LaSalle County Power Station

Technical Requirements Manual

(TRM)

LaSalle County Nuclear Power Station, Unit 1 and 2
Facility Operating License Nos. NPF-11 (Unit 1) and NPF-18 (Unit 2)
NRC Docket Nos. STN 50-373 (Unit 1) and 50-374 (Unit 2)

AFFECTED PAGE LIST - TECHNICAL REQUIREMENTS MANUAL

AFFECTED PAGE LIST - TECHNICAL REQUIREMENTS MANUAL

AFFECTED PAGE LIST - TECHNICAL REQUIREMENTS MANUAL

Bases

AFFECTED PAGE LIST - TECHNICAL REQUIREMENTS MANUAL

Bases (cont.)

AFFECTED PAGE LIST - TECHNICAL REQUIREMENTS MANUAL

Appendices

BASES

BASES

1.0 USE AND APPLICATION

1.1 Definitions

---NOTE---
The defined terms of this section appear in capitalized type and are applicable throughout the Technical Requirements Manual and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Requirement that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an 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	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	A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

(continued)

1.1 Definitions

CORE ALTERATION	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.
CORE OPERATIING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Requirements.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all required 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	A MODE shall correspond to any one inclusive combination of MODE switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Technical Specifications Table 1.1-1 with fuel in the reactor vessel.

(continued)

1.1 Definitions (continued)

OFFSITE DOSE CALCULATION MANUAL (ODCM)	The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Program and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Radioactive Effluent Release Reports.
OPERABLE – OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified function(s) are also capable of performing their related support function(s).
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3546 MWt.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Requirements Manual (TRM) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TRM are <u>AND</u> and <u>OR</u>. The physical arrangement of these connectors constitutes logical conventions with specific meanings.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with he statement of the Condition, Completion Time, Surveillance, or Frequency.
EXAMPLES	The following examples illustrate the use of logical connectors.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. TLCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example, the logical connector AND is used to indicate that, when in Condition A, both Required Actions A.1 and A.2 must be completed.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. TLCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2 and A.3 are alternate choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Action may be chosen. If A.2 is chose, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Technical Requirements Manual Limiting Condition for Operation (TLCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with a TLCO state Condition that typically describe the ways in which the requirements of the TLCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Times.

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the TLCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the TLCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single TLCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting form the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent divisions, subsystem, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

(continued)

DESCRIPTION (continued)

However, when a <u>subsequent</u> division, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, tow criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the <u>first</u> inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extension does not apply to those TLCOs that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual TLCOs.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced form a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ." Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Condition A and B in Example 1.3-3 may not be extended.

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are in to be in MODE 3 within 12 hours AND in MODE 4 within 36 hours. A total of 12 hours is allowed for reaching MODE 3 and a total of 36 hours (not 48 hours) is allowed for reaching MODE 4 from the time that Condition B was entered. If MODE 3 is reached within 6 hours, the time allowed for reaching MODE 4 is the next 30 hours because the total time allowed for reaching Mode 4 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 4 is the next 36 hours.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Action B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. TLCO 3.0.c is entered, since the ACTIONS do not include a Condition from more than one inoperable pump. The Completion Time clock for Condition A does not stop after TLCO 3.0.c is entered, but continues to be tracked form the time Condition A was initially entered.

While in TLCO 3.0.c, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not expired, TLCO 3.0.c may be exited and operation continued in accordance with Condition A.

(continued)

EXAMPLES

EXAMPLE 1.3-2 (continued)

While in TLCO 3.0.c, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, TLCO 3.0.c may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked form the time the Condition A Completion Time expired.

On restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues form the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for > 7 days.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the TLCO
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours AND 10 days from discovery to meet TLCO
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

(continued)

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked form the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured form the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

The Completion Times of Conditions A and B are modified by a logical connector, with a separate 10 day Completion Time measured form the time it was discovered the TLCO was not met. In this example, without the separate Completion Time, it would be possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the TLCO. The separate Completion Time modified by the phrase “from discovery of failure to meet the TLCO” is designed to prevent indefinite continued operation while not meeting the TLCO. This Completion Time allows for an exception to the normal “time zero” for beginning the Completion Time “clock.” In this instance, the Completion Time “time zero” is specified as commencing at the time the associated Condition was entered.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent vale being inoperable for > 4 hours.

If the Completion Time of 4 hours (plus the extension) expires while one or more valves are still inoperable, Condition B is entered.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

--------------------------------NOTE-------------------------------------
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform TSR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per TSR 3.0.b to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be completed within the first 8 hour interval. If Required Action A.1 is followed and the Required Action is not met within the Completion Time (plus the extension allowed by TSR 3.0.b), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

(continued)

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated. AND A.2 Restore subsystem to OPERABLE status.	1 hour AND Once per 8 hours thereafter 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each “Once per 8 hours thereafter” interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by TSR 3.0.b), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues form the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When “Immediately” is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE	The purpose of this section is to define the proper use and application of Frequency requirements.
DESCRIPTION	Each Technical Requirements Manual Surveillance Requirement (TSR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Technical Requirements Manual Limiting Condition for Operation (TLCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the TSR. The "specified Frequency" is referred to throughout this section and each of the Requirements of Section 3.0, Technical Requirements Manual Surveillance Requirement (TSR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each TSR, as well as certain Notes in the Surveillance column that modify performance requirements. Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by TSR 3.0.a. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both. Example 1.4-4 discusses these special situations. Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated TLCO is within its Applicability, represent potential TSR 3.0.d conflicts. To avoid these conflicts, the TSR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With a TSR satisfied, TSR 3.0.d imposes no restriction. The use of "met" or "performed" in these instances conveys specified meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to

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1.0 USE AND APPLICATION

1.4 Frequency

DESCRIPTION (continued)

specifically determine the ability to meet the acceptance criteria. TSR 3.0.d restrictions would not apply if both the following conditions are satisfied:

a. The Surveillance is not required to be performed; and

b. The Surveillance is not required to be met or, even if required to be met, is not known to be failed.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the TLCO (TLCO not shown) is MODES 1, 2, and 3.

<u>EXAMPLE 1.4-1</u>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK	12 hours

Example 1.4-1 contains the type of TSR most often encountered in the Technical Requirements Manual (TRM). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by TSR 3.0.b for operational flexibility. The measurement of this interval continues at all times, event when the TSR is not required to be met per TSR 3.0.a (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the TLCO). If the interval specified by TSR 3.0.b is exceeded while the unit is in a MODE or other specified condition in the

(continued)

1.0 USE AND APPLICATION

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

Applicability of the TLCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then TSR 3.0.c becomes applicable.

If the interval as specified by TSR 3.0.b is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the TLCO for which performance of the TSR is required, the Surveillance must be performed within the Frequency requirements of TSR 3.0.b prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of TSR 3.0.d.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

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1.0 USE AND APPLICATION

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-2 (continued)

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by TSR 3.0.b.

"Thereafter" indicates future performances must be established per TSR 3.0.b, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
--------------------------NOTE-------------------------- Not required to be performed until 12 hours after ≥ 25% RTP. --	
Perform channel adjustment.	7 days

The interval continues whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day interval (plus the extension

(continued)

1.0 USE AND APPLICATION

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-3 (continued)

allowed by TSR 3.0.b), but operation was < 25% RTP, it would not constitute a failure of the TSR or failure to meet the TLCO. Also, no violation of TSR 3.0.d occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power $\geq$ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of TSR 3.0.c would apply.

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
--------------------------NOTE-------------------------- Only required to be met in MODE 1. --- Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by TSR 3.0.b), but the unit was not in MODE 1, there would be no failure of the TSR nor failure to meet the TLCO. Therefore, no violation of TSR 3.0.d occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), TSR 3.0.d would require satisfying the TSR.

1.0 USE AND APPLICATION

1.5 TLCO and TSR Implementation

The Technical Requirements Manual (TRM) provides those limitations upon plant operations which are part of the licensing basis for the station but do not meet the criteria for continued inclusion in the Technical Specifications.

It also provides information which supplements the Technical Specifications such as specific plant setpoint calculation numbers for Technical Specification equipment. Nothing in the TRM shall supersede any Technical Specification requirement.

TLCOs and TSRs are implemented the same as Technical Specifications (see TRM 3.0). However, TLCOs and TSRs are treated as plant procedures and are not part of the Technical Specifications. Therefore the following exceptions apply:

a. Violations of the Action or Surveillance requirements in a TLCO are not reportable as conditions prohibited by, or deviations from, the Technical Specifications per 10 CFR 50.72 or 10 CFR 50.73.

b. Power reduction or plant shutdowns required to comply with the Actions of a TLCO are not reportable per 10 CFR 50.72 or 10 CFR 50.73.

1.0 USE AND APPLICATION

1.6 Technical Requirements Manual Revisions

Changes to this manual shall be made under the following provisions:

a. Changes to the TRM shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to TRM without prior NRC approval provided the change does not require NRC approval pursuant to 10 CFR 50.59.

c. The TRM revision process shall contain provisions to ensure that the TRM is maintained consistent with the UFSAR.

d. Proposed changes that require NRC approval shall be reviewed and approved by the NRC prior to implementation. Changes to the TRM implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e) as modified by approved exemptions.

2.1.a MISCELLANEOUS TEST REQUIREMENTS

---NOTE---
Failure to meet the surveillance requirement requires immediate actions to determine OPERABILITY of the associated equipment.

APPLICABILITY: As defined in the TSR

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 2.1.a.1	---------------------------NOTE-------------------------------- Only applicable in MODE 1. --- Perform isotopic analysis of an offgas sample, including quantitative measurements of Xe-133, Xe-135, and Kr-88.	31 days
TSR 2.1.a.2	---------------------------NOTE------------------------------- Only applicable in MODES 1, 2, and 3, during CORE ALTERATIONS, during operations with the potential for draining the reactor vessel and during handling of irradiated fuel assemblies in secondary containment. --- Verify that upon an outside air smoke detection test signal, each Control Room Area Filtration System emergency subsystem switches to the pressurization mode of operation.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 2.1.a.3	------------------------------NOTE-------------------------------- TSR 2.1.a.3 verifies that the low-low set function of the Safety Relief Valve (SRV) system does not interfere with the OPERABILITY of the ADS and is only applicable in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig. --- Perform a functional test of the low-low set function.	24 months
TSR 2.1.a.4	-----------------------------NOTE-------------------------------- TSR 2.1.a.4 provides the scram time limit for <800 psig steam dome pressure to satisfy Technical Specification SR 3.1.4.3 and is only applicable in MODES 1 and 2. --- Verify each affected control rod scram time is within limits of Technical Specification Table 3.1.4-1 with any reactor pressure. The control rod scram time acceptance criteria shall be ≤ 2.04 seconds from fully withdrawn to notch position 05 at 0 psig reactor steam dome pressure.	Prior to declaring control rod OPERABLE after work on the control rod or CRD System that could affect scram time
TSR 2.1.a.5	-----------------------------NOTE-------------------------------- Only applicable when associated diesel generator is required to be OPERABLE. --- Drain each fuel oil storage tank, remove the accumulated sediment, and clean the tank using sodium hypochlorite or equivalent solution.	10 years

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 2.1.a.6	-----------------------------NOTE------------------------------- Only applicable when associated diesel generator is required to be OPERABLE. --- Perform a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND, of the ASME Code in accordance with ASME Code Section XI, Article IWD-5000.	10 years

3.0 TECHNICAL REQUIREMENTS MANUAL LIMITING CONDITION FOR OPERATION (TLCO) APPLICABILITY

TLCO 3.0.a	TLCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in TLCO 3.0.b.
TLCO 3.0.b	Upon discovery of a failure to meet a TLCO, the Required Actions of the associated Conditions shall be met, except as provided in TLCO 3.0.e. If the TLCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.
TLCO 3.0.c	When a TLCO 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 inoperabilities; and c. Within 12 hours, obtain Shift Operations Superintendent or designee approval of the compensatory actions and the plan for exiting TLCO 3.0.c. Exceptions to this TLCO are stated in the individual TLCOs. Where corrective measures are completed that permit operation in accordance with the TLCO or ACTIONS, completion of the actions required by TLCO 3.0.c is not required. TLCO 3.0.c is only applicable in MODES 1, 2, and 3.
TLCO 3.0.d	When a TLCO is not met, entry into a MODE or other specified condition in the Applicability shall not be made except when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the (continued)

3.0 TLCO APPLICABILITY

TLCO 3.0.d (continued)	Applicability for an unlimited period of time. This TLCO 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. Exceptions to this TLCO are stated in the individual TLCOs. TLCO 3.0.d is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, and 3.
TLCO 3.0.e	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 TLCO 3.0.b for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.
TLCO 3.0.f	TLCOs, including associated ACTIONS, shall apply to each unit individually, unless otherwise indicated. Whenever the TLCO refers to a system or component that is shared by both units, the ACTIONS will apply to both units simultaneously.

3.0 TECHNICAL REQUIREMENTS MANUAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

TSR 3.0.a	TSRs shall be met during the MODES or other specified conditions in the Applicability for individual TLCOs, unless otherwise stated in the TSR. Failure to meet a TSR, whether such failure is experienced during the performance of the TSR or between performances of the TSR, shall be failure to meet the TLCO. Failure to perform a TSR within the specified Frequency shall be failure to meet the TLCO except as provided in TSR 3.0.c. TSRs do not have to be performed on inoperable equipment or variables outside specified limits.
TSR 3.0.b	The specified Frequency for each TSR is met if the TSR 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 a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance. Exceptions to this TSR are stated in the individual TSRs.
TSR 3.0.c	If it is discovered that a TSR was not performed within its specified Frequency, then compliance with the requirement to declare the TLCO 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 TSR. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed. If the TSR is not performed within the delay period, the TLCO must immediately be declared not met, and the applicable Condition(s) must be entered. When the TSR is performed within the delay period and the TSR is not met, the TLCO must immediately be declared not met, and the applicable Condition(s) must be entered.

(continued)

3.0 TSR APPLICABILITY (continued)

TSR 3.0.d	Entry into a MODE or other specified condition in the Applicability of a TLCO shall not be made unless the TLCO's TSRs have been met within their specified Frequency. 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. TSR 3.0.d is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, and 3.
TSR 3.0.e	TSRs shall apply to each unit individually, unless otherwise indicated.

This section is no longer used.

3.3 INSTRUMENTATION

3.3.a Control Rod Drive Reactor Protection System (RPS) Instrumentation

TLCO 3.3.a The Control Rod Drive RPS instrumentation for each Function in Table T3.3.a-1 shall be OPERABLE.

APPLICABILITY: According to Table T3.3.a-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table T3.3.a-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table T3.3.a-1.	E.1 Be in MODE 3.	12 hours
F. As required by Required Action D.1 and referenced in Table T3.3.a-1.	F.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTES--

1. These TSRs apply to each Control Rod Drive RPS Function in Table T3.3.a-1.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains Control Rod Drive RPS trip capability.

SURVEILLANCE		FREQUENCY
TSR 3.3.a.1	Perform CHANNEL TEST.	31 days
TSR 3.3.a.2	Perform CHANNEL CALIBRATION.	24 months
TSR 3.3.a.3	Perform LOGIC SYSTEM FUNCTIONAL TEST.	48 months

Table T3.3.a-1 (page 1 of 1)
Control Rod Drive RPS Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITION REFERENCED FROM REQUIRED ACTION D.1	ALLOWABLE VALUE
1. Charging Water Header Pressure – Low	2	2	E	≥ 1124 psig
	5[(a)]	2	F	≥ 1124 psig
2. Delay Timer	2	2	E	≤ 9.4 seconds
	5[(a)]	2	F	≤ 9.4 seconds

(a) With any control rod withdrawn for a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.c Control Rod Block Instrumentation

TLCO 3.3.c The control rod block instrumentation for each Function in Table T3.3.c-1 shall be OPERABLE.

APPLICABILITY: According to Table T3.3.c-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. For Functions 1.a, 1.b, 1.c, 1.d, 2.a, 2.b, 2.c, 2.d, 3.a, 3.b, 3.c, and 3.d, one required channel inoperable.	A.1 Restore inoperable channel to OPERABLE status.	7 days
B. For Functions 4.a, 4.b, 5.a, 5.b, and 5.c, one or more required channels inoperable.	B.1 Place inoperable channel(s) in trip.	12 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. For Functions 1.a, 1.b, 1.c, 1.d, 2.a, 2.b, 2.c, 2.d, 3.a, 3.b, 3.c, and 3.d, two or more required channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	C.1 Place inoperable channel(s) in trip.	1 hour

SURVEILLANCE REQUIREMENTS

-----NOTE-----
1. Refer to Table T3.3.c-1 to determine which TSRs apply to each Control Rod Block Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains Control Rod Block capability.

SURVEILLANCE		FREQUENCY
TSR 3.3.c.1	-----NOTE----- Not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. -----	
	Perform CHANNEL FUNCTIONAL TEST.	7 days
	-----NOTE----- Functions 3.b – 3.d -----	
	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.c.2	-----NOTE----- For Function 1.d, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. -----	
	Perform CHANNEL FUNCTIONAL TEST.	92 days
TSR 3.3.c.3	Perform CHANNEL CALIBRATION.	92 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.c.4	------------------------------NOTES-------------------------------- 1. For Function 1.d, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. 2. Neutron detectors are excluded. --- Perform CHANNEL CALIBRATION.	184 days
TSR 3.3.c.5	------------------------------NOTES-------------------------------- 1. For Functions 2.b, 2.d, 3.b, and 3.d, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. 2. Neutron detectors are excluded. --- Perform CHANNEL CALIBRATION.	24 months

Table T3.3.c-1 (page 1 of 2)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Average Power Range Monitors				
a. Flow Biased Neutron Flux – Upscale	1	4	TSR 3.3.c.2 TSR 3.3.c.4	≤ 0.61W + 56.9%[(a)] RTP
b. Inoperative	1,2	4	TSR 3.3.c.2	N.A.
c. Downscale	1	4	TSR 3.3.c.2 TSR 3.3.c.4	≥ 3% RTP
d. Neutron Flux – High	2	4	TSR 3.3.c.2 TSR 3.3.c.4	≤ 14% RTP
2. Source Range Monitors				
a. Detector not full in	2[(b)]	3	TSR 3.3.c.1	N.A.
	5	2	TSR 3.3.c.1	N.A.
b. Upscale	2[(c)]	3	TSR 3.3.c.1 TSR 3.3.c.5	≤ 5×10^5 cps
	5	2	TSR 3.3.c.1 TSR 3.3.c.5	≤ 5×10^5 cps
c. Inoperative	2[(c)]	3	TSR 3.3.c.1	N.A.
	5	2	TSR 3.3.c.1	N.A.
d. Downscale	2[(d)]	3	TSR 3.3.c.1 TSR 3.3.c.5	≥ 0.5 cps
	5	2	TSR 3.3.c.1 TSR 3.3.c.5	≥ 0.5 cps

(a) Allowable Value is ≤ 0.54W + 44.7% RTP when reset for single loop operation per Technical Specification 3.4.1, “Recirculation Loops Operating.”

(b) With detector count rate < 100 cps and the Intermediate Range Monitor (IRM) channels are on range 2 or below.

(c) With IRM channels on range 7 or below.

(d) With IRM channels on range 2 or below.

Table T3.3.c-1 (page 2 of 2)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Intermediate Range Monitors				
a. Detector not full in	2, 5(f)	6	TSR 3.3.c.1	N.A.
b. Upscale	2, 5(f)	6	TSR 3.3.c.1 TSR 3.3.c.5	≤ 110/125 of full scale
c. Inoperative	2, 5(f)	6	TSR 3.3.c.1	N.A.
d. Downscale	2(e), 5(f)	6	TSR 3.3.c.1 TSR 3.3.c.5	≥ 3/125 of full scale
4. Scram Discharge Volume				
a. Water Level – High	1, 2, 5(f)	2	TSR 3.3.c.2 TSR 3.3.c.5	≤ 767 ft. 5.125 inches
b. Scram Discharge Volume Switch in Bypass	5(f)	1	TSR 3.3.c.2	N.A.
5. Recirculation Flow Unit				
a. Upscale	1	2	TSR 3.3.c.2 TSR 3.3.c.3	≤ 111/125 of full scale
b. Inoperative	1	2	TSR 3.3.c.2	N.A.
c. Comparator	1	2	TSR 3.3.c.2 TSR 3.3.c.3	≤ 11% flow deviation

(e) With IRM channels on range 2 or higher.

(f) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.d Post Accident Monitoring (PAM) Instrumentation

TLCO 3.3.d The PAM instrumentation for each Function in Table T3.3.d-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE------------- Not applicable to Functions 4 and 5. ------------------------------- One or more Functions with one required channel inoperable.	A.1 --------------NOTE----------------- Only applicable to Function 2. -------------------------------------- Restore required channel to OPERABLE status.	30 days
	<u>AND</u>	
	A.2 -------------NOTE------------------ Only applicable to Functions 1, 3, 6, and 7. -------------------------------------- Restore required channel to OPERABLE status.	7 days

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------NOTE----------- Only applicable to Function 2. --------------------------- Two required channels inoperable.	B.1 Restore one required channel to OPERABLE status.	7 days
C. Required Action and associated Completion Time of Condition A or B not met.	C.1.1 Initiate action to restore required channel to OPERABLE status. <u>OR</u> C.1.2 Initiate alternate method of monitoring the appropriate parameters. <u>AND</u> C.2 Prepare a corrective action program document.	Immediately Immediately Immediately
D. --------NOTE----------- Only applicable to Functions 4 and 5. --------------------------- One or more Functions with one required channel inoperable.	D.1 Initiate alternate method of monitoring the appropriate parameters. <u>AND</u> D.2 Restore required channel to OPERABLE status.	72 hours 7 days

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition D not met.	E.1 Prepare a corrective action program document.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTES--
1. These TSRs apply to each Function in Table T3.3.d-1, except where identified in the TSR.

2. For Function 2, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other required Function 2 channel is OPERABLE.

SURVEILLANCE		FREQUENCY
TSR 3.3.d.1	Perform CHANNEL CHECK.	31 days
TSR 3.3.d.2	------------------------------NOTE------------------------------ For Function 3, not required to be performed until 12 hours after reactor steam pressure is adequate to perform the test. --- Perform CHANNEL CALIBRATION, for Functions other than Function 6 and 7.	24 months
TSR 3.3.d.3	Perform CHANNEL CALIBRATION for Functions 6 and 7.	92 days

Table T3.3.d-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS
1.	Suppression Chamber Air Temperature	1
2.	Drywell Air Temperature	2, in 1 division
3.	Safety/Relief Valve Position Indicators	1/valve
4.	Main Stack Noble Gas Monitor	1
5.	Standby Gas Treatment System Stack Noble Gas Monitor	1
6.	Drywell O_2 Concentration Analyzer	1
7.	Drywell H_2 Concentration Analyzer	1

3.3 INSTRUMENTATION

3.3.e Emergency Core Cooling System (ECCS) Discharge Line Keep Fill Alarm Instrumentation

TLCO 3.3.e The ECCS discharge line keep fill alarm instrumentation shall be OPERABLE.

APPLICABILITY: When the associated ECCS subsystem is OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more ECCS discharge line keep fill alarm instrumentation channel(s) inoperable.	A.1 Perform Technical Specification SR 3.5.1.1 for the affected ECCS subsystem.	24 Hours <u>AND</u> Once per 24 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.e.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.e.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be as follows:	24 months

System	Low Pressure Allowable Value (psig)
Low Pressure Core Spray	≥ 46.5
Low Pressure Coolant Injection (LPCI) “A”	≥ 42.0
LPCI “B”	≥ 39.6
LPCI “C”	≥ 45.7
High Pressure Core Spray	≥ 44.4

3.3 INSTRUMENTATION

3.3.f Emergency Core Cooling System (ECCS) Header Differential Pressure Instrumentation

TLCO 3.3.f ECCS header differential pressure instrumentation shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more ECCS header differential pressure channel(s) inoperable.	A.1 Restore inoperable ECCS header differential pressure instrumentation channel. <u>OR</u> A.2 Determine associated ECCS header differential pressure locally.	72 hours 72 hours <u>AND</u> Once per 12 hours thereafter
B. Required Action and associated Completion Time not met.	B.1 Declare associated ECCS inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.f.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.f.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be as follows: System — Allowable Value Low Pressure Core Spray / Low Pressure Coolant Injection — $\pm$ 4.0 psid High Pressure Core Spray — $\leq$ - 0.5 psid	24 months

3.3 INSTRUMENTATION

3.3.g Reactor Core Isolation Cooling (RCIC) System Discharge Line Keep Fill Alarm Instrumentation

TLCO 3.3.g The RCIC discharge line keep fill alarm instrumentation shall be OPERABLE.

APPLICABILITY: When RCIC is OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC discharge line keep fill alarm instrumentation channel inoperable.	A.1 Perform Technical Specification SR 3.5.3.1 for the affected RCIC subsystem.	24 hours <u>AND</u> Once per 24 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.g.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.g.2	Perform CHANNEL CALIBRATION. The Allowable Value for the low pressure setpoint shall be ≥ 35.1 psig.	24 months

3.3 INSTRUMENTATION

3.3.h High/Low Pressure Interface Valve Leakage Pressure Monitors

TLCO 3.3.h The high/low pressure interface valve leakage pressure monitors shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3, except monitors of the residual heat removal (RHR) shutdown cooling flow path when in, or during the transition to or from, the shutdown cooling mode of operation.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more high/low pressure interface valve leakage pressure monitors inoperable.	A.1 Restore inoperable high/low pressure interface valve leakage pressure monitor(s). <u>OR</u> A.2 Verify pressure to be less than the associated alarm Allowable Value by observing local indication.	7 days 7 days <u>AND</u> Once per 12 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.h.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.h.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be as follows: System — Allowable Value (psig) High Pressure Core Spray — ≤ 109 Low Pressure Core Spray — ≤ 523 Low Pressure Coolant Injection/Shutdown Cooling — ≤ 468 RHR Shutdown Cooling — ≤ 195 Reactor Core Isolation Cooling — ≤ 99	24 months

3.3 INSTRUMENTATION

3.3.i Emergency Core Cooling System (ECCS) Instrumentation

TLCO 3.3.i One channel per trip system of the Automatic Depressurization System (ADS) Manual Inhibit Function shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome > 150 psig.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status.	5 days from discovery of inoperable channel concurrent with High Pressure Core Spray or Reactor Core Isolation Cooling inoperable. <u>AND</u> 9 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.i.1	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months

3.3 INSTRUMENTATION

3.3.j Primary Containment Isolation Instrumentation

TLCO 3.3.j The primary containment isolation instrumentation for each Function in Table T3.3.j-1 shall be OPERABLE.

APPLICABILITY: According to Table T3.3.j-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	24 hours
B. One or more Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter Condition referenced in Table T3.3.j-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table T3.3.j-1.	D.1 Close the affected isolation valve(s).	1 hour

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action C.1 and referenced in Table T3.3.j-1.	E.1 Initiate action to restore channel to OPERABLE status.	Immediately
	<u>OR</u>	
	E.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling (SDC) System.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTES--
1. Refer to Table T3.3.j-1 to determine which TSRs apply for each primary containment isolation instrumentation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the redundant isolation valve in each associated line is OPERABLE and required isolation instrumentation for that redundant valve is OPERABLE.

SURVEILLANCE		FREQUENCY
TSR 3.3.j.1	Perform CHANNEL CHECK.	12 hours
TSR 3.3.j.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
TSR 3.3.j.3	Perform CHANNEL CALIBRATION.	92 days
TSR 3.3.j.4	Perform CHANNEL CALIBRATION.	24 months
TSR 3.3.j.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months

Table T3.3.j-1 (page 1 of 1)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITION REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Water Cleanup Isolation – Pump Suction Flow – High	1, 2, 3	1	D	TSR 3.3.j.1 TSR 3.3.j.2 TSR 3.3.j.4 TSR 3.3.j.5	≤ 613 gpm
2. Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow – High	3	1	E	TSR 3.3.j.2 TSR 3.3.j.3 TSR 3.3.j.5	≤ 185 inches Wc H_2O

This section no longer used.

3.3 INSTRUMENTATION

3.3.I Meteorological Monitoring Instrumentation

TLCO 3.3.I The meteorological monitoring instrumentation channels in Table T3.3.1-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required meteorological monitoring instrumentation channels inoperable.	A.1 Restore channel to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Prepare a corrective action program report outlining the cause of the malfunction and plans for restoring the channel to OPERABLE status.	10 days

SURVEILLANCE REQUIREMENTS

---NOTE---
These TSRs apply to each Function in Table T3.3.I-1.

