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1.0 PURPOSE

The purpose of this manual is to specify requirements which have been removed from the Clinton Technical Specifications as a result of the conversion to Improved Technical Specifications.

1.1 DEFINITIONS

ACTION

1.1.1 ACTION shall be that part of an Operational Requirement that prescribes required actions to be taken under designated conditions with specified completion times.

ACTUAL TRIP SETPOINT (ATSP)

1.1.2 The actual trip value of the sensed process variable found in the conclusion of the setpoint calculation. It is equivalent to or more conservative than the Nominal Trip Setpoint (NTSP). The ATSP, as such, may provide additional margin to the process or analytical limit.

CHANNEL CALIBRATION

1.1.3 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter 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 inplace 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.

CHANNEL CHECK

1.1.4 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.

CHANNEL FUNCTIONAL TEST

1.1.5 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 OPERABILITY. The CHANNEL FUNCTION TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

CORE ALTERATION

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

a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); and

b. Control rod movement, provided there are no fuel assemblies in the associated core cell.

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

FUNCTIONAL-FUNCTIONALITY

1.1.7 A system, subsystem, train, component, or device shall be FUNCTIONAL or have FUNCTIONALITY when it is capable of performing its specified function, as set forth in the current licensing basis.

FUNCTIONALITY does not apply to specified safety functions, but does apply to the ability of non-TS SSCs to perform other specified functions that have a necessary support function.

LOGIC SYSTEM FUNCTIONAL TEST

1.1.8A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components required for OPERABILITY of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.

MODE

1.1.9 A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel as specified in the CPS Technical Specifications.

NOMINAL TRIP SETPOINT (NTSP)

1.1.10 The calculated limiting value of the sensed process variable at which a trip could have been set. The actual trip value (ATSP) may be more conservative than the limiting value.

RATED THERMAL POWER

1.1.11 RATED THERMAL POWER (RTP) shall be a total reactor core heat transfer rate to the reactor coolant of 3473 MWt.

SELF TEST SYSTEM

1.1.12 The SELF TEST SYSTEM (STS) shall be that automatic test system designed to continually monitor the solid state nuclear system protection system (NSPS) functional circuitry by injecting short-duration pulses into circuits and verifying proper circuit response to various input combinations. The SELF TEST SYSTEM is designed to maintain surveillance over all NSPS cabinet circuitry essential to the Reactor Protection System, Emergency Core Cooling Systems, Reactor Core Isolation Cooling System, and the Nuclear Steam Supply Shutoff System on a continuous cyclic basis.

The SELF TEST SYSTEM may be used to perform various surveillance testing functions to satisfy technical specifications requirements for those components it is designed to monitor. The STS may be used to augment conventional testing methods to perform CHANNEL CHECKS, CHANNEL FUNCTIONAL TESTS, CHANNEL CALIBRATIONS, RESPONSE TIME TESTS and LOGIC SYSTEM FUNCTIONAL TESTS provided that OPERABILITY of the STS has first been verified.

SITE BOUNDARY

1.1.13 The SITE BOUNDARY shall be that line beyond which the land is neither owned, nor leased, nor otherwise controlled by the licensee.

1.2 GENERAL OPERATIONAL REQUIREMENTS

1.2.1 Operational Requirements shall be met during the MODES or other specified conditions in the Applicability, except as provided in Operational Requirement 1.2.2.

1.2.2 Upon discovery of a failure to meet an Operational Requirement, the ACTION requirements of the associated Operational Requirement shall be met. If the Operational Requirement is met or is no longer applicable prior to expiration of the specified completion time(s), completion of the ACTION(s) requirements is not required, unless otherwise stated.

1.2.3 When an Operational Requirement is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, action shall be initiated within 1 hour to:

a. Implement appropriate compensatory actions as needed;

b. Verify that the plant is not in an unanalyzed condition or that a required safety function is not compromised by the inoperabilites, and

c. Within 12 hours, obtain Shift Operations Superintendent or designee approval of the compensatory actions and the plan for exiting the Operational Requirement 1.2.3.

Exceptions to this requirement are stated in the individual Operational Requirements.

Where corrective measures are completed that permit operation in accordance with the Operational Requirement or ACTIONS, completion of the actions required by this requirement is not required.

This requirement is only applicable in MODES 1, 2, and 3.

1.2.4 When an Operational Requirement is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time.

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and

1.2 GENERAL OPERATIONAL REQUIREMENTS (Cont'd)

establishment of risk management actions, if appropriate; exceptions to this requirement are stated in the individual Operational Requirements, or

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

This requirement shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

1.2.5 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to Operational Requirement 1.2.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

1.3 GENERAL TESTING REQUIREMENTS

1.3.1 Testing Requirements shall be met during the MODES or other specified conditions in the Applicability for individual Operational Requirements, unless otherwise stated in the Testing Requirement. Failure to meet a Testing Requirement, whether such failure is experienced during the performance of the Testing Requirement or between performances of the Testing Requirement, shall be failure to meet the Operational Requirement. Failure to perform a Testing Requirement within the specified Frequency shall be failure to meet the Operational Requirement, except as provided in Testing Requirement 1.3.3. Testing Requirements do not have to be performed on inoperable equipment or variables outside specified limits.

1.3.2 The specified Frequency for each Testing Requirement is met if the Testing Requirement is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If an ACTION requires periodic performance on a "once per ..." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Testing Requirement are stated in the individual Operational Requirements.

1.3.3 If it is discovered that a Testing Requirement was not performed within its specified Frequency, then compliance with the requirement to declare the Operational Requirement 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 Testing Requirement. A risk evaluation shall be performed for any Testing Requirement delayed greater than 24 hours and the risk impact shall be managed.

If the Testing Requirement is not performed within the delay period, the Operational Requirement must immediately be declared not met, and the applicable ACTIONS must be entered.

When the Testing Requirement is performed within the delay period and the Testing Requirement is not met, the Operational Requirement must immediately be declared not met, and the applicable ACTION(s) must be entered.

1.3.4 Entry into a MODE or other specified condition in the Applicability of an Operational Requirement shall only be made when the Operational Requirement's Testing Requirements have been met within their specified Frequency, except as provided by Operational Requirement 1.2.3. When an Operational Requirement is not met due to Testing Requirements not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with Operational Requirement 1.2.4.

1.3 GENERAL TESTING REQUIREMENTS (Cont'd)

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

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

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in the Operational Requirements:

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

c. The provisions of Testing Requirement 1.3.2 are applicable to the above required frequencies for performing inservice inspection activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other Technical Specification Surveillance Requirements and Operational Requirements Manual Testing Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Operational Requirement.

f. The Inservice Inspection Program for piping identified in NRC Generic Letter 88-01 shall be performed in accordance with the NRC Staff positions on schedule except for Category 'D' welds, methods and personnel, and sample expansion included in the generic letter.

1.3 GENERAL TESTING REQUIREMENTS (Cont'd)

For Category 'D' welds, BWR Owner's Group Vessel Internal Project (VIP) document BWRVIP-75 schedule shall be utilized.

2.0 OPERATIONAL REQUIREMENTS

2.1 REACTIVITY CONTROL SYSTEMS

2.1.1 CONTROL ROD DRIVE HOUSING SUPPORT

OPERATIONAL REQUIREMENTS

Refer to USAR Section 4.6.1.2.3.

2.1.2 Deleted.

2.2 INSTRUMENTATION

2.2.1 AVERAGE POWER RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION

OPERATIONAL REQUIREMENT

The APRM control rod block instrumentation channels in Table 2.2.1-1 shall be OPERABLE with their trip setpoints set consistent with the values specified in Table 3.2.1-1.

APPLICABILITY

TABLE 2.2.1-1
APRM APPLICABILITY

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION*	APPLICABLE MODES
a. Flow Biased Upscale	3	1
b. Inoperative	3	1, 2
c. Downscale	3	1
d. Upscale, Startup	3	2

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance provided at least one other OPERABLE channel in the same trip function is monitoring that parameter.

ACTION

3.2.1 With the number of OPERABLE Channels:

a. One less than required by the minimum OPERABLE channels per trip function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the minimum OPERABLE channels per trip function requirement, place at least one inoperable channel in the tripped condition within 1 hour.

2.2.1 AVERAGE POWER RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION (continued)

TABLE 3.2.1-1
APRM TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
a. Flow Biased Upscale		
1) During two recirculation loop operation:		
a) Flow Biased	0.58 W + 50%** with a maximum of	≤ 0.55 W + 56%** with a maximum of
b) High Flow Clamped	≤ 108.0% of RATED THERMAL POWER	≤ 110.0% of RATED THERMAL POWER
2) During single recirculation loop operation:		
a) Flow Biased	0.58 (W-ΔW) + 32%**	≤ 0.55 (W-ΔW) + 37.5%**
b) High Flow Clamped	Not required OPERABLE	Not required OPERABLE
b. Inoperative	NA	NA
c. Downscale	≥ 5% of RATED THERMAL POWER	≥ 3% OF RATED THERMAL POWER
d. Upscale Startup	≤ 12% of RATED THERMAL POWER	≤ 14% of RATED THERMAL POWER

** The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with note (a) of the Reactor Protection System trip setpoint table (Table 1) in Attachment 2.

2.2.1 AVERAGE POWER RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION (continued)

TESTING REQUIREMENTS

4.2.1.1 Deleted.

4.2.1.2 Perform a CHANNEL FUNCTIONAL TEST every 92 days for the following trip functions:
- a. Flow-Biased Upscale
- b. Inoperative
- c. Downscale
- d. Upscale, Startup

4.2.1.3 Perform a CHANNEL CALIBRATION, except for neutron detectors, every 184 days for the following trip functions:
- a. Flow-Biased Upscale
- b. N/A
- c. Downscale
- d. Upscale, Startup

BASES

5.2.1 The control rod block functions are provided consistent with the requirements of Technical Specifications 3.3.2.1, Control Rod Block Instrumentation and 3.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

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

2.2.2 SOURCE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Source Range Monitoring (SRM) control rod block instrumentation channels in Table 2.2.2-1 shall be OPERABLE with their trip setpoints set consistent with the values specified in Table 3.2.2-1.

APPLICABILITY

TABLE 2.2.2-1
SRM APPLICABILITY

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(e)	APPLICABLE MODES
a. Detector not full in (a)	3	2#
b. Upscale (b)	3	2#
c. Inoperative (b)	3	2#
d. Downscale (c)	3	2#

With IRMs on range 2 or below.

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

(b) This function shall be automatically bypassed when the associated IRM channels are on range 8 or higher.

(c) This function shall be automatically bypassed when the IRM channels are on range 3 or higher.

(e) A channel may be placed in an inoperable status for up to 6 hours for required surveillance provided at least one other OPERABLE channel in the same trip function is monitoring that parameter.

2.2.2 <u>SOURCE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION</u> (continued)

ACTIONS

3.2.2 With the number of OPERABLE Channels:

a. One less than required by the minimum OPERABLE channels per trip function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the minimum OPERABLE channels per trip function requirement, place at least one inoperable channel in the tripped condition within 1 hour.

TABLE 3.2.2-1
SOURCE RANGE MONITORS TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
a. Detector not full in	N/A	N/A
b. Upscale	$\leq 1 \times 10^5$ cps	$\leq 1.6 \times 10^5$ cps
c. Inoperative	N/A	N/A
d. Downscale	≥ 3 cps	≥ 1.8 cps

TESTING REQUIREMENTS

4.2.2.1 Perform a CHANNEL FUNCTIONAL TEST every 31 days for the following trip functions:

a. Detector not full in
b. Upscale
c. Inoperative
d. Downscale

2.2.2 SOURCE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION (continued)

4.2.2.2 Perform a CHANNEL CALIBRATION, except neutron detectors, every 24 months for the following trip functions:

a. N/A
b. Upscale
c. N/A
d. Downscale

4.2.2.3 The provisions of Testing Requirement 1.3.4 are not applicable to the Source Range Monitor Testing requirements for entry into MODE 2# from MODE 1, provided the testing requirements are performed within 12 hours after entering MODE 2#.

BASES

5.2.2 The control rod block functions are provided consistent with the requirements of Technical Specification 3.3.2.1, Control Rod Block Instrumentation and 3.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

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

2.2.3 INTERMEDIATE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Intermediate Range Monitoring (IRM) control rod block instrumentation channels in Table 2.2.3-1 shall be OPERABLE with their trip setpoints set consistent with the values specified in Table 3.2.3-1.

APPLICABILITY

TABLE 2.2.3-1
IRM APPLICABILITY

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(e)	APPLICABLE MODES
a. Detector not full in	6	2
b. Upscale	6	2
c. Inoperative	6	2
d. Downscale (d)	6	2

(d) This function shall be automatically bypassed when the IRM channels are on range 1.

(e) A channel may be placed in an inoperable status for up to 6 hours for required surveillance provided at least one other OPERABLE channel in the same trip function is monitoring that parameter.

ACTIONS

3.2.3 With the number of OPERABLE Channels:

a. One less than required by the minimum OPERABLE channels per trip function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the minimum OPERABLE channels per trip function requirement, place at least one inoperable channel in the tripped condition within 1 hour.

2.2.3 INTERMEDIATE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION (continued)

TABLE 3.2.3-1
INTERMEDIATE RANGE MONITORING TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
a. Detector not full in	NA	NA
b. Upscale	$\leq$ 108/125 full scale	$\leq$ 110/125 full scale
c. Inoperative	NA	NA
d. Downscale	$\geq$ 5/125 full scale	$\geq$ 3/125 full scale

TESTING REQUIREMENTS

4.2.3.1 Perform a CHANNEL FUNCTIONAL TEST every 31 days for the following trip functions:

a. Detector Not Full In
b. Upscale
c. Inoperative
d. Downscale

4.2.3.2 Perform a CHANNEL CALIBRATION, except neutron detectors, every 24 months for the following trip functions:

a. N/A
b. Upscale
c. N/A
d Downscale

4.2.3.3 The provisions of Testing Requirement 1.3.4 are not applicable to the Intermediate Range Monitor Testing Requirements for entry into MODE 2, from MODE 1, provided the Testing Requirements are performed within 12 hours after entering MODE 2.

BASES

5.2.3 The control rod block functions are provided consistent with the requirements of Technical Specifications 3.3.2.1, Control Rod Block Instrumentation and 3.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

2.2.3 INTERMEDIATE RANGE MONITORS - CONTROL ROD BLOCK INSTRUMENTATION (continued)

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

2.2.4 SCRAM DISCHARGE VOLUME - CONTROL ROD BLOCK INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Scram Discharge Volume (SDV) control rod block instrumentation channels in Table 2.2.4-1 shall be OPERABLE with their trip setpoints set consistent with the values specified in Table 3.2.4-1.

APPLICABILITY

TABLE 2.2.4-1
SCRAM DISCHARGE VOLUME APPLICABILITY

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(e)	APPLICABLE MODES
a. Water Level - High	2	1, 2

(e) A channel may be placed in an inoperable status for up to 6 hours for required surveillance provided at least one other OPERABLE channel in the same trip function is monitoring that parameter.

ACTION

3.2.4 With the number of OPERABLE channels less than required by the minimum OPERABLE channels per trip function requirement, verify within 1 hour that a sufficient number of channels remain OPERABLE to initiate a rod block by the associated trip function, and place at least one inoperable channel in the tripped condition within 24 hours. Otherwise, initiate a rod block.

2.2.4 SCRAM DISCHARGE VOLUME - CONTROL ROD BLOCK INSTRUMENTATION (continued)

TABLE 3.2.4-1
SCRAM DISCHARGE VOLUME TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
a. Water Level-High, C11-N602A	≤ 12"#	≤ 19 7/8"#
b. Water Level-High, C11-N602B	≤ 12"##	≤ 19 7/8"##

Instrument zero is 758' 5" msl.
Instrument zero is 758' 4 1/2" msl.

TESTING REQUIREMENTS

4.2.4.1 Perform a CHANNEL CHECK on the instruments listed in Table 2.2.4-1 every 12 hours.

4.2.4.2 Perform a CHANNEL FUNCTIONAL TEST on the instruments listed in Table 2.2.4-1 every 92 days.

4.2.4.3 Perform a CHANNEL CALIBRATION on the instruments listed in Table 4.2.4-1 every 92 days for the Analog Trip Module.

4.2.4.4 Perform a CHANNEL CALIBRATION on the instruments listed in Table 2.2.4-1 every 24 months.

BASES

5.2.4 The control rod block functions are provided consistent with the requirements of Technical Specifications 3.3.2.1, Control Rod Block Instrumentation, and 3.2, Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

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

2.2.5 REACTOR COOLANT SYSTEM RECIRCULATION FLOW - CONTROL ROD BLOCK INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Reactor Coolant System Recirculation Flow control rod block instrumentation channels in Table 2.2.5-1 shall be OPERABLE with their trip setpoints set consistent with the values specified in Table 3.2.5-1.

APPLICABILITY

TABLE 2.2.5-1
REACTOR RECIRCULATION FLOW ROD BLOCK APPLICABILITY

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(e)	APPLICABLE MODES
a. Upscale	3	1

(e) A channel may be placed in an inoperable status for up to 6 hours for required surveillance provided at least one other OPERABLE channel in the same trip function is monitoring that parameter.

ACTION

3.2.5 With the number of OPERABLE channels less than required by the minimum OPERABLE channels per trip function requirement, verify within one hour that a sufficient number of channels remain OPERABLE to initiate a rod block by the associated trip function, and place at least one inoperable channel in the tripped condition within 24 hours. Otherwise, initiate a rod block.

TABLE 3.2.5-1
REACTOR RECIRCULATION FLOW ROD BLOCK TRIP SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
a. Upscale	$\leq$ 113 % of rated flow	$\leq$ 116 % of rated flow

2.2.5 <u>REACTOR COOLANT SYSTEM RECIRCULATION FLOW - CONTROL ROD BLOCK INSTRUMENTATION</u> (continued)

<u>TESTING REQUIREMENTS</u>

4.2.5.1 Deleted.

4.2.5.2 Perform a CHANNEL FUNCTIONAL TEST on the instruments listed in Table 2.2.5-1 every 92 days.

4.2.5.3 Perform a CHANNEL CALIBRATION on the instruments listed in Table 2.2.5-1 every 184 days.

<u>BASES</u>

5.2.5 The control rod block functions are provided consistent with the requirements of Technical Specifications 3.3.2.1, Control Rod Block Instrumentation, and 3.2, Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

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

2.2.6 AREA RADIATION MONITORING INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Area Radiation Monitoring Instrumentation in Table 2.2.6-1 shall be OPERABLE with their alarm/trip setpoints set consistent with the values specified in Table 2.2.6-1.

APPLICABILITY

TABLE 2.2.6-1
AREA RADIATION MONITORING APPLICABILITY

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT
Area Monitors			
a. New Fuel Storage Vault	1	#	≤ 2.5 mR/hr**
b. Spent Fuel Storage Pool	1	##	≤ 2.5 mR/hr**
c. Control Room Direct Radiation Monitor	1	At all times	≤ 2.5 mR/hr**

** Alarm only.

With fuel in the new storage vault.

With irradiated fuel in the spent fuel storage pool.

ACTION:

3.2.6.1 With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 2.2.6-1, adjust the setpoint to within the limits within 4 hours or declare the channel inoperable.

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

3.2.6.3 The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

2.2.6 AREA RADIATION MONITORING INSTRUMENTATION (continued)

TESTING REQUIREMENTS

4.2.6.1 Perform a CHANNEL CHECK on the instruments listed in Table 2.2.6-1 every 12 hours.

4.2.6.2 Perform a CHANNEL FUNCTIONAL TEST on the instruments listed in Table 2.2.6-1 every 31 days.

4.2.6.3 Perform a CHANNEL CALIBRATION on the instruments listed in Table 2.2.6-1 every 24 months.

BASES

5.2.6 The OPERABILITY of the radiation monitoring instrumentation ensures that:

(1) the radiation levels are continually measured in the areas served by the individual channels;
(2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and
(3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident.

This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 60, 61, 63 and 64.

2.2.7 SEISMIC MONITORING INSTRUMENTATION

OPERATIONAL REQUIREMENTS

The seismic monitoring instrumentation shown in Table 3.2.7-1 shall be OPERABLE.

APPLICABILITY At all times

ACTION

3.2.7

a. With one or more of the above required seismic monitoring instruments inoperable for more than 30 days, initiate a Condition Report.

b. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TESTING REQUIREMENTS

4.2.7.1 Perform a CHANNEL FUNCTIONAL TEST for each of the required seismic monitoring instruments at the frequencies shown in Table 4.2.7-1.

4.2.7.2 Perform a CHANNEL CALIBRATION for each of the required seismic monitoring instruments at the frequencies shown in Table 4.2.7-1.

