials released in gaseous effluents from the site to the UNRESTRICTED AREA shall be limited to the following:

   a. For noble gases: Less than or equal to a dose rate of 500 mRems/yr to the total body and less than or equal to a dose rate of 3000 mRems/yr to the skin, and

   b. For iodine-131, iodine-133, tritium, and for all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to a dose rate of 1500 mRems/yr to any organ.

8. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents to the UNRESTRICTED AREA conforming to Appendix I of 10 CFR 50,

9. Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from 1-131, 1-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluent released beyond the SITE BOUNDARY conforming to Appendix I of 10 CFR 50,

10. 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.

b. 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 an 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.

6.8.5 Station 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 station battery cells with float voltage < 2.13 volts, and

b. Actions to equalize and test station battery cells that have been discovered with electrolyte level below the top of the plates.

6.9 REPORTING REQUIREMENTS

In addition to the applicable reporting requirements of 10 CFR, the following identified reports shall be submitted to the Administrator of the NRC Region I office unless otherwise noted.

6.9.1 ROUTINE REPORTS

a. Startup Report. 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 plant. The report shall address each of the tests identified in the FSAR and shall in general 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 specified details required in license conditions based on other commitments shall be included in this report.

   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 power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

b. DELETED

c. DELETED

d. Radioactive Effluent Release Report

The 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 effluent 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.

e. Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year.

The Report shall include summaries, interpretations, and an 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.

f. CORE OPERATING LIMITS REPORT (COLR)

1. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle for the following:

   a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.10.A

   b. The K_f core flow adjustment factor for Specification 3.10.C.

   c. The MINIMUM CRITICAL POWER RATIO (MCPR) for Specification 3.10.C.

   d. The LOCAL LINEAR HEAT GENERATION RATE (LLHGR) for Specification 3.10.B.

   e. The Average Power Range Monitor (APRM) stability protection settings for Specifications 2.3.A.1 and 2.3.B.

   and shall be documented in the COLR.

2. 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. GPU Nuclear (GPUN) Topical Report (TR) 020, Methods for the Analysis of Boiling Water Reactors Lattice Physics, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

   b. GPUN TR 021, Methods for the Analysis of Boiling Water Reactors Steady State Physics, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

c. GPUN TR 033, Methods for the Generation of Core Kinetics Data for RETRAN-02, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

d. GPUN TR 040, Steady-State and Quasi-Steady-State Methods Used in the Analysis of Accidents and Transients, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

e. GPUN TR 045, BWR-2 Transient Analysis Model Using the Retran Code, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

f. NEDE-31462P and NEDE-31462, Oyster Creek Nuclear Generating Station SAFER/CORECOOL/GESTR-LOCA Loss-of-Coolant Accident Analysis, (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

g. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, (GESTAR II) (The approved revision at the time reload analyses are performed shall be identified in the COLR.)

h. DELETED

i. XN-75-55-(A); XN-75-55, Supplement 1-(A); XN-75-55, Supplement 2-(A), Revision 2, "Exxon Nuclear Company WREM-Based NJP-BWR ECCS Evaluation Model and Application to the Oyster Creek Plant," April 1977

j. XN-75-36(NP)-(A); XN-75-36(NP), Supplement 1-(A), "Spray Cooling Heat Transfer Phase Test Results, ENC- 8x8 BWR Fuel 60 and 63 Active Rods, Interim Report," October 1975

k. NEDC-33065P, Rev. 0, "Application of Stability Long-Term Solution Option II for Oyster Creek," April 2002.

3. 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.

4. 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.

Basis: 6.9.1.e - RELOCATED TO THE ODCM.

6.9.2 <u>REPORTABLE EVENTS</u>

The submittal of Licensee Event Reports shall be accomplished in accordance with the requirements set forth in 10 CFR 50.73.