SURVEILLANCE		FREQUENCY
TSR 3.3.I.1	Perform CHANNEL CHECK.	24 hours
TSR 3.3.I.2	Perform CHANNEL CALIBRATION.	184 days

Table T3.3.I-1 (page 1 of 1)
Meteorological Monitoring Instrumentation

FUNCTION (INSTRUMENT AND LOCATION)			REQUIRED CHANNELS
1.	Wind Speed[(a)]		
	a.	Elevation 200 ft	1
	b.	Elevation 375 ft	1
2.	Wind Direction[(a)]		
	a.	Nominal Elevation 200 ft	1
	b.	Nominal Elevation 375 ft	1
3.	Air Temperature Difference[(a)] (Elevation 33/200 ft or Elevation 33/375 ft)		1

(a) Meteorological Monitoring Instrumentation is shared between LaSalle 1 and 2.

3.3 INSTRUMENTATION

3.3.m Explosive Gas Monitoring Instrumentation

TLCO 3.3.m One Main Condenser Off Gas Treatment – Hydrogen Monitor channel shall be OPERABLE with its Alarm Setpoint set to ensure that the limits of the Explosive Gas and Storage Tank Radioactivity Monitoring Program are not exceeded.

APPLICABILITY: During operation of the main condenser air ejector.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required hydrogen monitor channel inoperable.	A.1.1 -------------NOTE---------------- Not applicable if recombiner(s) temperature remains constant and THERMAL POWER has not changed. -------------------------------------	
	Take grab samples.	Once per 4 hours
	<u>AND</u>	
	A.1.2 -------------NOTE--------------- Only applicable if recombiner(s) temperature remains constant and THERMAL POWER has not changed. -------------------------------------	
	Take grab samples.	Once per 8 hours
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 Analyze grab samples. <u>AND</u> A.3 Restore channel to OPERABLE status.	Within 4 hours following each grab sample 30 days
B. Required Action and associated Completion Time not met.	B.1 Prepare a corrective action program report.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.m.1	Perform CHANNEL CHECK.	24 hours
TSR 3.3.m.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.m.3	---------------------------NOTE------------------------------------ CHANNEL CALIBRATION shall include use of standard gas samples containing a nominal: 1. One volume percent hydrogen, balance nitrogen, and 2. Four volume percent hydrogen, balance nitrogen. --- Perform CHANNEL CALIBRATION.	92 days

3.3 INSTRUMENTATION

3.3.n Reactor Vessel Water Level Reference Leg Continuous Backfill System

TLCO 3.3.n The Reactor Vessel Water Level Reference Leg Continuous Backfill System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each reference leg.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Continuous backfill flow < 0.35 gph to instrument reference leg(s). OR Continuous backfill flow > 0.8 gph to instrument reference leg(s).	A.1 Restore normal backfill flow (approximately 0.48 gph) to the associated instrument reference leg. OR A.2 Isolate backfill to the associated reference leg(s).	8 hours 8 hours
B. Continuous backfill flow isolated to one instrument reference leg.	B.1 Restore normal backfill flow to the associated instrument reference leg.	30 days
C. Continuous backfill isolated to more than one instrument reference leg.	C.1 Restore normal backfill flow to the associated instrument reference legs.	7 days

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition B or C not met.	D.1 Establish compensatory measures in accordance with required procedures for the associated instrument reference leg(s).	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.n.1	Verify backfill flow to each applicable reference leg is ≥ 0.35 gph and ≤ 0.8 gph.	24 hours
TSR 3.3.n.2	Verify, by a water leak test on the following check valves, that valve leakage rate is ≤ 3.8 cc/hr. 1(2) C11-F422A 1(2)C11-F422E 1(2) C11-F423A 1(2)C11-F423E 1(2) C11-F422B 1(2)C11-F422F 1(2) C11-F423B 1(2)C11-F423F 1(2) C11-F422D 1(2)C11-F422G 1(2) C11-F423D 1(2)C11-F423G	24 months

3.3 INSTRUMENTATION

3.3.o Seismic Monitoring Instrumentation

TLCO 3.3.o The seismic monitoring instrumentation in Table T3.3.o-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more seismic monitoring instruments inoperable.	A.1 Restore instrument to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Prepare a corrective action program report outlining the cause of the malfunction and the plans for restoring the instrument to OPERABLE status.	10 days

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ------------NOTE-------------- Required Actions C.2, C.3, and C.4 shall be completed whenever Condition C is entered. ----------------------------------- One or more seismic instruments actuated during a valid seismic event ≥ 0.01g.	C.1 Restore actuated instruments to OPERABLE status.	24 hours
	<u>AND</u>	
	C.2 Perform TSR 3.3.o.3 for each actuated instrument.	5 days
	<u>AND</u>	
	C.3 Analyze data retrieved from instruments to determine the magnitude of the vibratory ground motion.	10 days
	<u>AND</u>	
	C.4 Prepare a corrective action program report describing the magnitude, frequency spectrum, and resultant effect upon facility features important to safety.	10 days

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table T3.3.o-1 to determine which TSRs apply for each instrument.

SURVEILLANCE		FREQUENCY
TSR 3.3.o.1	Perform CHANNEL CHECK.	31 days
TSR 3.3.o.2	Perform CHANNEL FUNCTIONAL TEST.	184 days
TSR 3.3.o.3	Perform CHANNEL CALIBRATION.	24 months

Table T3.3.o-1 (page 1 of 1)
Seismic Monitoring Instrumentation

INSTRUMENTS AND SENSOR LOCATIONS[a]	MEASUREMENT RANGE	REQUIRED NUMBER OF INSTRUMENTS	SURVEILLANCE REQUIREMENTS
1. Triaxial Accelerometers			
a. Containment Foundation El. 673'-4"	± 2g, 120db dynamic range, 0-50 Hz	1	TSR 3.3.o.1 TSR 3.3.o.2 TSR 3.3.o.3
b. Containment Structurel El. 820'-6"	± 2g, 120db dynamic range, 0-50 Hz	1	TSR 3.3.o.1 TSR 3.3.o.2 TSR 3.3.o.3
c. Free Field	± 2g, 120db dynamic range, 0-50 Hz	1	TSR 3.3.o.1 TSR 3.3.o.2 TSR 3.3.o.3
d. Aux. Elec. Equip. Room	± 2g, 120db dynamic range, 0-50 Hz	1	TSR 3.3.o.1 TSR 3.3.o.2 TSR 3.3.o.3
2. Peak Recording Accelerographs			
a. SGTS	± 1g, 20:1 dynamic range, 0-20 Hz	1	TSR 3.3.o.3
b. RHR Line in Reactor Building Rotunda	± 1g, 20:1 dynamic range, 0-20 Hz	1	TSR 3.3.o.3
c. HPCS Diesel Generator Control Panel	± 1g, 20:1 dynamic range, 0-20 Hz	1	TSR 3.3.o.3
d. Main Control Board	± 1g, 20:1 dynamic range, 0-20 Hz	1	TSR 3.3.o.3
3. Triaxial Seismic Switches			
a. Containment Foundation El. 673'-4"	0.005 to 0.15 g adjustable	1	TSR 3.3.o.2 TSR 3.3.o.3
b. Internal Trigger[b]	adjustable	1[c]	TSR 3.3.o.2 TSR 3.3.o.3
4. GNC-CR Central Recorder – PNL 0PA11J, Unit 1 Aux. Elec. Equip. Room	0.005g to 1.0 g	1	TSR 3.3.o.1 TSR 3.3.o.2 TSR 3.3.o.3

(a) All seismic sensors and instruments are located in LaSalle Unit 1.

(b) Adjustable setpoint.

(c) With reactor control room annunciation.

3.3 INSTRUMENTATION

3.3.p Fire Protection Instrumentation

TLCO 3.3.p The fire protection instrumentation shown in Table T3.3.p-1 (Unit 1) and T3.3.p-2 (Unit 2) shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the fire protection instrumentation is required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE------------ Only applicable for instruments outside primary containment. ----------------------------- One or more required instruments inoperable for reasons other than Condition C.	A.1 Establish a fire watch patrol. <u>AND</u> A.2 Perform a fire watch inspection of the affected zone(s). <u>AND</u> A.3.1 Restore the instrument to OPERABLE status. <u>OR</u> A.3.2 Prepare a corrective action program report.	1 hour Once per hour 14 days 14 days

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -----------NOTE------------- Only applicable for instruments inside primary containment. -------------------------------- One or more required instruments inoperable for reasons other than Condition C.	B.1.1 Monitor primary containment air temperature at the locations listed in the Bases for SR 3.6.1.5.1.	Once per hour
	OR	
	B.1.2.1 Establish a fire watch patrol.	1 hour
	AND	
	B.1.2.2 Perform a fire watch inspection of the affected zone(s).	Once per 8 hours
	AND	
	B.2.1 Restore the instrument to OPERABLE status.	14 days
	OR	
	B.2.2 Prepare a corrective action program report.	14 days
C. One or more required instruments inoperable due to loss of the Fire Detection Display (FDD).	C.1 Establish continuous monitoring of affected zone(s) at the Fire Alarm Control Panel (FACP).	1 hour
	AND	
	C.2.1 Restore the instrument to OPERABLE status.	14 days
	OR	
	C.2.2 Prepare a corrective action program report.	14 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.p.1	Perform CHANNEL FUNCTIONAL TEST of the refuel floor ultra-violet detectors.	184 days
TSR 3.3.p.2	Demonstrate NFPA Standard 72D supervised circuits associated with the refuel floor ultra-violet detectors are OPERABLE.	184 days
TSR 3.3.p.3	--------------------------NOTE------------------------------ For detectors which are inaccessible during operation, only required to be performed during MODE 4 or 5 entry exceeding 24 hours. --- Perform CHANNEL FUNCTIONAL TEST.	 12 months
TSR 3.3.p.4	---------------------------NOTE-------------------------------- For supervised circuits with detectors which are inaccessible during operation, only required to be performed during MODE 4 or 5 entry exceeding 24 hours. --- Demonstrate NFPA Standard 72D supervised circuits associated with each required fire protection instrument are OPERABLE.	 12 months

Table T3.3.p-1 (page 1 of 4)
Fire Protection Instrumentation (Unit 1)

INSTRUMENTS / LOCATION		REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A. Unit 1 Fire Protection Instrumentation				
1.	Cable Spreading Room (Dry Pipe Sprinkler System)			21
2.	Diesel Generator Corridor (Dry Pipe Sprinkler System)			7
3.	Unit 0 Cables Over Lab (Dry Pipe Sprinkler System)			32
4.	Diesel Generator (0DG01K) Room (CO_2 Flooding System)	2		
5.	Diesel Generator (1DG01K) Room (CO_2 Flooding System)	2		
6.	HPCS Diesel Generator Room (CO_2 Flooding System)	2		
7.	Control Room Ventilation (VC) Return Air Monitor System A			1
8.	Control Room Ventilation (VC) Outside Air Monitor System A			1
9.	Auxiliary Electric Equipment Room Ventilation (VE) Return Air Monitor System A			1
10.	SGTS Equipment Train (1VG01S)	1		
11.	Control Room Emergency Make-up Air Filter Unit (0VC01SA)	1		
12.	Control Room HVAC Supply Air Filter Unit (0VC01FA)	1		
13.	Auxiliary Electric Equipment Room HVAC Supply Air Filter Unit (0VE01FA)	1		
14.	Reactor Bldg./Containment			
	a. Refuel Floor, Zone 1-26 El. 843'6", Fire Hazard Zone Area 1		6	
	b. Reactor Bldg. East, Zone 1-24 El. 820'6", Fire Hazard Zone 2B1			11
	c. Reactor Bldg. West, Zone 1-23 El. 820'6", Fire Hazard Zone 2B2			9
	d. Reactor Bldg. South, Zone 1-36 El. 786'6", Fire Hazard Zone 2D			18
	e. Reactor Bldg. North, Zone 1-37 El. 786'6", Fire Hazard Zone 2D			17
	f. Reactor Bldg. South, Zone 1-34 El. 761', Fire Hazard Zone 2E			22
	g. Reactor Bldg. North, Zone 1-35 El. 761', Fire Hazard Zone 2E			18
	h. Containment, Zone 1-16P [(a)] El. 761' and 777', Fire Hazard Zone 2J			7
	i. Containment, Zone 1-16 [(a)] El. 740' and 749', Fire Hazard Zone 2J			9
	j. Reactor Bldg., Zone 1-17 El. 740', Fire Hazard Zone 2F			5
	k. Reactor Bldg. North, Zone 1-17P El. 740', Fire Hazard Zone 2F			11
	l. Reactor Bldg. SW, Zone 1-22 El. 710'6", Fire Hazard Zone 2G			4

(continued)

(a) The fire protection instruments located within the primary containment are not required to be OPERABLE during the performance of Type A Containment Leakage Rate Tests or when primary containment is inerted.

Table T3.3.p-1 (page 2 of 4)
Fire Protection Instrumentation (Unit 1)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A. Unit 1 Fire Protection Instrumentation (continued)			
14. Reactor Bldg./Containment (continued)			
m. Reactor Bldg. NW, Zone 1-22P El. 710'6", Fire Hazard Zone 2G			6
n. Reactor Bldg. South, Zone 1-32 El. 694', Fire Hazard Zones 2H1, 2H2, 2H3			17
o. Reactor Bldg. North, Zone 1-33 El. 694', Fire Hazard Zones 2H1, 2H4, 2H5			20
p. Reactor Bldg. South, Zone 1-30 El. 673', Fire Hazard Zones 2I1, 2I2, 2I3			19
q. Reactor Bldg. North, Zone 1-31 El. 673', Fire Hazard Zone 2I1, 2I4, 2I5			20
r. Reactor Bldg. West, Zone 1-40 El. 807', Fire Hazard Zone 2C			7
15. Auxiliary Building/Turbine Bldg.			
a. Aux. Bldg. Vent Floor, Zone 1-1 El. 815', Fire Hazard Zone Area 4A			2
b. Aux. Bldg. Vent Floor, Zone 1-2 El. 786'6", Fire Hazard Zone 4B			8
c. Control Room, Zone 1-5 El. 768', Fire Hazard Zone 4C1			15
d. Computer Room, Zone 1-6 El. 768', Fire Hazard Zone 4C4			8
e. Reactor Prot. M-G Set Room, Zone 1-12 El. 749', Fire Hazard Zone 4D3			12
f. Cable Spreading Area, Zone 1-18 El. 749', Fire Hazard Zone 5A4			15
g. Div. 2 SWGR Room, Zone 1-8 El. 731', Fire Hazard Zone 4E3			15
h. Aux. Electric Equipment Room, Zone 1-27 El. 731', Fire Hazard Zone 4E1			13
i. Aux. Bldg. Corridor, Zone 1-3 El. 731', Fire Hazard Zone 5B13			5
j. Aux. Bldg. Corridor, Zone 1-7 El. 731', Fire Hazard Zone 5B13			12
k. Div. 1 SWGR Room, Zone 1-9 El. 710'6", Fire Hazard Zone 4F1			17
l. Aux. Bldg. Corridor, Zone 1-4 El. 710'6", Fire Hazard Zone 5C11			9
m. Div. 3 SWGR Room, Zone 1-10 El. 687', Fire Hazard Zone 5D1			5

(continued)

Table T3.3.p-1 (page 3 of 4)
Fire Protection Instrumentation (Unit 1)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A. Unit 1 Fire Protection Instrumentation (continued)			
15. Auxiliary Building/Turbine Bldg. (continued)			
n. Aux. Bldg., Zone 1-39 El. 768', Fire Hazard Zone 4C2			11
o. Aux. Bldg., Zone 1-38 El. 663', Fire Hazard Zone 6E			8
16. DG Bldg./DG Bldg. Corridor			
a. DG. Bldg., Zone 1-29 El. 736'6", Fire Hazard Zones 7A1, 7A2, 7A3			17
b. DG Bldg. Corridor, Zone 1-25 El. 710'6", Fire Hazard Zone 5C11			3
c. DG. Bldg., Zone 1-28 El. 674', Fire Hazard Zones 7C4, 7C5, 7C6			15
17. Off Gas Building			
a. Off Gas Building, Zone 1-15P El. 710'6", Fire Hazard Zone 10A1			3
b. Off Gas Building, Zone 1-15 El. 690', Fire Hazard Zone 10B1			6
B. Unit 2 Fire Protection Instrumentation Required for Unit 1			
1. Cable Spreading Room (Dry Pipe Sprinkler System)			15
2. Diesel Generator Corridor (Dry Pipe Sprinkler System)			9
3. Diesel Generator (2DG01K) Room (CO_2 Flooding System)	2		
4. Control Room Ventilation (VC) Return Air Monitor System B			1
5. Control Room Ventilation (VC) Outside Air Monitor System B			1
6. Auxiliary Electric Equipment Room Ventilation (VE) Return Air Monitor System B			1
7. SGTS Equipment Train (2VG01S)	1		
8. Control Room Emergency Make-up Air Filter Unit (0VC01SB)	1		
9. Control Room HVAC Supply Air Filter Unit (0VC01FB)	1		
10. Auxiliary Electric Equipment Room HVAC Supply Air Filter Unit (0VE01FB)	1		
11. Auxiliary Building/Turbine Bldg.			
a. Aux. Bldg. Vent Floor, Zone 2-1 El. 815', Fire Hazard Zone 4A			5
b. Aux. Bldg. Vent Floor, Zone 2-2 El. 786'6", Fire Hazard Zone 4B			9
c. Control Room, Zone 2-5 El. 768', Fire Hazard Zone 4C1			17

(continued)

Table T3.3.p-1 (page 4 of 4)
Fire Protection Instrumentation (Unit 1)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
B. Unit 2 Fire Protection Instrumentation Required for Unit 1 (continued)			
11. Auxiliary Building/Turbine Bldg. (continued)			
d. CAS, Zone 2-6 El. 768', Fire Hazard Zone 4C5			3
e. Reactor Prot. M-G Set Room, Zone 2-12 El. 749', Fire Hazard Zone 4D4			12
f. Cable Spreading Area, Zone 2-18 El. 749', Fire Hazard Zone 5A4			13
g. Div. 2 SWGR Room, Zone 2-8 El. 731', Fire Hazard Zone 4E4			15
h. Aux. Electric Equipment Room, Zone 2-27 El. 731', Fire Hazard Zone 4E2			12
i. Aux. Bldg. Corridor, Zone 2-3 El. 731', Fire Hazard Zone 5B13			5
j. Aux. Bldg. Corridor, Zone 2-7 El. 731', Fire Hazard Zone 5B13			12
k. Div. SWGR Room, Zone 2-9 El. 710'6", Fire Hazard Zone 4F2			17
l. Aux. Bldg. Corridor, Zone 2-4 El. 710'6", Fire Hazard Zone 5C11			9
m. Aux. Bldg., Zone 2-39 El. 768', Fire Hazard Zone 4C3			10
12. DG Bldg./DG Bldg. Corridor			
a. DG. Bldg., Zone 2-29 El. 736'6", Fire Hazard Zones 8A1, 8A2			14
b. DG Bldg. Corridor, Zone 2-25 El. 710'6", Fire Hazard Zone 5C11			3
c. DG Bldg., Zone 2-28 El. 674', Fire Hazard Zones 8C3, 8C4, 8C5			11
13. Reactor Bldg.			
a. Refuel Floor, Zone 2-26 El. 843'6", Fire Hazard Zone 1		6	
b. Reactor Bldg. East, Zone 2-24 El. 820'6", Fire Hazard Zone 3B1			11
c. Reactor Bldg. West, Zone 2-40 El. 807', Fire Hazard Zone 3C			7

Table T3.3.p-2 (page 1 of 4)
Fire Protection Instrumentation (Unit 2)

INSTRUMENTS / LOCATION				REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A.	Unit 2 Fire Protection Instrumentation					
	1.	Cable Spreading Room (Dry Pipe Sprinkler System)				15
	2.	Diesel Generator Corridor (Dry Pipe Sprinkler System)				9
	3.	Diesel Generator (2DG01K) Room (CO_2 Flooding System)		2		
	4.	HPCS Diesel Generator Room (CO_2 Flooding System)		2		
	5.	Control Room Ventilation (VC) Return Air Monitor System B				1
	6.	Control Room Ventilation (VC) Outside Air Monitor System B				1
	7.	Auxiliary Electric Equipment Room Ventilation (VE) Return Air Monitor System B				1
	8.	SGTS Equipment Train (2VG01S)		1		
	9.	Control Room Emergency Make-up Air Filter Unit (OVC01SB)		1		
	10.	Control Room HVAC Supply Air Filter Unit (0VC01FB)		1		
	11.	Auxiliary Electric Equipment Room HVAC Supply Air Filter Unit (0VE01FB)		1		
	12.	Reactor Bldg./Containment				
		a.	Refuel Floor, Zone 2-26 El. 843'6", Fire Hazard Zone Area 1		6	
		b.	Reactor Bldg. East, Zone 2-24 El. 820'6", Fire Hazard Zone 3B1			11
		c.	Reactor Bldg. West, Zone 2-23 El. 820'6", Fire Hazard Zone 3B2			9
		d.	Reactor Bldg. South, Zone 2-36 El. 786'6", Fire Hazard Zone 3D			19
		e.	Reactor Bldg. North, Zone 2-37 El. 786'6", Fire Hazard Zone 3D			17
		f.	Reactor Bldg. South, Zone 2-34 El. 761', Fire Hazard Zone 3E			23
		g.	Reactor Bldg. North, Zone 2-35 El. 761', Fire Hazard Zone 3E			18
		h.	Containment, Zone 2-16P[a] El. 761' and 777', Fire Hazard Zone 3J			7
		i.	Containment, Zone 2-16[a] El. 740' and 749', Fire Hazard Zone 3J			9

(continued)

(a) The fire protection instruments located within the primary containment are not required to be OPERABLE during the performance of Type A Containment Leakage Rate Tests or when primary containment is inerted.

Table T3.3.p-2 (page 2 of 4)
Fire Protection Instrumentation (Unit 2)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A. Unit 2 Fire Protection Instrumentation (continued)			
12. Reactor Bldg./Containment (continued)			
j. Reactor Bldg., Zone 2-17 El. 740', Fire Hazard Zone 3F			5
k. Reactor Bldg. North, Zone 2-17P El. 740', Fire Hazard Zone 3F			11
l. Reactor Bldg. SW, Zone 2-22 El. 710'6", Fire Hazard Zone 3G			4
m. Reactor Bldg. NW, Zone 2-22P El. 710'6", Fire Hazard Zone 3G			6
n. Reactor Bldg. South, Zone 2-32 El. 694', Fire Hazard Zones 3H1, 3H2, 3H3			17
o. Reactor Bldg. North, Zone 2-33 El. 694', Fire Hazard Zones 3H1, 3H4, 3H5			20
p. Reactor Bldg. South, Zone 2-30 El. 673', Fire Hazard Zones 3I1, 3I2, 3I3			19
q. Reactor Bldg. North, Zone 2-31 El. 673', Fire Hazard Zone 3I1, 3I4, 3I5			20
r. Reactor Bldg. West, Zone 2-40 El. 807', Fire Hazard Zone 3C			7
13. Auxiliary Building/Turbine Bldg.			
a. Aux. Bldg. Vent Floor, Zone 2-1 El. 815', Fire Hazard Zone 4A			5
b. Aux. Bldg. Vent Floor, Zone 2-2 El. 786'6", Fire Hazard Zone 4B			9
c. Control Room, Zone 2-5 El. 768', Fire Hazard Zone 4C1			17
d. CAS, Zone 2-6 El. 768', Fire Hazard Zone 4C5			3
e. Reactor Prot. M-G Set Room, Zone 2-12 El. 749', Fire Hazard Zone 4D4			12
f. Cable Spreading Area, Zone 2-18 El. 749', Fire Hazard Zone 5A4			13
g. Div. 2 SWGR Room, Zone 2-8 El. 731', Fire Hazard Zone 4E4			15
h. Aux. Electric Equipment Room, Zone 2-27 El. 731', Fire Hazard Zone 4E2			12
i. Aux. Bldg. Corridor, Zone 2-3 El. 731', Fire Hazard Zone 5B13			5
j. Aux. Bldg. Corridor, Zone 2-7 El. 731', Fire Hazard Zone 5B13			12
k. Div. 1 SWGR Room, Zone 2-9 El. 710'6", Fire Hazard Zone 4F2			17

(continued)

Table T3.3.p-2 (page 3 of 4)
Fire Protection Instrumentation (Unit 2)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
A. Unit 2 Fire Protection Instrumentation (continued)			
13. Auxiliary Building/Turbine Bldg. (continued)			
l. Aux. Bldg. Corridor, Zone 2-4 El. 710'6", Fire Hazard Zone 5C11			9
m. Div. 3 SWGR Room, Zone 2-10 El. 687', Fire Hazard Zone 5D2			5
n. Aux. Bldg., Zone 2-39 El. 768', Fire Hazard Zone 4C3			10
o. Aux. Bldg. Zone 2-38 El. 663', Fire Hazard Zone 6E			8
14. DG Bldg./DG Bldg. Corridor			
a. DG Bldg., Zone 2-29 El. 736'6", Fire Hazard Zones 8A1, 8A2			14
b. DG Bldg. Corridor, Zone 2-25 El. 710'6", Fire Hazard Zone 5C11			3
c. DG Bldg., Zone 2-28 El. 674', Fire Hazard Zone 8C3, 8C4, 8C5			11
B. Unit 1 Fire Protection Instrumentation Required for Unit 2			
1. Cable Spreading Room (Dry Pipe Sprinkler System)			21
2. Diesel Generator Corridor (Dry Pipe Sprinkler System)			7
3. Unit 0 Cables Over Lab (Dry Pipe Sprinkler System)			32
4. Diesel Generator (0DG01K) Room (CO_2 Flooding System)	2		
5. Diesel Generator (1DG01K) Room (CO_2 Flooding System)	2		
6. Control Room Ventilation (VC) Return Air Monitor System A			1
7. Control Room Ventilation (VC) Outside Air Monitor System A			1
8. Auxiliary Electric Equipment Room Ventilation (VE) Return Air Monitor System A			1
9. SGTS Equipment Train (1VG01S)	1		
10. Control Room Emergency Make-up Air Filter Unit (OVC01SA)	1		
11. Control Room HVAC Supply Air Filter Unit (0VC01FA)	1		
12. Auxiliary Electric Equipment Room HVAC Supply Air Filter Unit (0VE01FA)	1		

(continued)

Table T3.3.p-2 (page 4 of 4)
Fire Protection Instrumentation (Unit 2)

INSTRUMENTS / LOCATION	REQUIRED NUMBER OF INSTRUMENTS HEAT	FLAME	SMOKE
B. Unit 1 Fire Protection Instrumentation Required for Unit 2 (continued)			
13. Auxiliary Building/Turbine bldg.			
a. Aux. Bldg. Vent Floor, Zone 1-1 El. 815', Fire Hazard Zone 4A			2
b. Aux. Bldg. Vent Floor, Zone 1-2 El. 786'6", Fire Hazard Zone 4B			8
c. Control Room, Zone 1-5 El. 768', Fire Hazard Zone 4C1			15
d. Computer Room, Zone 1-6 El. 768', Fire Hazard Zone 4C4			8
e. Reactor Prot. M-G Set Room, Zone 1-12 El. 749', Fire Hazard Zone 4D3			12
f. Cable Spreading Area, Zone 1-18 El. 749', Fire Hazard Zone 5A4			15
g. Div. 2 SWGR Room, Zone 1-8 El. 731', Fire Hazard Zone 4E3			15
h. Aux. Electric Equipment Room, Zone 1-27 El. 731', Fire Hazard Zone 4E1			13
i. Aux. Bldg. Corridor, Zone 1-3 El. 731', Fire Hazard Zone 5B13			5
j. Aux. Bldg. Corridor, Zone 1-7 El. 731', Fire Hazard Zone 5B13			12
k. Div. SWGR Room, Zone 1-9 El. 710'6", Fire Hazard Zone 4F1			17
l. Aux. Bldg. Corridor, Zone 1-4 El. 710'6", Fire Hazard Zone 5C11			9
14. DG Bldg./DG Bldg. Corridor			
a. DG Bldg., Zone 1-29 El. 736'6", Fire Hazard Zones 7A1, 7A2, 7A3			17
b. DG Bldg. Corridor, Zone 1-25 El. 710'6", Fire Hazard Zone 5C11			3
c. DG Bldg., Zone 1-28 El. 674', Fire Hazard Zones 7C4, 7C5, 7C6			15
15. Off Gas Building			
a. Off Gas Building, Zone 1-15P El. 710'6", Fire Hazard Zone 10A1			3
b. Off Gas Building, Zone 1-15 El. 690', Fire Hazard Zone 10B1			6
16. Reactor Bldg.			
a. Refuel Floor, Zone 1-26 El. 843'6", Fire Hazard Zone 1		6	
b. Reactor Bldg. East, Zone 1-24 El. 820'6", Fire Hazard Zone 2B1			11

3.3 INSTRUMENTATION

3.3.q Feedwater Flow Instrumentation

TLCO 3.3.q The Leading Edge Flow Meter instrumentation system shall be OPERABLE.