4.2.7.3 Each of the above required seismic monitoring instruments actuated during a seismic event $\geq$ 0.02g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Condition Report shall be initiated describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

2.2.7 SEISMIC MONITORING INSTRUMENTATION (continued)

TABLE 3.2.7-1
SEISMIC MONITORING INSTRUMENTATION

MEASUREMENT RANGE

INSTRUMENTS/LOCATIONS	FREQUENCY RANGE (HZ)	FULL SCALE SENSITIVITY (g)	DYNAMIC RANGE ZERO TO PEAK	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Accelerometers				
a. Concrete pad (outside) El. 740' 10"	1 to 30	±2	100:1	l(c)
b. Aux. Bldg., El. 712'	1 to 30	±2	100:1	l(a)(c)
c. Containment Bldg., El. 851'	1 to 30	±2	100:1	l(a)(c)
d. Control Bldg., El. 737'	1 to 30	±2	100:1	l(a)(c)
e. Containment(drywell wall), E1.779'-10"	1 to 30	±2	100:1	l(a)(c)
2. Triaxial Peak Accelerographs (Passive)				
a. Aux. Bldg., El. 718'	0 to 30	±5	20:1	1
b. DG Bldg., El. 729'	0 to 30	±5	20:1	1
c. Containment Bldg., El. 791'	0 to 30	±5	20:1	1
3. Triaxial Seismic Switches				
Aux. Bldg., El. 712'	0.1 to 30	±0.2	40:1	1(a)(b)
4. Recorders				
a. Circulating Water Screen House (Passive Triaxial Response Spectrum Recorder)	2 to 25	NA	NA	1
b. Main Control Room Central Recording Unit	1 to 30	NA	NA	1
5. Seismic Data Analyzer				
Main Control Room	1 to 30	NA	NA	1

(a) With main control room annunciation.
(b) Adjustable setpoint
(c) Accelerometer provides input to the Central Recording Unit.

2.2.7 SEISMIC MONITORING INSTRUMENTATION (continued)

TABLE 4.2.7-1
SEISMIC MONITORING TESTING FREQUENCIES

INSTRUMENTS/LOCATIONS	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1 . Triaxial Accelerometers		
a. Concrete pad (outside), El. 740' 10"	31 days	24 months
b. Aux. Bldg.,El. 712'	31 days	24 months
c. Containment Bldg., El. 851'	31 days	24 months
d. Control Bldg., El. 737'	31 days	24 months
e. Containment (drywell wall) El. 779'- 10"	31 days	24 months
2. Triaxial Peak Accelerographs (Passive)		
a. Aux Bldg., El. 718'	NA	24 months
b. DG Bldg., El. 729'	NA	24 months
c. Containment Bldg., El. 791'	NA	24 months
3. Triaxial Seismic Switches		
Aux. Bldg., El. 712'	31 days	24 months
4. Recorders		
a. Circulating Water Screen House (Passive Triaxial Response Spectrum Recorder)	NA	24 months
b. Main Control Room Central Recording Unit	NA	24 months
5. Seismic Data Analyzer		
Main Control Room	31 days	24 months

2.2.7 SEISMIC MONITORING INSTRUMENTATION (continued)

BASES

5.2.7 The OPERABILITY of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit. This instrumentation is consistent with the recommendations of Regulatory Guide 1.12 "Instrumentation for Earthquakes", April 1974.

2.2.8 METEOROLOGICAL MONITORING INSTRUMENTATION

OPERATIONAL REQUIREMENTS

The meteorological monitoring instrumentation channels shown in Table 3.2.8-1 shall be OPERABLE.

APPLICABILITY At all times

ACTION

3.2.8

a. With one or more meteorological monitoring instrumentation channels inoperable for more than 7 days, initiate a Condition Report.

b. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TABLE 3.2.8-1

METEOROLOGICAL MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
1. Wind Speed	
a. El. 768'	1
b. El. 932'	1
2. Wind Direction	
a. El. 768'	1
b. El. 932'	1
3. Air Temperature Difference	
El. 768'/932'	1

2.2.8 METEOROLOGICAL MONITORING INSTRUMENTATION (continued)

TESTING REQUIREMENTS

4.2.8.1 Perform a CHANNEL CHECK every 24 hours for each of the meteorological monitoring instrumentation channels shown in Table 3.2.8-1.

4.2.8.2 Perform a CHANNEL CALIBRATION every 184 days for each of the meteorological monitoring instrumentation channels shown in Table 3.2.8-1.

BASES

5.2.8 The OPERABILITY of the meteorological monitoring instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. This instrumentation is consistent with the recommendations of Regulatory Guide 1.23 "Onsite Meteorological Programs," with exceptions as noted in the Project Position on Regulatory Guide 1.23 in Subsection l.8 of the CPS USAR.

2.2.9 TRAVERSING IN-CORE PROBE SYSTEM

OPERATIONAL REQUIREMENTS

The traversing in-core probe system shall be OPERABLE with:

a. Three movable detectors, drives and readout equipment to map the core, and

b. Indexing equipment to allow three detectors to be calibrated in a common location.

APPLICABILITY When the traversing in-core probe is used for:

a. Recalibration of the LPRM detectors, and

b. Monitoring the APLHGR, LHGR, or MCPR.*

* Only the detector(s) in the location(s) of interest are required to be OPERABLE.

ACTION

3.2.9 With the traversing in-core probe system inoperable, do not use the system for the above applicable monitoring or calibration functions. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TESTING REQUIREMENTS

4.2.9.1 The traversing in-core probe system shall be demonstrated OPERABLE by normalizing each of the above required detector outputs within 72 hours prior to use when required for the LPRM or calibration functions.

BASES

5.2.9 The OPERABILITY of the traversing in-core probe (TIP) system with the specified, minimum complement of equipment ensures that the measurements obtained from use of this equipment accurately represent the spatial neutron flux distribution of the reactor core. The 3D MONICORE system is capable of adapting its calculation with sufficient accuracy with one TIP out-of-service, therefore only 3 of the 4 detectors are required to be operable for a full core monitoring or calibration.

2.2.9 <u>TRAVERSING IN-CORE PROBE SYSTEM</u> (continued)

The TIP system OPERABILITY is demonstrated by normalizing all required probes (i.e., detectors) prior to performing an LPRM calibration function. Monitoring core thermal limits may involve utilizing individual detectors to monitor selected areas of the reactor core, thus all detectors may not be required to be OPERABLE. The operability of individual detectors to be used for monitoring is demonstrated by comparing the detector(s) output with data obtained during the previous LPRM calibrations.

2.2.10 Deleted

2.2.11 MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING INSTRUMENTATION

OPERATIONAL REQUIREMENTS

At least one main condenser offgas treatment system explosive gas monitoring instrumentation channel shall be OPERABLE with its alarm/trip setpoint set to ensure that the concentration of hydrogen in the main condenser offgas treatment system will not exceed 4% by volume.

APPLICABILITY During operation of the main condenser air ejector.

ACTION

3.2.11

a. With the explosive gas monitoring instrumentation channel alarm/trip setpoint less conservative than 4%, declare the channel inoperable and take the ACTION required below.

b. With less than 1 explosive gas monitoring instrumentation channel OPERABLE, operation of the main condenser offgas treatment system may continue provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours. Restore the inoperable channel to OPERABLE status within 30 days and, if unsuccessful, initiate a Condition Report.

TESTING REQUIREMENTS

4.2.11.1 Perform a CHANNEL CHECK of the main condenser offgas treatment system explosive gas monitoring instrumentation every 24 hours.

4.2.11.2 Perform a CHANNEL FUNCTIONAL TEST of the main condenser offgas treatment system explosive gas monitoring instrumentation every 31 days.

4.2.11.3 Perform a CHANNEL CALIBRATION* of the main condenser offgas treatment system explosive gas monitoring instrumentation every 92 days.

* The CHANNEL CALIBRATION shall include the use of standard samples containing a nominal,

1. 1.0 vol. % hydrogen, balance nitrogen, and
2. 4.0 vol. % hydrogen, balance nitrogen.

2.2.11 <u>MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING INSTRUMENTATION</u> (continued)

BASES

5.2.11 The main condenser offgas treatment system explosive gas monitoring instrumentation is provided to monitor and control the concentrations of potentially explosive gas mixtures in the main condenser offgas treatment system.

The intent of the * note attached to the CHANNEL CALIBRATION requirement is to specify that the CHANNEL CALIBRATION is to be performed using at least two separate gas samples of different, specific hydrogen concentrations appropriate for the sensor range. The balance of the sample gas mixture (normally nitrogen) is not necessarily restricted purely to nitrogen but must be in accordance with the requirements or recommendations provided by the manufacturer of the explosive gas monitoring instrumentation.

2.2.12 FEEDWATER SYSTEM/MAIN TURBINE TRIP

OPERATIONAL REQUIREMENT

The feedwater/main turbine trip Function shall have 3 channels of reactor vessel water level – high, level 8, instrumentation OPERABLE.

APPLICABILITY

Mode 1

ACTION

3.2.12

a. With one or more required channel(s) inoperable, restore channel(s) to an OPERABLE status within 7 days.

b. With the feedwater/main turbine trip Function not maintained, restore feedwater/main turbine trip capability within 72 hours.

c. With Action and Completion Time not met for 3.2.12.a or 3.2.12.b, enter General Operational Requirement 1.2.3.

---NOTE---
A Channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Channel in the tripped condition provided at least one other OPERABLE Channel is monitoring that parameter.

TESTING REQUIREMENTS

4.2.12.1 Perform a CHANNEL CHECK every 12 hours.

4.2.12.2 Perform a CHANNEL FUNCTIONAL TEST every 184 days.

4.2.12.3 Perform a CHANNEL CALIBRATION every 24 months. The trip setpoint shall be 52.0 inches.

4.2.12.4 Perform a LOGIC SYSTEM FUNCTIONAL TEST every 24 months.

BASES

5.2.12 Trip function can be maintained by removing the affected component (feedwater pump(s) and/or main turbine) from service and administratively controlling the status in a tripped condition.

2.2.13 ADS ACCUMULATOR LOW PRESSURE ALARM SYSTEM INSTRUMENTATION

OPERATIONAL REQUIREMENTS

The ADS accumulator low pressure alarm system instrumentation shall be OPERABLE with an alarm setpoint of $\geq$ 140 psig on decreasing pressure.

APPLICABILITY MODES 1, 2*, and 3*

* Not required when reactor steam dome pressure is less than or equal to 150 psig

ACTION

3.2.13.1 With an ADS accumulator low pressure alarm system instrumentation channel(s) inoperable:

a. Determine the associated ADS accumulator system pressure from alternate indication and verify that ADS accumulator pressure is greater than or equal to 140 psig at least once per 12 hours,

b. Restore the inoperable ADS accumulator low pressure alarm system instrumentation channel(s) to OPERABLE status within 30 days and, if unsuccessful, initiate a Condition Report.

c. The provisions of Operational Requirement 1.2.4 are not applicable.

TESTING REQUIREMENTS

4.2.13.1 At least once per 31 days, performing a CHANNEL FUNCTIONAL TEST of the accumulator low pressure alarm system.

4.2.13.2 At least once per 24 months, performing a CHANNEL CALIBRATION of the accumulator low pressure alarm system and verifying an alarm setpoint of $\geq$ 140 psig on decreasing pressure.

2.2.14 NSPS SELF TEST SYSTEM

OPERATIONAL REQUIREMENTS

The SELF TEST SYSTEM (STS) of the Nuclear System Protection System shall be OPERABLE and operating in the fully automatic mode.*

* In lieu of continuous, fully automatic operation, the STS may be operated manually or in a partially automatic mode such that it performs all required tests at least once per 7 days during Modes 1, 2, and 3; or at least once per 90 days during Modes 4 and 5.

APPLICABILITY MODES 1, 2, 3, 4, and 5.

ACTION

3.2.14.1 With the STS not operating in the required mode, i.e., in the fully automatic mode or being operated in a manual or partially automatic mode such that all required tests are performed at least once per 7 days during Modes 1, 2, and 3; or at least once per 90 days during Modes 4 and 5.

a. In Modes 1, 2, and 3, restore the STS to the required mode within 30 days, and initiate a Condition Report.

b. In Modes 4 and 5, restore the STS to the required mode within 90 days or suspend CORE ALTERATIONS and operations with a potential for draining the reactor vessel, verify all insertable control rods to be fully inserted and lock the reactor mode switch in the Shutdown position within one hour.

3.2.14.2 The provisions of Operational Requirement 1.2.3 and 1.2.4 are not applicable.

2.2.14 NSPS SELF TEST SYSTEM (continued)

TESTING REQUIREMENTS

4.2.14.1 Status indications of the STS shall be obtained at least once per 24 hours, whenever the STS is operating in the fully or partially automatic mode.

BASES

5.2.14 This specification provides the minimum requirements necessary to preserve the STS's ability to perform its intended function of detecting and determining the location of a fault in the functional NSPS.

The Self Test System (STS) is an overlay testing and surveillance subsystem which provides the capability to continuously and automatically perform testing of all active circuitry within the NSPS panels, essential to the safe shutdown of the reactor. The primary purpose of the STS is to enhance the availability of the NSPS by optimizing the time to detect and determine the location of a failure in the functional system. Each of the four NSPS cabinets, with one cabinet associated with each of the four Class IE powered NSPS divisions, contains its own controller. The STS may be used for post-maintenance testing and to augment conventional testing methods which include CHANNEL CHECKS, CHANNEL FUNCTIONAL TESTS, CHANNEL CALIBRATIONS, RESPONSE TIME TESTS and LOGIC SYSTEM FUNCTIONAL TESTS.

Under the provision of the ACTION statement, with the STS inoperable or not operating in the required mode of operation, 30 days is allowed to restore the STS to the required mode during MODES 1, 2, 3; 90 days is allowed during MODES 4, 5. The Operational Requirement includes an allowance for manually operating the STS to perform testing equivalent to that which is normally performed during automatic operation. System operating characteristics allow the operator to determine that the STS is operating automatically or partially automatically. Manual or partially automatic STS testing is required to be performed at least once per 7 days during MODES 1, 2, 3 and at least once per 90 days during MODES 4, 5. These frequencies and allowed out-of-service times have been shown by analysis to be acceptable for supporting adequate overall availability of the NSPS (Reference: EAS-67-1089, "Proposed Improved Technical Specification for Clinton Nuclear Power Station Nuclear Systems Protection System (NSPS) Self Test System (STS)"). Maintaining the STS in a partially automatic mode as much as possible (whenever it is not operating in the fully automatic mode) provides further enhancement of the NSPS availability.

2.2.15 SUPPRESSION POOL WATER TEMPERATURE INDICATORS

OPERATIONAL REQUIREMENT

Sixteen suppression pool water temperature indicators, with at least two channels in each suppression pool sector, shall be OPERABLE with the high water temperature alarm set for ≤ 93° F.

APPLICABILITY MODES 1, 2, and 3

ACTION

3.2.15.1 With fewer than 16 suppression pool water temperature indicators OPERABLE, within 4 hours of indicator inoperability verify at least one temperature indicator OPERABLE in each of eight suppression pool sectors.

3.2.15.2 With no OPERABLE suppression pool water temperature indicator in one suppression pool sector, either restore at least one inoperable temperature indicator in each suppression pool sector to OPERABLE status within 7 days or verify suppression pool water temperature to be within limit at least once per 12 hours.

3.2.15.3 With no OPERABLE suppression pool water temperature indicator in two or more suppression pool sectors, restore at least one inoperable temperature indicator in at least seven suppression pool sectors to OPERABLE status within 8 hours.

3.2.15.4 The provisions of Operational Requirement 1.2.3 are not applicable.

TESTING REQUIREMENTS

4.2.15.1 Perform a CHANNEL CHECK of the suppression pool water temperature indicators, at least once per 24 hours.

4.2.15.2 Perform a CHANNEL FUNCTIONAL TEST of the suppression pool water temperature indicators, at least once per 31 days.

4.2.15.3 Perform a CHANNEL CALIBRATION of the suppression pool water temperature indicators, with the water high temperature alarm setpoint set for ≤ 93° F, at least once per 24 months.

2.2.16 MAIN STEAM LINE RADIATION MONITORING (MSLRM) INSTRUMENTATION

OPERATIONAL REQUIREMENT

The Main Steam Line Radiation Monitoring (MSLRM) Instrumentation shown in Table 3.2.16-1 shall be OPERABLE with their alarm/trip setpoints set consistent with the values specified in Table 3.2.16-1.

APPLICABILITY See Table 3.2.16-1

ACTIONS

3.2.16.1

a. With a MSLRM channel trip setpoint less conservative than the allowable value shown in Table 3.2.16-1, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. Restore the inoperable channel to OPERABLE within 30 days or initiate a Condition Report.

Table 3.2.16-1
MSLRM Instrumentation

INSTRUMENTATION	MINIMUM CHANNELS	ALARM/ TRIP SETPOINT	ALLOWABLE VALUE	APPLICABILITY
1. MECHANICAL VACUUM PUMP a. Main Steam Line Radiation-High	1	≤ 1.5 x full power background #	≤ 3.6 x full power background #	Modes 1, 2, 3
b. Main Steam Line Radiation-High High	2 (a)	3.0 x full power background	≤ 6.0 x full power background	Modes 1, 2, 3 when the mechanical vacuum pump is operating (b)

Alarm Setpoint.

(a) A channel may be placed in an inoperable status for required testing.

(b) Not isolated from main condenser.

2.2.16 MAIN STEAM LINE RADIATION MONITORING (MSLRM) INSTRUMENTATION (continued)

TESTING REQUIREMENTS

4.2.16.1 Perform a CHANNEL CHECK every 12 hours for the MSLRM instrumentation.

4.2.16.2 Perform a CHANNEL FUNCTIONAL TEST every 92 days for the MSLRM instrumentation.

4.2.16.3 Perform a CHANNEL CALIBRATION every 24 months for the MSLRM instrumentation.

4.2.16.4 LOGIC SYSTEM FUNCTIONAL TESTS shall be performed at least once per 24 months.

BASES

5.2.16 The Main Steam Line Radiation (MSLR) High-High mechanical vacuum pump trip function is provided to detect a significant increase in the radiation levels in the main steam lines when the mechanical vacuum pump is aligned to the main condenser. Isolation signals generated from the MSLRs are not credited for any design basis event. The MSLR CRVICS isolation and RPS Scram functions were removed from the Technical Specifications based on the applicability of General Electric Topical Report NEDO-31400A, "Safety Evaluation for Eliminating the Boiling Water Reactor Main Steam Line Radiation Monitor," to CPS. This Topical Report provided the results of generic evaluations which indicated that the main steam line radiation monitors are unnecessary to ensure compliance with the radiation dose guidelines of 10 CFR 100. With the elimination of the main steam line radiation monitor isolation function from the plant design the main control room alarm function and the automatic trip of the Mechanical Vacuum Pump are retained. The high radiation alarm alerts operators to consider other plant indications in determining the source of the increased radiation, such as the onset of leakage from a fuel pin(s). These actions will ensure that any significant increases in the levels of radioactivity in the main steam lines will be expeditiously controlled (by procedure) to limit both occupational doses and environmental releases.

Alarm and trip settings are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability. Two channels are required operable to provide mechanical vacuum pump trip capability. Either channel will initiate the MSL Radiation - High annunciator.

2.2.17 HYDROGEN MONITORING EQUIPMENT

OPERATIONAL REQUIREMENTS

One Channel of Primary Containment and Drywell Hydrogen Monitoring Equipment shall be OPERABLE.

APPLICABILITY

MODES 1 and 2

ACTIONS

3.2.17
a. With the required channel inoperable, restore the required channel to an OPERABLE status within 7 days.
b. With Action and Completion Time of 3.2.17.a not met, initiate a Condition Report, and identify an alternate means of monitoring hydrogen.

TESTING REQUIREMENTS

4.2.17.1 Perform a CHANNEL CHECK every 31 days.

4.2.17.2 Perform a CHANNEL CALIBRATION every 92 days.

BASES

5.2.17 A hydrogen monitor is required to assess the degree of core damage during a beyond design-basis accident and confirm that random or deliberate ignition has taken place. If an explosive mixture that could threaten containment integrity exists during a beyond design-basis accident, then other severe accident management strategies, such as purging and/or venting, would need to be considered. A hydrogen monitor is needed to implement these severe accident management strategies. With the elimination of the design-basis LOCA hydrogen release, hydrogen monitor is no longer required to mitigate design-basis accidents and, therefore, the hydrogen monitor does not meet the definition of a safety-related component as defined in 10CFR50.2. The actions ensure that the regulatory commitment to maintain a hydrogen monitoring system capable of diagnosing beyond design-basis accidents is maintained.

2.3 REACTOR COOLANT SYSTEMS

2.3.1 REACTOR COOLANT SYSTEM CHEMISTRY

OPERATIONAL REQUIREMENTS

The chemistry of the reactor coolant system shall be maintained within the limits specified in the Table 3.3.1-1.

APPLICABILITY At all times.