6.9.3 UNIQUE REPORTING REQUIREMENTS

Special reports shall be submitted to the Director of Regulatory Operations Regional Office within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification.

a. Materials Radiation Surveillance Specimen Reports (4.3A)

b. (Deleted)

c. Results of required leak tests performed on sealed sources if the tests reveal the presence of 0.005 microcuries or more of removable contamination.

d. Deleted

e-j. Pursuant to the ODCM.

k. Records of results of analyses required by the Radiological Environmental Monitoring Program.

l. Failures and challenges to Relief and Safety Valves which do not constitute an LER will be the subject of a special report submitted to the Commission within 60 days of the occurrence. A challenge is defined as any automatic actuation (other than during surveillance or testing) of Safety or Relief Valves.

m. Plans for compliance with standby liquid control Specifications 3.2.C.3(b) and 3.2.C.3(c)(1) or plans to obtain enrichment test results per Specification 4.2.E.5.

n. Inoperable high range radioactive noble gas effluent monitor (3.13.H)

6.10 RECORD RETENTION

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principle maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. All Licensee Event Reports.

d. Records of surveillance activities, inspections and calibrations required by these technical specifications.

e. Records of reactor tests and experiments.

f. Records of changes made to operating procedures.

g. Deleted.

h. Records of sealed source leak tests and results.

i. Records of annual physical inventory of all source material of record.

6.10.2 The following records shall be retained for the duration of the Facility Operating License:

a. Record and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

c. Records of facility radiation and contamination surveys.

d. Records of doses received by all individuals for whom monitoring was required entering radiation control areas.

e. Records of gaseous and liquid radioactive material released to the environs.

f. Records of transient or operational cycles for those facility components designed for a limited number of transients or cycles.

g. Records of training and qualification for current members of the plant staff.

h. Records of inservice inspections performed pursuant to these technical specifications.

i. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

j. Deleted.

k. Records of Environmental Qualification which are covered under the provisions for paragraph 6.14.

l. Records of the service lives of all snubbers, including the date which the service life commences, and associated installation and maintenance records.

m. Records of results of analyses required by the Radiological Environmental Monitoring Program.

n. Records of reviews performed for changes made to the OFFSITE DOSE CALCULATION MANUAL and the PROCESS CONTROL PLAN.

o. Records of radioactive shipments

6.10.3 Quality Assurance Records shall be retained as specified by the QATR.

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 (Deleted)

6.13 HIGH RADIATION AREA

6.13.1 In lieu of the "control device" or "alarm signal" required by Section 20.1601 of 10 CFR 20, each high radiation area in which the intensity of radiation at 30 cm (11.8 in.) is greater than deep dose equivalent of 100 mRem/hr but less than 1,000 mRem/hr shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP).

NOTE: Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are following plant radiation protection procedures for entry into high radiation areas.

An individual or group of individuals permitted to enter such areas shall be provided with one or more of the following:

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a pre-set integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

c. A health physics qualified individual (i.e., qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for providing positive exposure control over the activities within the area and who will perform periodic radiation surveillance at the frequency in the RWP. The surveillance frequency will be established by the management position responsible for radiological controls.

6.13.2 Specification 6.13.1 shall also apply to each high radiation area in which the intensity of radiation is greater than deep dose equivalent of 1,000 mRem/hr at 30 cm (11.8 in.) but less than 500 rads in 1 hour at 1 meter (3.28 ft.) from sources of radioactivity. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of operations and/or radiation protection supervision on duty.

6.14 ENVIRONMENTAL QUALIFICATION

A. By no later than June 30, 1982 all safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of Class IE Electrical Equipment in Operating Reactors" (DOR Guidelines); or, NUREG-0588 "Interim Staff Position of Environmental Qualification of Safety-Related Electrical Equipment," December 1979. Copies of these documents are attached to Order for Modification of License DPR-16 dated October 24, 1980.