APPLICABILITY: MODE 1, with THERMAL POWER > 3489 MWt

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more systems inoperable.	A.1 Restore required instruments to OPERABLE status.	72 hours
B. REQUIRED ACTION and associated COMPLETION TIME of CONDITION A not met.	B.1 Reduce power to $\leq$ 3489 MWt.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.q.1	Perform CHANNEL CHECK.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.a Structural Integrity

TLCO 3.4.a The structural integrity of ASME Code Class 1, 2, and 3 components shall be maintained in accordance with the Inservice Inspection and Testing Programs.

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----------NOTE------------- Only applicable to ASME Code Class 1 components. -------------------------------- Structural integrity of one or more ASME component(s) not in conformance.	A.1 Restore the structural integrity of the affected component to within its limits.	Prior to increasing the RCS temperature to > 50°F above the minimum temperature required by NDT considerations
	<u>OR</u>	
	A.2 Isolate the affected component.	Prior to increasing the RCS temperature to > 50°F above the minimum temperature required by NDT considerations

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -----------NOTE-------------- Only applicable to ASME Code Class 2 components. --------------------------------- Structural integrity of one or more ASME component(s) not in conformance.	B.1 Restore the structural integrity of the affected component to within its limits. <u>OR</u> B.2 Isolate the affected component.	Prior to increasing RCS temperature to > 200°F Prior to increasing RCS temperature to > 200°F
C. -----------NOTE--------------- Only applicable to ASME Code Class 3 components. ---------------------------------- Structural integrity of one or more ASME component(s) not in conformance.	C.1 Restore the structural integrity of the affected component to within its limits. <u>OR</u> C.2 Isolate the affected component.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.a.1	Verify the structural integrity of ASME Code Class 1, 2, and 3 components.	In accordance with the Inservice Inspection and Testing Programs

3.4 REACTOR COOLANT SYSTEM

3.4.b Reactor Coolant System (RCS) Chemistry

TLCO 3.3.d The chemistry of the RCS shall be maintained within the limits specified in Table T3.4.b-1 and Table T3.4.b-2.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS chemistry not within limits in MODE 1.	A.1 Restore RCS chemistry to within limits.	72 hours <u>AND</u> 336 hours cumulative in the past 365 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. Conductivity > 10 μmho/cm at 25°C in MODE 1. <u>OR</u> Chloride concentration > 0.5 ppm in MODE 1.	C. Be in MODE 2.	12 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. ------------NOTE--------------- Not applicable during Noble Metal Chemical Applications (injection and cleanup periods). ----------------------------------- RCS chemistry not within required limits in MODE 2 or 3.	D.1 Restore RCS chemistry to within limits.	48 hours
E. Required Action and associated Completion Time of Condition D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. -------------NOTE---------------- Not applicable during Noble Metal Chemical Applications (injection and cleanup periods). ---------------------------------- Chloride concentration not within required limits in other than MODES 1, 2, and 3.	F.1 Restore RCS chemistry to within limits.	24 Hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. ------------NOTE--------------- Not applicable during Noble Metal Chemical Applications (injection and cleanup periods). ----------------------------------- Conductivity not within required limits in other than MODES 1, 2, and 3.	G.1 Restore RCS chemistry to within limits.	72 hours
H. RCS chemistry not within required limits in MODE 3 during Noble Metal Chemical Application (injection and cleanup).	H.1 Initiate action to be in MODE 4.	Immediately
I. Conductivity, chlorides or pH not within required limits in other than MODES 1, 2, and 3 during Noble Metal Chemical Application (injection and cleanup).	I.1 Restore RCS chemistry to within required limits.	72 hours form start of Noble Metal Chemical Application
	<u>AND</u>	
	I.2 -------------NOTE--------------- Only required when conductivity or pH is not within required limits. ------------------------------------ Prepare a corrective action program report.	72 hours form start of Noble Metal Chemical Application

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. ------------NOTE-------------- Not applicable during Noble Metal Chemical Applications (injection and cleanup periods). ---------------------------------- Chlorides not within required limits in other than MODES 1, 2, and 3. <u>AND</u> Required Action F.1 or I.1 and associated Completion Time not met.	J.1 Determine, by engineering evaluation, that the structural integrity of the RCS remains acceptable for continued operation.	Prior to entering MODE 2 or 3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.b.1	-----------------------------NOTE-------------------------------- Only applicable when the continuous recording conductivity monitor is inoperable. --- Obtain a dip or flow through conductivity measurement of the reactor coolant.	4 hours in MODE 1, 2, or 3 <u>AND</u> 24 hours in other than MODES 1, 2, and 3
TSR 3.4.b.2	Analyze a sample of the reactor coolant for chlorides and conductivity.	72 hours <u>AND</u> Once per 8 hours whenever conductivity is $> 1.0\ \mu$mho/cm at 25°C
TSR 3.4.b.3	-----------------------------NOTE------------------------------- Only applicable during Noble Metal Chemical Application (injection and cleanup). --- Analyze a sample of the Reactor Coolant for pH.	72 hours

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.b.4	Perform a CHANNEL CHECK of the continuous conductivity monitor with a flow cell.	7 days <u>AND</u> Once per 24 hours whenever conductivity is > 1.0 µmho/cm at 25°C

Table T3.4.b-1 (page 1 of 1)
Reactor Coolant System Chemistry Limits

MODE	CHLORIDES (ppm)	CONDUCTIVITY LESS OPTIONAL SOLUBLE IRON DEDUCTION (μmhos/cm at 25°C)
1	≤ 0.2	≤ 1.0
2, 3	≤ 0.1	≤ 2.0
At All Other Times	≤ 0.5	≤ 10.0

Table T3.4.b-2 (page 1 of 1)
Reactor Coolant System Chemistry Limits
During Noble Chemical Addition

MODE	CHLORIDES (ppm)	CONDUCTIVITY (μmhos/cm at 25°C)	pH
3	$\leq$ 0.1	$\leq$ 20.0	4.3 $\leq$ pH $\leq$ 9.9
At All Other Times	$\leq$ 0.5	$\leq$ 20.0	4.3 $\leq$ pH $\leq$ 9.9

3.5 EMERGENCY CORE COOLING SYSTEM (ECCS)

3.5.a ECCS Corner Room Watertight Doors

TLCO 3.5.a The ECCS corner room watertight doors and penetration seals shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODES 4 and 5 when associated ECCS subsystem is required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more ECCS corner room watertight doors or penetration seals inoperable.	A.1 Restore inoperable ECCS corner room watertight doors and penetration seals to OPERABLE status.	14 days
B. Required Action and associated Completion Time not met.	B.1 Declare affected ECCS subsystems inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.5.a.1	Verify each ECCS corner room watertight door is closed, except during entry to and exit from the room.	31 days
TSR 3.5.a.2	Visually inspect the ECCS corner room watertight door seals and room penetration seals and verify no abnormal degradation, damage, or obstructions.	24 months

3.5 EMERGENCY CORE COOLING SYSTEM (ECCS)

3.5.b Safety Relief Valve (SRV) System Low-Low Set (LLS) Function

TLCO 3.5.b The Division 2 LLS function of the low and medium LLS SRVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, when steam dome pressure is >150 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. The required Division 2 LLS function of the low or medium LLS SRV inoperable.	A.1 Enter TS 3.5.1 Condition G for ADS accumulator backup compressed gas system inoperable. AND A.2 Initiate action to restore the required LLS function(s) to OPERABLE status.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.5.b.1	----------------------------- Note ----------------------------- First performance of TSR 3.5.b.1 for Unit 1 will be no later than L1R14 and for Unit 2 no later than L2R13 refueling outages. --- Perform a functional test of the Division 2 LLS function.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.a Main Steam Isolation Valve (MSIV) Alternate Leakage Treatment (ALT) Paths

TLCO 3.6.a The MSIV ALT paths shall be functional.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV ALT path not functional.	A.1 Restore the MSIV ALT path.	30 days
B. Two MSIV ALT paths not functional.	B.1 Restore one MSIV ALT path.	7 days
C. Required Action and associated Completion Times of A or B not met.	C.1 Evaluate the ability to provide a flow path for MSIV leakage to the main condensers.	72 hours
D. Required Action and associated Completion Time of C not met. OR Two MSIV ALT paths not functional for reasons other than Condition A or B.	D.1 Verify one compensatory measure is available for limiting the release during a DBA LOCA due to MSIV leakage.	72 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.a.1	Verify that each manual, power operated, or automatic valve in the flow path that is not locked, sealed, or otherwise secured, is in the correct position or is available to be manually aligned to its correct position from the control room.	31 days
TSR 3.6.a.2	Perform Inservice Test Program surveillances on the valves listed in Table T3.6.a-1 (Unit 1) and Table T3.6.a-2 (Unit 2).	In accordance with the Inservice Testing Program
TSR 3.6.a.3	Perform inspections of the MSIV ALT path boundary piping and associated snubbers and supports.	In accordance with Section XI of the ASME Code

Table T3.6.a-1
MSIV Alternate Leakage Treatment Valves (Unit 1)

VALVE	PRIMARY METHOD OF ACTUATION	SECONDARY METHOD OF ACTUATION	ALT PATH POSITION
1 B21-F418A	Remote Manual	Local Manual	Closed
1 B21-F418B	Remote Manual	Local Manual	Closed
1 B21-F020	Remote Manual	Local Manual	Closed
1 B21-F070	Remote Manual	Local Manual	Open
1 B21-F071	Remote Manual	Local Manual	Open
1 B21-F072	Remote Manual	Local Manual	Open
1 B21-F073	Remote Manual	Local Manual	Open

Table T3.6.a-2
MSIV Alternate Leakage Treatment Path Valves (Unit 2)

VALVE	PRIMARY METHOD OF ACTUATION	SECONDARY METHOD OF ACTUATION	ALT PATH POSITION
2 B21-F418A	Remote Manual	Local Manual	Closed
2 B21-F418B	Remote Manual	Local Manual	Closed
2 B21-F020	Remote Manual	Local Manual	Closed
2 B21-F070	Remote Manual	Local Manual	Open
2 B21-F071	Remote Manual	Local Manual	Open
2 B21-F072	Remote Manual	Local Manual	Open
2 B21-F073	Remote Manual	Local Manual	Open

3.6 CONTAINMENT SYSTEMS

3.6.b Suppression Chamber – Drywell Vacuum Breaker Position Indication

TLCO 3.6.b Position indication shall be OPERABLE for OPERABLE suppression chamber-to-drywell vacuum breakers.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each position indication.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required position indicators inoperable.	A.1 Restore required inoperable position indicator to OPERABLE status. <u>OR</u> A.2 Verify the associated suppression chamber-to-drywell vacuum breaker is closed.	14 days 14 days <u>AND</u> Once per 14 days thereafter
B. Required Action and associated Completion Time not met.	B.1 Declare associated suppression chamber-to-drywell vacuum breaker inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.b.1	Perform CHANNEL FUNCTIONAL TEST.	92 days

3.6 Containment Systems

3.6. c.
Primary Containment Hydrogen Mixing Subsystem

TLCO 3.6.c Two Primary Containment Hydrogen Mixing Subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One primary containment hydrogen mixing subsystem inoperable.	A.1 -------------------------- **-NOTE-** TLCO 3.0.d is not applicable. -------------------------- Restore primary containment hydrogen mixing subsystem to **OPERABLE** status.	30 days
B. Two primary containment hydrogen mixing subsystems inoperable	B.1 Verify by administrative means that the hydrogen mixing function is maintained.	1 hour **<u>AND</u>** Once per 12 hours thereafter
	<u>AND</u>	
	B.2 Restore one primary containment hydrogen mixing subsystem to **OPERABLE** status.	7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.c.1	------------------------ Note ----------------------------- First performance of TSR 3.6.c.1 for Unit 2 will be no later than L2R14 refueling outage. -- Perform a fan functional test for each primary containment hydrogen-mixing subsystem.	24 months
TSR 3.6.c.2	Perform required leak rate testing in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Testing Program

3.7 PLANT SYSTEMS

3.7.a Residual Heat Removal Service Water (RHRSW) System - Shutdown

TLCO 3.7.a Each RHRSW subsystem associated with an RHR subsystem required OPERABLE by LCO 3.4.10, “RHR Shutdown Cooling System – Cold Shutdown,” LCO 3.9.8, “RHR-High Water Level,” or LCO 3.9.9, “RHR – Low Water Level,” shall be OPERABLE.

APPLICABILITY: MODES 4 and 5.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each RHRSW subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RHRSW subsystems inoperable.	A.1 Declare associated RHR shutdown cooling subsystem(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.a.1	Verify each RHRSW manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days

3.7 PLANT SYSTEMS

3.7.b Diesel Generator Cooling Water (DGCW) System-Shutdown

TLCO 3.7.b The DGCW System shall be OPERABLE.

APPLICABILITY: MODES 4, 5 and during movement of irradiated fuel assemblies in the secondary containment when the associated diesel generator is required to be OPERABLE.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each DGCW subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DGCW subsystems inoperable.	A.1 Declare supported component(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.b.1	Verify each required DGCW subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
TSR 3.7.b.2	Verify each required DGCW pump starts automatically on each required actual or simulated initiation signal.	24 months

3.7 PLANT SYSTEMS

3.7.c Ultimate Heat Sink (UHS) - Shutdown

TLCO 3.7.c The Core Standby Cooling System (CSCS) pond shall be OPERABLE.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel in secondary containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CSCS pond inoperable due to sediment deposition or bottom elevation not within limit.	A.1 Restore CSCS pond to OPERABLE status.	90 days
B. Required Action and associated Completion Time not met. <u>OR</u> CSCS pond inoperable for reasons other than Condition A.	B.1 Declare the required Residual Heat Removal Service Water subsystems and Diesel Generator Cooling Water subsystems inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.c.1	Verify cooling water temperature supplied to the plant from the CSCS pond is in accordance with the limit specified in the UFSAR.	24 hours
TSR 3.7.c.2	Verify sediment level is $\leq$ 1.5 ft in the intake flume and the CSCS pond as determined by a series of sounding cross-sections compared to as-built soundings.	24 months
TSR 3.7.c.3	Verify CSCS pond bottom elevation is $\leq$ 686.5 ft.	24 months

3.7 PLANT SYSTEMS

3.7.d Liquid Holdup Tanks

TLCO 3.7.d The quantity of radioactive material contained in any outside temporary tanks shall be less than or equal to the limits calculated in the OFFSITE DOSE CALCULATION MANUAL.

APPLICABILITY: At all times.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Quantity of radioactive material in one or more of the outside temporary tanks not within limits.	A.1 Suspend all additions of radioactive material to the affected tank(s).	Immediately
	AND	
	A.2 Reduce affected tank contents to within limits.	48 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.d.1	-------------------NOTE------------------------ Not required to be performed until 7 days after the start of addition if tank(s) is empty at the beginning of the addition. --- Determine the quantity of radioactive material of each outside temporary tank is within limits by analyzing a representative sample of the tank's contents.	7 days when radioactive material is being added to the tank(s) <u>AND</u> Once within 7 days after each completion of addition of radioactive material to the tank

3.7 PLANT SYSTEMS

3.7.e Explosive Gas Mixture

TLCO 3.7.e The concentration of hydrogen in the Main Condenser Offgas Treatment System shall be $\leq$ 4% by volume.

APPLICABILITY: During Main Condenser Air Ejector System operation.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Hydrogen concentration in the Main Condenser Offgas Treatment System > 4% by volume.	A.1 Restore concentration to within limits.	48 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.e.1	Verify hydrogen concentration in the Main Condenser Offgas Treatment System is $\leq$ 4% by volume.	24 hours

3.7 PLANT SYSTEMS

3.7.f Sealed Source Contamination

TLCO 3.7.f Each sealed source containing radioactive material either in excess of 100 μCi of beta and/or gamma emitting material or 5 μCi of alpha emitting material shall be free of $\geq$ 0.005 μCi of removable contamination.

APPLICABILITY: At all times.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more sealed sources with removable contamination not within limits.	A.1 Withdraw the sealed source from use.	Immediately
	<u>AND</u>	
	A.2.1 Initiate action to decontaminate and repair the sealed source.	Immediately
	<u>OR</u>	
	A.2.2 Initiate action to dispose of the sealed source in accordance with NRC regulations.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Initiate a corrective action program report.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Sealed sources which are continuously enclosed within a shielded mechanism (e.g., 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. Startup sources and fission detectors previously subjected to core flux are exempted from the TSRs.

SURVEILLANCE		FREQUENCY
TSR 3.7.f.1	Perform leakage and contamination testing for all sealed sources containing radioactive materials with a half-life > 30 days (excluding Hydrogen 3) and in any form other than gas which are in use.	184 days
TSR 3.7.f.2	--------------------------NOTE------------------------------------ Only required to be performed if not tested within the previous 184 days. -- Perform leakage and contamination testing for each sealed source and fission detector which are stored and not in use.	Prior to use or transfer to another licensee

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.f.3	Perform leakage and contamination testing on sealed sources and fission detectors transferred without a certificate indicating the last test date which are stored and not in use.	Prior to use
TSR 3.7.f.4	Perform leakage and contamination testing for each sealed startup source and fission detector.	Once within 31 days prior to being subjected to core flux or installed in the core <u>AND</u> Once within 31 days following repair or maintenance to sources

3.7 PLANT SYSTEMS

3.7.g Area Temperature Monitoring

TLCO 3.7.g The temperature limit of each area in Table T3.7.g-1 shall not be exceeded for > 8 hours, or by > 30^{o} F.

APPLICABILITY: Whenever the equipment in the affected area is required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE--------------- Required Actions A.1, A.2 and A.3 shall be completed whenever Condition A is entered. ---------------------------------- One or more area temperatures exceeding the temperature limit by > 30^{o} F.	A.1 Restore area temperature to within limit.	4 hours
	<u>AND</u>	
	A.2 Prepare a corrective action program document.	Immediately
	<u>AND</u>	
	A.3 Perform an analysis to demonstrate the continued OPERABILITY of the affected equipment.	30 days

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------NOTE--------- Required Actions B.1 and B.2 shall be completed whenever Condition B is entered. ---------------------- One or more area temperatures exceeding the temperature limit for > 8 hours.	B.1 Prepare a corrective action program document. AND B.2 Perform an analysis to demonstrate the continued OPERABILITY of the affected equipment.	Immediately 30 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.g.1	Verify each area temperature is within limits in accordance with Table T3.7.g-1.	24 hours

Table T3.7.g-1 (page 1 of 1)
Area Temperature Monitoring

AREA			TEMPERATURE LIMIT (°F)
A.	Unit Area Temperature Monitoring		
	1.	Control Room	50 – 104
	2.	Auxiliary Electric Equipment Room	50 – 104
	3.	Diesel Generator Rooms	50 – 122
	4.	Division 1, 2, and 3 Switchgear Rooms	50 – 104
	5.	High Pressure Core Spray, Low Pressure Core Spray, Residual Heat Removal, and Reactor Core Isolation Cooling Rooms	50 – 150
	6.	Primary Containment	
		a. Drywell	50 – 150
		b. Beneath Reactor Pressure Vessel	50 – 185
B.	Opposite Unit Area Temperature Monitoring Required for Unit		
	1.	Auxiliary Electric Equipment Room	50 – 104
	2.	Division 2 Diesel Generator Room	50 – 122
	3.	Division 1 and 2 Switchgear Rooms	50 – 104

3.7 PLANT SYSTEMS

3.7.h Structural Integrity of Class 1 Structures

TLCO 3.7.h The structural integrity of Class 1 structures shall be maintained.

APPLICABILITY: At all times

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Settlement of any Class 1 structure not within allowable final settlement value.	A.1 Initiate action to prepare a corrective action program report outlining the action taken, the cause of the excessive settlement, and plans and schedule for restoration.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.h.1	Verify the total settlement of each Class 1 structure and differential settlement between Class 1 structures, when determined to the nearest 0.01 foot by measurement and calculation, are within limits.	31 days when observed settlement is >0.01 feet from the previous reading <u>AND</u> 24 months
TSR 3.7.h.2	Prepare and submit a report to the Plant Operations Review Committee which includes settlement and differential settlement plots versus time and a comparison of allowable and actual settlement.	Once within 24 months after observed settlement is > 0.01 feet from the previous reading <u>AND</u> 24 months thereafter until settlement has stabilized

3.7 PLANT SYSTEMS

3.7.i Snubbers

TLCO 3.7.i All required snubbers shall be OPERABLE.

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

ACTIONS

---NOTES---

1. Separate Condition entry is allowed for each snubber.

2. Enter applicable Conditions and Required Action for systems made inoperable by snubbers.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE--------------- Required Action A.2 shall be completed whenever this Condition is entered due to a functional failure of the snubber(s). ----------------------------------- One or more required snubber(s) inoperable.	A.1 Replace or restore the snubber to OPERABLE status. AND A.2 Perform an engineering evaluation on the attached component to determine if the component is acceptable for continued operation.	72 hours 72 hours
B. Required Action and associated Completion Time not met.	B.1 Declare the attached system inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.i.1	Perform augmented inservice inspection.	In accordance with the Augmented Inservice Inspection Program

3.7 PLANT SYSTEMS

3.7.j Fire Suppression Water System

TLCO 3.7.j The Fire Suppression Water system shall be OPERABLE.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One fire pump or water supply inoperable.	A.1 Restore equipment to OPERABLE status. OR A.2 Prepare a corrective action program report outlining the cause of the malfunction and the plans for restoring the pump or water supply to OPERABLE status.	7 days 7 days
B. --------NOTE----------- Separate Condition entry is allowed for each Fire Suppression Water System inoperability. ---------------------- Fire Suppression Water System inoperable for reasons other than Condition A.	B.1 Establish a backup water supply.	24 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.j.1	Verify the electrolyte level of each pilot cell of the battery for each diesel driven fire pump is above the plates.	31 days
TSR 3.7.j.2	Verify pilot cells specific gravity of the battery for each diesel driven fire pump, corrected to 77°F, is ≥ 1.200.	31 days
TSR 3.7.j.3	Verify the overall battery voltage for each diesel driven fire pump is ≥ 24 volts.	31 days
TSR 3.7.j.4	Verify the diesel driven fire pump fuel day tank contains ≥ 170 gallons of usable fuel.	31 days
TSR 3.7.j.5	Start each required fuel transfer pump and transfer fuel from the storage tank to the day tank.	31 days
TSR 3.7.j.6	Start each fire pump from ambient conditions and operate each fire pump on recirculation flow for ≥ 30 minutes.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.j.7	Verify that each normally open valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	92 days
TSR 3.7.j.8	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
TSR 3.7.j.9	Verify the voltage of each connected battery is $\geq$ 25 volts under float charge and has not decreased more than 2.8 volts from the value observed during the original test.	92 days
TSR 3.7.j.10	Verify the specific gravity, corrected to 77°F, of each connected cell is $\geq$ 1.200 and has not decreased more than 0.05 from the value observed during previous test.	92 days
TSR 3.7.j.11	Verify the electrolyte level of each connected cell is above the plates.	92 days
TSR 3.7.j.12	Cycle each testable valve in the flow path through one complete cycle of full travel.	12 months
TSR 3.7.j.13	Verify the battery for each diesel driven fire pump shows no visual indication of physical damage or abnormal deterioration.	18 months
TSR 3.7.j.14	Verify the battery terminal connections for each diesel driven fire pump are clean, tight, free of corrosion and coated with anti-corrosion material.	18 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.j.15	Inspect the diesel of each diesel driven fire pump.	In accordance with the manufacturers recommendations
TSR 3.7.j.16	Perform a system functional test, which includes simulated automatic actuation of the system throughout its operating sequence and: a. Verify that each automatic valve in the flow path actuates to its correct position; b. Verify that each fire suppression pump develops $\geq$ 3750 gpm at a system head of $\geq$ 205 feet; and c. Verify that each fire suppression pump starts sequentially to maintain the fire suppression water system pressure $\geq$ 118 psig.	18 months
TSR 3.7.j.17	Cycle each valve in the flow path that is not testable during plant operation through at least one complete cycle of the full travel.	24 months
TSR 3.7.j.18	Perform a flow test of the system.	36 months

3.7 PLANT SYSTEMS

3.7.k , Spray and Sprinkler Systems

TLCO 3.7.k The Deluge, Spray and Sprinkler Systems shown in Table T3.7.k-1 (Unit 1) and Table T3.7.k-2 (Unit 2) shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the Deluge, Spray and Sprinkler Systems are required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Deluge, Spray or Sprinkler System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Deluge Systems inoperable. <u>OR</u> One or more Spray/Sprinkler Systems inoperable.	A.1 --------------NOTE---------------- Not applicable for Diesel Generator Corridor Systems with inoperable cable tray fire wrap. ------------------------------------- Establish an hourly fire watch patrol. <u>AND</u>	1 hour
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	--------------NOTE---------------- Only applicable for Diesel Generator Corridor Systems with inoperable cable tray fire wrap. --------------------------------------	
		Establish a continuous fire watch with backup fire suppression equipment.	1 hour
	AND		
	A.3.1	Restore the system to OPERABLE status.	14 days
	OR		
	A.3.2	Prepare a corrective action report.	14 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.k.1	Verify each normally open valve in the flow path is in the correct position.	92 days
TSR 3.7.k.2	Cycle each testable valve in the flow path through one complete cycle of full travel.	12 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.k.3	Perform a system functional test, which includes simulated automatic action of the system, and verify that automatic valves in the flow path that are testable during plant operation actuate to their correct positions on a test signal.	18 months
TSR 3.7.k.4	Perform visual inspection of the pre-action/dry pipe Spray, Sprinkler and Deluge headers to verify their integrity.	24 months
TSR 3.7.k.5	Perform visual inspection of each deluge nozzle's spray area to verify that the spray pattern is not obstructed.	24 months
TSR 3.7.k.6	Cycle each valve in the flow path that is not testable during plant operation through one complete cycle of full travel.	24 months

Table T3.7.k-1
Deluge, Spray and Sprinkler Systems (Unit 1)

	Location	Elevation	Fire Zone
A.	Unit 1 Deluge, Spray and Sprinkler Systems		
1.	Diesel fuel storage tank (0D001T) room	674'0"	7C3
2.	Diesel fuel storage tank (1D001T) room	674'0"	7C2
3.	HPCS diesel fuel storage tank (1D002T) room	674'0"	7C1
4.	HPCS diesel day tank (1D004T) room	710'6"	7B4
5.	Diesel generator day tank (0D002T) room	710'6"	7B6
6.	Diesel generator day tank (1D005T) room	710'6"	7B5
7.	Cable spreading room	749'0"	4D1
8.	Standby gas treatment system equipment train (1VG 01S)[a]	820'6"	2B1
9.	Control room emergency makeup filter unit (0VC 01SA)[a]	786'6"	4B
10.	Auxiliary electric equipment room HVAC supply air filter (0VE 01FA)[a]	786'6"	4B
11.	Control room HVAC supply air filter unit (0VC 01FA)[a]	786'6"	4B
12.	Cable area above laboratories, Unit 0	710'6"	4F3
13.	Diesel generator corridor	710'6"	5C11
14.	Railroad Access Area	710'6"	2G
B.	Unit 2 Deluge, Spray and Sprinkler Systems Required For Unit 1		
1.	Diesel fuel storage tank (2D001T) room	674'0"	8C2
2.	Diesel generator day tank (2D005T) room	710'6"	8B4
3.	Cable spreading room	749'0"	4D2
4.	Diesel generator corridor	710'6"	5C11
5.	Control room emergency makeup filter unit (0VC 01SB)[a]	786'6"	4B
6.	Auxiliary electric equipment room HVAC supply air filter unit (0VE 01FB)[a]	786'6"	4B
7.	Control room HVAC supply air filter unit (0VC 01FB)[a]	786'6"	4B
8.	Standby gas treatment system equipment train (2VG01S)[a]	820'6"	3B1

(a) Surveillance Requirements TSRs 3.7.k.3 and 3.7.k.5 are not applicable. Surveillance Requirement TSR 3.7.k.4 is not applicable to piping within the charcoal beds.