ACTION

3.3.1.1 In MODE 1:

a. With the conductivity, chloride concentration, or pH exceeding the limit specified in Table 3.3.1-1 for less than 72 hours during one continuous time interval and, for conductivity and chloride concentration, for less than 336 hours per year, but with the conductivity less than 10 micro mho/cm at 25°C and with the chloride concentration less than 0.5 ppm, this need not be reported to the Commission and the provisions of Operational Requirement 1.2.4 are not applicable.

b. With the conductivity, chloride concentration, or pH exceeding the limit specified in Table 3.3.1-1 for more than 72 hours during one continuous time interval or with the conductivity and chloride concentration exceeding the limit specified in Table 3.3.1-1, for more than 336 hours per year, be in at least MODE 2 within the next 6 hours.

c. With the conductivity exceeding 10 micro mho/cm at 25°C or chloride concentration exceeding 0.5 ppm, be in at least MODE 3 within 12 hours and in MODE 4 within the next 24 hours.

3.3.1.2 In MODES 2 and 3 with the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.3.1-1 for more than 48 hours during one continuous time interval, be in at least MODE 3 within the next 12 hours and in MODE 4 within the following 24 hours.

2.3.1 REACTOR COOLANT SYSTEM CHEMISTRY (continued)

3.3.1.3 At all other times:

a. With the conductivity or pH exceeding the limit specified in Table 3.3.1-1, restore the conductivity and pH to within the limit within 72 hours, or perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to MODE 3.

b. With the chloride concentration exceeding the limit specified in Table 3.3.1-1 restore the chloride concentration to within the limit within 24 hours, or perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to MODE 3.

c. The provisions of Operational Requirement 1.2.3 are not applicable.

TESTING REQUIREMENTS

4.3.1.1 The reactor coolant conductivity and chlorides shall be determined to be within the specified chemistry limit by measurement prior to pressurizing the reactor during each reactor startup, if not performed within the previous 72 hours.

4.3.1.2 Reactor coolant samples shall be analyzed for chlorides at least once per 72 hours, and every 8 hours whenever conductivity is greater than the limit in Table 3.3.1-1.

4.3.1.3 Reactor coolant samples shall be analyzed for conductivity at least once per 72 hours.

4.3.1.4 Reactor coolant samples shall be analyzed for pH every 8 hours whenever conductivity is greater than the limit in Table 3.3.1-1.

2.3.1 REACTOR COOLANT SYSTEM CHEMISTRY (continued)

4.3.1.5 Reactor coolant conductivity shall be continuously recorded. If the continuous recording conductivity monitor is inoperable, obtain in-line conductivity measurements, or a dip sample from the fuel pool, every 4 hours in MODES 1, 2 and 3, and every 24 hours at all other times.

4.3.1.6 Perform a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell every 7 days, and every 24 hours when the conductivity is greater than the limit in Table 3.3.1-1.

Table 3.3.1-1
REACTOR COOLANT SYSTEM CHEMISTRY LIMITS

MODE	CHLORIDES	CONDUCTIVITY (µmhos/cm @ 25°C)	pH
1	$\leq$ 0.2 ppm	$\leq$ 1.0	$5.6 \leq pH \leq 8.6$
2 and 3	$\leq$ 0.1 ppm	$\leq$ 2.0	$5.6 \leq pH \leq 8.6$
At all other times	$\leq$ 0.5 ppm	$\leq$ 10.0	$5.3 \leq pH \leq 8.6$

BASES

5.3.1 The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel.

The effect of chloride is not as great when the oxygen concentration in the coolant is low, thus the 0.2 ppm limit on chlorides is permitted during POWER OPERATION. During shutdown and refueling operations, the temperature necessary for stress corrosion to occur is not present so a 0.5 ppm concentration of chlorides is not considered harmful during these periods.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. When the conductivity is within limits, the pH, chlorides and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

The testing requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

During outage refueling with no available means to obtain an in-line conductivity measurement, dip sample conductivity may be obtained from the fuel pool when the reactor vessel head is removed and the reactor cavity is flooded.

2.3.2 STRUCTURAL INTEGRITY

OPERATIONAL REQUIREMENTS

The structural integrity of ASME Code Class 1, 2 and 3 components shall be maintained in accordance with Testing Requirement 4.3.2.

APPLICABILITY MODES 1, 2, 3, 4, and 5.

ACTION

3.3.2

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

d. The provisions of Operational Requirement 1.2.4 are not applicable.

TESTING REQUIREMENTS

2.3.3 Operational Requirement 1.3.5.

BASES

5.3.2 The inspection programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant.

2.3.2 STRUCTURAL INTEGRITY (continued)

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code 1975 Edition and Addenda through Winter 1975.

The inservice inspection program for ASME Code Class 1, 2 and 3 components will be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the NRC pursuant to 10 CFR Part 50.55a(g)(6)(i).

2.4. PLANT SYSTEMS

2.4.1 SNUBBERS

OPERATIONAL REQUIREMENTS

All required snubbersshall be OPERABLE. Not applicable to snubbers installed on non-safety related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system. (Non-ISI snubbers)

APPLICABILITY

MODES 1, 2, and 3.
MODES 4 and 5 for snubbers located on systems required OPERABLE in those MODES.

---NOTE---
Separate Condition entry is allowed for each snubber.

ACTION

3.4.1 With one or more required snubbers removed or inoperable:

a. Immediately determine if attached system is OPERABLE.

b. Within 72 hours, replace or restore the inoperable snubber(s) to OPERABLE status.

AND

c. Within 72 hours, perform an engineering evaluation on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

d. Required Actions and associated Completion Times of 3.4.1.a, 3.4.1.b. and 3.4.1.c not met, immediately declare the attached system inoperable and follow the appropriate Required Actions for that system.

3.4.2 An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type, which may be subject to the same failure mode.

2.4.1 SNUBBERS (continued)

If any snubber selected for functional testing either fails to lock up or fails to move, i.e., frozen-in-place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Testing Requirement 4.4.1.e for snubbers not meeting the functional test acceptance criteria.

4.4.1 Each required snubber shall be demonstrated OPERABLE by the performance of the following inservice inspection program in addition to the requirements of Operational Requirement 1.3.5.

a. Visual Inspections

For the purpose of Visual Inspections Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible and accessible) may be inspected independently according to the schedule determined by the Inservice Inspection Program Plan.

b. Visual Inspection Acceptance Criteria

Visual inspections shall verify that (1) the snubber has 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 acceptable for the purpose of establishing the next visual inspection interval, provided 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 Testing Requirement 4.4.1.f. All snubbers found connected to an inoperable common hydraulic fluid reservoir shall be counted as unacceptable for determining the next inspection interval. 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. Transient Event Inspection

An inspection shall be performed of all required snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients, as determined from a review of operational data or a visual inspection of the systems, within 72 hours for accessible areas and within 6 months for inaccessible areas following this determination. In addition to satisfying the visual inspection

2.4.1 SNUBBERS (continued)

acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

d. Functional Tests

For the purpose of Functional Testing Snubbers, Defined Test Plan Groups (DTPGs) may be per the Inservice Inspection Program Plan. At least once per refueling outage, a representative sample of snubbers shall be tested using one of the sample plans identified in the ISI Program Plan for each DTPG. The sample plan shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected prior to the test period or the sample plan used in the prior test period shall be implemented.

e. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range in both tension and compression;

2. Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range;

3. For mechanical snubbers, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

4. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

f. Functional Testing of Repaired and Replaced Snubbers

Snubbers that fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers that have repairs that might affect the functional test result shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

2.4.1 SNUBBERS (continued)

5.4.1 All required snubbers are required OPERABLE to ensure that the structural integrity of the reactor coolant system and all other safety related systems is maintained during and following a seismic or other event initiating dynamic loads.

For the purpose of Functional Testing, snubbers may be classified in accordance with ASME OM Code, Subsection ISTD. Snubbers may be classified as one population, or divided into the two categories of accessible and inaccessible, or grouped by design, manufacturer, size and type. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either Manufacturer.

When a required snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

A representative sample of the installed snubbers will be functionally tested to establish operational readiness at least once per refueling interval. Observed failures of these sample snubbers will require functional testing of additional units. To provide further assurance of snubber operability, snubbers are examined at the frequencies required in the ASME OM Code, Subsection ISTD and applicable Code Cases.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs. The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records, i.e., newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc. The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

2.4.2 SEALED SOURCE CONTAMINATION

OPERATIONAL REQUIREMENTS

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

The isotope segments of the GE 14i Isotope Test Assembly program contain double encapsulated cobalt targets that have characteristics similar to the description of a sealed source. These isotope segments are not a sealed source and are not subject to the requirements of this section.

APPLICABILITY At all times.

ACTION

3.4.2

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

1. Decontaminate and repair the sealed source, or
2. Dispose of the sealed source in accordance with Commission Regulations.

b. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TESTING REQUIREMENTS

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

a. The licensee, or

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

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

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

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

1. With a half-life greater that 30 days, excluding Hydrogen 3, and
2. In any form other than gas.

2.4.2 <u>SEALED SOURCE CONTAMINATION</u> (continued)

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

4.4.2.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

<u>BASES</u>

5.4.2 The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

2.4.4 LIQUID STORAGE TANKS

OPERATIONAL REQUIREMENTS

The quantity of radioactive material contained in each of the following unprotected outdoor tanks shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

a. Cycled Condensate Storage Tank
b. RCIC Storage Tank
c. Outside temporary tank.

APPLICABILITY At all times

ACTION

3.4.4

a. With the quantity of radioactive material in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Radioactive Effluent Release Report.

b. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TESTING REQUIREMENTS

4.4.4 The quantity of radioactive material contained in each of the above listed tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

* Tanks included in this Operational Requirement are those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

2.4.4 LIQUID STORAGE TANKS (continued)

BASES

5.4.4 The tanks listed in this section include all those outdoor storage tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in each of the specified tanks provides assurance that in the event of an uncontrolled release of the contents from any of these tanks, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

2.4.5 MAIN CONDENSER OFFGAS HYDROGEN MONITORING

OPERATIONAL REQUIREMENTS

The concentration of hydrogen in the main condenser offgas treatment system shall be limited to less than or equal to 4% by volume.

APPLICABILITY Whenever the main condenser air ejector is in operation.

ACTION

3.4.5

a. With the concentration of hydrogen in the main condenser offgas treatment system exceeding the limit, restore the concentration to within the limit within 48 hours.

b. The provisions of Operational Requirements 1.2.3 and 1.2.4 are not applicable.

TESTING REQUIREMENTS

4.4.5 The concentration of hydrogen in the main condenser offgas treatment system shall be determined to be within the above limits by continuously monitoring the waste gases in the main condenser offgas treatment system whenever the main condenser evacuation system is in operation with the hydrogen monitors required OPERABLE by Operational Requirement 2.2.11.

BASES

5.4.5 Although there should normally be more than sufficient steam flow to the steam jet air ejectors to ensure adequate dilution of hydrogen (and thus prevent the offgas from attaining hydrogen levels in excess of the flammability limit), this specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the offgas holdup system is monitored and maintained below the flammability limit of hydrogen. Maintaining the concentration of hydrogen below its flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

2.4.6 DRYWELL POST-LOCA VACUUM RELIEF VALVES

OPERATIONAL REQUIREMENTS

All drywell post-LOCA vacuum relief valves position indicators shall be OPERABLE.

APPLICABILITY MODES 1, 2, and 3.

ACTION

3.4.6 With the position indicator of one or more OPERABLE drywell post-LOCA vacuum relief valve(s) inoperable, verify at least one vacuum relief valve in each affected penetration to be closed** at least once per 24 hours, and initiate a condition report. The provisions of Operational Requirement 1.2.3 and 1.2.4 are not applicable.

** Drywell post-LOCA vacuum relief valves may be opened on an intermittent basis under administrative controls to perform required surveillance testing.

TESTING REQUIREMENTS

4.4.6.1 At least once per 31 days verify the position indicator OPERABLE by observing expected valve movement during the cycling test.

4.4.6.2 At least once per 24 months verify the position indicator OPERABLE by performance of a CHANNEL CALIBRATION.

2.4.8 SPENT FUEL STORAGE, CASK STORAGE AND UPPER CONTAINMENT POOLS

OPERATIONAL REQUIREMENTS

At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the spent fuel storage, cask storage and upper containment fuel pool racks.

APPLICABILITY Whenever irradiated fuel assemblies are in the spent fuel storage, cask storage or upper containment fuel pools.

ACTION

3.4.8 With the above requirements not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel storage or upper containment fuel pool areas, as applicable after placing the fuel assemblies and crane load in a safe condition. The provisions of Operational Requirement 1.2.3 are not applicable.

TESTING REQUIREMENTS

4.4.8 The water level in the spent fuel storage and upper containment fuel pools shall be determined to be at least at its minimum required depth at least once per 7 days.

BASES

5.4.8 The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

With irradiated fuel assemblies in the cask storage pool, the gates between the cask storage pool and spent fuel pool must be open to ensure removal of decay heat from the cask storage pool. Thus, water level in the cask storage pool is monitored via the spent fuel pool level indication.

2.4.9 ESSENTIAL SWITCHGEAR ROOM (VX) VENTILATION

OPERATIONAL REQUIREMENTS

The temperature of the areas cooled by the Division 1, 2 and 3 essential switchgear heat removal (VX) system shall be maintained $\leq$ 95 degrees F.

APPLICABILITY

Whenever the equipment in the associated area is required to be OPERABLE.

ACTION

3.4.9.1 With an area temperature greater than 95 degrees F,
a. Perform TR 4.4.9.1 within 1 hour and every 4 hours thereafter, and
b. Restore the area temperature to within the limit within 24 hours, or place the safety related switchgear heat removal coil cabinet in service, if not already in service.

3.4.9.2 With an area temperature greater than 104 degrees F,

a. Immediately take action to restore the area temperatures within 8 hours, and

b. Declare the equipment in the affected area inoperable.

3.4.9.3 If Action 3.4.9.2 is entered, prepare a report in accordance with Operational Requirement 6.6.

TESTING REQUIREMENTS

4.4.9.1 Verify the temperature of the areas cooled by the VX system to be $\leq$ 95 degrees F every 12 hours.

BASES

5.4.9.1 The switchgear heat removal (VX) system is discussed in USAR Section 9.4.5.2. The VX system is designed to limit the maximum temperatures inside the switchgear rooms to 95 degrees F during normal plant operation and to 104 degrees F during abnormal plant operation in conformance with equipment ambient temperature ratings and requirements. However, cooling system equipment is sized to maintain a nominal room temperature of 95 degrees under normal and abnormal operating conditions. The VX system for each division consists of two independent switchgear heat removal coil cabinets, one safety-related and one non-safety related, connected to a common supply duct system. Each VX system coil cabinet consists of a filter, cooling coil, and fan. The non-safety related VX system coil cabinet has a chilled water coil fed from the plant chilled water system and is utilized for cooling during normal station operating conditions only. The safety-related VX system coil cabinet is a standby and has a

2.4.9 ESSENTIAL SWITCHGEAR ROOM (VX) VENTILATION (continued)

refrigerant evaporator coil fed from a water-cooled condensing unit located within the switchgear room. This coil is to be utilized during abnormal operating conditions or upon failure of the chilled water VX system coil cabinets. The condenser heat is removed by shutdown service water or plant service water as discussed in USAR Subsections 9.2.1.2 and 9.2.1.1, respectively.

ORM 2.4.9 is applicable to the general areas of the essential switchgear rooms, and the equipment in these areas; however, ORM 2.4.9 is not directly applicable to the inverter rooms or the battery rooms. Refer to TS LCO 3.8.7 and 3.8.8 for the inverters and TS LCO 3.8.6 for the batteries.

2.4.10 PRIMARY CONTAINMENT HYDROGEN RECOMBINER

OPERATIONAL REQUIREMENTS

One Primary Containment Hydrogen Recombiner shall be OPERABLE.

APPLICABILITY

When both divisions of hydrogen igniters are inoperable, requiring entry into TS 3.6.3.2, Condition B.

ACTION

3.4.10 With no hydrogen recombiner OPERABLE, immediately enter TS 3.6.3.2, Condition C.

TESTING REQUIREMENTS

4.4.10.1 Perform a FUNCTIONAL TEST for the hydrogen recombiner, every 24 months.

4.4.10.2 Visually examine the Primary Containment Hydrogen Recombiner enclosure and very there is no evidence of abnormal conditions, every 24 months.

4.4.10.3 Perform a resistance to ground test for each heater phase, every 24 months.

BASES

5.4.10.1 The revised 10CFR50.44 no longer defines a design-basis LOCA hydrogen release, and eliminated requirements for hydrogen control systems to mitigate such a release. The installation of hydrogen recombiners and/or vent and purge systems required by 10CFR50.44(b)(3) was intended to address the limited quantity and rate of hydrogen generation that was postulated from a design-basis LOCA. The NRC found that this hydrogen release is not risk-significant because the design-basis LOCA hydrogen release does not contribute to the conditional probability of a large release up to approximately 24 hours after the onset of core damage. In addition, these systems were ineffective at mitigating hydrogen releases from risk-significant beyond design-basis accidents. Therefore, the NRC eliminated the hydrogen release associated with a design-basis LOCA from 10CFR50.44 and the associated requirements that necessitated the need for the hydrogen recombiners and the backup hydrogen vent and purge systems. As a result, the NRC determined that the hydrogen recombiners no longer meet any of the four criteria in 10 CFR 50.36(c)(s)(ii) for retention in Technical Specifications and the existing TS requirements may, therefore, be eliminated for all plants.

2.5 ELECTRICAL POWER SYSTEMS

2.5.1 CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

OPERATIONAL REQUIREMENTS

Primary and backup containment penetration conductor overcurrent protective devices associated with each primary containment electrical penetration circuit shall be OPERABLE. The scope of these protective devices excludes those circuits for which credible fault currents would not exceed the electrical penetrations' design ratings.

APPLICABILITY MODES 1, 2, and 3.

ACTION

3.5.1

a. With one or more of the required containment penetration conductor overcurrent protective devices inoperable, evaluate the affected system or component for operability and enter the appropriate Technical Specification and/or ORM ACTION for the affected system and:

1. For 6.9-kV circuit breakers, remove the 6.9-kV circuit(s) from service by racking out the breaker within 72 hours and verify the inoperable breaker(s) to be racked out at least once per 7 days thereafter.

2. For lower voltage circuit breakers (excluding the upper containment polar crane), de-energize the inoperable circuit by tripping and taking appropriate administrative controls for the associated redundant circuit breaker(s) for molded case circuit breakers [or by racking out the associated redundant circuit breaker(s) for unit substation circuit breakers] within 72 hours and verify the redundant circuit breaker to be tripped at least once per 7 days thereafter.

3. For the upper containment polar crane containment penetration conductor overcurrent protective devices (cubicle 7B C08 relays and trip circuit of breaker 3B of panel 1AP11E) or circuit breaker 7B of panel 1AP11E inoperable, declare the polar crane inoperable and de-energize the inoperable circuit by racking out circuit breaker 7B of panel 1AP11E within 72 hours, and verify circuit breaker 7B of panel 1AP11E to be racked out at least once per 7 days thereafter.

2.5.1 CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES (continued)

ACTION (continued)

b. The provisions of Operational Requirement 1.2.4 are not applicable to overcurrent devices in 6.9-kV circuits which have their inoperable circuit breakers racked out or to lower voltage circuits which have the redundant circuit breaker tripped.

TESTING REQUIREMENTS

4.5.1 Each of the required containment penetration conductor overcurrent protective devices shall be demonstrated OPERABLE:

a. At least once per 72 months:

1. By verifying that all medium voltage 6.9-kV and polar crane circuit breakers are OPERABLE by performing:

   a) A CHANNEL CALIBRATION of the associated protective relays, and

   b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed.

2. By subjecting each 6.9-kV and polar crane circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

b. At least once per 96 months:

1. By selecting and functionally testing all low voltage molded case circuit breakers. Testing of these circuit breakers shall consist of injecting currents in excess of the breaker's nominal setpoint and measuring the response time of the long time delay and short time delay trip elements and setpoint of the instantaneous element where applicable. The measured response time shall be compared to the manufacturer's data to ensure that it is less than or equal to a value specified by the manufacturer.

2. By subjecting each low voltage molded case circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

2.5.1 <u>CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES</u> (continued)

<u>BASES</u>

5.5.1 Containment electrical penetrations and penetration conductors are protected by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers by periodic surveillance. The low-frequency motor generator set electrical power supply to the reactor recirculation pumps is provided with one overcurrent protection circuit breaker since the generator's maximum output under fault conditions is less than the penetration's design rating. The surveillance requirements applicable to lower voltage circuit breakers provides assurance of breaker reliability by testing all circuits breakers within the specified period.

2.5.2 MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

OPERATIONAL REQUIREMENTS

The thermal overload protection of each valve in safety systems with a bypass device(s) integral with the motor starter shall be bypassed continuously for those directions for which the valve performs an active safety function.

APPLICABILITY Whenever the motor operated valve is required to be OPERABLE.