B. By no later than December 1, 1980, complete and auditible records must be available and maintained at a central location which describe the environmental qualification method used for all safety-related electrical equipment in sufficient detail to document the degree of compliance with the DOR Guidelines or NUREG-0588. Thereafter, such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.15 INTEGRITY OF SYSTEMS OUTSIDE CONTAINMENT

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

1. Provisions establishing preventative maintenance and periodic visual inspection requirements, and

2. System leak test requirements, to the extent permitted by system design and radiological conditions, for each system at a frequency of once every 24 months. The systems subject to this testing are (1) Core Spray, (2) Containment Spray, (3) Reactor Water Cleanup, (4) Isolation Condenser, and (5) Shutdown Cooling.

6.16 IODINE MONITORING

The licensee shall implement 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:

a. Training of personnel,

b. Procedures for monitoring, and

c. Provisions for maintenance of sampling and analysis equipment.

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*Areas requiring personnel access for establishing hot shutdown condition.

6.17 Deleted

6.18 PROCESS CONTROL PLAN

a. Licensee initiated changes to the PCP:

1. Shall be submitted to the NRC in the Annual Radioactive Effluent Release Report for the period in which the changes were made. This submittal shall contain:

    a. sufficiently detailed information to justify the changes without benefit of additional or supplemental information;

    b. a determination that the changes did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

    c. documentation that the changes have been reviewed and approved pursuant to Section 6.8.2.

2. Shall become effective upon review and approval by licensee management.

6.19 OFFSITE DOSE CALCULATION MANUAL

a. The ODCM shall be approved by the Commission prior to implementation.

b. Licensee initiated changes to the ODCM shall be submitted to the NRC in the Annual Radioactive Effluent Release Report for the period in which the changes were made. This submittal shall contain:

    1. sufficiently detailed information to justify the changes without benefit of additional or supplemental information;

    2. a determination that the changes did not reduce the accuracy or reliability of dose calculations or setpoint determination; and,

    3. documentation that the changes have been reviewed and approved pursuant to Section 6.8.2.

c. Change(s) shall become effective upon review and approval by licensee management.

6.20 MAJOR CHANGES TO RADIOACTIVE WASTE TREATMENT SYSTEMS

DELETED.

6.21 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:

   1. A change in the TS incorporated in the license or

   2. A change to the updated FSAR (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 Specification 6.21.b.1 or 6.21.b.2 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).

6.22 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 HVAC 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 a 30-day integrated dose of 5 rem TEDE. 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.

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.

The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

1. The Oyster Creek CRE boundary operability is not dependent on a measured unfiltered air inleakage value (Reference Oyster Creek letter to NRC dated November 17, 2005, Letter No. 2130-05-20218). No inleakage testing for determining the unfiltered air inleakage past the CRE boundary into the CRE is required at the Oyster Creek site.

d. Measurement, at designated locations, of the CRE pressure relative to areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem (train) of the Control Room Ventilation System operating at the design flow rate, at a Frequency of 24 months. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

e. 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 Section 1.24 are applicable to the frequencies for assessing CRE habitability measuring CRE pressure and assessing the CRE boundary as required by paragraphs d and c, respectively.

6.23 <u>Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)</u>

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

   i) Limiting Conditions for Operation Section 3.3, "Reactor Coolant"
   ii) Surveillance Requirements Section 4.3, "Reactor Coolant"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

   i) SIR-05-044-A, "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors"

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

APPENDIX B

TO OPERATING LICENSE NO. DPR- 16

ENVIRONMENTAL TECHNICAL SPECIFICATIONS

FOR

OYSTER CREEK NUCLEAR GENERATING STATION

DOCKET NO. 50-219

OCEAN COUNTY, NEW JERSEY

EXELON GENERATION COMPANY, LLC

NOVEMBER 1978*

*Issued to the ASLB on this date; issued by License Amendment No. 37, June 6, 1979.

Table Of Contents

INTRODUCTION

The bases, which provide technical support for the OCETS, are included for informational purposes in order to clarify the intent of the specification. These bases are not part of the OCETS nor do they constitute limitations or requirements on the licensee.