Table T3.7.k-2
Deluge, Spray and Sprinkler Systems (Unit 2)

	Location	Elevation	Fire Zone
A.	Unit 2 Deluge, Spray and Sprinkler Systems		
1.	Diesel fuel storage tank (2D001T) room	674'0"	8C2
2.	HPCS diesel fuel storage tank (2D002T) room	674'0"	8C1
3.	HPCS diesel day tank (2D004T) room	710'6"	8B3
4.	Diesel generator day tank (2D005T) room	710'6"	8B4
5.	Cable spreading room	749'0"	4D2
6.	Control room emergency makeup filter unit (0VC 01SB)[a]	786'6"	4B
7.	Auxiliary electric equipment room HVAC supply air filter unit (0VE 01FB)[a]	786'6"	4B
8.	Control room HVAC supply air filter unit (0VC 01FB)[a]	786'6"	4B
9.	Standby gas treatment system equipment train (2VG01S)[a]	820'6"	3B1
10.	Diesel generator corridor	710'6"	5C11
B.	Unit 1 Deluge, Spray and Sprinkler Systems Required For Unit 2		
1.	Diesel fuel storage tank (1D001T) room	674'0"	7C2
2.	Diesel generator day tank (1D005T) room	710'6"	7B5
3.	Cable spreading room	749'0"	4D1
4.	Diesel generator corridor	710'6"	5C11
5.	Diesel fuel storage tank (0D001T) room	674'0"	7C3
6.	Diesel generator day tank (0D002T) room	710'6"	7B6
7.	Standby gas treatment system equipment train (1VG 01S)[a]	820'6"	2B1
8.	Control room emergency makeup filter unit (0VC 01SA)[a]	786'6"	4B
9.	Auxiliary electric equipment room HVAC supply air filter (0VE 01FA)[a]	786'6"	4B
10.	Control room HVAC supply air filter unit (0VC 01FA)[a]	786'6"	4B
11.	Cable area above laboratories, Unit 0	710'6"	4F3

(a) Surveillance Requirements TSRs 3.7.k.3 and 3.7.k.5 are not applicable. Surveillance Requirement TSR 3.7.k.4 is not applicable to piping within the charcoal beds.

3.7 PLANT SYSTEMS

3.7.I CO_2 Systems

TLCO 3.7.I The following low pressure CO_2 Systems shall be OPERABLE.

1. Division 1 Diesel Generator (DG) room.
2. Division 2 DG room.
3. Division 3 DG room.
4. Opposite Unit Division 2 DG room.

APPLICABILITY: Whenever equipment protected by the low pressure CO_2 Systems is required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each CO_2 System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required CO_2 System inoperable.	A.1 Establish an hourly fire watch patrol.	1 hour
	<u>AND</u>	
	A.2.1 Restore System to OPERABLE status.	14 days
	<u>OR</u>	
	A.2.2 Prepare a corrective action program report.	14 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.I.1	Verify CO_2 storage tank level is > 50% full.	7 days
TSR 3.7.I.2	Verify CO_2 storage tank pressure is > 290 psig.	7 days
TSR 3.7.I.3	Verify each normally open valve in the flow path is in its correct position.	92 days
TSR 3.7.I.4	Verify the system valves actuate, manually and automatically, upon receipt of a simulated actuation signal.	18 months
TSR 3.7.I.5	Verify flow from each nozzle during a “Puff Test.”	18 months
TSR 3.7.I.6	Verify the active components of the CO_2 system that closes the VD dampers will actuate upon receipt of a simulated actuation signal.	48 months

3.7 PLANT SYSTEMS

3.7.m Fire Hose Stations

TLCO 3.7.m The fire hose stations shown in Table T3.7.m-1 (Unit 1) and T3.7.m-2 (Unit 2) shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the fire hose stations is required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each hose station.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required fire hose stations inoperable.	A.1 --------------NOTE--------------- Only applicable if inoperable fire hose is the primary means of fire suppression. ------------------------------------- Place additional fire hose from an OPERABLE hose station to protect the affected area(s)/zone(s). AND	 1 hour (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 --------------NOTE--------------- Not applicable if inoperable hose is a primary means of fire suppression. -------------------------------------	
	Place additional fire hose from an OPERABLE hose station to protect the affected area(s)/zone(s).	24 hour
	<u>AND</u>	
	A.3.1 Restore the inoperable fire hose station(s) to OPERABLE status.	14 days
	<u>OR</u>	
	A.3.2 Prepare a corrective action program report.	14 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.m.1	Perform visual inspection of the required hose stations accessible during plant operations to assure all required equipment is at the station.	92 days
TSR 3.7.m.2	Perform visual inspection of the required hose stations not accessible during plant operations to assure all required equipment is at the station.	24 months
TSR 3.7.m.3	Remove each required fire hose for inspection and reracking.	24 months
TSR 3.7.m.4	Perform a gasket inspection and replace any degraded gaskets in the couplings.	24 months
TSR 3.7.m.5	Partially open each required hose station valve to verify OPERABILITY and no flow blockage.	36 months
TSR 3.7.m.6	Perform a hydrostatic test of each required hose.	Once within 5 years after purchase date AND Between 5 and 8 years after purchase date AND 2 years thereafter

Table T3.7.m-1 (page 1 of 3)
Fire Hose Stations (Unit 1)

LOCATION	PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 1 Fire Hose Stations			
1. Area 1	Area 1	843'6"	F 101 FB 102 F 103 F 104 F 105
2. Zone 2B1	Zone 2B1	820'6"	FB 108 F 109 F 111
3. Zone 2B2	Zone 2B2	820'6"	FB 107 FB 110
4. Zone 2C	Zone 2C	807'0"	F 112 F 113 F 114
5. Zone 2D	Zone 2D	786'6"	FB 115 F 116 FB 117 F 118
6. Zone 2E	Zone 2E	761'0"	F 119 F 120 F 121 F 122
7. Zone 2F	Zone 2F Zone 2J Zone 2K	740'0"	FB 123 F 124 F 125 F 126 FB 127
8. Zone 2H1	Zone 2H1 Zone 2H2 Zone 2H3 Zone 2H4 Zone 2H5	694'6"	F 135 F 133 F 138 F 140
9. Zone 2H2	Zone 2H2	694'6"	F 134
10. Zone 2H3	Zone 2H3	694'6"	F 136
11. Zone 2H4	Zone 2H4	694'6"	F 139
12. Zone 2H5	Zone 2H5	694'6"	F 137
13. Zone 2I1	Zone 2I1 Zone 2I2 Zone 2I3 Zone 2I4 Zone 2I5	673'4"	FB 141 FB 144 FB 146 FB 148
14. Zone 2I2	Zone 2I2	673'4"	F 142
15. Zone 2I3	Zone 2I3	673'4"	F 143
16. Zone 2I4	Zone 2I4	673'4"	F 147
17. Zone 2I5	Zone 2I5	673'4"	F 145

(continued)

Table T3.7.m-1 (page 2 of 3)
Fire Hose Stations (Unit 1)

LOCATION		PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 1 Fire Hose Stations (continued)				
18.	Zone 4A	Zone 4A	815'0"	FB 149
				F 150
19.	Zone 4B	Zone 4B	786'6"/794'0"	F 151
				FB 152
				F 153
20.	Zone 4C2 and 5A3	Zone 4C1	768'0"	F 154
		Zone 4C2		FB 175
		Zone 4C3		FB 176
		Zone 4C4		
		Zone 4C5		
21.	Zone 5A4	Zone 5A4	749'0"	FB 248
		Zone 4D1		FB 253
		Zone 4D2		
		Zone 4D3		
22.	Zone 5B3 and 5B13	Zone 5B13	731'/735'	FB 250
		Zone 4E1		FB 155
		Zone 4E2		
		Zone 4E3		FB 185
		Zone 4E4		
		Zone 5B1		
23.	Zone 5B4 and 5B5	Zone 5B1	731'0"	FB 180
		Zone 5B4	731'0"	FB 184
				FB 180
24.	Zone 5C11	Zone 5C11	710'6"	FB 164
				FB 192
		Zone 7B1, 7B2, 7B3		FB 156
		Zone 7B4, 7B5, 7B6		FB 191
		Zone 4F1, 4F3		FB 157
		Zone 5D1		FB 164
25.	Zone 7A1	Zone 7A1	736'6"	F 162
26.	Zone 7A3	Zone 7A2	736'6"	F 163
		Zone 7A3		
27.	Zone 7C4	Zone 7C1	674'0"	FB 165
		Zone 7C4		
28.	Zone 7C5	Zone 7C2	674'0"	F 166
		Zone 7C5		
29.	Zone 7C5	Zone 7C3	674'0"	F 167
		Zone 7C6		
30.	Zone 2G	Zone 2G	710'6"	F 128
				F 129
				F 130
				F 131
				F 132
31.	Zone 10A1	Zone 10A1	710'6"	FB 205
	Zone 10A2			FB 206
				FB 256

(continued)

Table T3.7.m-1 (page 3 of 3)
Fire Hose Stations (Unit 1)

LOCATION		PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 1 Fire Hose Stations (continued)				
32.	Zone 10 B1	Zone 10B1	690'0"	FB 207
33.	Zone 10 C3	Zone 10C3	674'0"	F 208 F 209
B. Unit 2 Fire Hose Stations Required for Unit 1.				
1.	Area 1	Area 1	843'6"	F 301 FB 302 F 303 F 304 F 305
2.	Zone 3B1	Zone 3B1	820'6"	FB 308 F 309 F 311
3.	Zone 4A	Zone 4A	815'0"	FB 349 F 350 FB 368 FB 450
4.	Zone 4B	Zone 4B	786'6"/794'0"	F 351 FB 352 F 353
5.	Zone 4C3 and 5A3	Zone 4C1 Zone 4C3 Zone 4C4 Zone 4C5	768'0"	FB 354 FB 375
6.	Zone 5A4	Zone 5A4 Zone 4D2 Zone 4D4	749'0"	FB 405
7.	Zone 5B13	Zone 5B13 Zone 4E2 Zone 4E4	731'0"	FB 355
8.	Zone 8A1 and 8A2	Zone 8A2	736'6"	F 362 F 363
9.	Zone 5C11	Zone 5C11 Zone 4F2 Zone 8B2 Zone 8B4	710'6"	FB 357 FB 391 FB 364
10.	Zone 8C3 and 8C4	Zone 8C2 Zone 8C4	674'0"	FB 365 F 366

Table T3.7.m-2 (page 1 of 3)
Fire Hose Stations (Unit 2)

LOCATION	PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 2 Fire Hose Stations			
1. Area 1	Area 1	843'6"	F 301 FB 302 F 303 F 304 F 305
3. Zone 3A	Zone 3A	832'0"	F 306
3. Zone 3B1	Zone 3B1	820'6"	FB 308 F 309 F 311
4. Zone 3B2	Zone 3B2	820'6"	FB 307 FB 310
5. Zone 3C	Zone 3C	807'0"	F 312 F 313 F 314
6. Zone 3D	Zone 3D	786'6"	FB 315 F 316 FB 317 F 318
7. Zone 3E	Zone 3E	761'0"	F 319 F 320 F 321 F 322
8. Zone 3F	Zone 3F Zone 3J Zone 3K	740'0"	FB 323 F 324 F 325 F 326 FB 327
9. Zone 3G	Zone 3G	710'6"	F 328 F 329 F 330 F 331 F 332 F 453
10. Zone 3H	Zone 3H1 Zone 3H2 Zone 3H3 Zone 3H4 Zone 3H5	694'6"	F 333 F 334 F 335 F 336 F 337 F 338 F 339 F 340
11. Zone 3I1	Zone 3I1 Zone 3I2 Zone 3I3 Zone 3I4 Zone 3I5 Zone 3I6	673'4"	FB 341 FB 344 FB 346 FB 348
12. Zone 3I2	Zone 3I2	673'4"	F 342

(continued)

Table T3.7.m-2 (page 2 of 3)
Fire Hose Stations (Unit 2)

LOCATION	PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 2 Fire Hose Stations (continued)			
13. Zone 3I3	Zone 3I3	673'4"	F 343
14. Zone 3I4	Zone 3I4	673'4"	F 347
15. Zone 3I5	Zone 3I5	673'4"	F 345
16. Zone 4A	Zone 4A	815'0"	FB 349 F 350 FB 368
17. Zone 4B	Zone 4B	786'6"/794'0"	F 351 FB 352 F 353
18. Zone 4C3 and 5A3	Zone 4C1 Zone 5A2 Zone 4C3 Zone 5A3 Zone 4C5	768'0"/754'0"	FB 354 FB 372 FB 451 FB 373 FB 374 FB 370 FB 371 FB 375 FB 377 FB 452
19. Zone 5A4	Zone 4D2 Zone 4D4 Zone 5A4	749'0"	FB 253 FB 405
20. Zone 5B4 and 5B6	Zone 5B2 Zone 5B4	731'0"	FB 380 FB 384 FB 380
21. Zone 5B3 and 5B13	Zone 5B13 Zone 5B3 Zone 4E2 Zone 4E4	731'/735'	FB 355
22. Zone 5C11	Zone 5C11 Zone 8B1, 8B2, 8B3 Zone 8B4 Zone 4F2, 4F3 Zone 5D2	710'6"	FB 357 FB 364 FB 386 FB 387 FB 389 FB 390 FB 391 FB 364
23. Zone 8A1	Zone 8A1	736'6"	F 362
24. Zone 8A2	Zone 8A2	736'6"	F 363
25. Zone 8C3	Zone 8C3 Zone 8C1 Zone 8C5	674'0"	FB 365
26. Zone 8C4	Zone 8C4 Zone 8C2	674'0"	F 366

(continued)

Table T3.7.m-2 (page 3 of 3)
Fire Hose Stations (Unit 2)

LOCATION	PROTECTED AREA	ELEVATION	HOSE RACK NUMBER
A. Unit 2 Fire Hose Stations (continued)			
27. Zone 6E	Zone 6E	663'0"	F 359 F 360 F 399 F 403 FB 404
B. Unit 1 Fire Hose Stations Required for Unit 2.			
1. Area 1	Area 1	843'6"	F 101 FB 102 F 103 F 104 F 105
2. Zone 2B1	Zone 2B1	820'6"	FB 108 F 109 F 111
3. Zone 4A	Zone 4A	815'0"	F 150 FB 149
4. Zone 4B	Zone 4B	786'6"/794'0"	F 151 FB 152 F 153
5. Zone 4C2 and 5A3	Zone 4C1 Zone 4C2 Zone 4C3 Zone 4C4 Zone 4C5	768'0"	F 154 FB 175 FB 176
6. Zone 5A4	Zone 5A4 Zone 4D1 Zone 4D2 Zone 4D3	749'0"	FB 248 FB 253
7. Zone 5B13	Zone 5B13 Zone 5B3 Zone 4E3 Zone 4E2 Zone 4E1	731'0"/735'0"	FB 250 FB 155 FB 185
8. Zone 7A3	Zone 7A3 Zone 7A2	736'6"	F 163
9. Zone 5C11	Zone 5C11 Zone 4F1 Zone 7B2 Zone 7B5 Zone 7B3 Zone 7B6	710'6"	FB 157 FB 191 FB 164 FB 192 FB 156
10. Zone 7C5 and 7C6	Zone 7C2 Zone 7C3 Zone 7C5 Zone 7C6	674'0"	F 167 F 166

3.7 PLANT SYSTEMS

3.7.n Safe Shutdown Lighting

TLCO 3.7.n All DC emergency lights installed to satisfy Section III.J of 10 CFR 50, Appendix R, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each DC emergency light.

-

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC emergency lights inoperable.	A.1 Establish backup lighting for the affected area.	1 hour
	AND	
	A.2.1 Restore inoperable DC emergency light to OPERABLE status.	14 days
	OR	
	A.2.2 Prepare a corrective action program report.	14 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.n.1	Perform a “quick check” of each required emergency lighting unit.	92 days
TSR 3.7.n.2	Demonstrate DC emergency lighting unit OPERABILITY.	18 months

3.7 PLANT SYSTEMS

3.7.o Fire Rated Assemblies

TLCO 3.7.o All fire rated assemblies shall be OPERABLE.

APPLICABILITY: At all times.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each fire rated assembly or sealing device.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more fire rated assemblies or sealing devices inoperable.	A.1.1	Establish a continuous fire watch on at least one side of the affected fire rated assembly(s) or device(s).	1 hour
	OR		
	A.1.2.1	Verify the OPERABILITY of fire detectors on at least one side of the affected fire rated assembly(s) or device(s).	1 hour
		AND	
	A.1.2.2	------------NOTE------------ Alternate compensatory measures can be taken based on a technical evaluation. --------------------------------	
		Establish an hourly fire watch patrol.	1 hour
	AND		

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.1	Restore inoperable fire rated assembly(s) or device(s) to OPERABLE status.	7 days
	<u>OR</u>		
	A.2.2	Prepare a corrective action program report.	7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.o.1	Verify the position of each closed fire door.	24 hours
TSR 3.7.o.2	Verify that fire doors with automatic hold-open and release mechanisms are free of obstructions.	24 hours
TSR 3.7.o.3	Verify the position of each locked closed fire door.	7 days
TSR 3.7.o.4	Perform a CHANNEL FUNCTIONAL TEST of the Fire Door Supervision System.	31 days
TSR 3.7.o.5	Inspect the fire door automatic hold-open, release and closing mechanism and latches.	184 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.o.6	Perform a visual inspection of: a. Exposed surfaces of each fire rated assembly; b. Each fire window/fire damper and associated hardware; and c. 10% of each type of sealed penetration.	24 months
TSR 3.7.o.7	-----------------------------NOTE---------------------------------- Only required to be performed if apparent changes in appearance or abnormal degradations are found during performance of TSR 3.7.o.6.c. --- Perform visual inspections of an additional 10% of each type of sealed penetration until a 10% sample with no apparent changes in appearance or abnormal degradation is found.	24 months

3.8 ELECTRICAL POWER SYSTEMS

3.8.a AC Circuits Inside Primary Containment

TLCO 3.8.a The following AC circuits inside primary containment shall be de-energized:

1. Installed welding grid systems 1A (2A) and 1B (2B);
2. All drywell lighting circuits; and
3. All drywell hoists and cranes circuits.

APPLICABILITY: MODES 1, 2, and 3, except during entry into the drywell.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required circuits energized.	A.1 Trip the associated circuit breaker(s) in the specified panel(s).	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.a.1	Verify each circuit breaker associated with required AC circuits inside primary containment that is not locked, sealed or otherwise secured is in the tripped position.	24 hours
TSR 3.8.a.2	Verify each circuit breaker associated with AC circuits inside primary containment that is locked, sealed or otherwise secured is in the tripped position.	31 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.b Primary Containment Penetration Conductor Overcurrent Protective Devices

TLCO 3.8.b The primary containment penetration conductor overcurrent protective devices in Table T3.8.b-1 for Unit 1 (Table T3.8.b-2 for Unit 2) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more primary containment penetration conductor overcurrent protective devices inoperable.	A.1 Restore the protective device to OPERABLE status. <u>OR</u> A.2.1 Verify the circuit is de-energized with the associated circuit breaker tripped. <u>AND</u>	72 hours 72 hours <u>AND</u> Once per 7 days thereafter (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.2 Determine OPERABILITY status of the affected system or component. <u>OR</u>	Immediately following initial performance of Required Action A.2.1
	A.3.1 Verify the circuit is de-energized with the associated circuit breaker racked out or removed.	72 hours <u>AND</u> Once per 7 days thereafter
	<u>AND</u> A.3.2 Determine OPERABILITY status of the affected system or component.	Immediately following initial performance of Required Action A.3.1
B. Required Actions and associated Completion Times of Condition A not met.	B.1 Be in MODE 3. <u>AND</u>	12 hours
	B.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.b.1	Perform CHANNEL CALIBRATION on the associated protective relays on a representative sample of the 6.9 kV and 4.16 kV circuit breakers.	24 months
TSR 3.8.b.2	Perform an integrated system functional test on a representative sample of the 6.9 kV and 4.16 kV circuit breakers, which includes simulated automatic actuation of the system to demonstrate that the overall penetration design remains within operable limits.	24 months
TSR 3.8.b.3	---------------------------NOTE------------------------------- Circuit breakers found inoperable during functional tests shall be restored to OPERABLE or replaced with OPERABLE circuit breakers prior to resuming operation. --- Functionally test a representative sample of each 480 V circuit breaker type.	 24 months
TSR 3.8.b.4	Perform an inspection and preventative maintenance for each circuit breaker in accordance with the manufacturer's recommendation.	60 months

Table T3.8.b-1 (page 1 of 2)
Primary Containment Penetration Conductor Overcurrent Protective Devices (Unit 1)

PROTECTIVE DEVICE NUMBER AND LOCATION	SYSTEM/COMPONENT POWERED
1. 6.9 kV Circuit Breakers	
a. Swgr. 151 (Cub. 4, Bkr. 3A)	RR Pump 1A, Primary - fast speed
b. Swgr. 152 (Cub. 4, Bkr. 3B)	RR Pump 1B, Primary - fast speed
c. Swgr. 151-1 (Cub.3, Bkr. 2A)	RR Pump 1A, Primary - low speed
d. Swgr. 152-1 (Cub. 3, Bkr. 2B)	RR Pump 1B, Primary - low speed
e. Swgr. 151-1 (Cub. 2, Bkr. 4A)	RR Pump 1A, Backup - fast speed
f. Swgr. 152-1 (Cub. 2, Bkr. 4B)	RR Pump 1B, Backup - fast speed
2. 4.16 kV Circuit Breakers	
a. Swgr. 141Y (Cub. 13, Bkr. 1A)	RR Pump 1A, Backup - low speed
b. Swgr. 142Y (Cub.14, Bkr. 1B)	RR Pump 1B, Backup - low speed
3. 480 VAC Circuit Breakers	
a. Swgr. 136Y (Compt. 403C)	VP/Pri. Cont. Vent Supply Fan 1B
b. Swgr. 135Y (Compt. 203A)	VP/Pri. Cont. Vent Supply Fan 1A
4. 480 VAC (Molded Case) Circuit Breakers	
a. Backup breakers are located in the back of the respective MCC.	
1. MCC 136Y-2 (Compt. C4)	RR/MOV 1B33-F067B
2. MCC 136Y-2 (Compt. A3)	RR/MOV 1B33-F023B
3. MCC 134X-1 (Compt. B3)	NB/MOV 1B21-F001
4. MCC 134X-1 (Compt. B4)	NB/MOV 1B21-F002
5. MCC 136Y-1 (Compt. B2) (Normal)	RH/MOV 1E12-F009
6. MCC 136Y-2 (Compt. C5)	RI/MOV 1E51-F063
7. MCC 135Y-1 (Compt. A1)	RR/MOV 1B33-F023A
8. MCC 135Y-1 (Compt. A4)	RR/MOV 1B33-F067A
9. MCC 133-1 (Compt. C2)	RT/MOV 1G33-F102

(continued)

Table T3.8.b-1 (page 2 of 2)
Primary Containment Penetration Conductor Overcurrent Protective Devices (Unit 1)

PROTECTIVE DEVICE NUMBER AND LOCATION	SYSTEM/COMPONENT POWERED
a. Backup breakers are located in the back of the respective MCC. (continued)	
10. MCC 133-1 (Compt. E1)	NB/MOV 1B21-F005
11. MCC 136Y-2 (Compt. B1)	NB/MOV 1B21-F016
12. MCC 136Y-2 (Compt. E1)	RH/MOV 1E12-F099A
13. MCC 136Y-1 (Compt. E4)	RT/MOV 1G33-F001
14. MCC 136Y-2 (Compt. A5)	WR/MOV 1WR180
15. MCC 136Y-2 (Compt. D6)	RH/MOV 1E12-F099B
16. MCC 136Y-1 (Compt. H5)	VP/MOV 1VP113B
17. MCC 136Y-1 (Compt. H4)	VP/MOV 1VP114A
18. MCC 136Y-1 (Compt. H3)	VP/MOV 1VP113A
19. MCC 136Y-1 (Compt. H6)	VP/MOV 1VP114B
20. MCC 136Y-2 (Compt. A4)	WR/MOV 1WR179
21. MCC 135Y-1 (Compt. D3)	RT/MOV 1G33-F101
22. MCC 135Y-1 (Compt. D4)	RT/MOV 1G33-F100
23. MCC 133-1 (Compt. C3)	RT/MOV 1G33-F106
24. MCC 136Y-2 (Compt. D5)	RI/MOV 1E51-F076
25. MCC 135X-1 (Compt. C2/C3) (Emerg)	RH/MOV 1E12-F009
26. MCC 133-2 (Compt. AC1)	VP/Drywell Cooler, 1VP15SA
27. MCC 133-2 (Compt. AB1)	VP/Drywell Cooler, 1VP15SE
28. MCC 133-2 (Compt. AB2)	VP/Drywell Cooler, 1VP15SD
29. MCC 134X-2 (Compt. H1)	VP/Drywell Cooler, 1VP15SB
30. MCC 134X-2 (Compt. H2)	VP/Drywell Cooler, 1VP15SC
31. MCC 134X-2 (Compt. J1)	VP/Drywell Cooler, 1VP15SF
b. Backup breakers are located in the front of the respective MCC.	
1. MCC 135X-2 (Compt. E4)	VP/Pri. Cont. Vent Supply Fan 1A Backup
2. MCC 136X-2 (Compt. G4)	VP/Pri. Cont. Vent Supply Fan 1B Backup

Table T3.8.b-2 (page 1 of 2)
Primary Containment Penetration Conductor Overcurrent Protective Devices (Unit 2)

PROTECTIVE DEVICE NUMBER AND LOCATION	SYSTEM/COMPONENT POWERED
1. 6.9 kV Circuit Breakers	
a. Swgr. 251 (Cub. 8, Bkr. 3A)	RR Pump 2A, Primary - fast speed
b. Swgr. 252 (Cub. 7, Bkr. 3B)	RR Pump 2B, Primary - fast speed
c. Swgr. 251-1 (Cub. 3, Bkr. 2A)	RR Pump 2A, Primary - low speed
d. Swgr. 252-1 (Cub. 3, Bkr. 2B)	RR Pump 2B, Primary - low speed
e. Swgr. 251-1 (Cub. 2, Bkr. 4A)	RR Pump 2A, Backup - fast speed
f. Swgr. 252-1 (Cub. 2, Bkr. 4B)	RR Pump 2B, Backup - fast speed
2. 4.16 kV Circuit Breakers	
a. Swgr. 241Y (Cub. 1, Bkr. 1A)	RR Pump 2A, Backup - low speed
b. Swgr. 242Y (Cub. 1, Bkr. 1B)	RR Pump 2B, Backup - low speed
3. 480 VAC Circuit Breakers	
a. Swgr. 236Y (Compt. 400A)	VP/Pri. Cont. Vent Supply Fan 2B
b. Swgr. 235Y (Compt. 202C)	VP/Pri. Cont. Vent Supply Fan 2A
4. 480 VAC (Molded Case) Circuit Breakers	
a. Backup breakers are located in the back of the respective MCC.	
1. MCC 236Y-2 (Compt. C4)	RR/MOV 2B33-F067B
2. MCC 236Y-2 (Compt. A3)	RR/MOV 2B33-F023B
3. MCC 234X-1 (Compt. B3)	NB/MOV 2B21-F001
4. MCC 234X-1 (Compt. B4)	NB/MOV 2B21-F002
5. MCC 236Y-1 (Compt. B2) (Normal)	RH/MOV 2E12-F009
6. MCC 236Y-2 (Compt. C5)	RI/MOV 2E51-F063
7. MCC 235Y-1 (Compt. A1)	RR/MOV 2B33-F023A
8. MCC 235Y-1 (Compt. A4)	RR/MOV 2B33-F067A
9. MCC 233-1 (Compt. C2)	RT/MOV 2G33-F102

(continued)

Table T3.8.b-2 (page 2 of 2)
Primary Containment Penetration Conductor Overcurrent Protective Devices (Unit 2)