ACTION

3.5.2 With the thermal overload protection for one or more of the above required valves not bypassed continuously in the valves' safety direction(s), continuously bypass the affected thermal overload within 8 hours or declare the affected valve(s) inoperable and apply the appropriate Technical Specification and/or ORM ACTION statement(s) for the affected system(s). When thermal overload protection is provided during maintenance, testing, or valve repositioning during normal operation, the time should be minimized and the bypass returned to service as soon as practicable. The 8 hour limitation applies under these conditions. If an emergency condition occurs demanding valve repositioning, return the thermal overload bypass circuitry to service.

TESTING REQUIREMENTS

4.5.2.1 The thermal overload protection for the above required valves shall be verified to be bypassed continuously in the valves' safety direction(s):

a. At least once per 6 years, and

b. Following maintenance on the motor starter.

4.5.2.2 The thermal overload protection for the above required valves shall be verified to be bypassed in the valves' safety direction(s) following maintenance, testing, or valve repositioning during normal operations during which the thermal overload protection was temporarily placed in force.

BASES

5.5.2 The bypassing of the motor-operated valves thermal overload protection continuously ensures that the thermal overload protection will not prevent safety-related valves from performing their function. The Surveillance Requirements for demonstrating the bypassing of the thermal overload protection continuously are in accordance with Regulatory Guide 1.106 "Thermal Overload Protection for Electric Motors on Motor-Operated Valves," Revision 1, March 1977.

2.5.3 ELECTRICAL POWER SYSTEMS

OPERATIONAL REQUIREMENTS

Battery cell parameters for the Division 1, 2, 3, and 4 batteries shall be within the limits of Table 2.5.3-1.

APPLICABILITY

When the associated battery is required to be OPERABLE.

ACTIONS

(NOTE: Separate condition entry is allowed for each battery.)

3.5.3.1 With one or more batteries with one or more battery cell parameters not within Table 2.5.3-1 Category A or B limits,

a. Verify pilot cell's electrolyte level and float voltage meet Table 2.5.3-1 Category C limits within 1 hour, and

b. Verify battery cell parameters meet Table 2.5.3-1 Category C limits within 24 hours and once per 7 days thereafter, and

c. Restore battery cell parameters to Category A and B limits of Table 2.5.3-1 within 31 days.

3.5.3.2 With required actions associated with 3.5.3.1 not met, or with one or more batteries with average electrolyte temperature of the representative cells <65 F, or with one or more batteries with one or more battery cell parameters not within Category C limits, immediately declare the associated battery inoperable.

TESTING REQUIREMENTS

4.5.3.1 Verify battery cell parameters meet Table 2.5.3-1 Category A limits at least once per 7 days.

4.5.3.2 Verify battery cell parameters meet Table 2.5.3-1 Category B limits at least once per 92 days and once within 72 hours after a battery overcharge of > 150V.

4.5.3.3 Verify average electrolyte temperature of representative cells is ≥ 65 F at least once per 92 days.

2.5.3 ELECTRICAL POWER SYSTEMS (continued)

TABLE 2.5.3-1

BATTERY CELL PARAMETER REQUIREMENTS

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark [(a)]	> Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark [(a)]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13V	≥ 2.13V	> 2.10V
Specific Gravity [(b)] [(c)]	≥ 1.195	≥ 1.190 AND Average of all connected cells ≥ 1.200	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥ 1.190

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. However, level correction is not required when battery charging is < 2 amps when on float charge.

(c) A battery charging current of < 2 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

2.6 REFUELING OPERATIONS

2.6.1 DECAY TIME -- REFUELING OPERATIONS

OPERATIONAL REQUIREMENTS

The reactor shall be subcritical for at least 24 hours.

APPLICABILITY MODE 5, during movement of irradiated fuel in the reactor pressure vessel.

ACTION

3.6.1 With the reactor subcritical for less than 24 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.

TESTING REQUIREMENTS

4.6.1 The reactor shall be determined to have been subcritical for at least 24 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

BASES

5.6.1 The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the safety analyses.

2.6.2 COMMUNICATIONS - REFUELING OPERATIONS

OPERATIONAL REQUIREMENTS

Direct communication shall be maintained between the control room and refueling platform personnel.

APPLICABILITY MODE 5, during CORE ALTERATIONS*.

* Except movement of control rods with their normal drive system.

ACTION

3.6.2 When direct communication between the control room and refueling platform personnel cannot be maintained, immediately suspend CORE ALTERATIONS.

TESTING REQUIREMENTS

4.6.2 Direct communication between the control room and refueling platform personnel shall be demonstrated at least once per 12 hours during CORE ALTERATIONS*.

* Except movement of control rods with their normal drive system.

BASES

5.6.2 The requirement for communications capability ensures that refueling platform personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

2.6.3 REFUELING PLATFORM -- REFUELING OPERATIONS

OPERATIONAL REQUIREMENTS

The refueling platform shall be OPERABLE and used for handling fuel assemblies or control rods, either:

a) within the reactor pressure vessel, or

b) during operations associated with the Inclined Fuel Transfer System (IFTS).

APPLICABILITY During handling of fuel assemblies or control rods, either:

a) within the reactor pressure vessel, or

b) during operations associated with the IFTS.

ACTION

3.6.3 With the requirements for refueling platform OPERABILITY not satisfied, suspend use of any inoperable refueling platform equipment from operations involving the handling of control rods and fuel assemblies within the reactor pressure vessel, or the IFTS, after placing the load in a safe condition.

TESTING REQUIREMENTS

4.6.3 Each refueling platform crane or hoist used for handling of control rods or fuel assemblies within the reactor pressure vessel, or the IFTS, shall be demonstrated OPERABLE within 7 days prior to the start of such operations with that crane or hoist by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1600 ± 50 pounds.

b. Demonstrating operation of the overload cutoff on the frame mounted, 500 lb, and monorail hoists when the load exceeds 500 ± 50 pounds.

c. Demonstrating operation of the uptravel interlock to maintain the top of the active fuel or control rods to $\geq$ 8 feet 6 inches below the water level.

d. Deleted.

e. Demonstrating operation of the slack cable cutoff on the main hoist when the load is less than 50 ± 10 pounds.

2.6.3 REFUELING PLATFORM - REFUELING OPERATIONS (continued)

f. Demonstrating operation of the loaded interlock on the main hoist when the load exceeds 700 ± 50 pounds.

g. Demonstrating operation of the main hoist raise power cutoff when the refueling platform area radiation monitor dose rate exceeds 50 mR/hr.

h. Demonstrating operation of the redundant loaded interlock (rod block) on the main hoist when the load exceeds 700 ± 50 pounds.

BASES

5.6.3 The OPERABILITY requirements ensure that the appropriate fuel handling equipment will be used for handling control rods and fuel assemblies during operations associated with the IFTS and within the reactor pressure vessel, that each crane and hoist has sufficient load capacity for handling fuel assemblies and/or control rods, and that the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

2.6.4 Deleted

2.6.5 CRANE TRAVEL - SPENT FUEL STORAGE POOL, CASK STORAGE POOL, UPPER CONTAINMENT FUEL POOL, AND NEW FUEL STORAGE VAULT - REFUELING OPERATIONS

OPERATIONAL REQUIREMENTS

Loads in excess of 1000 pounds shall be prohibited from travel over fuel assemblies in the spent fuel storage racks in the spent fuel storage and cask storage pools, upper containment fuel pool racks or new fuel storage vault racks.

APPLICABILITY With fuel assemblies in the spent fuel storage pool racks in the spent fuel storage and cask storage pools, upper containment fuel pool racks, or the new fuel storage vault racks.

ACTION

3.6.5 With the requirements of the above Operational Requirement not satisfied, place the crane load in a safe condition. The provisions of Operational Requirement 1.2.3 are not applicable.

TESTING REQUIREMENTS

4.6.5.1 Crane physical stops which prevent fuel building overhead crane travel with loads in excess of 1000 pounds over fuel assemblies in the spent fuel storage pool racks shall be demonstrated OPERABLE (except as allowed per License Amendment 170 as described in ORM Bases 5.6.5):

a. Within 7 days prior to handling loads with the fuel building overhead crane, and

b. At least once per 7 days while handling loads with the fuel building overhead crane.

4.6.5.2 Loads other than fuel assemblies or control rods shall be verified to weigh less than or equal to 1000 pounds before travel over fuel assemblies in the upper containment fuel storage pool or the new fuel storage vault racks.

BASES

5.6.5 The restriction on movement of loads in excess of the nominal weight of a fuel assembly over other fuel assemblies in the pools ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses. The fuel building overhead crane physical stops preclude travel of the fuel building overhead crane over the fuel building spent fuel storage pool racks. The stops also ensure that handling of heavy loads is within the guidelines of NUREG-0612 which precludes dropping a heavy load onto safety-related equipment. Although weighing more than 1000 pounds itself, the fuel building overhead crane main hoist load block need not be considered a load provided no loads are being handled by the fuel building overhead crane and the main hoist load block is secured in accordance with plant rigging procedures for single failure proof rigging. This will ensure that

2.6.5 <u>CRANE TRAVEL - SPENT FUEL STORAGE POOL, CASK STORAGE POOL, UPPER CONTAINMENT FUEL POOL, AND NEW FUEL STORAGE VAULT - REFUELING OPERATIONS</u> (continued)

movement of the load block is in accordance with NUREG- 0612. With these controls in force, the crane physical stops may be removed and the secured load block allowed to travel over the fuel building spent fuel storage pool. The physical stops do not prevent the crane from traveling over the cask storage pool.

License Amendment 170 was approved for the Clinton Power Station "Onsite Spent Fuel Storage Expansion" project. Consistent with the license amendment request and the NRC's Safety Evaluation, Amendment 170 allows the Fuel Building Crane (1HC07G) to be used as an alternate crane if the temporary crane is inoperable. This allows 1HC07G functional access over the spent fuel pool (SFP) for this project. This permits the crane physical stops to be removed without securing the main hoist load block for the duration of the Spent Fuel Pool Expansion project.

Barriers will be established in procedures to ensure the safe load path is used and that no heavy loads travel over fuel, as follows:

1. Whenever the Fuel Building Crane is operated past (east of) the bridge travel limit switch setpoint, a dedicated spotter in direct communication with the crane operator will be assigned to ensure that loads in excess of 1000 pounds are prohibited from traveling over fuel assemblies.

2. Whenever the Fuel Building Crane physical stops do not restrict crane travel over the SFP, either:
    a. A crane operator is stationed in the area to prevent unauthorized activities until physical travel stops are repositioned, or,
    b. An equipment status tag is hung on the crane disconnect to alert the crane operator that the crane travel stops have been moved and will not restrict crane travel over the SFP.

2.6.6 INCLINED FUEL TRANSFER SYSTEM - REFUELING OPERATIONS

OPERATIONAL REQUIREMENTS

The following conditions shall be met for the inclined fuel transfer system (IFTS):

1. Transferring non-irradiated components:

    a. At least one IFTS carriage position indicator shall be OPERABLE at each carriage position;

    b. At least one liquid level sensor shall be OPERABLE;

    c. The blocking valve located in the fuel building IFTS hydraulic power unit shall be OPERABLE.

2. In addition to Operational Requirements l.a, l.b, and l.c above, when transferring irradiated components:

    a. The access doors (including removable shields) of all rooms through which the transfer system penetrates shall be closed and locked;

    b. All access doors (including removable shields) interlocks shall be OPERABLE;

    c. Any keylock switch that provides IFTS access control-transfer system lockout shall be OPERABLE.

APPLICABILITY During IFTS operation.

ACTION

3.6.6 With the requirements of the above Operational Requirement not satisfied, suspend IFTS operation with the IFTS at either terminal point. The provisions of Operational Requirement 1.2.3 are not applicable.

TESTING REQUIREMENTS

4.6.6.1 Verify prior to use and once per 30 days during operation of the IFTS:

a. At least one IFTS carriage position indicator is OPERABLE at each carriage position,

b. At least one liquid level indicator is OPERABLE, and

c. The blocking valve in the Fuel Building IFTS hydraulic power unit is OPERABLE.

2.6.6 INCLINED FUEL TRANSFER SYSTEM - REFUELING OPERATIONS (continued)

4.6.6.2 Verify the following within 4 hours prior to transfer of irradiated components with the IFTS:

a. No personnel are in areas immediately adjacent to the IFTS, and

b. All access doors (including removable shields) to rooms through which the IFTS penetrates are closed and locked.

4.6.6.3 Verify prior to use and once per 30 days during transfer of irradiated components with the IFTS:

a. All access door (including removable shields) interlocks are OPERABLE, and

b. The keylock switches which provide IFTS access or control-transfer system lockout are OPERABLE.

BASES

5.6.6 The purpose of the inclined fuel transfer system specification is to control personnel access to those potentially high radiation areas immediately adjacent to the system and to assure safe operation of the system.

2.6.7 MODE SWITCH POSITION

OPERATIONAL REQUIREMENTS

The reactor mode switch shall be locked in the Shutdown or Refuel position*.

* Except as provided in Technical Specification Special Operations LCO 3.10.2 and 3.10.8.

APPLICABILITY MODE 4**, 5

ACTION

3.6.7 With the reactor mode switch not locked in the Shutdown or Refuel position as specified, suspend CORE ALTERATIONS and lock the reactor mode switch in the Shutdown or Refuel position.

TESTING REQUIREMENTS

4.6.7 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel Position at least once per 12 hours.

** When the contained water volume of the suppression pool is less than 98,700 ft^3, which is equivalent to a suppression pool level of 12' 8", or Technical Specification 3.10.4 is being utilized.

6.0 ADMINISTRATIVE REQUIREMENTS

6.1 Administrative Requirements are contained in Section 13.1.2.3 of the USAR for operating shift crews (USAR Change Package 8-215).

6.2 Not Used

6.3 Not Used

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Director-Operations Training and shall meet or exceed the requirements of 10 CFR Part 55.

6.5 REVIEW AND AUDIT

6.5.1 PLANT OPERATIONS REVIEW COMMITTEE (PORC)

Refer to USAR Section 13.4.1, "Plant Operations Review Committee."

6.5.2 NUCLEAR SAFETY REVIEW BOARD (NSRB)

Refer to Updated Safety Analysis Report section 13.4.2, Nuclear Safety Review Board.

6.5.3 TECHNICAL REVIEW AND CONTROL

ACTIVITIES

Procedures required by Technical Specification 5.4.1 and ORM 6.8 and other procedures which affect plant nuclear safety as determined by the Manager-Clinton Power Station or the responsible manager* and changes thereto, other than editorial or typographical changes, shall be reviewed as follows:

6.5.3.1 TECHNICAL REVIEW

a. Each such procedure or procedure change shall be independently reviewed by an individual knowledgeable in the area affected other than the individual who prepared the procedure, or procedure change. The applicable Department Head/Designee shall approve all plant procedures and changes thereto, prior to implementation.

b. Individuals responsible for reviews performed in accordance with Item 6.5.3.1.a above shall be designated by the Manager-Clinton Power Station or the responsible manager*. Each such review shall include a determination of whether or not additional, cross-disciplinary, review is necessary. If deemed necessary, such review shall be performed by the review personnel of the appropriate discipline.

   Individuals performing these reviews shall meet or exceed the qualifications stated in ANSI/ANS 3.1-1978 for the appropriate discipline.

c. When a review pursuant to 10 CFR 50.59 is required, it shall be included in the procedure or the procedure change review. Pursuant to 10 CFR 50.59, NRC approval of items requiring NRC review shall be obtained prior to the Manager-Clinton Power Station approval for implementation.

d. Written records of reviews performed in accordance with Item 6.5.3.1.a above, including recommendations for approval or disapproval, shall be prepared and maintained.

[*The responsible manager must be the equivalent of the Manager - Clinton Power Station with respect to his/her level of responsibility within corporate structure.]

6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for any of those conditions identified in 10CFR50.73:

a. The Commission shall be notified and a report submitted pursuant to the requirements of 10CFR50.73, and

b. The reportable event shall be reviewed by the PORC.

c. The report shall be submitted to the NSRB and the CPS Site Vice President.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The CPS Site Vice President, Manager-Clinton Power Station, and the NSRB shall be notified within 24 hours.

b. The Safety Limit Violation Report shall be reviewed by the PORC. This report shall describe: (1) applicable circumstances preceding the violation, (2) effects of the violation upon unit components, systems, or structures, and (3) corrective action taken to prevent recurrence.

c. The Safety Limit Violation Report shall be submitted to the CPS Site Vice President, Manager-Clinton Power Station, and the NSRB within 30 days of the violation.

6.8 PROCEDURES AND PROGRAMS

PROCEDURES

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. Refueling operations;

b. Surveillance and test activities of safety-related equipment;

c. Security Plan implementation;

d. Emergency Plan implementation;

e. Fire Protection Program implementation;

f. Process Control Program implementation; and

g. Offsite Dose Calculation Manual implementation.

REVIEW AND APPROVAL

6.8.2 Each procedure of Technical Specification 5.4.1 and Operational Requirement 6.8.1 and changes thereto, shall be reviewed in accordance with Updated Safety Analysis Report section 13.4.1 and Operational Requirement 6.5.3 as applicable and shall be approved by the applicable Department Head/Designee prior to implementation and reviewed periodically as set forth in administrative procedures.

TEMPORARY CHANGES

6.8.3 Temporary changes to procedures of Technical Specification 5.4.1 and Operational Requirement 6.8.1 may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

c. The change is documented, reviewed in accordance with Updated Safety Analysis Report section 13.4.1 and Operational Requirement 6.5.3 as appropriate, and approved by the applicable Department Head/Designee within 14 days of implementation.

6.8 PROCEDURES AND PROGRAMS (continued)

6.8.4 The following programs shall be established, implemented, and maintained:

a. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions.
This program shall include the following:

1. Training of personnel,
2. Procedures for monitoring, and
3. Provisions for maintenance of sampling and analysis equipment.

b. Fire Protection Program

A program to implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Safety Analysis Report as amended, and as approved in the Safety Evaluation Report (NUREG-0853) dated February 1982 as supplemented. Noncompliance with the above Fire Protection Systems described in plant procedure CC-AA-211 shall be reported in accordance with Operational Requirement 6.6.1.

c. 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.

6.9 REPORTING REQUIREMENTS

STARTUP REPORT

6.9.1.1 Summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

6.9.1.2 The startup report shall address each of the tests identified in the Updated Safety Analysis Report and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the startup report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation) supplementary reports shall be submitted at least every 3 months until all three events have been completed.

OTHER REPORTS

6.9.2 If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures and any non-valid failures experienced by that EDG in that time period shall be reported to the Commission within 30 days. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108,
Revision 1, August 1977.

6.10 RECORD RETENTION

Record retention requirements are contained in the Exelon Standard Records Retention Schedule (SRRS).

6.11 RADIATION PROTECTION PROGRAM

6.11.1 Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

6.12 Not Used

6.13 PROCESS CONTROL PROGRAM (PCP)

The Process Control Program shall contain the current formula, sampling, analyses, tests, and determinations to be made to ensure that the 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 Part 20, 10 CFR Part 61, 10 CFR Part 71 and Federal and State regulations, burial ground requirements and other requirements governing the disposal of the radioactive waste.

Changes to the PCP:

a. Shall be documented and records of reviews performed shall be retained as required by the Exelon Standard Record Retention Schedule.
   This documentation shall contain:

   1. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s), and

   2. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

b. Shall become effective after review and acceptance by the PORC and the approval of the Manager - Clinton Power Station.

This attachment contains the list of instrumentation required by Technical Specification LCO 3.3.3.2.

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

	DIVISION I		DIVISION II	
INSTRUMENT	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE
1. SRV 51D Temp. Supp. Pool Temp.	1C61-R506	1	1C61-R513	1
2. SRV 51C Temp. Supp. Pool Temp	1C61-R507	1	1C61-R514	1
3. SRV 51G Temp. Supp. Pool Temp	1C61-R508	1	1C61-R512	1
4. Supp. Pool Level	1C61-R504	1	1C61-R511	1
5. RPV Level	1C61-R010	1	1C61-R509	1
6. RPV Pressure	1C61-R011	1	1C61-R510	1
7. Upper DW Temp.	1C61-R501	1	N/A	N/A
8. Lower DW Temp.	1C61-R502	1	N/A	N/A
9. SX Strainer. Dsch. Outlet Press.	1C61-R503	1	1PI-SX024B	1
10. RCIC Cond. Storage Tank Level	1C61-R505	1	N/A	N/A
11. RHR Loop Flow	1C61-R005	1	1E12-R008B*	1
12. RCIC Turb. Speed	1C61-R003	1	N/A	N/A
13. RCIC Pump Flow	1C61-R001	1	N/A	N/A
14. RCIC Turb. Flow Control.	1C61-R001	1	N/A	N/A

*Division II RHR pump flow is determined by RHR pump discharge pressure instrumentation at panel 1H22-P021.