1.0 Environmental Monitoring

1.1 Non-Radiological Monitoring

1.1.1 Biotic - Aquatic

A. Fish Kill Monitoring Program

Objective

The objective of this program is to determine the species composition, abundance and distribution of station-induced fish kills due to winter shutdowns.

Specifications

After each Station shutdown, when the intake water temperature is below 8.5 degrees C (47.3 degrees F), visual inspections for fish shall be made along the shores of the discharge canal and the lower reaches of Oyster Creek within 24 hours of the initiation of the shutdown in accordance with the procedures prepared by the licensee per Section 3.4. A continuous temperature record shall be maintained through the 24-hour period after reaching cold shutdown.

Reporting Requirements

For planned shutdowns with the temperature of the intake water below 8.5 degrees C (47.3 degrees F), the NRC Region I office will be notified at least 24 hours in advance of such shutdown. This notification shall not be given for unplanned, automatic, or manual station trips.

If the shutdown results in greater than 100 fish killed and/or stressed, this event shall be reported to the NRC in accordance with Section 3.5.2.

1.0 Environmental Monitoring

Bases

The Final Environmental Statement for the Oyster Creek Nuclear Generating Station documents cold shock fish kills associated with rapid temperature decreases caused by plant shutdown during the winter.

Station shutdowns during winter months are, on occasion, unavoidable. Due to the physical configuration of the station and the discharge canal, some mortality to organisms may be experienced during winter shutdowns.

Mortality information associated with a winter shutdown will provide the empirical bases on which to judge the impact of these fishkills on Barnegat Bay, Oyster Creek, and Forked River.

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2.0 Special Monitoring And Study Activities

2.1 Unusual or Important Environmental Events

Enviromnental Monitoring Requirements

Unusual or important events are those that cause potentially significant environmental impact or that could be of public interest concerning environmental impact from station operation. The following are examples: on-site plant or animal disease outbreaks; unusual mortality of any species protected by the Endangered Species Act of 1973; fish kills in the vicinity of the site; unusually high impingement mortality episodes.

Action

Should an unusual or important event occur, the licensee shall make a non-routine prompt report to the NRC in accordance with the provisions of Subsection 3.5.2.

If an event is reportable under 10 CFR 50.72, then a duplicate immediate report is not required. However, a follow-up written report is required in accordance with Subsection 3.5.2.

2.0 Special Monitoring And Study Activities

Bases

Prompt reporting to the NRC of unusual or important events as described above is necessary for responsible and orderly regulation of the nation's system of nuclear power reactors. The information provided may be useful or necessary to others concerned with the same environmental resources. Prompt knowledge and action may serve to alleviate the magnitude of the environmental impact.

3.0 ADMINISTRATIVE CONTROL

This section describes administrative and management controls established by the Applicant to provide continuing protection to the environment and to implement the environmental technical specifications.

3.1 Responsibility

Corporate responsibility for implementation of the Oyster Creek Environmental Technical Specifications and for assuring that plant operations are controlled in such a manner as to provide continuing protection of the environment has been assigned by the Chief Nuclear Officer to the Vice President - Oyster Creek.

The responsibility for conducting the studies as set forth in Section 1.1 (Non-Radiological Monitoring) and all of Section 2.0 (Special Monitoring and Study Activities) rests with the management position responsible for environmental affairs, who reports to the Vice President - Oyster Creek.

Administrative measures are defined in Section 3.3 which provide that the individual or group responsible for auditing or otherwise verifying that an activity has been correctly performed is independent of the individual or group responsible for performing the activity.

3.2 Organization

Lines of authority, responsibility and communication shall be established and defined from the highest management levels through intermediate levels to and including operating organization positions. Organizational charts will be documented in the Updated FSAR and updated in accordance with 10 CFR 50.71e.