	PROTECTIVE DEVICE NUMBER AND LOCATION	SYSTEM/COMPONENT POWERED
a.	Backup breakers are located in the back of the respective MCC. (continued)	
10.	MCC 233-1 (Compt. E1)	NB/MOV 2B21-F005
11.	MCC 236Y-2 (Compt. B1)	NB/MOV 2B21-F016
12.	MCC 236Y-2 (Compt. E1)	RH/MOV 2E12-F099A
13.	MCC 236Y-1 (Compt. E4)	RT/MOV 2G33-F001
14.	MCC 236Y-2 (Compt. A5)	WR/MOV 2WR180
15.	MCC 236Y-2 (Compt. D6)	RH/MOV 2E12-F099B
16.	MCC 236Y-1 (Compt. H5)	VP/MOV 2VP113B
17.	MCC 236Y-1 (Compt. H4)	VP/MOV 2VP114A
18.	MCC 236Y-1 (Compt. H3)	VP/MOV 2VP113A
19.	MCC 236Y-1 (Compt. H6)	VP/MOV 2VP114B
20.	MCC 236Y-2 (Compt. A4)	WR/MOV 2WR179
21.	MCC 235Y-1 (Compt. D3)	RT/MOV 2G33-F101
22.	MCC 235Y-1 (Compt. D4)	RT/MOV 2G33-F100
23.	MCC 233-1 (Compt. C3)	RT/MOV 2G33-F106
24.	MCC 236Y-2 (Compt. D5)	RI/MOV 2E51-F076
25.	MCC 235X-1 (Compt. C2/C3) (Emerg)	RH/MOV 2E12-F009
26.	MCC 233-2 (Compt. AC1)	VP/Drywell Cooler, 2VP15SA
27.	MCC 233-2 (Compt. AB1)	VP/Drywell Cooler, 2VP15SE
28.	MCC 233-2 (Compt. AB2)	VP/Drywell Cooler, 2VP15SD
29.	MCC 234X-2 (Compt. H1)	VP/Drywell Cooler, 2VP15SB
30.	MCC 234X-2 (Compt. H2)	VP/Drywell Cooler, 2VP15SC
31.	MCC 234X-2 (Compt. J1)	VP/Drywell Cooler, 2VP15SF
b.	Backup breakers are located in the front of the respective MCC.	
1.	MCC 235X-2 (Compt. AA4)	VP/Pri. Cont. Vent Supply Fan 2A Backup
2.	MCC 236X-2 (Compt. AA4)	VP/Pri. Cont. Vent Supply Fan 2B Backup

3.8 ELECTRICAL POWER SYSTEMS

3.8.c Motor Operated Valves Thermal Overload Protection Devices

TLCO 3.8.c The thermal overload protection devices of each valve listed in Table T3.8.c-1 for Unit 1 (Table T3.8.c-2 for Unit 2) shall be:

1. For valves with a thermal overload protection bypass device, bypassed continuously or under accident conditions, as applicable, by an OPERABLE bypass device; and

2. For valves without a thermal overload protection bypass device, OPERABLE.

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

ACTIONS

---NOTES---

1. Separate Condition entry is allowed for each thermal overload protection device or bypass device.

2. Enter applicable Conditions and Required Actions for systems made inoperable by thermal overload protection or bypass devices, except as provided in LCO 3.0.6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE--------------- Only applicable for valves with a thermal overload protection bypass device. ---------------------------------- Thermal overload protection for one or more valves not bypassed continuously. <u>OR</u> Integral bypass device inoperable.	A.1 Bypass the thermal overload. <u>OR</u> A.2 Declare the affected valve(s) inoperable.	8 hours 8 hours
B. ------------NOTE--------------- Only applicable for valves without a thermal overload protection bypass device. ---------------------------------- Thermal overload protection inoperable.	B.1 Declare the affected valve(s) inoperable. <u>OR</u> B.2 Continuously bypass thermal overload.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.c.1	----------------------------NOTE---------------------------------- Not required to be met for valves without a thermal overload protection bypass device. --- Verify thermal overload protection is continuously bypassed for those thermal overloads temporarily placed in force only when the valve motors are undergoing periodic maintenance or testing. <u>AND</u> Perform CHANNEL FUNCTIONAL TEST of the bypass circuitry for those thermal overloads normally in force during operation and bypassed under accident conditions.	24 months <u>AND</u> Prior to declaring the associated valve OPERABLE following maintenance on the motor starter
TSR 3.8.c.2	----------------------------NOTES-------------------------------- 1. Not required to be met for valves without a thermal overload protection bypass device. 2. Only applicable to valves with thermal overload protection continuously bypassed. --- Verify thermal overload protection is continuously bypassed.	Following maintenance or testing during which the thermal overload protection was temporarily placed in force

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.c.3	---------------------------NOTE--------------------------- Not required to be met for valves with a thermal overload protection bypass device. --- Perform CHANNEL CALIBRATION of a representative sample of thermal overload devices.	24 months <u>AND</u> Prior to declaring the associated valve OPERABLE following maintenance on the motor starter

Table T3.8.c-1 (page 1 of 3)
Thermal Overload Protection Devices (Unit 1)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
a.	1VG001	Accident Conditions	SGT System
	1VG003	Accident Conditions	
	2VG001	Accident Conditions	
	2VG003	Accident Conditions	
b.	1VP113A	Accident Conditions	Primary Containment Chilled Water Coolers
	1VP113B	Accident Conditions	
	1VP114A	Accident Conditions	
	1VP114B	Accident Conditions	
	1VP053A	Accident Conditions	
	1VP053B	Accident Conditions	
	1VP063A	Accident Conditions	
	1VP063B	Accident Conditions	
c.	1VQ038(*)	Accident Conditions	Primary Containment Vent and Purge System
	1VQ032	Accident Conditions	
	1VQ035	Accident Conditions	
	1VQ047	Accident Conditions	
	1VQ048	Accident Conditions	
	1VQ050	Accident Conditions	
	1VQ051	Accident Conditions	
	1VQ068	Accident Conditions	
	1VQ037(*)	Accident Conditions	
	2VQ037(*)	Accident Conditions	
	2VQ038(*)	Accident Conditions	
d.	1WR179	Accident Conditions	RBCCW System
	1WR180	Accident Conditions	
	1WR040	Accident Conditions	
	1WR029	Accident Conditions	
e.	1B21 - F067A	Accident Conditions	Main Steam System
	1B21 - F067B	Accident Conditions	
	1B21 - F067C	Accident Conditions	
	1B21 - F067D	Accident Conditions	
	1B21 - F019	Accident Conditions	
	1B21 - F016	Accident Conditions	
	1B21 - F020	Continuous	
	1B21 - F068	Continuous	
	1B21 - F070	Continuous	
	1B21 - F069	Continuous	
	1B21 - F071	Continuous	
	1B21 - F072	Continuous	
	1B21 - F073	Continuous	
	1B21 - F418A	Continuous	
	1B21 - F418B	Continuous	
f.	1B21 - F065A	Continuous	Main Feedwater System
	1B21 - F065B	Continuous	
g.	1E21 - F001	Continuous	LPCS System
	1E21 - F005	Accident Conditions	
	1E21 - F011	Accident Conditions	
	1E21 - F012	Accident Conditions	

(continued)

(*) These valves have thermal overload bypass for Accident Conditions from both Unit 1 and Unit 2.

Table T3.8.c-1 (page 2 of 3)
Thermal Overload Protection Devices (Unit 1)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
h.	1C41 - F001A	Accident Conditions	SLC System
	1C41 - F001B	Accident Conditions	
i.	1G33 - F001	Accident Conditions	RWCU System
	1G33 - F004	Accident Conditions	
	1G33 - F040	Continuous	
j.	1E12 - F052A	Accident Conditions	RHR System
	1E12 - F064A	Accident Conditions	
	1E12 - F087A	Accident Conditions	
	1E12 - F004A	Continuous	
	1E12 - F047A	Continuous	
	1E12 - F048A	Accident Conditions	
	1E12 - F003A	Continuous	
	1E12 - F026A	Accident Conditions	
	1E12 - F068A	Continuous	
	1E12 - F073A	Continuous	
	1E12 - F074A	Continuous	
	1E12 - F011A	Accident Conditions	
	1E12 - F024A	Accident Conditions	
	1E12 - F016A	Accident Conditions	
	1E12 - F017A	Accident Conditions	
	1E12 - F027A	Accident Conditions	
	1E12 - F004B	Continuous	
	1E12 - F047B	Continuous	
	1E12 - F048B	Accident Conditions	
	1E12 - F003B	Continuous	
	1E12 - F068B	Continuous	
	1E12 - F073B	Continuous	
	1E12 - F074B	Continuous	
	1E12 - F026B	Accident Conditions	
	1E12 - F011B	Accident Conditions	
	1E12 - F024B	Accident Conditions	
	1E12 - F006B	Continuous	
	1E12 - F016B	Accident Conditions	
	1E12 - F017B	Accident Conditions	
	1E12 - F042B	Accident Conditions	
	1E12 - F064B	Accident Conditions	
	1E12 - F093	Continuous	
	1E12 - F021	Accident Conditions	
	1E12 - F004C	Continuous	
	1E12 - F052B	Accident Conditions	
	1E12 - F087B	Accident Conditions	
	1E12 - F099B	Accident Conditions	
	1E12 - F099A	Accident Conditions	
	1E12 - F008	Accident Conditions	
	1E12 - F009	Accident Conditions	
	1E12 - F040A	Accident Conditions	
	1E12 - F040B	Accident Conditions	
	1E12 - F049A	Accident Conditions	
	1E12 - F049B	Accident Conditions	
	1E12 - F053A	Accident Conditions	
	1E12 - F053B	Accident Conditions	
	1E12 - F006A	Continuous	
	1E12 - F023	Accident Conditions	

(continued)

Table T3.8.c-1 (page 3 of 3)
Thermal Overload Protection Devices (Unit 1)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
j.	1E12 - F027B	Accident Conditions	RHR System
	1E12 - F042A	Accident Conditions	
	1E12 - F042C	Accident Conditions	
	1E12 - F064C	Accident Conditions	
	1E12 - F094	Continuous	
k.	1E51 - F086	Accident Conditions	RCIC System
	1E51 - F022	Accident Conditions	
	1E51 - F068	Continuous	
	1E51 - F069	Continuous	
	1E51 - F080	Accident Conditions	
	1E51 - F046	Accident Conditions	
	1E51 - F059	Accident Conditions	
	1E51 - F063	Accident Conditions	
	1E51 - F019	Accident Conditions	
	1E51 - F031	Continuous	
	1E51 - F045	Accident Conditions	
	1E51 - F008	Accident Conditions	
	1E51 - F010	Accident Conditions	
	1E51 - F013	Accident Conditions	
	1E51 - F076	Accident Conditions	
	1E51 - F360	Accident Conditions	
l.	1E22 - F004	Accident Conditions	HPCS System
	1E22 - F012	Accident Conditions	
	1E22 - F015	Continuous	
	1E22 - F023	Accident Conditions	
m.	1HG001A	None	Hydrogen Recombiner System
	1HG001B	None	
	1HG002A	None	
	1HG002B	None	
	1HG005A	None	
	1HG005B	None	
	1HG006A	None	
	1HG006B	None	
	1HG003	None	
	1HG009	None	
	1HG018	None	
	1HG025	None	
	1HG026	None	
	1HG027	None	
	1E12-F312A	None	
	1E12-F312B	None	
	2HG003	None	
	2HG009	None	
	2HG018	None	
	2HG025	None	
	2HG026	None	
	2HG027	None	

Table T3.8.c-2 (page 1 of 3)
Thermal Overload Protection Devices (Unit 2)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
a.	1VG001	Accident Conditions	SGT System
	1VG003	Accident Conditions	
	2VG001	Accident Conditions	
	2VG003	Accident Conditions	
b.	2VP113A	Accident Conditions	Primary Containment Chilled Water Coolers
	2VP113B	Accident Conditions	
	2VP114A	Accident Conditions	
	2VP114B	Accident Conditions	
	2VP053A	Accident Conditions	
	2VP053B	Accident Conditions	
	2VP063A	Accident Conditions	
	2VP063B	Accident Conditions	
c.	2VQ038(*)	Accident Conditions	Primary Containment Vent and Purge system
	2VQ032	Accident Conditions	
	2VQ035	Accident Conditions	
	2VQ047	Accident Conditions	
	2VQ048	Accident Conditions	
	2VQ050	Accident Conditions	
	2VQ051	Accident Conditions	
	2VQ068	Accident Conditions	
	2VQ037(*)	Accident Conditions	
	1VQ037(*)	Accident Conditions	
	1VQ038(*)	Accident Conditions	
d.	2WR179	Accident Conditions	RBCCW System
	2WR180	Accident Conditions	
	2WR040	Accident Conditions	
	2WR029	Accident Conditions	
e.	2B21 - F067A	Accident Conditions	Main Steam System
	2B21 - F067B	Accident Conditions	
	2B21 - F067C	Accident Conditions	
	2B21 - F067D	Accident Conditions	
	2B21 - F019	Accident Conditions	
	2B21 - F016	Accident Conditions	
	2B21 - F020	Continuous	
	2B21 - F068	Continuous	
	2B21 - F070	Continuous	
	2B21 - F069	Continuous	
	2B21 - F071	Continuous	
	2B21 - F072	Continuous	
	2B21 - F073	Continuous	
	2B21 - F418A	Continuous	
	2B21 - F418B	Continuous	
f.	2B21 - F065A	Continuous	Main Feedwater System
	2B21 - F065B	Continuous	
g.	2E21 - F001	Continuous	LPCS System
	2E21 - F005	Accident Conditions	
	2E21 - F011	Accident Conditions	
	2E21 - F012	Accident Conditions	

(continued)

(*) These valves have thermal overload bypass for Accident Conditions from both Unit 1 and Unit 2.

Table T3.8.c-2 (page 2 of 3)
Thermal Overload Protection Devices (Unit 2)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
h.	2C41 - F001A	Accident Conditions	SLC System
	2C41 - F001B	Accident Conditions	
i.	2G33 - F001	Accident Conditions	RWCU System
	2G33 - F004	Accident Conditions	
	2G33 - F040	Continuous	
j.	2E12 - F052A	Accident Conditions	RHR System
	2E12 - F064A	Accident Conditions	
	2E12 - F087A	Accident Conditions	
	2E12 - F004A	Continuous	
	2E12 - F047A	Continuous	
	2E12 - F048A	Accident Conditions	
	2E12 - F003A	Continuous	
	2E12 - F026A	Accident Conditions	
	2E12 - F068A	Continuous	
	2E12 - F073A	Continuous	
	2E12 - F074A	Continuous	
	2E12 - F011A	Accident Conditions	
	2E12 - F024A	Accident Conditions	
	2E12 - F016A	Accident Conditions	
	2E12 - F017A	Accident Conditions	
	2E12 - F027A	Accident Conditions	
	2E12 - F004B	Continuous	
	2E12 - F047B	Continuous	
	2E12 - F048B	Accident Conditions	
	2E12 - F003B	Continuous	
	2E12 - F068B	Continuous	
	2E12 - F073B	Continuous	
	2E12 - F074B	Continuous	
	2E12 - F026B	Accident Conditions	
	2E12 - F011B	Accident Conditions	
	2E12 - F024B	Accident Conditions	
	2E12 - F006B	Continuous	
	2E12 - F016B	Accident Conditions	
	2E12 - F017B	Accident Conditions	
	2E12 - F042B	Accident Conditions	
	2E12 - F064B	Accident Conditions	
	2E12 - F093	Continuous	
	2E12 - F021	Accident Conditions	
	2E12 - F004C	Continuous	
	2E12 - F052B	Accident Conditions	
	2E12 - F087B	Accident Conditions	
	2E12 - F099B	Accident Conditions	
	2E12 - F099A	Accident Conditions	
	2E12 - F008	Accident Conditions	
	2E12 - F009	Accident Conditions	
	2E12 - F040A	Accident Conditions	
	2E12 - F040B	Accident Conditions	
	2E12 - F049A	Accident Conditions	
	2E12 - F049B	Accident Conditions	
	2E12 - F053A	Accident Conditions	
	2E12 - F053B	Accident Conditions	
	2E12 - F006A	Continuous	
	2E12 - F023	Accident Conditions	

(continued)

Table T3.8.c-2 (page 3 of 3)
Thermal Overload Protection Devices (Unit 2)

	VALVE NUMBER	BYPASS DEVICE (Continuous) (Accident Conditions) (None)	SYSTEM(S) AFFECTED
j.	2E12 - F027B	Accident Conditions	RHR System
	2E12 - F042A	Accident Conditions	
	2E12 - F042C	Accident Conditions	
	2E12 - F064C	Accident Conditions	
	2E12 - F094	Continuous	
k.	2E51 - F086	Accident Conditions	RCIC System
	2E51 - F022	Accident Conditions	
	2E51 - F068	Continuous	
	2E51 - F069	Continuous	
	2E51 - F080	Accident Conditions	
	2E51 - F046	Accident Conditions	
	2E51 - F059	Accident Conditions	
	2E51 - F063	Accident Conditions	
	2E51 - F019	Accident Conditions	
	2E51 - F031	Continuous	
	2E51 - F045	Accident Conditions	
	2E51 - F008	Accident Conditions	
	2E51 - F010	Accident Conditions	
	2E51 - F013	Accident Conditions	
	2E51 - F076	Accident Conditions	
	2E51 - F360	Accident Conditions	
l.	2E22 - F004	Accident Conditions	HPCS System
	2E22 - F012	Accident Conditions	
	2E22 - F015	Continuous	
	2E22 - F023	Accident Conditions	
m.	2HG001A	None	Hydrogen Recombiner System
	2HG001B	None	
	2HG002A	None	
	2HG002B	None	
	2HG005A	None	
	2HG005B	None	
	2HG006A	None	
	2HG006B	None	
	2HG003	None	
	2HG009	None	
	2HG018	None	
	2HG025	None	
	2HG026	None	
	2HG027	None	
	2E12-F312A	None	
	2E12-F312B	None	
	1HG003	None	
	1HG009	None	
	1HG018	None	
	1HG025	None	
	1HG026	None	
	1HG027	None	

3.8 ELECTRICAL POWER SYSTEMS

3.8.d Battery Monitoring and Maintenance

TLCO 3.8.d The Division 1, 2, and 3, and opposite unit Division 2 batteries shall be maintained in accordance with the Battery Monitoring and Maintenance Program of Technical Specification 5.5.14 with battery cell parameters within the limits of Table T3.8.d-1.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE-------------- Required Actions A.4 and A.5, when applicable, shall be completed if this Condition is entered. ------------------------------- One or more batteries with one or more battery cell parameters not within Table T3.8.d-1 Category A or B limits.	A.1 Verify pilot cells electrolyte level and float voltage meet Table T3.8.d-1 Category C limits. <u>AND</u> A.2 Verify battery cell parameters meet Table T3.8.d-1 Category C limits. <u>AND</u>	1 hour 24 hours <u>AND</u> Once per 7 days thereafter (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore battery cell parameters to Table T3.8.d-1 Category A and B limits.	31 days
	AND	
	A.4 -------------NOTE------------- Only applicable if electrolyte level is less than the limit. ---------------------------------	
	Conduct an equalizing charge of the affected battery cells(s).	31 days
	AND	
	A.5 -------------NOTE------------- Only applicable if electrolyte level is less than the limit. ---------------------------------	
	Conduct IEEE-450 recommended testing of the affected battery cells(s).	31 days
B. Required Action and associated Completion Time not met. OR One or more batteries with one or more Surveillance acceptance criteria of this Requirement not met for reasons other than Condition A.	B.1 Initiate action to prepare a corrective action program report outlining the action taken, the cause of failing to meet the acceptance criteria, and the plans and schedule for restoration.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.d.1	Verify battery cell parameters meet Table T3.8.d-1 Category A limits.	31 days
TSR 3.8.d.2	Verify battery cell parameters meet Table T3.8.d-1 Category B limits.	92 days <u>AND</u> Once within 7 days after battery discharge < 110 V for 125 V batteries and < 220 V for the 250 V battery <u>AND</u> Once within 7 days after battery overcharge > 150 V for 125 V batteries and > 300 V for the 250 V battery
TSR 3.8.d.3	Verify average electrolyte temperature of representative cells is $\geq$60°F for 125 V batteries, and $\geq$ 65°F for 250 V battery.	92 days
TSR 3.8.d.4	Verify no visible corrosion at battery terminals and connectors. <u>OR</u> Verify battery connection resistance is ≤ 1.5E-4 ohm for inter-cell connections, and ≤ 1.5E-4 ohm for terminal connections.	92 days

(continued)

SURVEILLANCE		FREQUENCY
TSR 3.8.d.5	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	24 months
TSR 3.8.d.6	Remove visible corrosion and verify battery cell to cell and terminal connections are coated with anti-corrosion material	24 months
TSR 3.8.d.7	Verify battery connection resistance is ≤ 1.5E-4 ohm for inter-cell connections, and ≤ 1.5E-4 ohm for terminal connections.	24 months

Table T3.8.d-1 (page 1 of 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 ≤ ¼ inch above maximum level indication mark[(a)]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[(a)]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[(b)(c)]	≥ 1.200	≥ 1.195 <u>AND</u> Average of all connected cells > 1.205	Not more than 0.020 below average of all connected cells <u>AND</u> Average of all connected cells ≥ 1.195

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

(b) Corrected for electrolyte temperature and level.

(c) A battery charging current of < 2 amps when on float charge is acceptable for meeting Category A and B 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.

3.9 REFUELING OPERATIONS

3.9.a Decay Time

TLCO 3.9.a The reactor shall be subcritical for ≥ 24 hours.

APPLICABILITY: During movement of irradiated fuel in the reactor vessel.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor subcritical for < 24 hours.	A.1 Suspend movement of irradiated fuel in the reactor vessel.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.a.1	Verify the reactor subcritical ≥ 24 hours by confirming the date and time of subcriticality.	Prior to initial movement of irradiated fuel in the reactor vessel each outage

3.9 REFUELING OPERATIONS

3.9.b Communications

TLCO 3.9.b Direct communications shall be maintained between the control room and refueling platform personnel.

APPLICABILITY: During CORE ALTERATIONS, except movement of control rods with their normal drive system.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Direct communications not maintained.	A.1 Suspend CORE ALTERATIONS.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.b.1	Demonstrate direct communications between the control room and refueling platform personnel.	12 hours

3.9 REFUELING OPERATIONS

3.9.c Crane and Hoist

TLCO 3.9.c All cranes and hoists used for handling fuel assemblies or control rods shall be OPERABLE.

APPLICABILITY: During movement of fuel assemblies or control rods within the reactor pressure vessel (RPV).

ACTIONS

--NOTE--
Separate Condition entry is allowed for each crane or hoist.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required cranes or hoists inoperable.	A.1 Suspend in-vessel movement of fuel assemblies or control rods with the inoperable crane or hoist.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.c.1	Demonstrate operation of the overload cutoff of each crane or hoist to be used for movement of fuel assemblies or control rods within the RPV: a. When the load exceeds 1600 +100 / -0 lbs for the NF500 mast; or b. When the load exceeds 1000 ± 50 lbs for the auxiliary hoists.	Once within 7 days prior to start of movement of fuel assemblies or control rods within the RPV using the associated crane or hoist
TSR 3.9.c.2	Demonstrate operation of the loaded interlock of each crane or hoist to be used for movement of fuel assemblies or control rods within the RPV: a. When the load exceeds 700 + 50 / -0 lbs for the NF500 mast; or b. When the load exceeds 400 ± 50 lbs for the auxiliary hoists.	Once within 7 days prior to start of movement of fuel assemblies or control rods within the RPV using the associated crane or hoist
TSR 3.9.c.3	Demonstrate operation of the slack cable cutoff of the fuel hoist when unloaded.	Once within 7 days prior to start of movement of fuel assemblies or control rods within the RPV using the fuel hoist

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.c.4	Demonstrate operation of the uptravel stops of the fuel hoist and auxiliary hoists when the grapple is ≥ 8 feet below the platform rails.	Once within 7 days prior to start of movement of fuel assemblies or control rods within the RPV using the associated crane or hoist
TSR 3.9.c.5	Demonstrate operation of the fuel hoist downtravel stop when downtravel exceeds 54 feet below the platform rails.	Once within 7 days prior to start of movement of fuel assemblies or control rods within the RPV using the fuel hoist

5.0 ADMINISTRATIVE CONTROLS

5.0.a Station Fire Brigade

The shift manning for the station Fire Brigade shall be as follows:

A site Fire Brigade of at least 5 members shall be maintained onsite at all times. However, the Fire Brigade composition may be less than the minimum requirements for a period of time not to exceed two hours in order to accommodate unexpected absence provided immediate action is taken to fill the required positions. The Fire Brigade shall not include the Shift Manager, one Unit Supervisor, the Shift Technical Advisor, and the 2 other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency.

5.0 ADMINISTRATIVE CONTROLS

5.0.b Startup Report

A summary report of plant startup and power escalation testing shall be submitted following (1) amendment to the license involving a planned increase in power level, (2) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (3) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

Startup reports shall be submitted within 90 days following resumption or commencement of commercial power operation.

5.0 ADMINISTRATIVE CONTROLS

5.0.c Technical Specification (TS) Programs and Manuals

Technical Specification Section 5.5 specifies the programs and manuals that must be established, implemented, and maintained as part of the station's Operating License. This TRM section describes the procedures, manuals, or processes used to implement the requirements of TS Section 5.5.

5.5.1 Offsite Dose Calculation Manual

Technical Specification 5.5.1, "Offsite Dose Calculation Manual," is implemented by CY-LA-170-301, LaSalle Offsite Dose Calculation Manual.

5.5.2 Primary Coolant Sources Outside Containment

Technical Specification 5.5.2, "Primary Coolant Sources Outside Containment," requires controls be provided to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The program is implemented by the following procedures:

LAP-100-14, LGP-1-1, LTS-300-7, LTS-300-8, LTS-300-9, LTS-400-2, LTS-400-11, LOP-NB-01, LOS-LP-Q1, LOS-HP-Q1, LOS-RH-Q1, LOS-RI-Q3, LOS-RI-Q5, LOS-RI-R3.

5.5.3 Deleted.

5.5.4 Radioactive Effluent Controls Program

Technical Specification 5.5.4, "Radioactive Effluent Controls Program," requires controls be established to conform with 10 CFR 50.36a for control of radioactive effluents and for maintaining doses to members of the public from radioactive effluents as low as reasonably achievable. This program is implemented through Sections 12.2, 12.3, and 12.4 of the LaSalle Offsite Dose Calculation Manual.

(continued)

5.0.c Technical Specification (TS) Programs and Manuals

5.5.5 Component Cyclic or Transient Limit Program

Technical Specification 5.5.5, “Component Cyclic or Transient Limit,” requires controls be provided to track the UFSAR, Table 5.2-4, cyclic and transient occurrences to ensure that components are maintained within design limits. The program is implemented by the procedures ER-AA-470 and LTP-300-9.

5.5.6 Inservice Inspection Program for Post Tensioning Tendons

Technical Specification 5.5.6, "Inservice Inspection Program for Post Tensioning Tendons," requires controls be provided for monitoring any tendon degradation in pre-stressed concrete containments, including the effectiveness of its corrosion prevention medium, to ensure containment structural integrity. The program is implemented by the procedure LAP-100-51.

5.5.7 Inservice Testing Program

Technical Specification 5.5.7, “Inservice Testing Program,” requires controls be established for inservice testing of ASME Code Class 1, 2, and 3 components. This program is implemented by the LaSalle County Station, Units 1 and 2, Inservice Testing Program Plan, 3rd Ten Year Interval and procedure ER-AA-321.

5.5.8 Ventilation Filter Testing Program (VFTP)

Technical Specification 5.5.8, "Ventilation Filter Testing Program (VFTP)," requires testing of the Engineered Safety Feature filter ventilation systems for the following Technical Specification systems:

Standby Gas Treatment (SGT) System
Control Room Area Filtration (CRAF) System.

The program is implemented by the following procedures:
LAP-300-45, LOS-VC-M1, LOS-VG-M1, LTS-400-1, LTS-400-2, LTS-400-12, LTS-400-13, LTS-400-14, LTS-400-16, LES-VC-01, LES-VG-01.

(continued)

5.0.c Technical Specification (TS) Programs and Manuals

5.5.9 Explosive Gas and Storage Tank Radioactivity Monitoring Program

Technical Specification 5.5.9, "Explosive Gas and Storage Tank Radioactivity Monitoring Program," requires controls be provided for potentially explosive gas mixtures contained in the Main Condenser Offgas Treatment System and the quantity of radioactivity contained in the outside temporary storage tanks. The program is implemented by TRM Specification 3.7.d, "Liquid Holdup Tanks," TRM Specification 3.7.e, "Explosive Gas Mixtures," and the following procedures:

LCP-140-1 (3.7.d), LOS-AA-S101 and LOS-AA-S201 (3.7.e).

5.5.10 Diesel Fuel Oil Testing Program

Technical Specification 5.5.10, "Diesel Fuel Oil Testing Program," requires testing requirements be provided for new fuel oil and stored fuel oil and includes sampling requirements and acceptance criteria. The program is implemented by TSR 2.1.a.5, 2.1.a.6, 3.7.j.8, B2.1.a and the following procedures:

LCP-110-63. LOS-DG-M1, LOS-DG-M2, LOS-DG-M6, LOS-DG-Q1, LOS-DG-Q2, LOS-DG-Q3, LOS-DO-M1, LOS-DO-Q1, LOS-DO-SR2, LOP-DO-01.