REMOTE SHUTDOWN SYSTEM CONTROLS

CONTROL	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE	
		DIVISION 1	DIVISION 2
l. RHR Pump	1E12-C002A/B	1	1
2. RHR Supp. Pool Suction Vlv.	1E12-F004A/B	1	1
3. RHR A Shutdown Cooling Suction Vlv.	1E12-F006A	1	N/A
4. RHR Shutdown Cooling Supply Outbd. Isol. Vlv.	1E12-F008	1	N/A
5. RHR HX Bypass Vlv.	1E12-F048A/B	1	1
6. RHR Test Line Vlv. to Supp. Pool	1E12-F024A/B	1	1
7. RHR HX Dsch. Vlv.	1E12-F003 A/B	1	1
8. Deleted			
9. RHR HX Inlet Vlv.	1E12-F047A/B	1	1
10. RHR HX SX Outlet Vlv	1E12-F068A/B	1	1
1 l. RHR Shutdown Cooling Return Vlv.	1E12-F053A/B	1	1
12. RHR RPV Inboard Inject. Vlv	1E12-F042A/B	1	1
13. RHR RPV Outboard Inject. Vlv.	1E12-F027A	1	N/A
14. RHR Cnmt. Spray Vlv.	1E12-F028A	1	N/A
15. Deleted			
16. Deleted			
17. RHR FP/FC Supply Vlv. Note (a)	1E12-F037A	1	N/A
18. RHR Pump Min. Flow Recirc. Vlv.	1E12-F064A/B	1	1
19. Deleted			
20. RHR B Shutdown Cooling Suction Vlv	1E12-F006B	N/A	1
21. Shutdown Cooling Inboard. Isol. Vlv.	1E12-F009	N/A	1
22. RPV Head Spray Vlv.	1E12-F023	N/A	1
23. Deleted			
24. RCIC Pump Cond. Stg. Tnk. Suction Vlv	1E51-F010	1	N/A
25. RCIC Supp. Pool Suction Vlv.	1E51-F031	1	N/A
26. RCIC First Test Line Isol. Vlv. To RCIC Storage Tank	1E51-F022	1	N/A
27. RCIC Inject. Vlv	1E51-F013	1	N/A
28. RCIC Min. Flow Recirc. Vlv.	1E51-F019	1	N/A
29. RCIC Second Test Line Isol. Vlv. To RCIC Stg. Tnk.	1E51-F059	1	N/A
30. RCIC Turbine L.O. Cooling Water Supply Valve	1E51-F046	1	N/A
31. RCIC Gland Seal Air Cmpsr.	1E51-C002F	1	N/A

REMOTE SHUTDOWN SYSTEM CONTROLS

CONTROL	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE	
		DIVISION 1	DIVISION 2
32. RCIC Outbd. Vac. Bkr. Vlv.	1E51-F077	1	N/A
33. RHR/RCIC Stm. Sply. Otbd. Isol. Vlv.	1E51-F064	1	N/A
34. RCIC Turb. Stm. Sply. Vlv.	1E51-F045	1	N/A
35. RCIC Turb. Xhst. Stop Vlv.	1E51-F068	1	N/A
36. RCIC Trip/Throttle Vlv.	1E51-C002E	1	N/A
37. RCIC Turb. Stm. Supply Warm-up Vlv.	1E51-F076	N/A	1
38. SRV 51C	1B21-F051C	1	1
39. SRV 51D	1B21-F051D	1	1
40. SRV 51G	1B21-F051G	1	1
41. RCIC Stm. Flow Cntrl.	N/A	1	N/A
42. RCIC Turb. Trip	N/A	1	N/A
43. DG 1A Vent. Fan	1VD01CA	1	N/A
44. DG 1A Oil Rm. A Xhst. Fan	1VD02CA	1	N/A
45. Div. 1 Switchgear Heat Removal Vent. Fan	1VX03CA	1	N/A
46. Battery Rm. 1A1 Xhst. Fan	1VX05CA	1	N/A
47. SX Pump. Rm. Sply. Fan	1VH01CA/B	1	1
48. RHR Pump. Rm. 1A Sply. Fan	1VY02C	1	N/A
49. RHR Ht. Xchg. Rm. A Sply. Fan	1VY03C	1	N/A
50. RCIC Pump. Rm. Sply. Fan	1VY04C	1	N/A
51. DG lA Ckt. Brkr	252-DGKA	1	N/A
52. DG 1A Fuel Oil Transfer Pump	1DO01PA	1	N/A
53. SX Pump	1SX01PA/B	1	1
54. SX/WS Isol. Vlv.	1SX014A/B	1	1
55. DG 1A OutletVlv.	1SX063A	1	N/A
56. SX 1A Strainer Inlet Vlv. Note (a)	1SX003A	1	N/A
57. SX 1A Strainer Outlet Vlv. Note (a)	1SX004A	1	N/A
58. SX 1A Strainer Bypass Vlv.	1SX008A	1	N/A
59. SX Xtie. Vlv.	1SX011A	1	N/A
60. RHR Ht. Xchg. 1A Demin. Water Supply. Vlv.	1SX082A	1	N/A
61. Fuel Pool Ht. Xchg. 1A SX Supply Vlv.	1SX012A	1	N/A
62. Fuel Pool Ht. Xchg. 1A SX Dsch. Vlv.	1SX062A	1	N/A
63. Fuel Pool M/U SX Sply. Vlv.	1SX016A	1	N/A
64. SX-SGTS Charcoal Bed Train A Deluge Vlv.	1SX073A	1	N/A
65. Cntl. Rm. HVAC Recirc. Unit A Deluge Vlv	1SX076A	1	N/A

REMOTE SHUTDOWN SYSTEM CONTROLS

CONTROL	EQUIPMENT NUMBER	MINIMUM CHANNELS OPERABLE	
		DIVISION 1	DIVISION 2
66. Cntl. Rm. HVAC M/U Unit A Deluge Vlv	1SX107A	1	N/A
67. RHR HX. Clg. Wtr. Sply. Vlv	1E12-F014A/B	1	1
68. RCIC Inbd. Vac. Bkr. Vlv	1E51-F078	N/A	1
69. RCIC Stm. Sply. Inbd. Isol. Vlv	1E51-F063	N/A	1
70. Remote Transfer Switch	1C61-HS501	N/A	N/A
71. Remote Transfer Switch	1C61-HS502	N/A	N/A
72. Remote Transfer Switch	1C61-HS508	N/A	N/A
73. Remote Transfer Switch	1C61-HS509	N/A	N/A
74. Remote Transfer Switch	1C61-HS510	N/A	N/A
75. Remote Transfer Switch	1C61-HS511	N/A	N/A
76. Remote Transfer Switch	1C61-HS527	N/A	N/A
77. Remote Transfer Switch	1C61-HS001	N/A	N/A
78. Remote Transfer Switch	1C61-HS002	N/A	N/A
79. Remote Transfer Switch	1C61-HS003	N/A	N/A
80. Remote Transfer Switch	1C61-HS004	N/A	N/A
81. Remote Transfer Switch	1C61-HS005	N/A	N/A
82. Remote Transfer Switch	1C61-HS006	N/A	N/A
83. Remote Transfer Switch	1C61-HS007	N/A	N/A
84. Remote Transfer Switch	1C61-HS008	N/A	N/A
85. Remote Transfer Switch	1C61-HS009	N/A	N/A
86. Remote Transfer Switch	1C61-HS010	N/A	N/A
87. Remote Transfer Switch	1C61-HS011	N/A	N/A
88. Remote Transfer Switch	1C61-HS012	N/A	N/A
89. Circuit Breaker 252-AT1AA1	1C61-HS565	1	N/A
90. RWCU Pump Suct. Outboard. Isol. Vlv.	1G33-F004	1	N/A
91. Remote Transfer Switch at MCC 1A3	1C61-HS567	N/A	N/A
92. MS Line Outboard. Drain Isolation Vlv.	1B21-F019	1	N/A
93. Remote Transfer Switch at MCC 1A3	1C61-HS571	N/A	N/A
94. Compress.Gas Hdr. Outboard. Isol. Vlv.	1IA012A	1	N/A
95. Remote Transfer Switch at MCC 1A3	1C61-HS569	N/A	N/A
96. Feedwater Shutoff Valve	1B21-F065A	1	N/A
97. Feedwater Shutoff Valve	1B21-F065B	1	N/A
98. Remote Transfer Switch at MCC 1A2	1C61-HS573A	N/A	N/A
99. Remote Transfer Switch at MCC 1A2	1C61-HS573B	N/A	N/A

Table Notations:
(a) Valve is de-energized with its breaker in the “off” position.

TABLE OF CONTENTS

NOTE: This Attachment contains the trip setpoints and response time limits for the instruments that are contained in the Technical Specifications.

TABLE 1

REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION TRIP SETPOINTS

TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1. Intermediate Range Monitors	
a. Neutron Flux-High	120/125 divisions of full scale
b. Inop	N/A
2. Average Power Range Monitors	
a. Neutron Flux-High, Setdown	≤ 15 % RTP
b. Flow Biased Simulated Thermal Power-High	0.58 (W) + 56% (a) and ≤ 111.0% RTP, (b)
c. Neutron Flux-High	118% RTP
d. Inop	N/A
3. Reactor Vessel Steam Dome Pressure – High	1065 psig
4. Reactor Vessel Water Level – Low, Level 3	8.9 inches above instrument zero*
5. Reactor Vessel Water Level – High, Level 8	52.0 inches above instrument zero*

TABLE 1 (Continued)

TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
6. Main Steam Line Isolation Valve – Closure	8% closed (c)
7. Dry well Pressure – High	1.68 psig
8. Scram Discharge Volume Water Level – High	
a. Transmitter	
1C11-N601A	29.85 inches†
1C11-N601B	29.85 inches†
1C11-N601C	29.85 inches††
1C11-N601D	29.85 inches††
b. Float Switch	
1C11-N013A	≤ 762 ft. 1.375 inches msl
1C11-N013B	≤ 762 ft. 1.125 inches msl
1C11-N013C	≤ 762 ft. 0.75 inches msl
1C11-N013D	≤ 762 ft. 1.125 inches msl
9. Turbine Stop Valve Closure	5% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low	590 psig
11. Reactor Mode Switch - Shutdown Position	N/A
12. Manual Scram	N/A

TABLE 1 NOTES

(a) The Average Power Range Monitor Scram Function varies as a function of recirculation loop drive flow (W). ΔW is the difference in indicated drive flow (in percent of drive flow which produces the same core flow) between two loop and single loop operation at the same core flow. ΔW = 0 for two loop operation. ΔW = 8% for single loop operation.

(b) Trip Setpoint is 0.58 (W- ΔW) + 37%[(a)] when reset for single recirculation loop operation per Technical Specification LCO 3.4.1, "Recirculation Loops Operating."

(c) For the Nominal Trip Setpoint associated with this Function, refer to Table 17

† Instrument zero is 759 ft. 11 inches msl.

†† Instrument zero is 759 ft. 10.5 inches msl.

* Instrument zero is 520.62 inches above Reactor Vessel zero.

TABLE 2

CONTROL ROD BLOCK INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Rod Pattern Control System	
	a. RWL High Power Setpoint	431 psig*
	b. Low Power Setpoint	138.0 ± 4.8 psig*
2.	Reactor Mode Switch-Shutdown Position	NA

TABLE 2 NOTES

* These are turbine first stage pressure values.

TABLE 3

END OF CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM
INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Turbine Stop Valve Closure	5% closed
2.	Turbine Control Valve Fast Closure, Trip Oil Pressure-Low	590 psig

TABLE 4

ATWS RECIRCULATION PUMP TRIP (ATWS-RPT) SYSTEM
INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches*
2.	Reactor Steam Dome Pressure – High	1127 psig

TABLE 4 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.

TABLE 5

EMERGENCY CORE COOLING SYSTEM (ECCS) INSTRUMENTATION TRIP SETPOINTS

TRIP FUNCTION			ACTUAL TRIP SETPOINT (ATSP)
1.		LOW PRESSURE COOLANT INJECTION-A (LPCI) AND LOW PRESSURE CORE SPRAY (LPCS) SUBSYSTEMS	
	a.	Reactor Vessel Water Level- Low Low Low, Level 1	-145.5 inches* (a)
	b.	Drywell Pressure – High	1.68 psig
	c.	LPCI Pump A Start-Time Delay Logic Card	5 seconds
	d.	Reactor Vessel Pressure-Low (Injection Permissive)	472 psig (a)
	e.	LPCS Pump Discharge Flow - Low (Bypass)	875 gpm
	f.	LPCI Pump A Discharge Flow - Low (Bypass)	1100 gpm
	g.	Manual Initiation	N/A
2.		LPCI B AND C SUBSYSTEMS	
	a.	Reactor Vessel Water Level - Low Low Low, Level 1	-145.5 inches* (a)
	b.	Drywell Pressure – High	1.68 psig
	c.	LPCI Pump B Start - Time Delay Logic Card	5 seconds
	d.	Reactor Vessel Pressure – Low (Injection Permissive)	472 psig (a)
	e.	LPCI Pump B and LPCI Pump C Discharge Flow - Low (Bypass)	1100 gpm
	f.	Manual Initiation	N/A

TABLE 5 (Continued)

EMERGENCY CORE COOLING SYSTEM (ECCS) INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
3.	HIGH PRESSURE CORE SPRAY (HPCS) SYSTEM	
	a. Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches* (a)
	b. Drywell Pressure - High	1.68 psig
	c. Reactor Vessel Water Level - High, Level 8	52.0 inches* (a)
	d. RCIC Storage Tank Level-Low	3.5 inches** (a)
	e. Suppression Pool Water Level – High	6.5 inches*** (a)
	f. HPCS Pump Discharge Pressure - High (Bypass)	145 psig
	g. HPCS System Flow Rate - Low (Bypass)	625 gpm
	h. Manual Initiation	N/A
4.	AUTOMATIC DEPRESSURIZATION SYSTEM (ADS) TRIP SYSTEM 1 (LOGIC A AND E)	
	a. Reactor Vessel Water Level- Low Low Low, Level 1	-145.5 inches* (a)
	b. Drywell Pressure - High	1.68 psig
	c. ADS Initiation Timer	105 seconds
	d. Reactor Vessel Water Level- Low, Level 3 (Confirmatory)	8.9 inches*
	e. LPCS Pump Discharge Pressure – High	145 psig (a)
	f. LPCI Pump A Discharge Pressure - High	125 psig (a)

TABLE 5 (Continued)

EMERGENCY CORE COOLING SYSTEM (ECCS) INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
4	AUTOMATIC DEPRESSURIZATION SYSTEM (ADS) TRIP SYSTEM 1 (LOGIC A AND E) (continued)	
	g. ADS Drywell Pressure Bypass Timer	6.0 minutes
	h. Manual Initiation	N/A
5	ADS TRIP SYSTEM 2 (LOGIC B AND F)	
	a. Reactor Vessel Water Level-Low Low Low, Level 1	-145.5 inches* (a)
	b. Drywell Pressure – High	1.68 psig
	c. ADS Initiation Timer	105 seconds
	d. Reactor Vessel Water Level-Low, Level 3 (Confirmatory)	8.9 inches*
	e. LPCI Pumps B and C Discharge Pressure – High	125 psig (a)
	f. ADS Drywell Pressure Bypass Timer	6.0 minutes
	g. Manual Initiation	N/A

TABLE 5 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.
** Instrument zero is elevation 739 ft. 10-3/4 inches msl.
*** Instrument zero is elevation 731 ft. 5 inches msl.
(a) For the Nominal Trip Setpoint associated with this Function, refer to Table 17

TABLE 6

REACTOR CORE ISOLATION COOLING (RCIC) SYSEM INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
a.	Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches*
b.	Reactor Vessel Water Level - High, Level 8	52.0 inches*
c.	RCIC Storage Tank Level - Low	3.5 inches**
d.	Suppression Pool Water Level - High	-8.5 inches***
e.	Manual Initiation	N/A

TABLE 6 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.
** Instrument zero is 739 ft. 10-3/4 inches msl.
*** Instrument zero is 732 ft. 8 inches msl.

TABLE 7

PRIMARY CONTAINMENT AND DRYWELL ISOLATION INSTRUMENTATION TRIP SETPOINTS

TRIP FUNCTION			ACTUAL TRIP SETPOINT (ATSP)
1.	MAIN STEAM LINE ISOLATION		
	a.	Reactor Vessel Water Level - Low Low Low, Level 1	-145.5 inches*
	b.	Main Steam Line Pressure – Low	849 psig
	c.	Main Steam Line Flow – High	279 psid
	d.	Condenser Vacuum – Low	8.5 inches Hg vacuum
	e.	Main Steam Tunnel Temperature – High	163°F
	f.	Main Steam Line Turbine Building Temperature – High	
		1E31 - N559 A, B, C, D (Module 1)	≤ 136.1°F
		1E31 - N560 A, B, C, D (Module 2)	≤ 136.1°F
		1E31 - N561 A, B, C, D (Module 3)	≤ 136.1°F
		1E31 - N562 A, B, C, D (Module 4)	≤ 136.1°F
		1E31 - N563 A, B, C, D (Module 5)	≤ 144.1°F
	g.	Manual Initiation	N/A
2.	PRIMARY CONTAINMENT AND DRYWELL ISOLATION		
	a.	Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches*
	b.	Drywell Pressure – High	1.68 psig
	c.	Reactor Vessel Water Level – Low Low, Level 2 (ECCS Divisions 1 and 2)	-45.5 inches*
	d.	Drywell Pressure - High (ECCS Divisions 1 and 2)	1.68 psig
	e.	Reactor Vessel Water Level - Low Low, Level 2 (HPCS NSPS Div. 3 and 4)	-45.5 inches*
	f.	Drywell Pressure - High (HPCS NSPS Div. 3 and 4)	1.68 psig
	g.	Containment Building Fuel Transfer Pool Ventilation Plenum Radiation - High	≤ 100 mR/hr

TABLE 7

PRIMARY CONTAINMENT AND DRYWELL ISOLATION INSTRUMENTATION TRIP SETPOINTS (Continued)

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
2.	PRIMARY CONTAINMENT AND DRYWELL ISOLATION (continued)	
h.	Containment Building Exhaust Radiation – High	≤ 100 mR/hr
i.	Containment Building Continuous Containment Purge (CCP) Exhaust Radiation – High	≤ 100 mR/hr
j.	Reactor Vessel Water Level - Low Low Low, Level 1	-145.5 inches*
k.	Containment Pressure - High	2.56 psid
l.	Manual Initiation	N/A
3.	REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM ISOLATION	
a.	Auxiliary Building RCIC Steam Line Flow – High	110 inches water
b.	RCIC Steam Line Flow - High, Time Delay	8 seconds
c.	RCIC Steam Supply Line Pressure – Low	60 psig
d.	RCIC Turbine Exhaust Diaphragm Pressure – High	10 psig
e.	RCIC Equipment Room Ambient Temperature – High	192°F
f.	Main Steam Line Tunnel Ambient Temperature – High	163°F
g.	Main Steam Line Tunnel Temperature Timer	26 minutes, 48 seconds
h.	Deleted	
i.	Drywell RCIC Steam Line Flow – High	179.5 inches water
j.	Drywell Pressure – High	1.68 psig
k.	Manual Initiation	N/A

TABLE 7

PRIMARY CONTAINMENT AND DRYWELL ISOLATION INSTRUMENTATION TRIP SETPOINTS (Continued)

TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
4. REACTOR WATER CLEANUP (RWCU) SYSTEM ISOLATION	
a. Differential Flow - High	≤ 59 gpm
b. Differential Flow - Timer	45 seconds
c. RWCU Heat Exchanger Equipment Room Temperature – High	190°F
d. RWCU Pump Rooms Temperature - High	≤ 186.5°F
e. Main Steam Line Tunnel Ambient Temperature – High	163°F
f. Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches*
g. Standby Liquid Control System Initiation	N/A
h. Manual Initiation	N/A
5. RHR SYSTEM ISOLATION	
a. RHR Heat Exchanger Ambient Temperature – High	≤ 144.5°F
b. Reactor Vessel Water Level - Low, Level 3	8.9 inches*
c. Reactor Vessel Water Level - Low, Level 3	8.9 inches*
d. Reactor Vessel Water Level - Low Low Low, Level 1	-145.5 inches*
e. Reactor Vessel Pressure - High	104 psig
f. Dry well Pressure - High	1.68 psig
g. Manual Initiation	N/A

TABLE 7 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.

TABLE 8

SECONDARY CONTAINMENT ISOLATION INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Reactor Vessel Water Level - Low Low, Level 2	-45.5 inches*
2.	Drywell Pressure - High	1.68 psig
3.	Containment Building Fuel Transfer Pool Ventilation Plenum Exhaust Radiation – High	≤ 100 mR/hr
4.	Containment Building Exhaust Radiation - High	≤ 100 mR/hr
5.	Containment Building Continuous Containment Purge (CCP) Exhaust Radiation - High	≤ 100 mR/hr
6.	Fuel Building Exhaust Radiation - High	≤ 10 mR/hr
7.	Manual Initiation	N/A

TABLE 8 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.