3.3 Review and Audit

Independent audit and review functions for environmental matters are the responsibility of the management position responsible for environmental affairs. This department is independent of line responsibility for the operation of the plant. The independent reviews and audits of the OCETS will be carried out by personnel from environmental affairs or by other Exelon Generation Company, LLC personnel, outside contractors or consultants at the request of the environmental affairs Personnel.

When individuals in the environmental affairs department of Exelon Generation Company, LLC perform any function relating to the OCETS other than independent audit and review, the Vice President - Oyster Creek will ensure that an independent review and audit of that work is performed by another individual in the environmental affairs department or some other who is not directly responsible for the specific activity being, reviewed and audited.

The audits and reviews will be performed as required by the Quality Assurance Topical Report (QATR).

Independent audits and reviews will encompass:

A. Coordination of the OCETS with the safety technical specifications to avoid conflicts and maintain consistency.

B. Compliance of station activities and operations with the OCETS.

C. Adequacy of the programs and station procedures which are involved in ensuring the plant is operated in accordance with the OCETS.

D. The proper functioning in accordance with the responsibilities listed in Section 3.1 of the OCETS.

E. Proposed changes to the OCETS and the evaluation of the impacts resulting from the changes.

F. Proposed written procedures, as described in Section 3.4.1 and proposed changes thereto which affect the environmental impact of the plant.

G. Proposed changes or modifications to plant systems or equipment and a determination of the environmental impact resulting from the changes.

H. Adequacy of investigations of violations of the OCETS and adequacy of and implementation of the recommendations to prevent recurrence of the violations.

3.4 Procedures

3.4.1 Detailed written procedures, including applicable check lists and instructions, will be prepared and adhered to for all activities involved in carrying out OCETS.

3.5 Plant Reporting Requirements

3.5.1 DELETED

3.5.2 Non-Routine Environmental Operating Reports

A prompt report shall be submitted in the event that an Unusual or Important Environmental Event occurs (as specified in Section 2.1). Such an occurrence will be reported within 24 hours to the NRC and within 30 days by a written report in accordance with 10 CFR 50.4. If an event is reportable under 10 CFR 50.72, then a duplicate immediate report is not required. However, a follow-up written report is required. The written report and, to the extent possible, the preliminary report shall (a) describe, analyze, and evaluate the occurrence, including the extent and magnitude of the impact, (b) describe the cause of the occurrence, and (c) indicate the corrective action, if necessary, taken (including any significant changes made in the procedures) to preclude repetition of the occurrence should the occurrence be station related.

3.5.3 Change in Environmental Technical Specifications

A. A report shall be made to the NRC prior to implementation of a change in plant design, in plant operation, or in procedures described in Section 3.4, only if the change would have a significant adverse effect on the environment or involves an environmental matter or question not previously reviewed and evaluated by the NRC. The report shall include a description and evaluation of the changes and a supporting justification.

B. Request for changes in environmental technical specifications shall be submitted in accordance with 10 CFR 50.90.

C. Changes or additions to required Federal, and State permits and certificates for the protection of the environment that pertain to the requirements of OCETS shall be reported to the NRC within 30 days of approval by the appropriate permitting authority. In the event that the licensee initiates or becomes aware of a request for changes to any of the water quality requirements, limits or values stipulated in any certification or permit issued pursuant to Section 401 or 402 of the Federal Water Pollution Control Act (PL 92-500) which is also the subject of an OCETS reporting requirement, NRC shall be notified following approval by the authorizing agency. The notification to the NRC shall include an evaluation of the environmental impact of the revised requirement, limit or value being sought.

3.6 Records Retention

3.6.1 Eighty (80%) percent data recovery annually for each environmental monitoring requirement is considered satisfactory for the purposes of the OCETS. The variability and uncertainty of environmental conditions demand allowance for some missed data in order to preclude an excessive reporting burden. This provision for missed data does not permit deliberate omission of sample collection or analyses but rather is meant to cover data missed due to circumstances beyond the control of the licensee, its representative or subcontractor. Records of the reasons for all missed data shall be retained with the data reports.