5.5.11 Technical Specification (TS) Bases Control Program

Technical Specification 5.5.11, "Technical Specification (TS) Bases Control Program," requires means be provided for processing changes to the Bases of the Technical Specifications. The program is implemented by Appendix H of the Technical Requirements Manual (TRM).

5.5.12 Safety Function Determination Program

Technical Specification 5.5.12, “Safety Function Determination Program,” requires means be provided to ensure a loss of function is detected and appropriate actions taken. The program is implemented by Appendix G of the TRM.

(continued)

5.0.c Technical Specification (TS) Programs and Manuals

5.5.13 Primary Containment Leakage Rate Testing Program

Technical Specification 5.5.13, “Primary Containment Leakage Rate Testing Program,” requires implementation of leakage rate testing of the primary containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B as modified by approved exemptions. The program is implemented by the following procedures:

ER-AA-380, LTP-300-33, LTP-600-1, LTP-600-5, LTP-600-7, LTP-600-11, LTS-100-XX (series), LTS-300-1, LTS-300-2, LTS-300-4, LTS-300-5, LTS-300-6, LTS-300-8, LTS-300-9, LTS-500-1, LTS-500-2, LTS-600-3, LTS-900-9, LTS-900-10, LTS-900-11, LTS-900-12, LTS-900-13.

5.5.14 Battery Monitoring and Maintenance Program

Technical Specification 5.5.14, “Battery Monitoring and Maintenance Program,” provides for the restoration and maintenance, based on the recommendations of IEEE Standard 450-1995, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications. The program is implemented by the following procedures:

LEP-DC-01, LEP-DC-02, LEP-DC-03, LEP-DC-04, LEP-DC-103, LEP-DC-104, LEP-DC-105, LEP-DC-106, LEP-PM-02, LES-DC-101A, LES-DC-101B, LES-DC-101C, LES-DC-101D, LTS-700-1, LTS-700-2, LTS-700-3, LTS-700-4, LTS-700-5, LTS-700-6, LTS-700-7, LTS-700-8, LTS-700-11, LTS-700-17, LTS-700-18, LTS-700-19, LTS-700-20, LOS-DC-Q2.

5.5.15 Control Room Envelope Habitability Program

Technical Specification 5.5.15, “Control Room Envelope Habitability Program″, requires habitability to be maintained in Control Room Envelope during normal operation as well as during radiological, hazardous chemical release or a smoke challenge.

Administration of the program will ensure habitability is maintained by periodic assessment of habitability, configuration control and preventative maintenance, maintaining positive pressure in the CRE with respect to its adjacent areas and performing in-leakage and filter testing. The program is implemented by the following procedures:

ER-AA-390, ER-AA-390-1001, LAP-300-45, LOS-VG-M1, LTS-400-12, LTS-400-13, LTS-400-14, LTS-400-16, LTS-400-17, LTS-400-28, LES-VC-01 and In-leakage testing procedure using Tracer Gas.

5.0.d Augmented Inservice Inspection Program

This program provides controls for inservice inspection and testing of snubbers applicable to TRM 3.7.i, “Snubbers.”

Examinations and testing of snubbers shall be in accordance with the 10CFR50.55a approved edition/addenda of the ASME OM Code, Subsection ISTD, except where written relief has been approved by the NRC, as referenced in the ISI Program Plan.

5.0 ADMINISTRATIVE CONTROLS

5.0.e Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) ensures that the risk impact of equipment out-of-service is appropriately evaluated prior to performing any maintenance activity. This program involves probabilistic and/or deterministic reviews to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergency conditions during all modes of plant operation. Consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions. The program includes the following:

- Provisions to ensure maintenance activities that affect redundant and diverse structures, systems and components (SSCs) that provide backup for the same function are minimized.

- Provisions to ensure the potential for planned activities to cause a plant transient are reviewed, and work on SSCs that would be required to mitigate the transient are avoided.

- Provisions to ensure work that is highly likely to exceed a Technical Specification or Technical Requirements Manual Completion Time requiring a plant shutdown is not scheduled. For activities that are expected to use a significant amount of allowed outage time (AOT), the program requires compensatory measures and contingency plans to minimize SSC unavailability and maximize SSC reliability.

- Provisions to ensure that for Maintenance Rule High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is monitored and trended.

The CRMP is used to assess the integrated capability of the plant. The goals of the program are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during planned maintenance activities. The LaSalle CRMP is consistent with the guidance set forth in Regulatory Guide 1.182, “Assessing and Managing Risk before Maintenance Activities at Nuclear Power Plants.” In addition, the LaSalle CRMP may be utilized as an assessment tool to evaluate the risk associated with proposed Technical Specification AOT and Surveillance Test Interval changes consistent with Regulatory Guide 1.177, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications”. The program is implemented by the following procedures:

ER-AA-600-XX (series), OU-AA-103, OU-LA-104, and WC-AA-101.

5.0 ADMINISTRATIVE CONTROLS

5.0.f Channel Distortion Monitoring Program

The Channel Distortion Monitoring Program provides the controls for establishing the testing population and surveillance testing of control cells that may experience channel distortion. The program is implemented by the following procedures:

NF-AB-135-1420, "Establishing Channel Distortion Monitoring Populations" and LOS-RD-SR7 "Channel Interference Monitoring"

Table A-1 (page 1 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves					
1. Main Steam Isolation Valves					
1B21-F022A, B, C, D	1	$\leq$ 5 and $\geq$ 3	2	N/A	Yes
1B21-F028A, B, C, D	1	$\leq$ 5 and $\geq$ 3	2	N/A	Yes
2. Main Steam Line Drain Valves					
1B21-F016	1	$\leq$ 15	2	N/A	Yes
1B21-F019	1	$\leq$ 15	2	N/A	Yes
1B21-F067A, B, C, D	1	$\leq$ 23	2	N/A	Yes
3. Reactor Coolant System Sample Lines Valves[(b)]					
1B33-F019	3	$\leq$ 5	2	N/A	Yes
1B33-F020	3	$\leq$ 5	2	N/A	Yes
4. Drywell Equipment Drain Valves					
1RE024	2	$\leq$ 20	2	N/A	Yes
1RE025	2	$\leq$ 20	2	N/A	Yes
1RE026	2	$\leq$ 15	2	N/A	Yes
1RE029	2	$\leq$ 15	2	N/A	Yes
5. Drywell Floor Drain Valves					
1RF012	2	$\leq$ 20	2	N/A	Yes
1RF013	2	$\leq$ 20	2	N/A	Yes
6. Reactor Water Cleanup Suction Valves					
1G33-F001[(c)]	5	$\leq$ 10	2	N/A	Yes
1G33-F004	5	$\leq$ 10	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(b) May be opened on an intermittent basis under administrative control.

(c) Not closed by SLC System actuation.

Table A-1 (page 2 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)					
7. RCIC Steam Line Valves					
1E51-F008	8	≤ 20	2	N/A	Yes
1E51-F063	8	≤ 15	2	N/A	Yes
1E51-F076	8	≤ 15	2	N/A	Yes
8. Containment Vent and Purge Valves					
1VQ026	4	≤ 10	2	N/A	Yes
1VQ027	4	≤ 10	2	N/A	Yes
1VQ029	4	≤ 10	2	N/A	Yes
1VQ030	4	≤ 10	2	N/A	Yes
1VQ031	4	≤ 10	2	N/A	Yes
1VQ032	4	≤ 5	2	N/A	Yes
1VQ034	4	≤ 10	2	N/A	Yes
1VQ035	4	≤ 5	2	N/A	Yes
1VQ036	4	≤ 10	2	N/A	Yes
1VQ040	4	≤ 10	2	N/A	Yes
1VQ042	4	≤ 10	2	N/A	Yes
1VQ043	4	≤ 10	2	N/A	Yes
1VQ047	4	≤ 5	2	N/A	Yes
1VQ048	4	≤ 5	2	N/A	Yes
1VQ050	4	≤ 5	2	N/A	Yes
1VQ051	4	≤ 5	2	N/A	Yes
1VQ068	4	≤ 5	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(d) Not used.

Table A-1 (page 3 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
9.	RCIC Turbine Exhaust Vacuum Breaker Line Valves					
	1E51-F080	9	N/A	2	N/A	Yes
	1E51-F086	9	N/A	2	N/A	Yes
10.	Containment Monitoring Valves					
	1CM017A, B	2	$\leq$ 5	2	N/A	Yes
	1CM018A, B	2	$\leq$ 5	2	N/A	Yes
	1CM019A, B	2	$\leq$ 5	2	N/A	Yes
	1CM020A, B	2	$\leq$ 5	2	N/A	Yes
	1CM021B[(e)]	2	$\leq$ 5	1	No	No
	1CM022A[(e)]	2	$\leq$ 5	1	No	No
	1CM025A[(e)]	2	$\leq$ 5	1	No	No
	1CM026B[(e)]	2	$\leq$ 5	1	No	No
	1CM027	2	$\leq$ 5	2	N/A	Yes
	1CM028	2	$\leq$ 5	2	N/A	Yes
	1CM029	2	$\leq$ 5	2	N/A	Yes
	1CM030	2	$\leq$ 5	2	N/A	Yes
	1CM031	2	$\leq$ 5	2	N/A	Yes
	1CM032	2	$\leq$ 5	2	N/A	Yes
	1CM033	2	$\leq$ 5	2	N/A	Yes
	1CM034	2	$\leq$ 5	2	N/A	Yes
11.	Drywell Pneumatic Valves					
	1IN001A and B	10	$\leq$ 30	2	N/A	Yes
	1IN017	10	$\leq$ 22	2	N/A	Yes
	1IN074	10	$\leq$ 22	2	N/A	Yes
	1IN075	10	$\leq$ 22	2	N/A	Yes
	1IN031	2	$\leq$ 5	1	No	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(e) Opens on an isolation signal.

Table A-1 (page 4 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
12.	RHR Shutdown Cooling Mode Valves					
	1E12-F008	6	$\leq$ 40	2	N/A	Yes
	1E12-F009	6	$\leq$ 40	2	N/A	Yes
	1E12-F023	6	$\leq$ 90	1	No	Yes
	1E12-F053A and B	6	$\leq$ 29	1	No	Yes
13.	Tip Guide Tube Ball Valves (Five Valves)					
	1C51-J004	7	N/A	1	No	No
14.	Reactor Building Closed Cooling Water System Valves					
	1WR029	2	$\leq$ 30	2	N/A	Yes
	1WR040	2	$\leq$ 30	2	N/A	Yes
	1WR179	2	$\leq$ 30	2	N/A	Yes
	1WR180	2	$\leq$ 30	2	N/A	Yes
15.	Primary Containment Chilled Water Inlet Valves					
	1VP113A and B	2	$\leq$ 90	2	N/A	Yes
	1VP063A and B	2	$\leq$ 40	2	N/A	Yes
16.	Primary Containment Chilled Water Outlet Valves					
	1VP053A and B	2	$\leq$ 40	2	N/A	Yes
	1VP114A and B	2	$\leq$ 90	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(f) Not used.

Table A-1 (page 5 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
17.	Recirc. Hydraulic Flow Control Line Valves					
	1B33-F338A and B	2	≤ 5	2	N/A	Yes
	1B33-F339A and B	2	≤ 5	2	N/A	Yes
	1B33-F340A and B	2	≤ 5	2	N/A	Yes
	1B33-F341A and B	2	≤ 5	2	N/A	Yes
	1B33-F342A and B	2	≤ 5	2	N/A	Yes
	1B33-F343A and B	2	≤ 5	2	N/A	Yes
	1B33-F344A and B	2	≤ 5	2	N/A	Yes
	1B33-F345A and B	2	≤ 5	2	N/A	Yes
18.	Feedwater Testable Check Valves					
	1B21-F032A and B	2	N/A	3	N/A	Yes
b. Manual Isolation Valves						
1.	1FC086	N/A	N/A	2	N/A	N/A
2.	1FC113	N/A	N/A	2	N/A	N/A
3.	1FC114	N/A	N/A	2	N/A	N/A
4.	1FC115	N/A	N/A	2	N/A	N/A
5.	1MC027(g)	N/A	N/A	2	N/A	N/A
6.	1MC033(g)	N/A	N/A	2	N/A	N/A
7.	1SA042(g)	N/A	N/A	2	N/A	N/A
8.	1SA046(g)	N/A	N/A	2	N/A	N/A
9.	1CM039	N/A	N/A	2	N/A	N/A
10.	1CM040	N/A	N/A	2	N/A	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(g) These penetrations are provided with removable spools outboard of the outboard isolation valve. During operation, these lines will be blind flanged using a double O-ring.

Table A-1 (page 6 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
b. Manual Isolation Valves (continued)						
11.	1CM041	N/A	N/A	2	N/A	N/A
12.	1CM042	N/A	N/A	2	N/A	N/A
13.	1CM043	N/A	N/A	2	N/A	N/A
14.	1CM044	N/A	N/A	2	N/A	N/A
15.	1CM045	N/A	N/A	2	N/A	N/A
16.	1CM046	N/A	N/A	2	N/A	N/A
17.	1CM085	N/A	N/A	3	N/A	N/A
18.	1CM086	N/A	N/A	3	N/A	N/A
19.	1CM089	N/A	N/A	3	N/A	N/A
20.	1CM090	N/A	N/A	3	N/A	N/A
c. Excess Flow Check Valves						
1.	1B21-F374	N/A	N/A	1	No	No
2.	1B21-F376	N/A	N/A	1	No	No
3.	1B21-F359	N/A	N/A	1	No	No
4.	1B21-F355	N/A	N/A	1	No	No
5.	1B21-F361	N/A	N/A	1	No	No
6.	1B21-F378	N/A	N/A	1	No	No
7.	1B21-F372	N/A	N/A	1	No	No
8.	1B21-F370	N/A	N/A	1	No	No
9.	1B21-F363	N/A	N/A	1	No	No
10.	1B21-F353	N/A	N/A	1	No	No
11.	1B21-F415A, B	N/A	N/A	1	No	No
12.	1B21-F357	N/A	N/A	1	No	No
13.	1B21-F382	N/A	N/A	1	No	No
14.	1B21-F328A, B, C, D	N/A	N/A	1	No	No
15.	1B21-F327A, B, C, D	N/A	N/A	1	No	No
16.	1B21-F413A, B	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 7 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
c. Excess Flow Check Valves (continued)						
17.	1B21-F344	N/A	N/A	1	No	No
18.	1B21-F365	N/A	N/A	1	No	No
19.	1B21-F443	N/A	N/A	1	No	No
20.	1B21-F439	N/A	N/A	1	No	No
21.	1B21-F437	N/A	N/A	1	No	No
22.	1B21-F441	N/A	N/A	1	No	No
23.	1B21-F445A, B	N/A	N/A	1	No	No
24.	1B21-F453	N/A	N/A	1	No	No
25.	1B21-F447	N/A	N/A	1	No	No
26.	1B21-F455A, B	N/A	N/A	1	No	No
27.	1B21-F451	N/A	N/A	1	No	No
28.	1B21-F449	N/A	N/A	1	No	No
29.	1B21-F367	N/A	N/A	1	No	No
30.	1B21-F326A, B, C, D	N/A	N/A	1	No	No
31.	1B21-F325A, B, C, D	N/A	N/A	1	No	No
32.	1B21-F350	N/A	N/A	1	No	No
33.	1B21-F346	N/A	N/A	1	No	No
34.	1B21-F348	N/A	N/A	1	No	No
35.	1B21-F471	N/A	N/A	1	No	No
36.	1B21-F473	N/A	N/A	1	No	No
37.	1B21-F469	N/A	N/A	1	No	No
38.	1B21-F475A, B	N/A	N/A	1	No	No
39.	1B21-F465A, B	N/A	N/A	1	No	No
40.	1B21-F467	N/A	N/A	1	No	No
41.	1B21-F463	N/A	N/A	1	No	No
42.	1B21-F380	N/A	N/A	1	No	No
43.	1G33-F312A, B	N/A	N/A	1	No	No
44.	1G33-F309	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 8 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
c. Excess Flow Check Valves (continued)						
45.	1E12-F315	N/A	N/A	1	No	No
46.	1E12-F359A, B	N/A	N/A	1	No	No
47.	1E12-F319	N/A	N/A	1	No	No
48.	1E12-F317	N/A	N/A	1	No	No
49.	1E12-F360A, B	N/A	N/A	1	No	No
50.	1E21-F304	N/A	N/A	1	No	No
51.	1E22-F304	N/A	N/A	1	No	No
52.	1E22-F341	N/A	N/A	1	No	No
53.	1E22-F342	N/A	N/A	1	No	No
54.	1B33-F319A, B	N/A	N/A	1	No	No
55.	1B33-F317A, B	N/A	N/A	1	No	No
56.	1B33-F313A, B, C, D	N/A	N/A	1	No	No
57.	1B33-F311A, B, C, D	N/A	N/A	1	No	No
58.	1B33-F315A, B, C, D	N/A	N/A	1	No	No
59.	1B33-F301A, B	N/A	N/A	1	No	No
60.	1B33-F307A, B, C, D	N/A	N/A	1	No	No
61.	1B33-F305A, B, C, D	N/A	N/A	1	No	No
62.	1CM004	N/A	N/A	1	No	No
63.	1CM002	N/A	N/A	1	No	No
64.	1CM012	N/A	N/A	1	No	No
65.	1CM010	N/A	N/A	1	No	No
66.	1VQ061	N/A	N/A	1	No	No
67.	1B21-F457	N/A	N/A	1	No	No
68.	1B21-F459	N/A	N/A	1	No	No
69.	1B21-F461	N/A	N/A	1	No	No
70.	1CM102	N/A	N/A	1	No	No
71.	1B21-F570	N/A	N/A	1	No	No
72.	1B21-F571	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 9 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves					
1. Reactor Feedwater and RWCU System Return					
1B21-F010A, B	N/A	N/A	3	N/A	N/A
1B21-F065A, B	N/A	N/A	3	N/A	Yes
1G33-F040	N/A	N/A	3	N/A	Yes
2. Residual Heat Removal/Low Pressure Coolant Injection System					
1E12-F042A, B, C	N/A	N/A	1	No	Yes
1E12-F016A, B	N/A	N/A	2	N/A	Yes
1E12-F017A, B	N/A	N/A	2	N/A	Yes
1E12-F004A, B, C	N/A	N/A	1	Yes	Yes
1E12-F027A, B	N/A	N/A	1	No	Yes
1E12-F024A, B	N/A	N/A	1	Yes	Yes
1E12-F021	N/A	N/A	1	Yes	Yes
1E12-F302	N/A	N/A	1	Yes	N/A
1E12-F064A, B, C	N/A	N/A	1	Yes	Yes
1E12-F011A, B	N/A	N/A	1	Yes	No
1E12-F088A, B, C	N/A	N/A	1	Yes	N/A
1E12-F025A, B, C	N/A	N/A	1	Yes	N/A
1E12-F030	N/A	N/A	1	Yes	N/A
1E12-F005	N/A	N/A	1	Yes	N/A
1E12-F073A, B	N/A	N/A	2	N/A	No
1E12-F074A, B	N/A	N/A	2	N/A	No
1E12-F055A, B	N/A	N/A	1	Yes	N/A
1E12-F036A, B	N/A	N/A	1	Yes	N/A
1E12-F311A, B	N/A	N/A	1	Yes	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 10 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)					
3. Low Pressure Core Spray System					
1E21-F005	N/A	N/A	1	No	Yes
1E21-F001	N/A	N/A	1	Yes	Yes
1E21-F012	N/A	N/A	1	Yes	Yes
1E21-F011	N/A	N/A	1	Yes	Yes
1E21-F018	N/A	N/A	1	Yes	N/A
1E21-F031	N/A	N/A	1	Yes	N/A
4. High Pressure Core Spray System					
1E22-F004	N/A	N/A	1	No	Yes
1E22-F015	N/A	N/A	1	Yes	Yes
1E22-F023	N/A	N/A	1	Yes	Yes
1E22-F012	N/A	N/A	1	Yes	Yes
1E22-F014	N/A	N/A	1	Yes	N/A
5. Reactor Core Isolation Cooling System					
1E51-F013	N/A	N/A	1	No	Yes
1E51-F069	N/A	N/A	2	N/A	Yes
1E51-F028	N/A	N/A	2	N/A	N/A
1E51-F068	N/A	N/A	2	N/A	Yes
1E51-F040	N/A	N/A	2	N/A	N/A
1E51-F031	N/A	N/A	1	Yes	Yes
1E51-F019	N/A	N/A	1	Yes	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 11 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)					
5. Reactor Core Isolation Cooling System (continued)					
1E51-F059[(h)]	N/A	N/A	2	N/A	Yes
1E51-F022[(h)]	N/A	N/A	2	N/A	Yes
1E51-F362[(i)]	N/A	N/A	2	N/A	N/A
1E51-F363[(i)]	N/A	N/A	2	N/A	N/A
6. Post LOCA Hydrogen Control					
1HG001A, B	N/A	N/A	2	N/A	Yes
1HG002A, B	N/A	N/A	2	N/A	Yes
1HG005A, B	N/A	N/A	2	N/A	Yes
1HG006A, B	N/A	N/A	2	N/A	Yes
7. Standby Liquid Control System					
1C41-F004A, B	N/A	N/A	3	N/A	N/A
1C41-F006	N/A	N/A	3	N/A	N/A
1C41-F007	N/A	N/A	3	N/A	N/A
8. Reactor Recirculation Seal Injection					
1B33-F013A, B	N/A	N/A	2	N/A	N/A
1B33-F017A, B	N/A	N/A	2	N/A	N/A
9. Drywell Pneumatic System					
1IN018	N/A	N/A	2	N/A	N/A
1IN100	N/A	N/A	1	No	No
1IN101	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(h) If valves 1E51-F362 and 1E51-F363 are locked closed and acceptably leak rate tested, then valves 1E51-F059 and 1E51-F022 are not considered to be primary containment isolation valves and are not required to be leak rate tested.

(i) Either the 1E51-F362 or the 1E51-F363 valve may be open when the RCIC System is in the standby mode of operation, and both valves may be open during operation of the RCIC System in the full flow test mode, providing that:

1) valve 1E51-F022 is acceptably leak rate tested, and

2) valve 1E51-F059 is deactivated, locked closed and acceptably leak rate tested, and

3) the spectacle flange, installed immediately downstream of the 1E51-F059 valve, is closed and acceptably leak rate tested.

Table A-1 (page 12 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)						
10.	Reference Leg Backfill					
	1C11-F422B	N/A	N/A	2	N/A	N/A
	1C11-F422D	N/A	N/A	2	N/A	N/A
	1C11-F422F	N/A	N/A	2	N/A	N/A
	1C11-F422G	N/A	N/A	2	N/A	N/A
	1C11-F423B	N/A	N/A	2	N/A	N/A
	1C11-F423D	N/A	N/A	2	N/A	N/A
	1C11-F423F	N/A	N/A	2	N/A	N/A
	1C11-F423G	N/A	N/A	2	N/A	N/A
11.	Control Rod Drive Insert Lines					
	1C11-D001-120	N/A	N/A	1	No	N/A
	1C11-D001-123	N/A	N/A	1	No	N/A
12.	Control Rod Drive Withdrawal Lines					
	1C11-D001-121	N/A	N/A	1	No	N/A
	1C11-D001-122	N/A	N/A	1	No	N/A
13.	RHR Shutdown Cooling					
	1E12-F460	N/A	N/A	2	N/A	N/A
14.	Primary Containment Chilled Water Inlet Valve					
	1VP198A	N/A	N/A	2	N/A	N/A
	1VP198B	N/A	N/A	2	N/A	N/A
15.	Primary Containment Chilled Water Outlet Valve					
	1VP197A	N/A	N/A	2	N/A	N/A
	1VP197B	N/A	N/A	2	N/A	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-1 (page 13 of 13)
Primary Containment Isolation Valves (Unit 1)

VALVE FUNCTION AND NUMBER		VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)						
16.	Reactor Building Closed Cooling Water System					
	1WR225	N/A	N/A	2	N/A	N/A
	1WR226	N/A	N/A	2	N/A	N/A
17.	Reactor Coolant System Sample Line Valve					
	1B33-F395	N/A	N/A	2	N/A	N/A
18.	Containment Monitoring Valves					
	1CM023B	N/A	N/A	1	No	No
	1CM024A	N/A	N/A	1	No	No

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 1 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves					
1. Main Steam Isolation Valves					
2B21-F022A, B, C, D	1	$\leq$ 5 and $\geq$ 3	2	N/A	Yes
2B21-F028A, B, C, D	1	$\leq$ 5 and $\geq$ 3	2	N/A	Yes
2. Main Steam Line Drain Valves					
2B21-F016	1	$\leq$ 15	2	N/A	Yes
2B21-F019	1	$\leq$ 15	2	N/A	Yes
2B21-F067A, B, C, D	1	$\leq$ 23	2	N/A	Yes
3. Reactor Coolant System Sample Line Valves(b)					
2B33-F019	3	$\leq$ 5	2	N/A	Yes
2B33-F020	3	$\leq$ 5	2	N/A	Yes
4. Drywell Equipment Drain Valves					
2RE024	2	$\leq$ 20	2	N/A	Yes
2RE025	2	$\leq$ 20	2	N/A	Yes
2RE026	2	$\leq$ 15	2	N/A	Yes
2RE029	2	$\leq$ 15	2	N/A	Yes
5. Drywell Floor Drain Valves					
2RF012	2	$\leq$ 20	2	N/A	Yes
2RF013	2	$\leq$ 20	2	N/A	Yes
6. Reactor Water Cleanup Suction Valves					
2G33-F001(c)	5	$\leq$ 10	2	N/A	Yes
2G33-F004	5	$\leq$ 10	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(b) May be opened on an intermittent basis under administrative control.

(c) Not closed by SLC System actuation.

Table A-2 (page 2 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
7.	RCIC Steam Line Valves					
	2E51-F008	8	≤ 20	2	N/A	Yes
	2E51-F063	8	≤ 15	2	N/A	Yes
	2E51-F076	8	≤ 15	2	N/A	Yes
8.	Containment Vent and Purge Valves					
	2VQ026	4	≤ 10	2	N/A	Yes
	2VQ027	4	≤ 10	2	N/A	Yes
	2VQ029	4	≤ 10	2	N/A	Yes
	2VQ030	4	≤ 10	2	N/A	Yes
	2VQ031	4	≤ 10	2	N/A	Yes
	2VQ032	4	≤ 5	2	N/A	Yes
	2VQ034	4	≤ 10	2	N/A	Yes
	2VQ035	4	≤ 5	2	N/A	Yes
	2VQ036	4	≤ 10	2	N/A	Yes
	2VQ040	4	≤ 10	2	N/A	Yes
	2VQ042	4	≤ 10	2	N/A	Yes
	2VQ043	4	≤ 10	2	N/A	Yes
	2VQ047	4	≤ 5	2	N/A	Yes
	2VQ048	4	≤ 5	2	N/A	Yes
	2VQ050	4	≤ 5	2	N/A	Yes
	2VQ051	4	≤ 5	2	N/A	Yes
	2VQ068	4	≤ 5	2	N/A	Yes
9.	RCIC Turbine Exhaust Vacuum Breaker Line Valves					
	2E51-F080	9	N/A	2	N/A	Yes
	2E51-F086	9	N/A	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(d) Not used

Table A-2 (page 3 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)					
10. Containment Monitoring Valves					
2CM017A, B	2	$\leq$ 5	2	N/A	Yes
2CM018A, B	2	$\leq$ 5	2	N/A	Yes
2CM019A, B	2	$\leq$ 5	2	N/A	Yes
2CM020A, B	2	$\leq$ 5	2	N/A	Yes
2CM021B[e]	2	$\leq$ 5	1	No	No
2CM022A[e]	2	$\leq$ 5	1	No	No
2CM025A[e]	2	$\leq$ 5	1	No	No
2CM026B[e]	2	$\leq$ 5	1	No	No
2CM027	2	$\leq$ 5	2	N/A	Yes
2CM028	2	$\leq$ 5	2	N/A	Yes
2CM029	2	$\leq$ 5	2	N/A	Yes
2CM030	2	$\leq$ 5	2	N/A	Yes
2CM031	2	$\leq$ 5	2	N/A	Yes
2CM032	2	$\leq$ 5	2	N/A	Yes
2CM033	2	$\leq$ 5	2	N/A	Yes
2CM034	2	$\leq$ 5	2	N/A	Yes
11. Drywell Pneumatic Valves					
2IN001A and B	10	$\leq$ 30	2	N/A	Yes
2IN017	10	$\leq$ 22	2	N/A	Yes
2IN074	10	$\leq$ 22	2	N/A	Yes
2IN075	10	$\leq$ 22	2	N/A	Yes
2IN031	2	$\leq$ 5	1	No	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(e) Opens on an isolation signal.