TABLE 9

RESIDUAL HEAT REMOVAL (RHR) CONTAINMENT SPRAY
SYSTEM INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Drywell Pressure-High	1.68 psig
2.	Containment Pressure-High	22.3 psia
3.	Reactor Vessel Water Level- Low Low Low, Level 1	-145.5 inches*
4.	Timers, System A and System B	610 seconds
5.	Timer, System B only	89 seconds
6.	Manual Initiation	N/A

TABLE 9 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.

TABLE 10

SUPPRESSION POOL MAKEUP (SPMU) SYSTEM INSTRUMENTATION TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)
1.	Drywell Pressure-High	1.68 psig
2.	Reactor Vessel Water Level-Low Low Low, Level 1	-145.5 inches*
3.	Suppression Pool Water Level-Low Low	37.6 inches**
4.	Timer	≤ 25 minutes
5.	Manual Initiation	N/A

TABLE 10 NOTES

* Instrument zero is 520.62 inches above Reactor Vessel zero.
** Instrument zero is 727 ft. 0 inches msl.

TABLE 11

LOSS OF POWER (LOP) INSTRUMENTATION TRIP SETPOINTS

TRIP FUNCTION	ACTUAL TRIP SETPOINT (ATSP)	ALLOWABLE VALUE
1. Division 1 -- 4.16 kV Emergency Bus Undervoltage		
a. Loss of Voltage# 4.16 kV basis (120-volt basis)	 2870 (82 volts)	 @ (≥ 67 and ≤ 97 volts)
b. Loss of Voltage - Time Delay #	2.2 seconds (inverse relay minimum operating time when offsite voltage is at 0 volts)	@
c. Degraded Voltage Reset (120-volt basis) Phase AB	(117.52 volts)	(≥ 117.39 and ≤ 117.59 volts)
d. Degraded Voltage Reset (120-volt basis) Phase BC	(117.66 volts)	(≥ 117.53 and ≤ 117.73 volts)
e. Degraded Voltage Drop-out (120-volt basis) Phase AB	(116.69 volts)	(≥ 115.921 volts)
f. Degraded Voltage Drop-out (120-volt basis) Phase BC	(116.83 volts)	(116.06 volts)
g. Degraded Voltage - Time Delay	15 seconds	@
2. Division 2 -- 4.16 kV Emergency Bus Undervoltage		
a. Loss of Voltage# 4.16 kV basis (120-volt basis)	 2870 (82 volts)	 @ (≥ 67 and ≤ 97 volts)
b. Loss of Voltage - Time Delay #	2.2 seconds (inverse relay minimum operating time when offsite voltage is at 0 volts)	@
c. Degraded Voltage Reset (120-volt basis) Phase AB	(117.52 volts)	(≥ 117.39 and ≤ 117.58 volts)
d. Degraded Voltage Reset (120-volt basis) Phase BC	(117.66 volts)	(≥ 117.53 and ≤ 117.73 volts)

e.	Degraded Voltage Drop-out (120-volt basis) Phase AB	(116.69 volts)	(≥ 115.918 volts)
f.	Degraded Voltage Drop-out (120-volt basis) Phase BC	(116.83 volts)	(116.06 volts)
g.	Degraded Voltage - Time Delay	15 seconds	@

3. Division 3 -- 4.16 kV Emergency Bus Undervoltage

a.	Loss of Voltage# 4.16 kV basis (120-volt basis)	 2520 volts (72 volts)	 @ (≥ 67 and ≤ 78 volts)
b.	Loss of Voltage - Time Delay #	2.5 seconds	@
c.	Degraded Voltage Reset (120-volt basis) Phase AB	(117.35 volts)	(≥ 117.22 and ≤ 117.42 volts)
d.	Degraded Voltage Reset (120-volt basis) Phase BC	(117.49 volts)	(≥ 117.35 and ≤ 117.55 volts)
e.	Degraded Voltage Drop-out (120-volt basis) Phase AB	(116.52 volts)	(≥ 115.753 volts)
f.	Degraded Voltage Drop-out (120-volt basis) Phase BC	(116.66 volts)	(≥ 115.884 volts)
e.	Degraded Voltage - Time Delay	15 seconds	@

TABLE 11 NOTES

\# These are inverse time delay voltage relays or instantaneous voltage relays with a time delay. The voltages shown are the pickup voltages of the relay. For the inverse time relays, voltage conditions proportionally below pickup voltage will result in decreased trip times.

@ See Technical Specification Table 3.3.8.1-1.

References: Calculation 19-AN-19
Amendment 169 to NPF-62

TABLE 12

REACTOR PROTECTION SYSTEM (RPS) ELECTRIC POWER MONITORING TRIP SETPOINTS

	TRIP FUNCTION	ACTUAL TRIP SETPOINT
1.	Overvoltage	
	Bus A	125.8 volts
	Bus B	125.2 volts
2.	Undervoltage	
	Bus A	116.5 volts
	Bus B	116.2 volts
3.	Underfrequency	
	Bus A	57.6 Hz
	Bus B	57.6 Hz

TABLE 13

REACTOR PROTECTION SYSTEM (RPS) ELECTRIC POWER MONITORING RESPONSE TIME LIMITS

	TRIP FUNCTION	RESPONSE TIME (Seconds)
1.	Intermediate Range Monitors	
	a. Neutron Flux - High	N/A
	b. Inop	N/A
2.	Average Power Range Monitors*	
	a. Neutron Flux - High, Setdown	N/A
	b. Flow Biased Simulated Thermal Power - High	≤ 0.09**
	c. Fixed Neutron Flux - High	≤ 0.09
	d. Inop	N/A
3.	Reactor Vessel Steam Dome Pressure - High***	≤ 0.33
4.	Reactor Vessel Water Level - Low, Level 3***	≤ 1.03
5.	Reactor Vessel Water Level - High, Level 8***	≤ 1.03
6.	Main Steam Isolation Valve – Closure	≤ 0.04
7.	Drywell Pressure – High	N/A
8.	Scram Discharge Volume Water Level - High	
	a. Transmitter	N/A
	b. Float Switch	N/A
9.	Turbine Stop Valve Closure	≤ 0.04
10.	Turbine Control Valve Fast Closure, Trip Oil Pressure – Low	≤ 0.05#
11.	Reactor Mode Switch - Shutdown Position	N/A
12.	Manual Scram	N/A

TABLE 13 NOTES

* Neutron detectors are exempt from response time testing. Response time shall be measured from the detector output or from the input of the first electronic component in the channel.

** Not including a simulated thermal power time constant specified in the COLR.

*** Channel sensors are exempt from periodic response time testing.

\# Measured from start of turbine control valve fast closure.

TABLE 14

END OF CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM
INSTRUMENTATION RESPONSE TIME LIMITS

	TRIP FUNCTION	RESPONSE TIME (msec)
1.	Turbine Stop Valve Closure	$\leq$ 140
2.	Turbine Control Valve Fast Closure, Trip Oil Pressure – Low	$\leq$ 140

TABLE 15

MAIN STEAM LINE ISOLATION INSTRUMENTATION RESPONSE TIME LIMITS

TRIP FUNCTION	RESPONSE TIME (Seconds)
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level - Low Low Low, Level 1	≤ 1.0*
b. Main Steam Line Pressure - Low	≤ 1.0*
c. Main Steam Line Flow - High	≤ 0.5*
d. Condenser Vacuum – Low	N/A
e. Main Steam Tunnel Temperature - High	N/A
f. Main Steam Line Turbine Building Temperature – High	N/A
g. Manual Initiation	N/A

TABLE 15 NOTES

* Response time for MSIV's only, no diesel generator delays assumed. Channel sensors are exempt from periodic response time testing.

TABLE 16

SETPOINT FOR THE CONTROL ROOM VENTILATION RADIATION MONITOR CHANNELS

TRIP FUNCTION	ACTUAL TRIP SETPOINT
1. MAIN CONTROL ROOM AIR INTAKE RADIATION - HIGH	
a. Transmitter, Indicating	
1RIXPR009A	≤ 10 mR/hr
1RIXPR009B	≤ 10 mR/hr
1RIXPR009C	≤ 10 mR/hr
1RIXPR009D	≤ 10 mR/hr

TABLE 17
NOMINAL TRIP SETPOINTS

TRIP FUNCTION	NOMINAL TRIP SETPOINT (NTSP)	CALCULATION (a)
Table 1, Function 6: Main Steam Line Isolation Valve – Closure	8.6 %	IP-C-0075
Table 5, Function 1 a: Reactor Vessel Water Level – Low Low Low, Level 1	-146.02 inches*	IP-C-0073
Table 5, Function 1d: Reactor Vessel Pressure – Low (Injection Permissive)	459.0 psig (lower)/ 489.0 psig (upper) 462.0 psig (lower)/ 486.0 psig (upper)	IP-C-0062##
Table 5, Function 2a: Reactor Vessel Water Level – Low Low Low, Level 1	-146.02 inches*	IP-C-0073
Table 5, Function 2d: Reactor Vessel Pressure – Low (Injection Permissive)	459.0 psig (lower)/ 489.0 psig (upper) 462.0 psig (lower)/ 486.0 psig (upper)	IP-C-0062###
Table 5, Function 3a: Reactor Vessel Water Level – Low Low, Level 2	-46.02 inches*	IP-C-0094
Table 5, Function 3c: Reactor Vessel Water Level – High, Level 8	53.4 inches*	IP-C-0094
Table 5, Function 3d: RCIC Storage Tank Level – Low	3.18 inches**	IP-C-0061
Table 5, Function 3e: Suppression Pool Water Level – High	9.95 inches***	IP-C-0087
Table 5, Function 4a: Reactor Vessel Water Level – Low Low Low, Level 1	-146.02 inches*	IP-C-0073
Table 5, Function 4e: LPCS Pump Discharge Pressure – High	126.6 psig (lower)/ 174.7 psig (upper)	IP-C-0065

TABLE 17
NOMINAL TRIP SETPOINTS (continued)

TRIP FUNCTION	NOMINAL TRIP SETPOINT (NTSP)	CALCULATION (a)
Table 5, Function 4f: LPCI Pump A Discharge Pressure – High	116.6 psig (lower)/ 133.4 psig (upper)	IP-C-0064#
Table 5, Function 5a: Reactor Vessel Water Level – Low Low Low, Level 1	-146.02 inches*	IP-C-0073
Table 5, Function 5e: LPCI Pumps B and C Discharge Pressure – High	116.6 psig (lower)/ 133.4 psig (upper)	IP-C-0064#
Relief and Low Low Set (LLS) Function:		
a. Relief Function	Low: 1109 psig Medium: 1119 psig High: 1129 psig	IP-C-0077
b. LLS Function	Low: 1035 psig Medium: 1075 psig High: 1115 psig	IP-C-0077

Notes:
(a) The referenced calculation was completed using Engineering Standard CI-01.00, "Instrument Setpoint Calculation Methodology." The referenced calculation determines the Nominal Trip Setpoints, the As-Found Tolerances and the As-Left Tolerances.

* Instrument zero is 520.62 inches above Reactor Vessel zero.
** Instrument zero is elevation 739 ft. 10-3/4 inches msl.
*** Instrument zero is elevation 731 ft. 5 inches msl.

#Transmitters: 1E12N055A, B, C; 1E12N056A, B, C
##Transmitters: 1B21N078A; 1B21N697E 1B21N097A, 1B21N697A
###Transmitters: 1B21N078B; 1B21N697F 1B21N097B, 1B21N697B

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1B21-F016	Continuous	Close	Nuclear Boiler
1B21-F019	Continuous	Close	Nuclear Boiler
1B21-F065A	Continuous	Open/Close	Nuclear Boiler
1B21-F065B	Continuous	Open/Close	Nuclear Boiler
1B21-F067A	Continuous	Close	Nuclear Boiler
1B21-F067B	Continuous	Close	Nuclear Boiler
1B21-F067C	Continuous	Close	Nuclear Boiler
1B21-F067D	Continuous	Close	Nuclear Boiler
1CC049	Continuous	Close	Component Cooling Water
1CC050	Continuous	Close	Component Cooling Water
1CC053	Continuous	Close	Component Cooling Water
1CC054	Continuous	Close	Component Cooling Water
1CC057	Continuous	Close	Component Cooling Water
1CC060	Continuous	Close	Component Cooling Water
1CC065	Continuous	Close	Component Cooling Water
1CC067	Continuous	Close	Component Cooling Water
1CC068	Continuous	Close	Component Cooling Water
1CC070	Continuous	Close	Component Cooling Water
1CC075A	Continuous	Close	Component Cooling Water
1CC075B	Continuous	Close	Component Cooling Water
1CC076A	Continuous	Close	Component Cooling Water
1CC076B	Continuous	Close	Component Cooling Water
1CC127	Continuous	Close	Component Cooling Water
1CC128	Continuous	Close	Component Cooling Water
1CY016	Continuous	Close	Cycled Condensate
1CY017	Continuous	Close	Cycled Condensate
1C41-F001A	Continuous	Open	Standby Liquid Control
1C41-F001B	Continuous	Open	Standby Liquid Control
1E12-F003A	Continuous	Open	Residual Heat Removal
1E12-F003B	Continuous	Open	Residual Heat Removal
1E12-F004A	Continuous	Open/Close	Residual Heat Removal
1E12-F004B	Continuous	Open/Close	Residual Heat Removal
1E12-F006A	Continuous	Open/Close	Residual Heat Removal
1E12-F006B	Continuous	Open/Close	Residual Heat Removal

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1E12-F008	Continuous	Open/Close	Residual Heat Removal
1E12-F009	Continuous	Close	Residual Heat Removal
1E12-F014A	Continuous	Open/Close	Residual Heat Removal
1E12-F014B	Continuous	Open/Close	Residual Heat Removal
1E12-F021	Continuous	Close	Residual Heat Removal
1E12-F023	Continuous	Open/Close	Residual Heat Removal
1E12-F024A	Continuous	Open/Close	Residual Heat Removal
1E12-F024B	Continuous	Open/Close	Residual Heat Removal
1E12-F027A	Continuous	Open/Close	Residual Heat Removal
1E12-F027B	Continuous	Open/Close	Residual Heat Removal
1E12-F028A	Continuous	Open/Close	Residual Heat Removal
1E12-F028B	Continuous	Open/Close	Residual Heat Removal
1E12-F037A	Continuous	Open/Close	Residual Heat Removal
1E12-F037B	Continuous	Open/Close	Residual Heat Removal
1E12-F040	Continuous	Close	Residual Heat Removal
1E12-F042A	Continuous	Open/Close	Residual Heat Removal
1E12-F042B	Continuous	Open/Close	Residual Heat Removal
1E12-F042C	Continuous	Open/Close	Residual Heat Removal
1E12-F047A	Continuous	Open	Residual Heat Removal
1E12-F047B	Continuous	Open	Residual Heat Removal
1E12-F048A	Continuous	Open/Close	Residual Heat Removal
1E12-F048B	Continuous	Open/Close	Residual Heat Removal
1E12-F049	Continuous	Close	Residual Heat Removal
1E12-F053A	Continuous	Open/Close	Residual Heat Removal
1E12-F053B	Continuous	Open/Close	Residual Heat Removal
1E12-F064A	Continuous	Open/Close	Residual Heat Removal
1E12-F064C	Continuous	Open/Close	Residual Heat Removal
1E12-F064B	Continuous	Open/Close	Residual Heat Removal
1E12-F068A	Continuous	Open	Residual Heat Removal
1E12-F068B	Continuous	Open	Residual Heat Removal
1E12-F094	Continuous	Open/Close	Residual Heat Removal
1E12-F096	Continuous	Open/Close	Residual Heat Removal
1E12-F105	Continuous	Open/Close	Residual Heat Removal
1E12-F496	Continuous	Open/Close	Residual Heat Removal
1E12-F497	Continuous	Open/Close	Residual Heat Removal
1E21-F001	Continuous	Open/Close	Low Pressure Core Spray
1E21-F005	Continuous	Open/Close	Low Pressure Core Spray
1E21-F011	Continuous	Open/Close	Low Pressure Core Spray

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1E21-F012	Continuous	Close	Low Pressure Core Spray
1E22-F001	Continuous	Open/Close	High Pressure Core Spray
1E22-F004	Continuous	Open/Close	High Pressure Core Spray
1E22-F010	Continuous	Close	High Pressure Core Spray
1E22-F011	Continuous	Close	High Pressure Core Spray
1E22-F012	Continuous	Open/Close	High Pressure Core Spray
1E22-F015	Continuous	Open/Close	High Pressure Core Spray
1E22-F023	Continuous	Close	High Pressure Core Spray
1E51-F010	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F013	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F019	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F022	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F031	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F045	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F046	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F059	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F063	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F064	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F068	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F076	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F077	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-F078	Continuous	Open/Close	Reactor Core Isolation Cooling
1E51-C002E	Continuous	Open/Close	Reactor Core Isolation Cooling
1FC007	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC008	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC011A	Continuous	Open/Close	Fuel Pool Cooling & Cleanup
1FC011B	Continuous	Open/Close	Fuel Pool Cooling & Cleanup

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1FC015A	Continuous	Open/Close	Fuel Pool Cooling & Cleanup
1FC015B	Continuous	Open/Close	Fuel Pool Cooling & Cleanup
1FC016A	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC016B	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC024A	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC024B	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC026A	Continuous	Open/Close	Fuel Pool Cooling & Cleanup
1FC026B	Continuous	Open/Close	Fuel Pool Cooling & Cleanup
1FC036	Continuous	Close	Fuel Pool Cooling & Cleanup
1FC037	Continuous	Close	Fuel Pool Cooling & Cleanup
1FP050	Continuous	Close	Fire Protection
1FP052	Continuous	Close	Fire Protection
1FP053	Continuous	Close	Fire Protection
1FP092	Continuous	Close	Fire Protection
1G33-F001	Continuous	Close	Reactor Water Cleanup
1G33-F004	Continuous	Close	Reactor Water Cleanup
1G33-F028	Continuous	Close	Reactor Water Cleanup
1G33-F034	Continuous	Close	Reactor Water Cleanup
1G33-F039	Continuous	Close	Reactor Water Cleanup
1G33-F040	Continuous	Close	Reactor Water Cleanup
1G33-F053	Continuous	Close	Reactor Water Cleanup
1G33-F054	Continuous	Close	Reactor Water Cleanup
1HG001	Continuous	Open/Close	H2 Recombining
1HG004	Continuous	Open/Close	H2 Recombining
1HG005	Continuous	Open/Close	H2 Recombining
1HG008	Continuous	Open/Close	H2 Recombining
1HG009A	Continuous	Open/Close	H2 Recombining
1HG009B	Continuous	Open/Close	H2 Recombining
1IA012A	Continuous	Open/Close	Instrument Air
1IA012B	Continuous	Open/Close	Instrument Air
1IA013A	Continuous	Open/Close	Instrument Air
1IA013B	Continuous	Open/Close	Instrument Air
OMC009	Continuous	Close	Make Up Condensate Storage
OMC010	Continuous	Close	Make Up Condensate Storage
1SF001	Continuous	Close	Suppression Pool Cleanup
1SF002	Continuous	Close	Suppression Pool Cleanup
1SF004	Continuous	Close	Suppression Pool Cleanup
1SM001A	Continuous	Open	Suppression Pool Makeup
1SM001B	Continuous	Open	Suppression Pool Makeup
1SM002A	Continuous	Open	Suppression Pool Makeup
1SM002B	Continuous	Open	Suppression Pool Makeup
1SX003A	Continuous	Open	Shutdown Service Water
1SX003B	Continuous	Open	Shutdown Service Water
1SX003C	Continuous	Open	Shutdown Service Water

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1SX004A	Continuous	Open	Shutdown Service Water
1SX004B	Continuous	Open	Shutdown Service Water
1SX004C	Continuous	Open	Shutdown Service Water
1SX006C	Continuous	Open	Shutdown Service Water
1SX008A	Continuous	Open/Close	Shutdown Service Water
1SX008B	Continuous	Open/Close	Shutdown Service Water
1SX008C	Continuous	Open/Close	Shutdown Service Water
1SX011A	Continuous	Open/Close	Shutdown Service Water
1SX011B	Continuous	Open/Close	Shutdown Service Water
1SX012A	Continuous	Open/Close	Shutdown Service Water
1SX012B	Continuous	Open/Close	Shutdown Service Water
1SX013D	Continuous	Open/Close	Shutdown Service Water
1SX013E	Continuous	Open/Close	Shutdown Service Water
1SX013F	Continuous	Open/Close	Shutdown Service Water
1SX014A	Continuous	Close	Shutdown Service Water
1SX014B	Continuous	Close	Shutdown Service Water
1SX014C	Continuous	Close	Shutdown Service Water
1SX016A	Continuous	Open/Close	Shutdown Service Water
1SX016B	Continuous	Open/Close	Shutdown Service Water
1SX017A	Continuous	Open/Close	Shutdown Service Water
1SX017B	Continuous	Open/Close	Shutdown Service Water
1SX020A	Continuous	Close	Shutdown Service Water
1SX020B	Continuous	Close	Shutdown Service Water
1SX062A	Continuous	Open/Close	Shutdown Service Water
1SX062B	Continuous	Open/Close	Shutdown Service Water
1SX063A	Continuous	Open	Shutdown Service Water
1SX063B	Continuous	Open	Shutdown Service Water
1SX071A	Continuous	Open/Close	Shutdown Service Water
1SX071B	Continuous	Open/Close	Shutdown Service Water
1SX073A	Continuous	Open/Close	Shutdown Service Water
1SX073B	Continuous	Open/Close	Shutdown Service Water
1SX074A	Continuous	Open/Close	Shutdown Service Water
1SX074B	Continuous	Open/Close	Shutdown Service Water
1SX076A	Continuous	Open/Close	Shutdown Service Water
1SX076B	Continuous	Open/Close	Shutdown Service Water
1SX082A	Continuous	Close	Shutdown Service Water
1SX082B	Continuous	Close	Shutdown Service Water
1SX095A	Continuous	Open	Shutdown Service Water
1SX095B	Continuous	Open	Shutdown Service Water

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NO.	BYPASS	DIRECTION	SYSTEM(S) AFFECTED
1SX105A	Continuous	Open/Close	Shutdown Service Water
1SX105B	Continuous	Open/Close	Shutdown Service Water
1SX107A	Continuous	Open/Close	Shutdown Service Water
1SX107B	Continuous	Open/Close	Shutdown Service Water
1VP004A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP004B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP005A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP005B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP014A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP014B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP015A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VP015B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1VQ006A	Continuous	Close	Drywell Purge - Containment HVAC
1VQ006B	Continuous	Close	Drywell Purge - Containment HVAC
1VR002A	Continuous	Close	Drywell Purge - Containment HVAC
1VR002B	Continuous	Close	Drywell Purge - Containment HVAC
1WO001A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO001B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO002A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO002B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO551A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO551B	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO552A	Continuous	Close	Drywell Cooling - Plant Chilled Water
1WO552B	Continuous	Close	Drywell Cooling - Plant Chilled Water

Note: This table presents the respective valve's overload bypass design direction(s). The "DIRECTION" should NOT be used to identify the respective valve's Design Basis Safety Function Direction. Valves' thermal overload protection may be bypassed in more than the Safety Function Direction. Refer to ORM section 2.5.2 for criteria regarding thermal overload protection.