3.6.2 Records relative to the following areas will be retained until the date of termination of the Operating License.

A. Records and drawings detailing plant design changes made to systems and equipment as described in Section 3.5.3.

B. Records of all environmental surveillance data.

3.6.3 All other records relating to the environmental technical specifications will be retained for five years following recording.

7590-01-P

UNITED STATES NUCLEAR REGULATORY COMMISSION

EXELON GENERATION COMPANY, LLC

OYSTER CREEK NUCLEAR GENERATING STATION

NOTICE OF ISSUANCE OF RENEWED FACILITY OPERATING LICENSE NO. DPR-16

FOR AN ADDITIONAL 20-YEAR PERIOD

RECORD OF DECISION

DOCKET NO. 50-219

Notice is hereby given that the U.S. Nuclear Regulatory Commission (the Commission) has issued Renewed Facility Operating License No. DPR-16 to Exelon Generation Company, LLC (the licensee), the operator of the Oyster Creek Nuclear Generating Station (OCNGS). Renewed facility operating license No. DPR-16 authorizes operation of OCNGS by the licensee at reactor core power levels not in excess of 1930 megawatts thermal, in accordance with the provisions of the OCNGS renewed license and its technical specifications.

The notice also serves as the record of decision for the renewal of Facility Operating License No. DPR-16, consistent with Title 10 of the *Code of Federal Regulations* (10 CFR), Section 51.103 "Record of Decision - general". As discussed in the final Supplemental Environmental Impact Statement (FSEIS) for OCNGS, dated January 2007, the Commission has considered a range of reasonable alternatives that included generation from oil, wind, solar, hydropower, geothermal, wood waste, municipal solid waste, other biomass-derived fuels, fuel cells, delayed retirement, conservation measures and, tidal and ocean energy. The factors considered in the record of decision can be found in the supplemental environmental impact statement for OCNGS.

OCNGS is a boiling water reactor located in Lacey Township, Ocean County, New Jersey, approximately two miles south of the community of Forked River. OCNGS was operated by AmerGen Energy Company, LLC, until January 9, 2009, when the license was transferred to Exelon Generation Company, LLC (74 FR 4777), in accordance with Section 184 of the Atomic Energy Act of 1954, as amended, and 10 CFR Section 50.80, "Transfer of Licenses". The application for the renewed license complied with the standards and requirements of the Atomic Energy Act of 1954 (the Act), as amended, and the Commission's regulations. As required by the Act and the Commission's regulations in 10 CFR Chapter I, the Commission has made appropriate findings, which are set forth in the license. Prior public notice of the action involving the proposed issuance of the renewed license and of an opportunity for a hearing regarding the proposed issuance of the renewed license was published in the *Federal Register* on September 15, 2005 (70 FR 54585).

For further details with respect to this action, see: (1) Exelon Generation Company, LLC, formerly AmerGen Energy Company, LLC, license renewal application for OCNGS dated July 22, 2005, as supplemented by letters dated through January 14, 2008; (2) the Commission's Safety Evaluation Report (NUREG-1875, Volumes 1 and 2), published on March 30, 2007, supplemented on September 19, 2008; (3) the licensee's updated safety analysis report; and (4) the Commission's FSEIS (NUREG-1437, Supplement 28), published on January 31, 2007. These documents are available at the NRC's Public Document Room, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, and can be viewed from the NRC Public Electronic Reading Room at http://www.nrc.gov/reading-rm/adams.html.

Copies of renewed facility operating license No. DPR-16, may be obtained by writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001, Attention: Director, Division of License Renewal. Copies of the OCNGS Safety Evaluation Report (NUREG-1875), Supplement 1, and the FSEIS (NUREG-1437, Supplement 28) may be purchased from the

National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161 (http://www.ntis.gov), 703-605-6000, or Attention: Superintendent of Documents, U.S. Government Printing Office, P.O. Box 371954 Pittsburgh, PA 15250-7954 (http://www.gpoaccess.gov), 202-512-1800.