Table A-2 (page 4 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
12.	RHR Shutdown Cooling Mode Valves					
	2E12-F008	6	$\leq$ 40	2	N/A	Yes
	2E12-F009	6	$\leq$ 40	2	N/A	Yes
	2E12-F023	6	$\leq$ 90	1	No	Yes
	2E12-F053A and B	6	$\leq$ 29	1	No	Yes
13.	Tip Guide Tube Ball Valves (Five Valves)					
	2C51-J004	7	N/A	1	No	No
14.	Reactor Building Closed Cooling Water System Valves					
	2WR029	2	$\leq$ 30	2	N/A	Yes
	2WR040	2	$\leq$ 30	2	N/A	Yes
	2WR179	2	$\leq$ 30	2	N/A	Yes
	2WR180	2	$\leq$ 30	2	N/A	Yes
15.	Primary Containment Chilled Water Inlet Valves					
	2VP113A and B	2	$\leq$ 90	2	N/A	Yes
	2VP063A and B	2	$\leq$ 40	2	N/A	Yes
16.	Primary Containment Chilled Water Outlet Valves					
	2VP053A and B	2	$\leq$ 40	2	N/A	Yes
	2VP114A and B	2	$\leq$ 90	2	N/A	Yes
17.	Recirc. Hydraulic Flow Control Line Valves					
	2B33-F338A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F339A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F340A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F341A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F342A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F343A and B	2	$\leq$ 5	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(f) Not used.

Table A-2 (page 5 of 12)
Primary Containment Isolation Valves (Unit 2)

	VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
a. Automatic Isolation Valves (continued)						
17.	Recirc. Hydraulic Flow Control Line Valves (continued)					
	2B33-F344A and B	2	$\leq$ 5	2	N/A	Yes
	2B33-F345A and B	2	$\leq$ 5	2	N/A	Yes
18.	Feedwater Testable Check Valves					
	2B21-F032A and B	2	N/A	3	N/A	Yes
b. Manual Isolation Valves						
1.	2FC086	N/A	N/A	2	N/A	N/A
2.	2FC113	N/A	N/A	2	N/A	N/A
3.	2FC114	N/A	N/A	2	N/A	N/A
4.	2FC115	N/A	N/A	2	N/A	N/A
5.	2MC027[g]	N/A	N/A	2	N/A	N/A
6.	2MC033[g]	N/A	N/A	2	N/A	N/A
7.	2SA042[g]	N/A	N/A	2	N/A	N/A
8.	2SA046[g]	N/A	N/A	2	N/A	N/A
9.	2CM039	N/A	N/A	2	N/A	N/A
10.	2CM040	N/A	N/A	2	N/A	N/A
11.	2CM041	N/A	N/A	2	N/A	N/A
12.	2CM042	N/A	N/A	2	N/A	N/A
13.	2CM043	N/A	N/A	2	N/A	N/A
14.	2CM044	N/A	N/A	2	N/A	N/A
15.	2CM045	N/A	N/A	2	N/A	N/A
16.	2CM046	N/A	N/A	2	N/A	N/A
17.	2CM085	N/A	N/A	3	N/A	N/A
18.	2CM086	N/A	N/A	3	N/A	N/A
19.	2CM089	N/A	N/A	3	N/A	N/A
20.	2CM090	N/A	N/A	3	N/A	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(g) These penetrations are provided with removable spools outboard of the outboard isolation valve. During operation, these lines will be blind flanged using a double O-ring.

Table A-2 (page 6 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
c. Excess Flow Check Valves						
1.	2B21-F374	N/A	N/A	1	No	No
2.	2B21-F376	N/A	N/A	1	No	No
3.	2B21-F359	N/A	N/A	1	No	No
4.	2B21-F355	N/A	N/A	1	No	No
5.	2B21-F361	N/A	N/A	1	No	No
6.	2B21-F378	N/A	N/A	1	No	No
7.	2B21-F372	N/A	N/A	1	No	No
8.	2B21-F370	N/A	N/A	1	No	No
9.	2B21-F363	N/A	N/A	1	No	No
10.	2B21-F353	N/A	N/A	1	No	No
11.	2B21-F415A, B	N/A	N/A	1	No	No
12.	2B21-F357	N/A	N/A	1	No	No
13.	2B21-F382	N/A	N/A	1	No	No
14.	2B21-F328A, B, C, D	N/A	N/A	1	No	No
15.	2B21-F327A, B, C, D	N/A	N/A	1	No	No
16.	2B21-F413A, B	N/A	N/A	1	No	No
17.	2B21-F344	N/A	N/A	1	No	No
18.	2B21-F365	N/A	N/A	1	No	No
19.	2B21-F443	N/A	N/A	1	No	No
20.	2B21-F439	N/A	N/A	1	No	No
21.	2B21-F437	N/A	N/A	1	No	No
22.	2B21-F441	N/A	N/A	1	No	No
23.	2B21-F445A, B	N/A	N/A	1	No	No
24.	2B21-F453	N/A	N/A	1	No	No
25.	2B21-F447	N/A	N/A	1	No	No
26.	2B21-F455A, B	N/A	N/A	1	No	No
27.	2B21-F451	N/A	N/A	1	No	No
28.	2B21-F449	N/A	N/A	1	No	No
29.	2B21-F367	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 7 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
c. Excess Flow Check Valves (continued)						
30.	2B21-F326A, B, C, D	N/A	N/A	1	No	No
31.	2B21-F325A, B, C, D	N/A	N/A	1	No	No
32.	2B21-F350	N/A	N/A	1	No	No
33.	2B21-F346	N/A	N/A	1	No	No
34.	2B21-F348	N/A	N/A	1	No	No
35.	2B21-F471	N/A	N/A	1	No	No
36.	2B21-F473	N/A	N/A	1	No	No
37.	2B21-F469	N/A	N/A	1	No	No
38.	2B21-F475A, B	N/A	N/A	1	No	No
39.	2B21-F465A, B	N/A	N/A	1	No	No
40.	2B21-F467	N/A	N/A	1	No	No
41.	2B21-F463	N/A	N/A	1	No	No
42.	2B21-F380	N/A	N/A	1	No	No
43.	2G33-F312A, B	N/A	N/A	1	No	No
44.	2G33-F309	N/A	N/A	1	No	No
45.	2E12-F315	N/A	N/A	1	No	No
46.	2E12-F359A, B	N/A	N/A	1	No	No
47.	2E12-F319	N/A	N/A	1	No	No
48.	2E12-F317	N/A	N/A	1	No	No
49.	2E12-F360A, B	N/A	N/A	1	No	No
50.	2E21-F304	N/A	N/A	1	No	No
51.	2E22-F304	N/A	N/A	1	No	No
52.	2E22-F341	N/A	N/A	1	No	No
53.	2E22-F342	N/A	N/A	1	No	No
54.	2B33-F319A, B	N/A	N/A	1	No	No
55.	2B33-F317A, B	N/A	N/A	1	No	No
56.	2B33-F313A, B, C, D	N/A	N/A	1	No	No

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 8 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
c. Excess Flow Check Valves (continued)						
57.	2B33-F311A, B, C, D	N/A	N/A	1	No	No
58.	2B33-F315A, B, C, D	N/A	N/A	1	No	No
59.	2B33-F301A, B	N/A	N/A	1	No	No
60.	2B33-F307A, B, C, D	N/A	N/A	1	No	No
61.	2B33-F305A, B, C, D	N/A	N/A	1	No	No
62.	2CM004	N/A	N/A	1	No	No
63.	2CM002	N/A	N/A	1	No	No
64.	2CM012	N/A	N/A	1	No	No
65.	2CM010	N/A	N/A	1	No	No
66.	2VQ061	N/A	N/A	1	No	No
67.	2B21-F457	N/A	N/A	1	No	No
68.	2B21-F459	N/A	N/A	1	No	No
69.	2B21-F461	N/A	N/A	1	No	No
70.	2CM102	N/A	N/A	1	No	No
71.	2B21-F570	N/A	N/A	1	No	No
72.	2B21-F571	N/A	N/A	1	No	No
d. Other Isolation Valves						
1.	Reactor Feedwater and RWCU System Return					
	2B21-F010A, B	N/A	N/A	3	N/A	N/A
	2B21-F065A, B	N/A	N/A	3	N/A	Yes
	2G33-F040	N/A	N/A	3	N/A	Yes
2.	Residual Heat Removal/Low Pressure Coolant Injection System					
	2E12-F042A, B, C	N/A	N/A	1	No	Yes
	2E12-F016A, B	N/A	N/A	2	N/A	Yes
	2E12-F017A, B	N/A	N/A	2	N/A	Yes

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 9 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)					
2. Residual Heat Removal/Low Pressure Coolant Injection System (continued)					
2E12-F004A, B, C	N/A	N/A	1	Yes	Yes
2E12-F027A, B	N/A	N/A	1	No	Yes
2E12-F024A, B	N/A	N/A	1	Yes	Yes
2E12-F021	N/A	N/A	1	Yes	Yes
2E12-F302	N/A	N/A	1	Yes	N/A
2E12-F064A, B, C	N/A	N/A	1	Yes	Yes
2E12-F011A, B	N/A	N/A	1	Yes	No
2E12-F088A, B, C	N/A	N/A	1	Yes	N/A
2E12-F025A, B, C	N/A	N/A	1	Yes	N/A
2E12-F030	N/A	N/A	1	Yes	N/A
2E12-F005	N/A	N/A	1	Yes	N/A
2E12-F073A, B	N/A	N/A	2	N/A	No
2E12-F074A, B	N/A	N/A	2	N/A	No
2E12-F055A, B	N/A	N/A	1	Yes	N/A
2E12-F036A, B	N/A	N/A	1	Yes	N/A
2E12-F311A, B	N/A	N/A	1	Yes	N/A
3. Low Pressure Core Spray System					
2E21-F005	N/A	N/A	1	No	Yes
2E21-F001	N/A	N/A	1	Yes	Yes
2E21-F012	N/A	N/A	1	Yes	Yes
2E21-F011	N/A	N/A	1	Yes	Yes
2E21-F018	N/A	N/A	1	Yes	N/A
2E21-F031	N/A	N/A	1	Yes	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 10 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)					
4. High Pressure Core Spray System					
2E22-F004	N/A	N/A	1	No	Yes
2E22-F015	N/A	N/A	1	Yes	Yes
2E22-F023	N/A	N/A	1	Yes	Yes
2E22-F012	N/A	N/A	1	Yes	Yes
2E22-F014	N/A	N/A	1	Yes	N/A
5. Reactor Core Isolation Cooling System					
2E51-F013	N/A	N/A	1	No	Yes
2E51-F069	N/A	N/A	2	N/A	Yes
2E51-F028	N/A	N/A	2	N/A	N/A
2E51-F068	N/A	N/A	2	N/A	Yes
2E51-F040	N/A	N/A	2	N/A	N/A
2E51-F031	N/A	N/A	1	Yes	Yes
2E51-F019	N/A	N/A	1	Yes	Yes
2E51-F059(h)	N/A	N/A	2	N/A	Yes
2E51-F022(h)	N/A	N/A	2	N/A	Yes
2E51-F362(i)	N/A	N/A	2	N/A	N/A
2E51-F363(i)	N/A	N/A	2	N/A	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

(h) If valves 2E51-F362 and 2E51-F363 are locked closed and acceptably leak rate tested, then valves 2E51-F059 and 2E51-F022 are not considered to be primary containment isolation valves and are not required to be leak rate tested.

(i) Either the 2E51-F362 or the 2E51-F363 valve may be open when the RCIC System is in the standby mode of operation, and both valves may be open during operation of the RCIC System in the full flow test mode, providing that:

1) valve 2E51-F022 is acceptably leak rate tested, and

2) valve 2E51-F059 is deactivated, locked closed and acceptably leak rate tested, and

3) the spectacle flange, installed immediately downstream of the 2E51-F059 valve, is closed and acceptably leak rate tested.

Table A-2 (page 11 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)						
6.	Post LOCA Hydrogen Control					
	2HG001A, B	N/A	N/A	2	N/A	Yes
	2HG002A, B	N/A	N/A	2	N/A	Yes
	2HG005A, B	N/A	N/A	2	N/A	Yes
	2HG006A, B	N/A	N/A	2	N/A	Yes
7.	Standby Liquid Control System					
	2C41-F004A, B	N/A	N/A	3	N/A	N/A
	2C41-F006	N/A	N/A	3	N/A	N/A
	2C41-F007	N/A	N/A	3	N/A	N/A
8.	Reactor Recirculation Seal Injection					
	2B33-F013A, B	N/A	N/A	2	N/A	N/A
	2B33-F017A, B	N/A	N/A	2	N/A	N/A
9.	Drywell Pneumatic System					
	2IN018	N/A	N/A	2	N/A	N/A
	2IN100	N/A	N/A	1	No	No
	2IN101	N/A	N/A	1	No	No
10.	Reference Leg Backfill					
	2C11-F422B	N/A	N/A	2	N/A	N/A
	2C11-F422D	N/A	N/A	2	N/A	N/A
	2C11-F422F	N/A	N/A	2	N/A	N/A
	2C11-F422G	N/A	N/A	2	N/A	N/A
	2C11-F423B	N/A	N/A	2	N/A	N/A
	2C11-F423D	N/A	N/A	2	N/A	N/A
	2C11-F423F	N/A	N/A	2	N/A	N/A
	2C11-F423G	N/A	N/A	2	N/A	N/A

(continued)

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

Table A-2 (page 12 of 12)
Primary Containment Isolation Valves (Unit 2)

VALVE FUNCTION AND NUMBER		VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (seconds)	NUMBER OF PCIVs IN PENETRATION	CLOSED SYSTEM PER LCO 3.6.1.3	LCO 3.3.3.1 POSITION INDICATION
d. Other Isolation Valves (continued)						
11.	Control Rod Drive Insert Lines					
	2C11-D001-120	N/A	N/A	1	No	N/A
	2C11-D001-123	N/A	N/A	1	No	N/A
12.	Control Rod Drive Withdrawal Lines					
	2C11-D001-121	N/A	N/A	1	No	N/A
	2C11-D001-122	N/A	N/A	1	No	N/A
13.	RHR Shutdown Cooling Mode Valve					
	2E12-F460	N/A	N/A	2	N/A	N/A
14.	Primary Containment Chilled Water Inlet Valve					
	2VP198A	N/A	N/A	2	N/A	N/A
	2VP198B	N/A	N/A	2	N/A	N/A
15.	Primary Containment Chilled Water Outlet Valve					
	2VP197A	N/A	N/A	2	N/A	N/A
	2VP197B	N/A	N/A	2	N/A	N/A
16.	Reactor Building Closed Cooling Water System					
	2WR225	N/A	N/A	2	N/A	N/A
	2WR226	N/A	N/A	2	N/A	N/A
17.	Reactor Coolant System Sample Line Valve					
	2B33-F395	N/A	N/A	2	N/A	N/A
18.	Containment Monitoring Valves					
	2CM023B	N/A	N/A	1	No	No
	2CM024A	N/A	N/A	1	No	No

(a) See Bases for Technical Specification 3.3.6.1 for isolation signal(s) that operates each valve group.

APPENDIX B

SECONDARY CONTAINMENT ISOLATION VALVES

Table B-1 (page 1 of 1)
Secondary Containment Isolation Valves

	DAMPER FUNCTION	ISOLATION TIME (seconds)
1.	Reactor Building Ventilation Supply Damper 1VR-04YA	10
2.	Reactor Building Ventilation Supply Damper 1VR-04YB	10
3.	Reactor Building Ventilation Exhaust Damper 1VR-05YA	10
4.	Reactor Building Ventilation Exhaust Damper 1VR-05YB	10
5.	Reactor Building Purge Train Isolation Damper 1VQ-037	90
6.	Reactor Building Purge Train Isolation Damper 1VQ-038	90
7.	Reactor Building Ventilation Supply Damper 2VR-04YA	10
8.	Reactor Building Ventilation Supply Damper 2VR-04YB	10
9.	Reactor Building Ventilation Exhaust Damper 2VR-05YA	10
10.	Reactor Building Ventilation Exhaust Damper 2VR-05YB	10
11.	Reactor Building Purge Train Isolation Damper 2VQ-037	90
12.	Reactor Building Purge Train Isolation Damper 2VQ-038	90

APPENDIX C

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

Table C-1 (page 1 of 1)
Reactor Coolant System Pressure Isolation Valves

	SYSTEM	VALVE NUMBER	FUNCTION
1.	LPCS	E21-F006	LPCS Injection
		E21-F005	LPCS Injection
2.	HPCS	E22-F005	HPCS Injection
		E22-F004	HPCS Injection
3.	RHR	E12-F041A	LPCI Injection
		E12-F041B	LPCI Injection
		E12-F041C	LPCI Injection
		E12-F042A	LPCI Injection
		E12-F042B	LPCI Injection
		E12-F042C	LPCI Injection
		E12-F050A	Shutdown Cooling Return
		E12-F050B	Shutdown Cooling Return
		E12-F053A	Shutdown Cooling Return
		E12-F053B	Shutdown Cooling Return
		E12-F009	Shutdown Cooling Suction
		E12-F008	Shutdown Cooling Suction
4.	RCIC	E51-F066	RCIC Head Spray
		E51-F065	RCIC Head Spray

APPENDIX D

INSTRUMENTATION TRIP SETPOINTS

Table T3.3.1.1-1 (page 1 of 1)
Reactor Protection System Instrumentation Trip Setpoints

		FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Intermediate Range Monitors		
	a.	Neutron Flux – high	L-001344
	b.	Inop	NA
2.	Average Power Range Monitors		
	a.	Neutron Flux – High, Setdown	L-001345
	b.	Flow Biased Simulated Thermal Power – Upscale	L-001345 [(a)] [(b)]
	c.	Fixed Neutron Flux – High	L-001345
	d.	Inop	NA
3.	Reactor Vessel Steam Dome Pressure – High		NED-I-EIC-0174
4.	Reactor Vessel Water Level – Low, Level 3		NED-I-EIC-0201 (Unit 1) NED-I-EIC-0203 (Unit 2)
5.	Main Steam Isolation Valve – Closure		L-002596
6.	Drywell Pressure – High		NED-I-EIC-0178
7.	Scram Discharge Volume Water Level – High		
	a.	Transmitter/Trip Unit	NED-I-EIC-0179
	b.	Float Switch	NED-I-EIC-0263
8.	Turbine Stop Valve – Closure		L-002596
9.	Turbine Control Valve Fast Closure, Trip Oil Pressure – Low		NED-I-EIC-0181, L-003699
10.	Reactor Mode Switch – Shutdown Position		NA
11.	Manual Scram		NA

(a) Nominal Trip Setpoint is shown in calculation L-001345 for single loop operation per LCO 3.4.1, “Recirculation Loops Operating.”

(b) The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

Table T3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation Trip Setpoints

FUNCTION			NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Rod Block Monitor		
	a.	Upscale	L-001345
	b.	Inop	NA
	c.	Downscale	L-001345
2.	Rod Worth Minimizer		NA
3.	Reactor Mode Switch – Shutdown Position		NA

Table T3.3.2.2-1 (page 1 of 1)
Feedwater System and Main Turbine High Water Level
Trip Instrumentation Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Feedwater System and Main Turbine High Level Trip Instrumentation	NED-I-EIC-0241 (Unit 1) NED-I-EIC-0234 (Unit 2)

Table T3.3.4.1-1 (page 1 of 1)
End-of-Cycle-Recirculation Pump Trip Instrumentation
Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Turbine Stop Valve – Closure	L-002596
2.	Turbine Control Valve Closure, Trip Oil Pressure – Low	NED-I-EIC-0181, L-003699

Table T3.3.4.2-1 (page 1 of 1)
Anticipated Transient Without Scram – Recirculation Pump
Trip Instrumentation Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Reactor Vessel Water Level – Low Low, Level 2	L-000978
2.	Reactor Steam Dome Pressure – High	L-000979

Table T3.3.5.1-1 (page 1 of 2)
Emergency Core Cooling System Instrumentation
Trip Setpoints

		FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Low Pressure Coolant Injection-A (LPCI) and Low Pressure Core Spray (LPCS) Subsystem		
	a.	Reactor Vessel Water Level – Low Low Low, Level 1	NED-I-EIC-0199
	b.	Drywell Pressure – High	NED-I-EIC-0194
	c.	LPCI Pump A Start – Time Delay Relay	L-002585
	d.	Reactor Steam Dome Pressure – Low (Injection Permissive)	NED-I-EIC-0202
	e.	LPCS Pump Discharge Flow – Low (Bypass)	NED-I-EIC-0198
	f.	LPCI Pump A Discharge Flow – Low (Bypass)	NED-I-EIC-0198
	g.	LPCS and LPCI A Injection Line Pressure – Low (Injection Permissive)	NED-I-EIC-0202
	h.	Manual Initiation	NA
2.	LPCI B and LPCI C Subsystems		
	a.	Reactor Vessel Water Level – Low Low Low, Level 1	NED-I-EIC-0199
	b.	Drywell Pressure – High	NED-I-EIC-0194
	c.	LPCI Pump B Start – Time Delay Relay	L-002585
	d.	Reactor Steam Dome Pressure – Low (Injection Permissive)	NED-I-EIC-0202
	e.	LPCI Pump B and LPCI Pump C Discharge Flow – Low (Bypass)	NED-I-EIC-0198
	f.	LPCI B and LPCI C Injection Line Pressure – Low (Injection Permissive)	NED-I-EIC-0202
	g.	Manual Initiation	NA
3.	High Pressure Core Spray (HPCS) System		
	a.	Reactor Vessel Water Level – Low Low, Level 2	NED-I-EIC-0193
	b.	Drywell Pressure – High	NED-I-EIC-0194
	c.	Reactor Vessel Water Level – High, Level 8	NED-I-EIC-0200 (Unit 1)
			NED-I-EIC-0195 (Unit 2)
	d.	HPCS Pump Discharge Pressure – High (Bypass)	NED-I-EIC-0197
	e.	HPCS System Flow Rate – Low (Bypass)	NED-I-EIC-0198
	f.	Manual Initiation	NA
4.	Automatic Depressurization System (ADS) Trip System A		
	a.	Reactor Vessel Water Level – Low Low Low, Level 1	NED-I-EIC-0199
	b.	Drywell Pressure – High	NED-I-EIC-0194
	c.	ADS Initiation Timer	L-002586

(continued)

Table T3.3.5.1-1 (page 2 of 2)
Emergency Core Cooling System Instrumentation
Trip Setpoints

FUNCTION			NOMINAL TRIP SETPOINT CALCULATION NUMBER
4.	ADS Trip System A (continued)		
	d.	Reactor Vessel Water Level – Low, Level 3 (Confirmatory)	NED-I-EIC-0175
	e.	LPCS Pump Discharge Pressure – High	NED-I-EIC-0197
	f.	LPCI Pump A Discharge Pressure – High	NED-I-EIC-0197
	g.	ADS Drywell Pressure Bypass Timer	L-002586
	h.	Manual Initiation	NA
5.	ADS Trip System B		
	a.	Reactor Vessel Water Level – Low Low Low, Level 1	NED-I-EIC-0199
	b.	Drywell Pressure – High	NED-I-EIC-0194
	c.	ADS Initiation Timer	L-002586
	d.	Reactor Vessel Water Level – Low, Level 3 (Confirmatory)	NED-I-EIC-0175
	e.	LPCI Pumps B & C Discharge Pressure – High	NED-I-EIC-0197
	f.	ADS Drywell Pressure Bypass Timer	L-002586
	g.	Manual Initiation	NA

Table T3.3.5.2-1 (page 1 of 1)
Reactor Core Isolation Cooling System Instrumentation
Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Reactor Vessel Water Level – Low Low, Level 2	NED-I-EIC-0199
2.	Reactor Vessel Water Level – High, Level 8	NED-I-EIC-0200 (Unit 1)
		NED-I-EIC-0195 (Unit 2)
3.	Condensate Storage Tank Level – Low	L-002590
4.	Manual Initiation	NA

Table T3.3.6.1-1 (page 1 of 2)
Primary Containment Isolation Instrumentation
Trip Setpoints

		FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Main Steam Line Isolation		
	a.	Reactor Vessel Water Level – Low Low Low, Level 1	NED-I-EIC-0205
	b.	Main Steam Line Pressure – Low	NED-I-EIC-0206
	c.	Main Steam Line Flow - High	NED-I-EIC-0207
	d.	Condenser Vacuum – Low	NED-I-EIC-0209
	e.	Main Steam Line Tunnel Differential Temperature – High	NED-I-EIC-0208
	f.	Manual Initiation	NA
2.	Primary Containment Isolation		
	a.	Reactor Vessel Water Level – Low Low, Level 2	NED-I-EIC-0205
	b.	Drywell Pressure – High	NED-I-EIC-0178
	c.	Reactor Building Ventilation Exhaust Plenum Radiation - High	L-001362
	d.	Fuel Pool Ventilation Exhaust Radiation – High	L-001362
	e.	Reactor Ventilation Water Level – Low Low Low, Level 1	NED-I-EIC-0205
	f.	Reactor Vessel Water Level – Low, Level 3	NED-I-EIC-0201 (Unit 1) NED-I-EIC-0203 (Unit 2)
	g.	Manual Initiation	NA
3.	Reactor Core Isolation Cooling (RCIC) System Isolation		
	a.	RCIC Steam Line Flow – High	NED-I-EIC-0210
	b.	RCIC Steam Line Flow –Timer	L-002593
	c.	RCIC Steam Supply Pressure – Low	NED-I-EIC-0211
	d.	RCIC Turbine Exhaust Diaphragm Pressure – High	NED-I-EIC-0212
	e.	RCIC Equipment Room Temperature – High	NED-I-EIC-0213
	f.	RCIC Equipment Room Differential Temperature – High	NED-I-EIC-0213
	g.	RCIC Steam Line Tunnel Temperature – High	NED-I-EIC-0213
	h.	RCIC Steam Line Tunnel Differential Temperature - High	NED-I-EIC-0213
	i.	Drywell Pressure – High	NED-I-EIC-0194
	j.	Manual Initiation	NA

(continued)

Table T3.3.6.1-1 (page 2 of 2)
Primary Containment Isolation Instrumentation
Trip Setpoints

FUNCTION			NOMINAL TRIP SETPOINT CALCULATION NUMBER
4.	Reactor Water Cleanup (RWCU) System Isolation		
	a.	Differential Flow – High	NED-I-EIC-0214
	b.	Differential Flow –Timer	L-002594
	c.	RWCU Heat Exchanger Areas Temperature – High	L-001420
	d.	RWCU Heat Exchanger Areas Ventilation Differential Temperature - High	L-001420
	e.	RWCU Pump and Valve Area Temperature – High	L-001420
	f.	RWCU Pump and Valve Area Differential Temperature - High	L-001420
	g.	RWCU Holdup Pipe Area Temperature – High	L-001420
	h.	RWCU Holdup Pipe Area Ventilation Differential Temperature – High	L-001420
	i.	RWCU Filter/Demineralizer Valve Room Area Temperature – High	L-001420
	j.	RWCU Filter/Demineralizer Valve Room Area Ventilation Differential Temperature – High	L-001420
	k.	Reactor Vessel Water Level – Low Low, Level 2	NED-I-EIC-0205
	l.	Standby Liquid Control System Initiation	NA
	m.	Manual Initiation	NA
5.	RHR Shutdown Cooling System Isolation		
	a.	Reactor Vessel Water Level – Low, Level 3	NED-I-EIC-0201 (Unit 1)
			NED-I-EIC-0203 (Unit 2)
	b.	Reactor Vessel Pressure – High	NED-I-EIC-0217
	c.	Manual Initiation	NA

Table T3.3.6.2-1 (page 1 of 1)
Secondary Containment Isolation Instrumentation
Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Reactor Vessel Water Level – Low Low, Level 2	NED-I-EIC-0205
2.	Drywell Pressure – High	NED-I-EIC-0178
3.	Reactor Building Ventilation Exhaust Plenum Radiation – High	L-001362
4.	Fuel Pool Ventilation Exhaust Radiation – High	L-001362
5.	Manual Initiation	NA

Table T3.3.7.1-1 (page 1 of 1)
Control Room Area Filtration (CRAF) System Instrumentation
Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Control Room Air Intake Radiation – High	L-002592

Table T3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation
Trip Setpoints

FUNCTION		NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Divisions 1 and 2 – 4.16 kV Emergency Bus Undervoltage	
a.	Loss of Voltage – 4.16 kV Basis	L-002588
b.	Loss of Voltage – Time Delay	L-002589
c.	Degraded Voltage – 4.16 kV Basis	4266/19AN71
d.	Degraded Voltage – Time Delay, No LOCA	L-002591
e.	Degraded Voltage – Time Delay, LOCA	L-002591
2.	Division 3 - 4.16 kV Emergency Bus Undervoltage	
a.	Loss of Voltage – 4.16 kV Basis	L-002588
b.	Loss of Voltage – Time Delay	L-002589
c.	Degraded Voltage – 4.16 kV Basis	4266/19AN71
d.	Degraded Voltage – Time Delay, No LOCA	L-002591
e.	Degraded Voltage – Time Delay, LOCA	L-002591

Table T3.3.8.2-1 (page 1 of 1)
Reactor Protection System Electric Power Monitoring
Trip Setpoints

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Overvoltage and time delay	L-001678 (Overvoltage)
		L-002598 (Time Delay)
2.	Undervoltage and time delay	L-001678 (Undervoltage)
		L-002598 (Time Delay)
3.	Underfrequency and time delay	L-001678 (Undervoltage)
		L-002598 (Time Delay)

Table T3.3.a.-2 (page 1 of 1)
Control Rod Drive RPS Instrumentation

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Charging Water Header Pressure – Low	NED-I-EIC-0182
2.	Delay Timer	L-002700

Table T3.3.c-2 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION			NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Average Power Range Monitors		
	a.	Flow Biased Simulated Thermal Power – Upscale	L-001345[(a)]
	b.	Inoperative	NA
	c.	Downscale	L-001345
	d.	Neutron Flux – High	L-001345
2.	Source Range Monitors		
	a.	Detector not full in	NA
	b.	Upscale	L-001343
	c.	Inoperative	NA
	d.	Downscale	L-001343
3.	Intermediate Range Monitors		
	a.	Detector not full in	NA
	b.	Upscale	L-001344
	c.	Inoperative	NA
	d.	Downscale	L-001344
4.	Scram Discharge Volume		
	a.	Water Level – High	NED-I-EIC-0263
	b.	Scram Discharge Volume Switch in Bypass	NA
5.	Recirculation Flow Unit		
	a.	Upscale	L-001345
	b.	Inoperative	NA
	c.	Comparator	L-001345

(a) Nominal Trip Setpoint is shown in calculation package L-001345 for single loop operation per Technical Specification 3.4.1, "Recirculation Loops Operating."