VALVE NUMBER		PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1. Automatic Isolation Valves

1) Main Steam Line C		5		1,2,3		No	9.0
	1B21-F022C		C,D,E,G H,J,U,R,X		3-5		
	1B21-F028C		C,D,E,G, H,J,U,R,X		3-5		
	1B21-F067C		C,D,E,G, H,J,U,R,X		14		
2) Main Steam Line A		6		1,2,3		No	9.0
	1B21-F022A		C,D,E,G H,J,U,R,X		3-5		
	1B21-F028A		C,D,E,G, H,J,U,R,X		3-5		
	1B21-F067A		C,D,E,G, H,J,U,R,X		14		
3) Main Steam Line D		7		1,2,3		No	9.0
	1B21-F022D		C,D,E,G H,J,U,R,X		3-5		
	1B21-F028D		C,D,E,G, H,J,U,R,X		3-5		
	1B21-F067D		C,D,E,G, H,J,U,R,X		14		

1 . Automatic Isolation Valves (Continued)

VALVE NUMBER		PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
4) Main Steam Line B		8		1,2,3		No	9.0
	1B21-F022B		C,D,E,G, H,J,U,R,X		3-5		
	1B21-F028B		C,D,E,G, H,J,U,R,X		3-5		
	1B21-F067B		C,D,E,G H,J,U,R,X		14		
5) Feedwater/RHR Line A		9		1,2,3	65	No	9.9
	1E12-F053A		A,T,X,R				
6) Feedwater/RHR Line B		10		1,2,3	65	No	9.9
	1E12-F053B		A,T,X,R				
7) RHR Shutdown Cooling		14		1,2,3,##		No	9.0
	1E12-F008		A,T,X,R		53		
	1E12-F009		A,T,X,R		53		
8) RHR A To Fuel Pool Cooling		15		1,2,3		No	9.0
	1E12-F037A (i)		A,T,X,R		120		

VALVE NUMBER		PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
1 . Automatic Isolation Valves (Continued)							
9) RHR B To Fuel Pool Cooling		16		1,2,3		No	9.0
	1E12-F037B (i)		A,T,L,R		120		
10) RHR A/LPCS Test Line		18		1,2,3		No	9.9
	1E12-F024A		L,U,(j)		45		
	1E21-F012		L,U,(j)		90		
11) RHR C Test Line		19		1,2,3		No	9.9
	1E12-F021		L,U,(j)		123		
12) RHR B Test Line		20		1,2,3		No	9.9
	1E12-F024B		L,U,(j)		45		
13) RCIC Suction		28		1,2,3		No	9.9
	1E51-F031		V,X,B,R,E,(e)		48		
14) HPCS Test Line		33		1,2,3		No	9.9
	1E22-F023		B, L		68		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1 . Automatic Isolation Valves (Continued)

15) Supp. Pool Cleanup Suction	34		1,2,3, #		Yes	9.9
1SF004		B,L,R		84		
16) RCIC	41/44		1,2,3, #		Yes	9.0
1E51-F077		V.L,(c)		21		
17) RHR Head Spray	42		1,2,3		No	9.0
1E12-F023		A,T,X,R		39		
18) RCIC Steam Supply	43		1,2,3, #		Yes	9.0
1E51-F063		V,E,X		41		
1E51-F064		V,E,R,B,X,(e)		41		
1E51-F076		V,E,X		14		
19) RCIC Turb Vac Bkr Line	44		1,2,3, #		Yes	9.0
1E51-F078		V,L,(c)		27		

1 . Automatic Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
20) Main Steam Drain Line	45		1,2,3, #(f)		Yes	9.0
1B21-F016		C,D,E,G,H,J, U,X,R		50		
1B21-F019		C,D,E,G,H,J U,X,R		50		
21) Comp. Cooling Water Supply	46		1,2,3, #		Yes	9.0
1CC049		B,L,R		84		
1CC050		B,L,R		45		
1CC127		B,L,R		64		
22) Comp. Cooling Water Return	47		1,2,3, #		Yes	9.0
1CC053		B,L,R		45		
1CC054		B,L,R		84		
1CC060		B,L,R		64		
23) Breathing Air	49		1,2,3, #		Yes	9.0
0RA026 (i)		B,L,R		NA		
0RA027 (i)		B,L,R		NA		
24) Make-up Condensate	50		1,2,3, #		Yes	9.0
0MC009		B,L,R		58		
0MC010		B,L,R		58		

1 . Automatic Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
25) Fuel Pool Cool/Cleanup Supply	52		1,2,3		No	9.0
1FC036		B,L,R		75		
1FC037		B,L,R		75		
26) Fuel Pool Cool/Cleanup Return	53		1,2,3		No	9.0
1FC007		B,L,R		66		
1FC008		B,L,R		66		
27) Fire Protection	56		1,2,3, #		Yes	9.0
1FP052		B,L,R		87		
28) Instrument Air Supply	57		1,2,3, #		Yes	9.0
1IA005		U		36		
1IA006		U		36		
29) Instrument Air Bottles	58		1,2,3, #		Yes	9.0
1IA012B		L,B,R		25		
30) Service Air Supply	59		1,2,3, #		Yes	9.0
1SA030		B,L,R		16		
1SA029		B,L,R		16		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1 . Automatic Isolation Valves (Continued)

31) RWCU Suction Line	60		1,2,3		No	9.0
1G33-F001		B,N,1,E,X,R,6,7		20		
1G33-F004		B,N,1,E,X,R,6,7		20		
32) RWCU Return to Filter	61		1,2,3		No	9.0
1G33-F053		B,N,1,E,X,R,7		21		
1G33-F054		B,N,1,E,X,R,7		21		
33) Hydrogen Recombiner Supply	62		1,2,3, #		Yes	9.0
1HG008		B,L,R		117		
34) RWCU To RHR/FW	64		1,2,3		No	9.0
1G33-F040		B,N,1,E,X,R,7		21		
1G33-F039		B,N,1,E,X,R,7		21		
35) RWCU Transfer to Radwaste	65		1,2,3, #		Yes	9.0
1WX019		B,L,R		2		
1WX020		B,L,R		2		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
1 . Automatic Isolation Valves (Continued)						
36) Process Sampling	68		1,2,3, #	NA	Yes	9.0
1PS016		B,L,R				
1PS017		B,L,R				
1PS022		B,L,R				
1PS023		B,L,R				
1PS034		B,L,R				
1PS035		B,L,R				
1PS055		B,L,R				
1PS056		B,L,R				
1PS069		B,L,R				
1PS070		B,L,R				
37) DW/Cont. Equip Drain	69		1,2,3		No	9.0
1RE021		B,L,R		16		
1RE022		B,L,R		16		
38) DW/Cont. Floor Drain	70		1,2,3		No	9.0
1RF021		B,L,R		16		
1RF022		B,L,R		16		
39) Hydrogen Recombiner Supply	71		1,2,3, #		Yes	9.0
1HG001		B,L,R		117		
40) Hydrogen Recombiner Return	72		1,2,3 #		Yes	9.0
1HG004		B,L,R		117		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
1 . Automatic Isolation Valves (Continued)						
41) Deleted						
42) Supp. Pool Cleanup Return	79		1,2,3		No	9.9
1SF001		B,L,R		114		
1SF002		B,L,R		126		
43) Fire Protection	81		1,2,3, #		Yes	9.0
1FP050		B,L,R		58		
1FP092		B,L,R		58		
44) Fire Protection	82		1,2,3, #		Yes	9.0
1FP053		B,L,R		68		
45) Cycle Condensate	85		1,2,3, #		Yes	9.0
1CY016		B,L,R		75		
1CY017		B,L,R		75		
46) RWCU Letdown	86		1,2,3, #		Yes	9.0
1G33-F028		B,N,1,E,X,R,7		24		
1G33-F034		B,N,1,E,X,R,7		24		

1 . Automatic Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
47) Deleted						
48) Containment HVAC Supply	101					9.0
1VR001A[i]		B,L,M,Z,5,R	1, 2, 3, #	4	Yes	
1VR001B[i]		B,L,M,Z,5,R	1, 2, 3, #	4	Yes	
1VR002A		P	1[g],2[g],3[g]	10	No	
1VR002B		P	1[g],2[g],3[g], #	10	Yes	
49) Containment HVAC Exhaust	102				Yes	9.0
1VQ004A[i]		B,L,M,Z,5,R	1,2,3, #	6		
1VQ004B[i]		B,L,M,Z,5,R	1,2,3, #	6		
1VQ006A		P	1[g],2[g],3[g], #	10		
1VQ006B		P	1[g],2[g],3[g], #	10		
50) Plant Chilled Water Supply	103		1,2,3, #		Yes	9.0
1WO001A		L,U,(j)		44		
1WO001B		L,U,(j)		44		
51) Plant Chilled Water Return	104		1,2,3, #		Yes	9.0
1WO002A		L,U,(j)		44		
1WO002B		L,U,(j)		44		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1 . Automatic Isolation Valves (Continued)

52) Containment Bldg. HVAC	106		1,2,3, #		Yes	9.0
1VR007B		B,L,M,Z,5,R		6		
1VR007A		B,L,M,Z,5,R		6		
53) DW Chilled Water Supply	107		1,2,3, #		Yes	9.0
1VP004B		L,U,(j)		84		
1VP005B		L,U,(j)		84		
54) DW Chilled Water Return	108				Yes	9.0
1VP014B		L,U,(j)	1,2,3, #	84		
1VP015B		L,U,(j)		84		
55) DW Chilled Water Supply	109				Yes	9.0
1VP004A		L,U,(j)	1,2,3, #	84		
1VP005A		L,U,(j)		84		
56) DW Chilled Water Return	110		1,2,3, #		Yes	9.0
1VP014A		L.U,(j)		84		
1VP015A		L,U,(j)		84		
57) Containment Bldg. HVAC	113		1,2,3, #		Yes	9.0
1VR006A		B,L,M,Z,5,R		6		
1VR006B		B,L,M,Z,5,R		6		

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1 . Automatic Isolation Valves (Continued)

58) Cont. Monit.	153		1,2,3	NA	No	9.0
1CM022		B,L,R				
1CM023		B,L,R				
1CM025		B,L,R				
1CM026		B,L,R				
59) Hydrogen Recombiner Supply	166		1,2,3, #	117	Yes	9.0
1HG005		B,L,R				
60) Containment HVAC	169		1,2,3, #	NA	Yes	9.0
1VR035		B,L,M,Z,5,R				
1VR036		B,L,M,Z,5,R				
1VR040		B,L,M,Z,5,R				
1VR041		B,L,M,Z,5,R				
61) Cont. Monit	173		1,2,3	NA	No	9.0
1CM048		B,L,R				
1CM047		B,L,R				
1CM011		B,L,R				
1CM012		B,L,R				
62) Instrument Air Bottles	206		1,2,3,#	25	Yes	9.0
1IA013B		B,L,R				
63) Process Sampling	210		1,2,3,#	NA	Yes	9.0
1PS038		B,L,R				
1PS037		B,L,R				

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

1 . Automatic Isolation Valves (Continued)

63) Process Sampling (continued)						
1PS004		B,L,R				
1PS005		B,L,R				
1PS010		B,L,R				
1PS009		B,L,R				
1PS031		B,L,R				
1PS032		B,L,R				

2. Manual Isolation Valves

1) RHR/LPCI A	15	NA	1,2,3	NA	No	9.0
1E12-F044A						
2) RHR/LPCI B Injection	16	NA	1,2,3	NA	No	9.0
1E12-F044B						
3) Containment Monitoring	152	NA	1,2,3	NA	No	9.0
1CM080A						
1CM080B						
1CM080C						
1CM081A						
1CM081B						
1CM081C						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

2 . Manual Isolation Valves (continued)

4) RHR A/LPCS Test Line	18	NA	1,2,3	NA	No	9.9
1E12-F011A						
5) RHR B Test Line	20	NA	1,2,3	NA	No	9.9
1E12-F011B						
6) Fire Protection	56	NA	1,2,3, #	NA	Yes	9.0
1FP051						
7) SX To Recirc. Pump	78	NA	1,2,3	NA	No	9.0
1CC074(j) (k)						
1CC073 (j) (k)						
8) Fire Protection	82	NA	1,2,3, #	NA	Yes	9.0
1FP054						
9) SX From Recirc. Pump	88	NA	1,2,3	NA	No	9.0
1CC071 (j) (k)						
1CC072 (j) (k)						

3. Test Connections, Vents, and Drains

1) Equipment Hatch	1	NA	1,2,3	NA	No	9.0
1CM099						
2) Fuel Handling	4	NA	1,2,3	NA	No	9.0
1F42-F304A						
1F42-F304B						
3) Main Steam Line C	5	NA	1,2,3	NA	No	9.0
1B21-F025C						
1E32-F327C						
1E32-F330A						
4) Main Steam Line A	6	NA	1,2,3	NA	No	9.0
1B21-F025A						
1E32-F327A						
1E32-F329A						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

5) Main Steam Line D	7	NA	1,2,3	NA	No	9.0
1B21-F025D						
1E32-F327D						
1E32-F330C						
6) Main Steam Line B	8	NA	1,2,3	NA	No	9.0
1B21-F025B						
1E32-F327B						
1E32-F329C						
7) Feedwater/RHR Line A	9	NA		NA		9.9
1B21-F063A			1,2,3, #		Yes	
1B21-F030A			1,2,3		No	
1B21-F518A			1,2,3		No	
1E12-F058A			1,2,3		No	
1E12-F349A			1,2,3		No	
1E12-F507			1,2,3		No	
1E12-F525A			1,2,3		No	
1E12-F501A			1,2,3		No	
1E12-F503A			1,2,3		No	
1E12-F523A			1,2,3		No	
1E12-F511A			1,2,3		No	
1E12-F513			1,2,3		No	

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

8) Feedwater/RHR Line B	10	NA		NA		9.9
1B21-F063B			1,2,3,#		Yes	
1B21-F030B			1,2,3		No	
1B21-F518B			1,2,3		No	
1E12-F058B			1,2,3		No	
1E12-F349B			1,2,3		No	
1G33-F057			1,2,3		No	
1E12-F505			1,2,3		No	
1E12-F525B			1,2,3		No	
1E12-F501B			1,2,3		No	
1E12-F503B			1,2,3		No	
1E12-F523B			1,2,3		No	
1E12-F516A			1,2,3		No	
1E12-F518			1,2,3		No	
9) RHR A Suction	11	NA	1,2,3	NA	No	9.9
1E12-F334A						
1E12-F335A						
10) RHR B Suction	12	NA	1,2,3	NA	No	9.9
1E12-F334B						
1E12-F335B						
11) RHR C Suction	13	NA	1,2,3	NA	No	9.9
1E12-F334C						
1E12-F335C						
12) RHR Shutdown Cooling	14	NA	1,2,3	NA	No	9.0
1E12-F001						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
3. Test Connections, Vents, and Drains (Continued)						
13) RHR/LPCI A Injection	15	NA	1,2,3	NA	No	9.0
1E12-F107A						
1E12-F331A						
1E12-F329A						
14) RHR/LPCI B Injection	16	NA	1,2,3	NA	No	9.0
1E12-F107B						
1E12-F331B						
1E12-F329B						
15) RHR/LPCI C Injection	17	NA	1,2,3	NA	No	9.0
1E12-F056C						
16) RHR A Test Line	18	NA	1,2,3	NA	No	9.9
1E12-F365A						
1E12-F366A						
1E21-F346						
1E21-F347						
1E12-F414						
1E12-F415						
1E12-F418						
1E12-F419						
1E12-F420						
1E12-F421						
17) RHR C Test Line	19	NA	1,2,3	NA	No	9.9
1E12-F353						
1E12-F354						
1E12-F428						
1E12-F429						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

18) RHR B Test Line	20	NA	1,2,3	NA	No	9.9
1E12-F365B						
1E12-F366B						
1E12-F426						
1E12-F427						
19) RHR HX	24	NA	1,2,3	NA	No	9.9
1E12-F432A						
1E12-F433A						
20) RHR HX	26	NA	1,2,3	NA	No	9.9
1E12-F432B						
1E12-F433B						
21) RCIC Pump Suction	28	NA	1,2,3	NA	No	9.9
1E51-F336						
1E51-F337						
22) RCIC Suction Release Discharge	31	NA	1,2,3	NA	No	9.9
1E12-F436						
1E12-F437						
23) LPCS Pump Suction	32	NA	1,2,3	NA	No	9.9
1E21-F331						
1E21-F344						
24) HPCS Test to Supp. Pool	33	NA	1,2,3	NA	No	9.9
1E22-F376						
25) Supp. Pool Cleanup Pump Suction	34	NA	1,2,3	NA	No	9.9
1SF034						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

26) HPCS Pump Discharge	35	NA	1,2,3	NA	No	9.0
1E22-F021						
27) LPCS Pump Discharge	36	NA	1,2,3	NA	No	9.0
1E21-F013						
28) RCIC	41	NA	1,2,3	NA	No	9.9
1E51-F041						
29) Head Spray	42	NA	1,2,3	NA	No	9.0
1E51-F034						
1E51-F391						
1E12-F061						
30) RCIC Turb Steam Supply	43	NA	1,2,3	NA	No	9.0
1E51-F399						
1E51-F072						
1E51-F401						
31) RCIC Turb Vacuum Breaker	44	NA	1,2,3	NA	No	9.0
1E51-F080						
1E51-F082						
1E51-F375						
1E51-F376						
1E51-F083						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

32) Main Steam Drain Line	45	NA	1,2,3	NA	No	9.0
1B21-F017						
33) CCW Supply	46	NA		NA		9.0
1CC164			1,2,3		No	
1CC266			1,2,3, #		Yes	
34) CCW Return	47	NA	1,2,3	NA	No	9.0
1CC165						
35) Makeup Condensate	50	NA	1,2,3	NA	No	9.0
1MC011						
36) Fuel Pool Cool/Cleanup Supply	52	NA	1,2,3	NA	No	9.0
1FC180						
37) Fuel Pool Cool/Cleanup Return	53	NA	1,2,3	NA	No	9.0
1FC181						
38) Fire Protection	56	NA	1,2,3	NA	No	9.0
1FP199						
39) Instrument Air	57	NA	1,2,3	NA	No	9.0
1IA039						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