All orders should clearly identify the NRC publication number and the requestor's Government Printing Office deposit account number or Visa or MasterCard number and expiration date.

Dated at Rockville, Maryland, this 8th day of April, 2009.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian E. Holian, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

Enclosure 1 contains the Renewed Facility Operating License No. DPR-16 including Appendices A and B. Enclosure 2 is a copy of the related *Federal Register* notice of issuance of the renewed license. The original has been sent to the Office of the Federal Register for publication. If you have any questions regarding this renewed license, please feel free to contact me at 301-415-1906 or by e-mail at Lisa.Regner@nrc.gov.

Sincerely,

\RA Donnie Ashley for

Lisa M. Regner, Senior Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-219

Enclosures:
1. Renewed Facility Operating License No. DPR-16
2. *Federal Register* Notice

cc: Distribution via Listserv

ADAMS Accession No.: Package: ML080380105
Transmittal Letter: ML080280440
Renewed Operating License: ML080170344
FRN: ML080280449

* Via email

OFFICE	PM/RPB2/DLR	Tech Editor *	LA/DLR	PM/DORL	BC/DORL
NAME	LRegner	KAzariah-Kribbs	YEdmonds	GMiller	HChernoff
DATE	04/03/09	03/20/09	04/03/09	04/02/09	04/06/09
OFFICE	BC/RERB/DLR	BC/RPB1/DLR	D/DLR	OGC	D/NRR
NAME	BPham (ELenning for)	DPelton	BHolian	BHarris	ELeeds (JWiggins for)
DATE	04/02/09	04/06/09	04/07/09	04/07/09	04/07/09
DATE	PM/RPB2/DLR				
NAME	LRegner (DAshley for)				
OFFICE	04/08/09				

OFFICIAL RECORD COPY

K. 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 the Oyster Creek license and the requirements of the Order approving the transfer, and consistent with the safety evaluation supporting such Order.

L. DELETED

M. At the time of the closing of the transfer of Oyster Creek, and the respective license from AmerGen Energy Company, LLC (AmerGen) to Exelon Generation Company, AmerGen shall transfer to Exelon Generation Company ownership and control of AmerGen Oyster Creek NQF, LLC, and AmerGen Consolidation, LLC shall be merged into Exelon Generation Consolidation, LLC. Also at the time of the closing, decommissioning funding assurance provided by Exelon Generation Company, using an additional method allowed under 10 CFR 50.75 if necessary, must be equal to or greater than the minimum amount calculated on that date pursuant to, and required by 10 CFR 50.75 for Oyster Creek. Furthermore, funds dedicated for Oyster Creek prior to closing shall remain dedicated to Oyster Creek following the closing. The name of AmerGen Oyster Creek NQF, LLC shall be changed to Exelon Generation Oyster Creek NQF, LLC at the time of the closing.

4. This license is effective as of the date of issuance and shall expire at midnight on April 9, 2029.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce S. Mallett **/RA/**
Deputy Executive Director for Reactor
and Preparedness Programs
Office of the Executive Director for Operations

Attachment:
Appendices A and B -
Technical Specifications

Date of Issuance:
Accession No.: ML080170344 EDATS: NRR-2009-0008

OFFICE	PM/RPB2/DLR	Tech Editor *	LA/DLR	PM/DORL	BC/DORL
NAME	LRegner	K Azariah-Kribbs	Y Edmonds	GMiller	HChernoff
DATE	04/03/09	03/20/09	04/03/09	04/02/09	04/06/09
OFFICE	BC/RERB/DLR	BC/RPB1/DLR	D/DLR	OGC	D/NRR
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DATE	04/02/09	04/06/09	04/07/09	04/07/09	04/07/09

DATE	DEDR/EDO
NAME	BMallett
OFFICE	04/08/09

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