40) Service Air Line	59	NA	1,2,3	NA	No	9.0
1SA046						
41) RWCU Pump Suction	60	NA		NA		9.0
1G33-F002			1,2,3		No	
42) RWCU Return	61	NA	1,2,3	NA	No	9.0
1G33-F061						
43) Hydrogen Recombiner	62	NA	1,2,3	NA	No	9.0
1HG019						
44) CRD Pump Discharge	63	NA	1,2,3	NA	No	9.0
1C11-F128						
45) RWCU Return	64	NA	1,2,3	NA	No	9.0
1G33-F055						
46) Containment Pressurization (test penet.)	67	NA	1,2,3	NA	No	9.0
1SA129						
47) Hydrogen Recombiner	71	NA	1,2,3	NA	No	
1HG016						9.0
1HG020						NA
48) Hydrogen Recombiner	72	NA	1,2,3	NA	No	
1HG017						9.0
1HG021						NA

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

49) RWCU Decon	74	NA	1,2,3	NA	No	9.0
1G33-F428						
50) SX To Recir. Pump	78	NA	1,2,3	NA	No	9.0
1CC170						
51) Supp. Pool Cleanup Return	79	NA	1,2,3	NA	No	9.0
1SF023						
52) Fire Protection	81	NA	1,2,3	NA	No	9.0
1FP201						
53) Fire Protection	82	NA	1,2,3	NA	No	9.0
1FP200						
54) Cycle Condensate	85	NA	1,2,3	NA	No	9.0
1CY019						
55) RWCU Letdown	86	NA	1,2,3	NA	No	9.0
1G33-F070						
56) SX From Recir. Pump	88	NA	1,2,3	NA	No	9.0
1CC171						
57) Containment HVAC Supply	101	NA	1,2,3	NA	No	9.0
1VR003						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
3. Test Connections, Vents, and Drains (Continued)						
58) Containment HVAC Return	102	NA	1,2,3	NA	No	9.0
1VQ007						
59) Containment HVAC	106	NA	1,2,3	NA	No	9.0
1VR011						
60) Drywell Chilled Water	107	NA	1,2,3	NA	No	9.0
1VP044B						
1VP077D						
61) Drywell Chilled Water	108	NA	1,2,3	NA	No	9.0
1VP047B						
1VP077B						
62) Drywell Chilled Water	109	NA	1,2,3	NA	No	9.0
1VP044A						
1VP077C						
63) Drywell Chilled Water	110	NA	1,2,3	NA	No	9.0
1VP047A						
1VP077A						
64) Containment HVAC	113	NA	1,2,3	NA	No	9.0
1VR012						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections, Vents, and Drains (Continued)

65) Deleted						
66) Drywell Pressure		NA		NA	No	9.0
1CM076	151		1,2,3			
1CM077	203					
67) Reactor Pressure	151	NA	1,2,3	NA	No	9.0
1CM072						
1CM073						
68) Reactor Pressure	160	NA	1,2,3	NA	No	9.0
1CM074						
1CM075						
69) Hydrogen Recombiner	166	NA	1,2,3	NA	No	9.0
1HG018						
70) Suppression Pool Level	177	NA	1,2,3	NA	No	9.9
1E51-F437A						
1E51-F437B						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

3. Test Connections. Vents, and Drains (Continued)

71) Suppression Pool Level	179	NA	1,2,3	NA	No	9.9
1E22-F381A						
1E22-F381B						
1SM027A						
1SM027B						
72) Suppression Pool Level	181	NA	1,2,3	NA	No	9.9
1SM026A						
1SM026B						
73) Suppression Pool Level	183	NA	1,2,3	NA	No	9.9
1CM100A						
1CM100B						

4. Other Isolation Valves

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
1) Main Steam Line C	5	NA	1,2,3	NA	No	9.0
1E32-F001J						
2) Main Steam Line A	6	NA	1,2,3	NA	No	9.0
1E32-F001A						
3) Main Steam Line D	7	NA	1,2,3	NA	No	9.0
1E32-F001N						
4) Main Steam Line B	8	NA	1,2,3	NA	No	9.0
1E32-F001E						
5) Feedwater/RHR Line A	9			NA		Note 1
1B21-F010A		NA	1,2,3, #		Yes	9.9
1B21-F065A		NA	1,2,3, #		Yes	
1B21-F032A		B,L,R	1,2,3, #		Yes	
1E12-F497		NA	1,2,3		No	
6) Feedwater/RHR Line B	10			NA		Note 1
1B21-F010B		NA	1,2,3, #		Yes	9.9
1B21-F065B		NA	1,2,3, #		Yes	
1B21-F032B		B,L,R	1,2,3, #		Yes	
1E12-F496		NA	1,2,3		No	
7) RHR A Suction Line	11	NA	1,2,3	NA	No	9.9
1E12-F004A						
8) RHR B Suction Line	12	NA	1,2,3	NA	No	9.9
1E12-F004B						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

9) RHR C Suction Line	13	NA	1,2,3	NA	No	9.9
1E12-F105						
10) RHR/LPCI A Injection	15	NA	1,2,3	NA	No	9.0
1E12-F027A						
1E12-F042A						
1E12-F028A						
11) RHR/LPCI B Injection	16	NA	1,2,3	NA	No	9.0
1E12-F027B						
1E12-F042B						
1E12-F028B						
12) RHR/LPCI C Injection	17	NA	1,2,3	NA	No	9.0
1E12-F042C						
13) RHR A/LPCS Test Line	18	NA	1,2,3	NA	No	9.9
1E21-F011						
1E12-F064A						
14) RHR C Test Line	19	NA	1,2,3	NA	No	9.9
1E12-F064C						
15) RHR B Test Line	20	NA	1,2,3	NA	No	9.9
1E12-F064B						
16) RHR A Suction Relief	21	NA	1,2,3	NA	No	9.9
1E12-F017A						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

17) RHR Shutdown Cool Relief	23	NA	1,2,3	NA	No	NA
1E12-F005						
18) RHR A HX Relief Line	24	NA	1,2,3	NA	No	9.9
1E12-F055A (Setpoint Raised)						
1E12-F112A						
19) RHR B Suction Relief	25	NA	1,2,3	NA	No	9.9
1E12-F017B						
20) RHR B HX Relief Line	26	NA	1,2,3	NA	No	9.9
1E12-F055B (Setpoint Raised)						
1E12-F112B						
21) RHR/LPCI B Inj. Relief	16/27	NA	1,2,3	NA	No	9.0
1E12-F025B						
22) RHR C Suction Relief	29	NA	1,2,3	NA	No	9.9
1E12-F101						
23) RHR/LPCI C Inj. Relief	30	NA	1,2,3	NA	No	9.9
1E12-F025C						
24) RHR To RCIC Suction Relief	31	NA	1,2,3	NA	No	9.9
1E12-F036						

4. Other Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
25) LPCS Suction Line	32	NA	1,2,3	NA	No	9.9
1E21-F001						
26) HPCS Test Line & Relief	33	NA	1,2,3	NA	No	9.9
1E22-F014						
1E22-F035						
1E22-F039						
1E22-F012						
27) HPCS Injection Line	35	NA	1,2,3	NA	No	9.0
1E22-F004						
28) LPCS Injection Line	36	NA	1,2,3	NA	No	9.0
1E21-F005						
29) HPCS Suction Line	37	NA	1,2,3	NA	No	9.9
1E22-F015						
30) LPCS Pump Relief Line	38	NA	1,2,3	NA	No	9.9
1E21-F018						
1E21-F031						
31) RCIC Min. Flow Relief	40	NA	1,2,3	NA	No	
1E51-F090						NA
1E51-F019						9.9

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

32) RCIC Turbine Exhaust		NA	1,2,3	NA	No	9.9
1E51-F068	41					
1E51-F040	28/41					
33) RCIC Head Spray	42	NA	1,2,3	NA	No	9.0
1E51-F013						
34) Deleted						
35) Make-Up Condensate	50	NA	1,2,3, #	NA	Yes	9.0
1MC090						
36) Instrument Air	57	NA	1,2,3	NA	No	9.0
1IA175						
37) Instrument Air Bottles	58	NA	1,2,3, #	NA	Yes	9.0
1IA042B						
1IA012A						
38) CRD	63	NA	1,2,3, #	NA	Yes	
1C11-F122						9.0
1C11-F083						
39) RWCU Transfer to Radwaste	65	NA	1,2,3, #	NA	Yes	9.0
1WX080						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
40) RHR Flush Line	76	NA	1,2,3	NA	No	9.9
1E12-F030						
41) RHR/LPCI A Injec. Relief	15/87	NA	1,2,3	NA	No	9.0
1E12-F025A						
42) NOT USED						
43) DW Chilled Water Relief	107	NA	1,2,3	NA	No	9.0
1VP023B						
44) DW Chilled Water Relief	108	NA	1,2,3	NA	No	9.0
1VP027B						
45) DW Chilled Water Relief	109	NA	1,2,3	NA	No	9.0
1VP023A						
46) DW Chilled Water	110	NA	1,2,3	NA	No	9.0
1VP027A						
47) Containment Press	150	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1CM003A(d)						
48) Drywell Pressure	151	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1CM051(d)						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

49) Reactor Pressure	151	NA	1,2,3	flow ≤ 1.2 gpm (b1)	No	NA
1CM066(d)						
50) Containment Bldg HVAC	156	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
lVG056B(d)						
51) Suppression Pool Level	157	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1CM002A(d)						
1CM003B(d)						
52) Reactor Pressure	160	NA	1,2,3	flow ≤ 1.2 gpm (b1)	No	NA
1CM067(d)						
53) Suppression Pool Level	164	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1SM010(d)						
54) Containment Bldg HVAC	165	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1VR016A(d)						
1VR016B(d)						
1VR018A(d)						
55) Containment Bldg. HVAC	167	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1VG057B(d)						

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)

4. Other Isolation Valves (Continued)

56) Containment Bldg. HVAC	168	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1VR018B(d)						
57) Suppression Pool	171	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1SM009(d)						
58) Not Used						
59) Suppression Pool Level	177	NA	1,2,3	flow < 1 gpm (b2)	No	NA
1E51-F377B(d)						
60) Suppression Pool Level	179	NA	1,2,3	flow < 1 gpm (b2)	No	NA
1E22-F332(d)						
1SM011(d)						
61) HPCS	180	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1E22-F330(d)						
62) Suppression Pool Level	181	NA	1,2,3	flow < 1 gpm (b2)	No	NA
1SM008(d)						
63) Suppression Pool Level	183	NA	1,2,3	flow < 1 gpm (b2)	No	NA
1CM002B(d)						

4. Other Isolation Valves (Continued)

VALVE NUMBER	PENETRATION NUMBER	ISOLATION SIGNAL (h)	APPLICABLE MODES	MAXIMUM ISOLATION TIME (Seconds)	SECONDARY CONTAINMENT BYPASS PATH (Yes/No)	TEST PRESSURE psig (a)
64) RCIC	200	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1E51-F377A(d)						
65) Drywell Pressure	203	NA	1,2,3	0.58 scfm < flow < 3 scfm (b2)	No	NA
1CM053(d)						
66) Deleted						
67) Deleted						
68) Instrument Air Bottles	206	NA	1,2,3, #	NA	Yes	9.0
1IA042A						
1IA013A						
69) Deleted						

TABLE NOTATIONS

(a) For test pressure = 9.0 psig, the valve(s) shall be pressurized using air or nitrogen, and for test pressure = 9.9 psig, the valve(s) shall be pressurized using water.

(b) Excess flow check valve actuation flow.

(b1) This excess flow check valve communicates with the reactor coolant pressure boundary. As such, it is tested per TS SR 3.6.1.3.12. See Bases SR 3.6.1.3.12.

(b2) This excess flow check valve does NOT communicate with the reactor coolant pressure boundary. The In-Service Testing (IST) program provides assurance of integrity in accordance with USAR Table 6.2-47. IST program testing is dependent on safety function as identified in the IST bases documents.

(c) Isolates on RCIC low steam line pressure only.

(d) Excess flow check valve.

(e) A manual isolation permissive is provided by the "B" signal for valves 1E51-F031 and 1E51-F064. The manual isolation pushbutton must be depressed for these valves to close.

(f) Valves shall be closed to support Secondary Containment OPERABILITY.

(g) Valves shall be "sealed closed" under administrative control to assure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. For valves supplied with keylock control switches, removal of the key in conjunction with tagging the control switches in the main control room in the closed position satisfies this requirement.

(h) Containment isolation trip signals are tabulated below:

Symbol	Description
A	Reactor Vessel Water Level Low (Level 3)
B	Reactor Vessel Water Level Low (Level 2)
C	Deleted
D	Main Steam Line High Flow
E	Main Steam Tunnel Temp. High
G	Main Steam in Turbine Building Temp. High
H	Turbine Inlet Pressure Low
J	Condenser Vacuum Low
L	Drywell Pressure High
M	Containment Exhaust Duct High Rad.
N	RWCU High Temp.
P	Containment Pressure-High
R	CRVICS Manual Initiation Pushbuttons
T	RHR Heat Exchanger Rooms A, B High Temp.
U	Reactor Water Level Low (Level 1)
V	RCIC High Steam Line Space Temp. RCIC Low Steam Line Pressure RCIC High Steam Flow High Turbine Exhaust Pressure RCIC Area High Temp.
X	Permissively Interlocked with Other Equipment
Z	High Rad. in Containment Refueling Pool Exhaust Duct
1	RWCU Equipment High Differential Flow
5	Containment Purge Duct High Radiation
6	SLC Initiation
7	RWCU Isolation Manual Initiation

(i) May be considered a manual valve as long as the valve is maintained closed by use of administrative control.

(j) This valve receives a closure signal upon manual initiation of the associated RHR division.

(k) The valves shall be "sealed closed" under administrative control to assure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal and lock the valve closed and prevent power from being supplied to the valve operator. The valves are considered manual valves as long as they are maintained closed by use of administrative control.

(1) Per Licensing Amendment 127 leakage through 1B21-F010A/B is not included in T.S. SR 3.6.1.3.11 limit. The valves are tested IAW CPS Inservice Testing Program requirements.

(m) EC 371540 authorized installation of a blind coupling on the outboard side of penetration 116. Valves 1C41-F340B and 1C41-F341B are abandoned-in-place.

\# During movement of recently irradiated fuel assemblies in the primary or secondary containment and during operations with a potential for draining the reactor vessel.

\## In Modes 4 and 5 when the associated isolation instrumentation is required OPERABLE per Technical Specification LCO 3.3.6.1 Function 5.c.

DRYWELL ISOLATION VALVES

System	Penetration Number	Valve(s)	Operator Type	Valve Type	Isolation Signal
RR Process Sampling	1MD-13	1B33-F019	AOV	Globe	B
		1B33-F020	AOV	Globe	B
Chilled Water for drywell cooling coil cabinets G & H	1MD-53	1WO551A	MOV	Gate	U,L
		1WO551B	MOV	Gate	U,L
		1WO552A	MOV	Gate	U,L
		1WO552B	MOV	Gate	U,L
Instrument Air	1MD-57	1IA007	AOV	Gate	U
		1IA008	AOV	Gate	U
Service Air	1MD-59	1SA031	AOV	Gate	B,L
		1SA032	AOV	Gate	B,L
Drywell Equipment Drains, pump discharge	1MD-69	1RE019	AOV	Gate	B,L
		1RE020	AOV	Gate	B,L
Drywell Floor Drains, pump discharge	1MD-70	1RF019	AOV	Gate	B,L
		1RF020	AOV	Gate	B,L
Drywell Purge Air inlet	1MD-101	1VQ001A	AOD	Butterfly	B,L,M,Z,5
		1VQ001B	AOD	Butterfly	B,L,M,Z,5
Drywell Purge Air outlet	1MD-102	1VQ002	AOD	Butterfly	B,L,M,Z,5
		1VQ003	AOD	Butterfly	B,L,M,Z,5
		1VQ005	AOD	Butterfly	B,L,M,Z,5
Breathing Air	1MD-106	0RA028	AOV	Gate	B,L
		0RA029	AOV	Gate	B,L
Fire Protection	1MD-124	1FP078	MOV	Gate	B,L (note 1)
		1FP079	MOV	Gate	B,L (note 1)
Condensate Makeup/RHR	1MD-125	1CY020	MOV	Gate	B,L (note 1)
		1CY021	MOV	Gate	B,L (note 1)
Leak Detection	1MD-182	1E31-F014	SOV	Gate	B,L
		1E31-F015	SOV	Gate	B,L
		1E31-F017	SOV	Gate	B,L
		1E31-F018	SOV	Gate	B,L

DRYWELL ISOLATION VALVES (Continued)

System	Penetration Number	Valve(s)	Operator Type	Valve Type	Isolation Signal
Standby Liquid Control	1MD-4	1C41-F006	-----	Check	-----
		1C41-F007	-----	Check	-----
		1C41-F336	-----	Check	-----
		1C41-F026	Manual	Globe	Locked Closed
RR Pump Seal Purge "A"	1MD-11	1B33-F013A	-----	Check	-----
		1B33-F017A	-----	Check	-----
RR Pump Seal Purge "B"	1MD-12	1B33-F013B	-----	Check	-----
		1B33-F017B	-----	Check	-----
RR Process Sampling	1MD-13	1B33-F021	Manual	Globe	Closed/Capped
RHR/LPCI "A"	1MD-15	1E12-F041A	-----	Check	-----
		1E12-F301A	AOV	Gate	NC/Open for test
		1E12-F056A	Manual	Globe	Locked Closed
RHR/LPCI "B"	1MD-16	1E12-F041B	-----	Check	-----
		1E12-F301B	AOV	Gate	NC/Open for test
		1E12-F056B	Manual	Globe	Locked Closed
		1E12-F456A	Manual	Globe	Locked Closed
		1E12-F373C	Manual	Globe	Locked Closed
RHR/LPCI "C"	1MD-17	1E12-F041C	-----	Check	-----
		1E12-F301C	AOV	Gate	NC/Open for test
		1E12-F456B	Manual	Globe	Locked Closed
		1E12-F351	Manual	Globe	Locked Closed
HPCS discharge to Reactor Pressure Vessel	1MD-35	1E22-F005	-----	Check	-----
		1E22-F304	AOV	Gate	NC/Open for test
		1E22-F366B	Manual	Globe	Locked Closed
LPCS discharge to Reactor Pressure Vessel	1MD-36	1E21-F006	-----	Check	-----
		1E21-F358	Manual	Globe	Locked Closed
		1E21-F340	AOV	Gate	NC/Open for test
		1E21-F356A	Manual	Globe	Locked Closed
Chilled Water for drywell cooling coil cabinets G & H	1MD-53	1WO557	Manual	Globe	Closed/Capped
		1WO570A	-----	Relief	-----
		1WO560	Manual	Globe	Closed/Capped
		1WO570B	-----	Relief	-----
Drywell Vacuum Breakers	1MD-72	1HG010A	-----	Check	-----
		1HG011A	-----	Check	-----

DRYWELL ISOLATION VALVES (Continued)

System	Penetration Number	Valve(s)	Operator Type	Valve Type	Isolation Signal
RHR	1MD-94	1E12-F073B	MOV	Globe	Closed
		1E12-F110B	-----	Check	-----
Dry well Purge Air inlet	1MD-101	1VQ011	Manual	Globe	Closed/Capped
Dry well Purge Air outlet	1MD-102	1VQ012	Manual	Globe	Closed/Capped
Drywell Vacuum Breakers	1MD-117	1HG010B	-----	Check	-----
		1HG011B	-----	Check	-----
Drywell Vacuum Breakers	1MD-119	1HG010D	-----	Check	-----
		1HG011D	-----	Check	-----
Drywell Vacuum Breakers	1MD-120	1HG010C	-----	Check	-----
		1HG011C	-----	Check	-----
Condensate Makeup/RHR	1MD-125	1E12-F073A	MOV	Globe	Closed
		1E12-F110A	-----	Check	-----
Leak Detection	1MD-182	1E31-F016	SOV	Gate	Failed Closed
		1E31-F019	SOV	Gate	Failed Closed

Table Legend

AOD - Air Operated Damper
AOV - Air Operated Valve
HPCS - High Pressure Core Spray
LPCI - Low Pressure Coolant Injection
LPCS - Low Pressure Core Spray
MOV - Motor Operated Valve
NC - Normally Closed
RHR - Residual Heat Removal
RR - Reactor Recirculation
SOV - Solenoid Operated Valve

Table Note

(1) Locked Shut and de-energized

Isolation Signals

Symbol	Description
B	Reactor Vessel Water Level Low (Level 2)
L	Drywell Pressure High
M	Containment Exhaust Duct High Radiation
U	Reactor Vessel Water Level Low (Level 1)
Z	High Radiation in Containment Refueling Pool Exhaust Duct
5	Containment Purge Duct High Radiation

Automatic Dampers

Damper	**Description**
1VF06Y	Fuel Building Supply Inboard Isolation Damper
1VF07Y	Fuel Building Exhaust Inboard Isolation Damper
1VF04Y	Fuel Building Supply Outboard Isolation Damper
1VF09Y	Fuel Building Exhaust Outboard Isolation Damper

Manual Dampers

Damper	**Description**
0VG03YA	Standby Gas Treatment System Train "A" Control Building Inlet Damper
0VG03YB	Standby Gas Treatment System Train "B" Control Building Inlet Damper