Table T3.3.e-1 (page 1 of 1)
ECCS Discharge Line Keep Fill Alarm Instrumentation

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Low Pressure Core Spray	NED-I-EIC-0156
2.	Low Pressure Coolant Injection (LPCI) “A”	NED-I-EIC-0153
3.	LPCI “B”	NED-I-EIC-0154
4.	LPCI “C”	NED-I-EIC-0155
5.	High Pressure Core Spray	NED-I-EIC-0157

Table T3.3.f-1 (page 1 of 1)
ECCS Header Differential Pressure Instrumentation

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Low Pressure Core Spray	L-002481
2.	Low Pressure Coolant Injection	L-002481
3.	High Pressure Core Spray	L-002481

Table T3.3.g-1 (page 1 of 1)
RCIC System Discharge Line Keep Fill Alarm Instrumentation

FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
RCIC System Discharge Line Keep Fill Alarm – Low Pressure	NED-I-EIC-0158

Table T3.3.h-1 (page 1 of 1)
High/Low Pressure Interface Valve Leakage Pressure Monitors

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	High Pressure Core Spray	L-002482
2.	Low Pressure Core Spray	L-002482
3.	Low Pressure Coolant Injection/Shutdown Cooling	L-002482
4.	RHR Shutdown Cooling	L-002482
5.	Reactor Core Isolation Cooling	L-002482

Table T3.3.j-2 (page 1 of 1)
Primary Containment Isolation Instrumentation

	FUNCTION	NOMINAL TRIP SETPOINT CALCULATION NUMBER
1.	Reactor Water Cleanup Isolation – Pump Suction Flow – High	L-001443
2.	Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow – High	NED-I-EIC-0218

Table E-1 (page 1 of 2)
Response Times

FUNCTION			RESPONSE TIME
1.	End-of-Cycle — Recirculation Pump Trip System		
	a.	Turbine Stop Valve — Closure	≤ 97 msecs[(a)]
	b.	Turbine Control Valve — Fast Closure	≤ 97 msecs[(a)]
2.	Emergency Core Cooling System		
	a.	Low Pressure Core Spray	≤ 60 secs[(b)(c)]
	b.	Low Pressure Coolant Injection (Pumps A, B, and C)	≤ 60 secs[(b)(c)]
	c.	High Pressure Core Spray	≤ 41 secs[(c)]
3.	Primary Containment Isolation — Main Steam Line Isolation		
	a.	Main Steam Line Flow — High	≤ 0.5 secs[(d)(e)(f)]
4.	Main Turbine Bypass System		≤ 200 msec

(continued)

(a) System response time is the time assumed in the analysis between initiation of the valve motion and complete suppression of the electric arc, i.e., 190 ms, less the time allotted for sensor response, i.e., 10 ms, and less the time allotted for breaker suppression determined by test, as correlated to manufacture's test results, i.e., 83 ms and plant operational test results.

(b) Injection valves shall be fully open in ≤ 40 seconds after receipt of Reactor Vessel Pressure and ECCS Injection Line Pressure Interlock signal concurrently with power source availability and receipt of an accident initiation signal.

(c) ECCS actuation instrumentation is eliminated from response time testing.

(d) For Main Steam Isolation Valves only.

(e) Sensor is eliminated from response time testing for the MSIV actuation logic circuits.

(f) Isolation system instrumentation response time specified for the Trip Function actuating the MSIVs shall be added to MSIV isolation time to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

Table E-1 (page 2 of 2)
Response Times

		FUNCTION	RESPONSE TIME
5	Reactor Protection System Response Times		
	a.	Average Power Range Monitor — Fixed Neutron Flux — High	$\leq$ 0.09 secs(g)
	b.	Reactor Vessel Water Level — Low, Level 3	$\leq$ 1.05 secs(h)
	c.	Main Steam Line Isolation Valve — Closure	$\leq$ 0.06 secs
	d.	Turbine Stop Valve — Closure	$\leq$ 0.06 secs
	e.	Turbine Control Valve Fast Closure, Trip Oil Pressure — Low	$\leq$ 0.08 secs(i)
	f.	OPRM Hardware	$\leq$ 400 msec

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

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

(i) Measured from the start of turbine valve fast closure.

APPENDIX F

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

Table F-1 (page 1 of 1)
Remote Shutdown Monitoring Instrumentation

	INSTRUMENT	REQUIRED NUMBER OF CHANNELS
1.	Reactor Vessel Pressure	1
2.	Reactor Vessel Water Level	1
3.	Residual Heat Removal Flow	1
4.	Residual Heat Removal Service Water Flow	1
5.	Residual Heat Removal Service Water Temperature	1
6.	Reactor Core Isolation Cooling Flow	1
7.	Reactor Core Isolation Cooling Turbine Speed	1
8.	Suppression Pool Water Level	1
9.	Suppression Pool Water Temperature	1

TABLE OF CONTENTS

A. PURPOSE

A.1 Objective

The purpose of the SFDP is to ensure that when Technical Specification LCO 3.0.6 is used to preclude performing the Conditions and Actions for inoperable SUPPORTED SYSTEMS:

- A LOSS OF SAFETY FUNCTION does not go undetected,
- The plant will be placed in a safe condition if a LOSS OF SAFETY FUNCTION is determined to exist, and
- A SUPPORTED SYSTEM(S) Completion Time will not be inappropriately extended.

B. REFERENCES

B.1 Technical Specification (TS) LCO 3.0.6.

B.2 TS 5.5.12, "Safety Function Determination Program (SFDP)"

C. DEFINITIONS

C.1 **SAFETY FUNCTION** –

An accident mitigation feature required by NRC regulation, plant design or Technical Specifications normally composed of two trains of support and supported equipment.

C.2 **LOSS OF SAFETY FUNCTION (LOSF)** –

A LOSF exists when, assuming no concurrent single failure and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed.
(SEE ATTACHMENT 1)

C.3 **SUPPORT SYSTEM** –

A system that is needed by another TS LCO required system to perform a safety function.

C.4 **SUPPORTED SYSTEM –**

A system, required by the TS, which requires a SUPPORT SYSTEM to ensure its safety function can be performed. Process parameters or operating limits do not comprise SUPPORTED SYSTEMS for the purposes of implementing TS LCO 3.0.6.

C.5 **MAXIMUM OUT OF SERVICE TIME (MOST) –**

A SUPPORTED SYSTEM made inoperable by a SUPPORT SYSTEM inoperability shall be restored to OPERABLE status within the MAXIMUM OUT OF SERVICE TIME. The MOST is the Completion Time specified in the Technical Specifications for restoring the first inoperable SUPPORT SYSTEM to OPERABLE status plus the time specified in the TS for restoring the SUPPORTED SYSTEM to OPERABLE status. (SEE ATTACHMENT 2 – Completion Time Extensions)

The inoperability of the SUPPORTED SYSTEM must only be directly attributed to its associated SUPPORT SYSTEM being inoperable and the SUPPORT SYSTEM Required Actions not specifically requiring immediate entry into the SUPPORTED SYSTEM Conditions and Required Actions.

D. LIMITATIONS

D.1 Reporting Requirements will be done in accordance with the Reportability Manual.

D.2 Changes to this Program shall be performed in accordance with the TRM Change Control Program.

D.3 The Shift Manager is responsible for implementing the Safety Function Determination Program.

E. PROCEDURE

E.1 LCO 3.0.6 REQUIREMENTS

E.1.1 TS LCO 3.0.2 states that upon discovery of a failure to meet a TS LCO, the Required Actions of the associated Conditions shall be met, except as provided in TS LCO 3.0.5 and TS LCO 3.0.6.

E.1.2 TS LCO 3.0.6 provides an exception to TS LCO 3.0.2 for SUPPORTED SYSTEMS by not requiring the Conditions and Required Actions for the SUPPORTED SYSTEMS to be performed when the failure to meet a TS LCO is solely due to a SUPPORT SYSTEM LCO not being met. In this situation, although the SUPPORTED SYSTEMS are determined to be inoperable as defined in the Technical Specifications, LCO 3.0.6 requires only the ACTIONS of the SUPPORT SYSTEM(S) to be performed. Although the affected equipment must still be declared inoperable, the Conditions and Required Actions for the SUPPORTED SYSTEMS are not required to be performed per TS LCO 3.0.6.

E.1.3 There are two types of SUPPORT SYSTEMS that must be considered when implementing TS LCO 3.0.6:

- SUPPORT SYSTEMS specifically addressed in Technical Specifications, and
- SUPPORT SYSTEMS that are not specifically addressed in Technical Specifications

NOTE

It may be necessary to perform Operability Determinations in accordance with procedure OP-AA-108-115 in order to determine SUPPORTED SYSTEMS made inoperable by inoperable SUPPORT SYSTEMS.

If the required SUPPORT SYSTEM is addressed in the Technical Specifications, then only the SUPPORT SYSTEM Conditions and Actions must be entered per TS LCO 3.0.6.

If the required SUPPORT SYSTEM is NOT addressed in the Technical Specifications, then the impact of the SUPPORT SYSTEM inoperability must be evaluated with respect to any SUPPORTED SYSTEM(S) that is addressed in Technical Specifications.

E.1.4 A single component inoperability may result in multiple inoperabilities within a single train and affect multiple TS LCOs. TS LCO 3.0.6 limits the amount of "cascading" Actions that are required when an inoperable SUPPORT SYSTEM renders a SUPPORTED SYSTEM inoperable.

E.1.5 Any SUPPORT SYSTEM inoperability must be evaluated with respect to the existing plant conditions to ensure that a LOSS OF SAFETY FUNCTION (LOSF) does not exist.

Example: The loss of a Residual Heat Removal Service Water (RHRSW) Pump to one RHRSW heat exchanger. If the heat exchanger bypass valve was found stuck open in the opposite subsystem, a LOSF will exist following a loss-of-coolant-accident and this plant configuration must be evaluated.

E.1.6 <u>When</u> TS LCO 3.0.6 is utilized, evaluations are required in accordance with TS 5.5.12, "Safety Function Determination Program (SFDP)".

E.1.7 <u>If</u> a LOSF is determined to exist by this program, the appropriate Conditions and Required Actions of the TS LCO in which the LOSF exists are required to be entered unless the LOSF is solely due to a single Tech Spec SUPPORT SYSTEM.

E.1.8 <u>When</u> a SUPPORT SYSTEM Required Action directs a SUPPORTED SYSTEM to be declared inoperable <u>or</u> directs entry into Conditions and Required Actions for a SUPPORTED SYSTEM, the applicable Conditions <u>and</u> Required Actions for the SUPPORTED SYSTEM shall be entered at the time specified (either immediately or following some delay period) by the SUPPORT SYSTEM Required Action.

E.1.9 It should be noted that for cases in which the inoperable SUPPORT SYSTEM is addressed in Technical Specifications, "cascading" Conditions and Required Actions may still be performed in lieu of entry into TS LCO 3.0.6.

E.2 T.S. 5.5.12, SAFETY FUNCTION DETERMINATION PROGRAM (SFDP) REQUIREMENTS

> **NOTE**
>
> If failure of a TS required SUPPORT SYSTEM results in the inoperability of a system outside of the TS, and that system is subsequently relied upon by a TS SUPPORTED SYSTEM, then LCO 3.0.6 could apply and only the SUPPORT SYSTEM Required Actions would be entered.

E.2.1 When TS LCO 3.0.6 is used as an exception to TS LCO 3.0.2, an evaluation is required to ensure a LOSF is detected and appropriate actions are taken.

E.2.2 Therefore, the SFDP requires:

E.2.2.1 Cross train checks to ensure a LOSF does not go undetected;

- Since "cascading" the Conditions and Required Actions of a Specification are not required when applying TS LCO 3.0.6, a possibility exists that unrelated concurrent failures of more than one system could result in the complete loss of both trains of a SUPPORTED SYSTEM. Therefore, upon a failure to meet two or more LCOs during the same time period, an evaluation shall be conducted to determine if a LOSF exists. Generally, this is done by confirming that the remaining required redundant system(s) are OPERABLE per ATTACHMENT 1 and TABLE 1. If a LOSF does exist, the SFDP directs that the appropriate actions be taken.

E.2.2.2 Placing the plant in a safe condition if a LOSF is detected;

- If a LOSF is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the LOSF exists are required to be entered unless the LOSF is solely due to a single Tech Spec SUPPORT SYSTEM per step E.3.4.

E.2.2.3 Controls on extending completion times on inoperable SUPPORTED SYSTEM(S);

- MOST is determined per ATTACHMENT 2.

E.2.2.4 Appropriate limitations and remedial or compensatory actions to be taken as a result of the SUPPORT SYSTEM(S) inoperability.

E.3 PROGRAM IMPLEMENTATION

Performing steps E.3.1 thru E.3.13 will implement the requirements of the SFDP. For each step, perform the action or determine if the statement is true. If a statement in a step is determined to be false, perform the action in the STATEMENT NOT TRUE column.

ACTION/STATEMENT TRUE	STATEMENT NOT TRUE
E.3.1 The degraded system renders a TS required system(s) inoperable.	E.3.1.1 No further evaluation is necessary. EXIT this procedure.
E.3.2 EVALUATE this inoperability's impact on any current SFDs and document on Worksheet (ATTACHMENT 3).	
E.3.3 The inoperable system is also a SUPPORT SYSTEM (Refer to TABLE 1).	E.3.3.1 PERFORM Conditions and Required Actions for the inoperable system and EXIT this procedure.
E.3.4 EVALUATE the OPERABILITY of all SUPPORTED SYSTEM(S) as a result of this TS SUPPORT SYSTEM inoperability.	
E.3.5 A SUPPORTED SYSTEM(S) is rendered inoperable.	E.3.5.1 No further evaluation is necessary. EXIT this procedure.

E.3 PROGRAM IMPLEMENTATION

> **NOTE**
>
> If there are multiple systems supported by the inoperable SUPPORT SYSTEM, perform Step E.3.6 for each SUPPORTED SYSTEM individually.

ACTION/STATEMENT TRUE	STATEMENT NOT TRUE
E.3.6 The inoperable SUPPORT SYSTEM Specification Conditions and Required Actions direct either the immediate declaration of inoperability of a SUPPORTED SYSTEM(S) or immediate performance of a SUPPORTED SYSTEM(S) Required Actions.	E.3.6.1 EITHER: • PERFORM both the SUPPORT and SUPPORTED SYSTEM(S) Required Actions and EXIT this procedure. **OR** • PERFORM SUPPORT SYSTEM Required Actions. AND • PERFORM a LOSF Evaluation for all inoperable SUPPORTED SYSTEM(S) per ATTACHMENT 1 and TABLE 1. GO TO Step E.3.8.
E.3.7 ENTER the TS Conditions and Required Actions for the SUPPORTED SYSTEM(S) and EXIT this procedure.	

E.3 PROGRAM IMPLEMENTATION

ACTION/STATEMENT TRUE	STATEMENT NOT TRUE
E.3.8 ATTACHMENT 1 has determined that No LOSF exists OR a LOSF exists that is solely due to the inoperability of a single Tech Spec SUPPORT SYSTEM LCO.	E.3.8.1 PERFORM the Conditions and Required Actions for the LCO in which the LOSF exists. EXIT this procedure.
E.3.9 INVOKE TS LCO 3.0.6 to defer entry into the Conditions and Required Actions associated with the inoperable SUPPORTED SYSTEM(S).	
E.3.10 CALCULATE the MOST for the inoperable SUPPORTED SYSTEM(S) using ATTACHMENT 2.	
E.3.11 COMPLETE the SFDP Tracking Worksheet per ATTACHMENT 3.	
E.3.12 The inoperable SUPPORT SYSTEM and all SUPPORTED SYSTEMS on the SFDP Tracking Worksheet are restored to OPERABLE status within the applicable MOST.	E.3.12.1 ENTER the associated Condition for the inoperable SUPPORTED SYSTEM Completion Time not being met for inoperable SUPPORTED SYSTEMS exceeding their MOST and PERFORM the Required Actions. E.3.12.2 When the SUPPORTED SYSTEM(S) that have exceeded their MOST are restored to an OPERABLE status, RE-PERFORM Step E.3.12.

E.3 PROGRAM IMPLEMENTATION

ACTION/STATEMENT TRUE	STATEMENT NOT TRUE
E.3.13 ENTER the time/date when the SUPPORT SYSTEM as well as all SUPPORTED SYSTEM(S) are restored to OPERABLE status and sign the SFDP Tracking Worksheet (ATTACHMENT 3).	

ATTACHMENT 1
LOSS OF SAFETY FUNCTION EVALUATION

A. Guidance for Safety Function Evaluation

TS 5.5.12 states that a LOSF exists when, assuming no concurrent single failure, and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed.

For the purpose of this program, a "graduated" approach may be taken for determining the "safety function" of the SUPPORTED SYSTEM(S). This approach, detailed below, is graduated from most to least conservative. Even if the least conservative method is used, the requirements of TS 5.5.12 will be met. In determining whether a LOSF has occurred, at least one of these methods must be used. To perform the LOSF Evaluation, GO TO Section B of this Attachment.

Method 1: Redundant Subsystem/Division/Train

a. For this method, the safety function is assumed to be the systems function as described in the TS BASES. This method confirms the OPERABILITY of the corresponding redundant SUPPORTED SYSTEM(S).

b. If one or more of the redundant systems are found to be INOPERABLE, a LOSF may exist. The appropriate ACTIONS for a LOSF may be taken or alternatively, Methods 2 or 3 may be used.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

SUPPORT/SUPPORTED SYSTEM(S) DIAGRAM

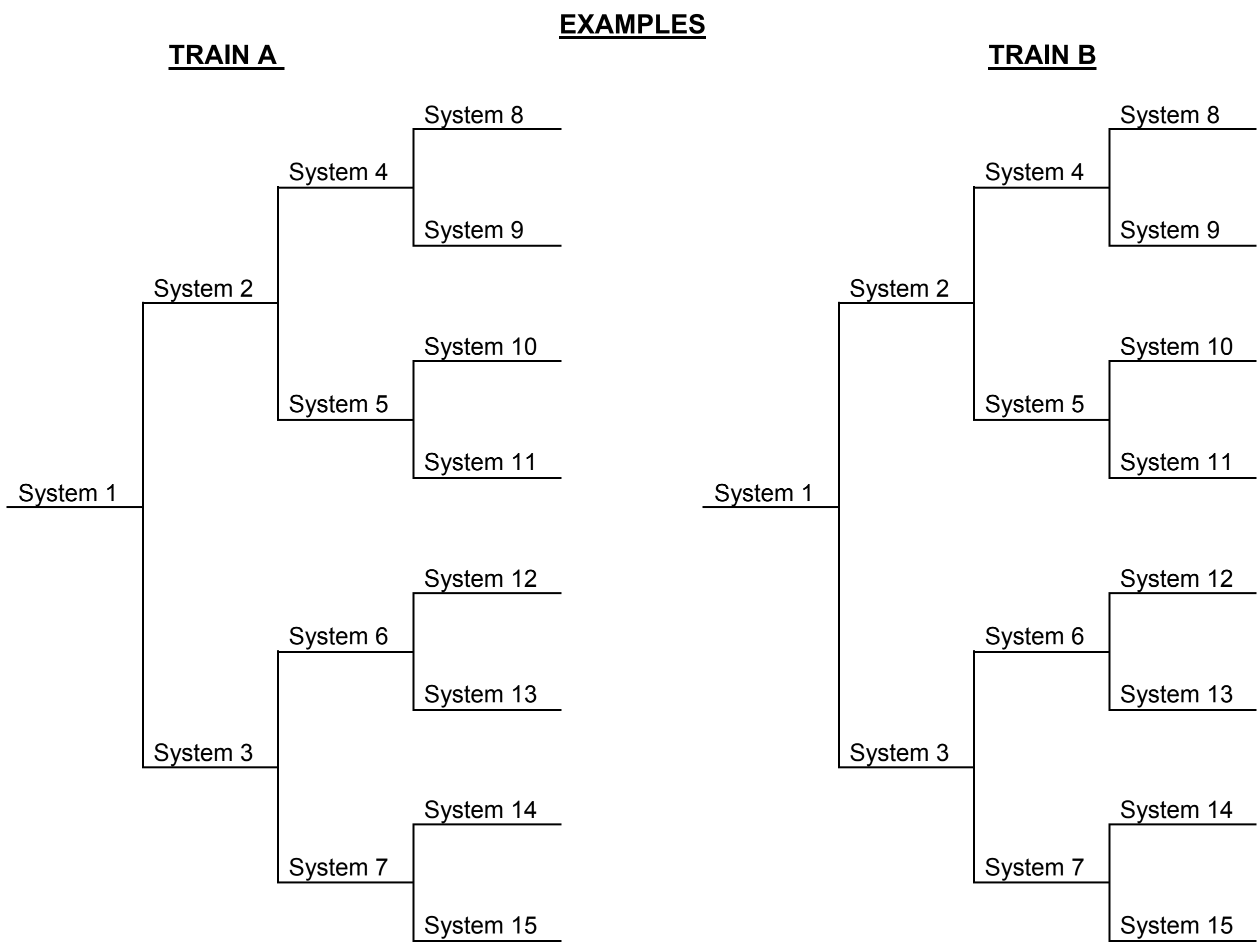
TS 5.5.12 lists three conditions when a LOSS OF SAFETY FUNCTION may exist. The following three examples are provided to explain each of the stated condition.

EXAMPLE 1

A LOSF may exist when a SUPPORT SYSTEM is inoperable, and:

A required system redundant to the systems(s) supported by the inoperable SUPPORT SYSTEM is also inoperable.

If system 2 of Train A is inoperable, and System 5 of Train B is inoperable, a LOSF may exist in SUPPORTED SYSTEM(S) 5, 10, 11.



Note: Chart reads from left to right, i.e., System 1 is a SUPPORT SYSTEM for Systems 2 through 15.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

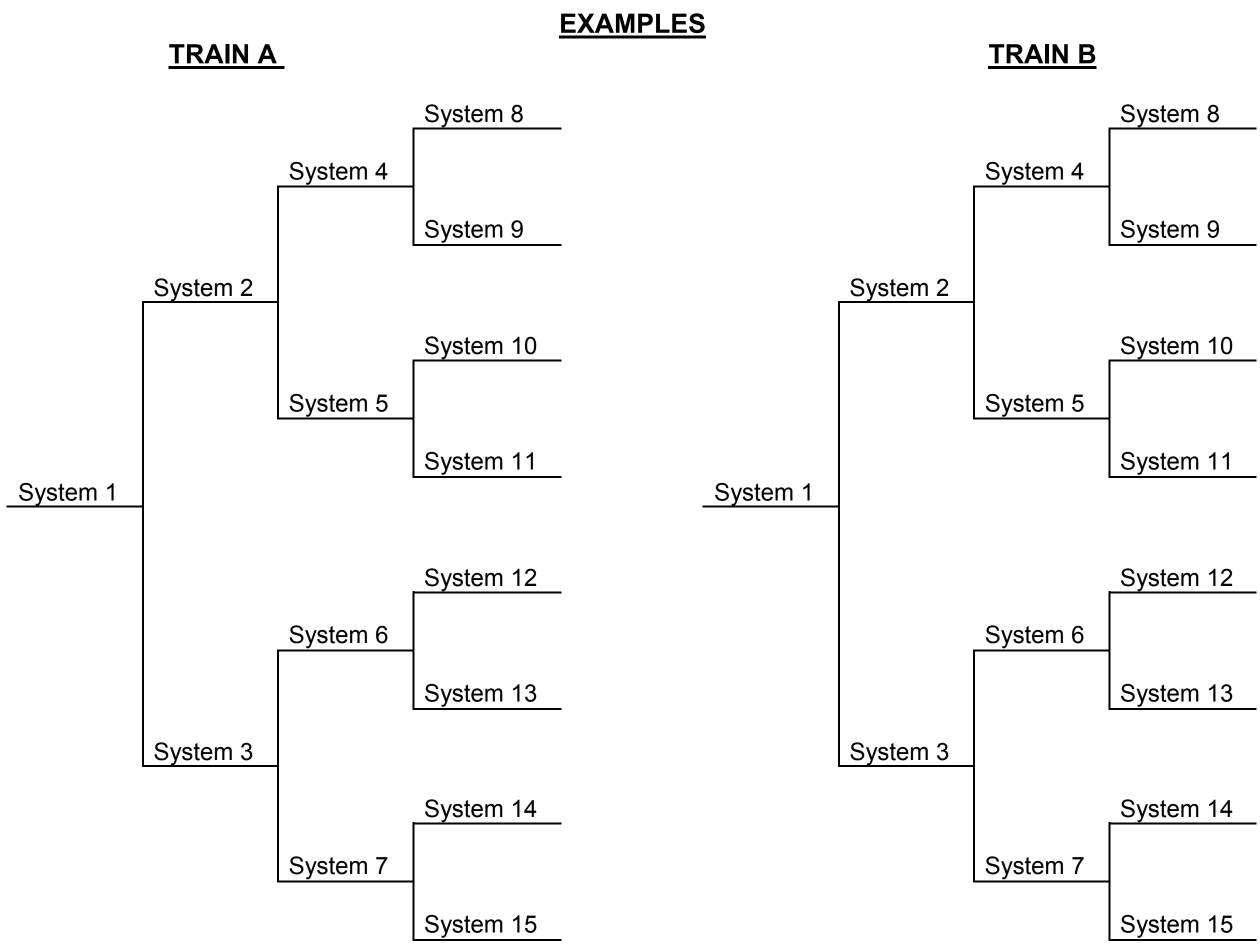
SUPPORT/SUPPORTED SYSTEM(S) DIAGRAM

EXAMPLE 2

A LOSF may exist when a SUPPORT SYSTEM is inoperable, and:

A required system redundant to the system(s) in turn supported by the inoperable SUPPORTED SYSTEM(S) is also inoperable.

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a LOSF may exist in System 11which is in turn supported by System 5.



Note: Chart reads from left to right, i.e., System 1 is a SUPPORT SYSTEM for Systems 2 through 15.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

SUPPORT/SUPPORTED SYSTEM(S) DIAGRAM

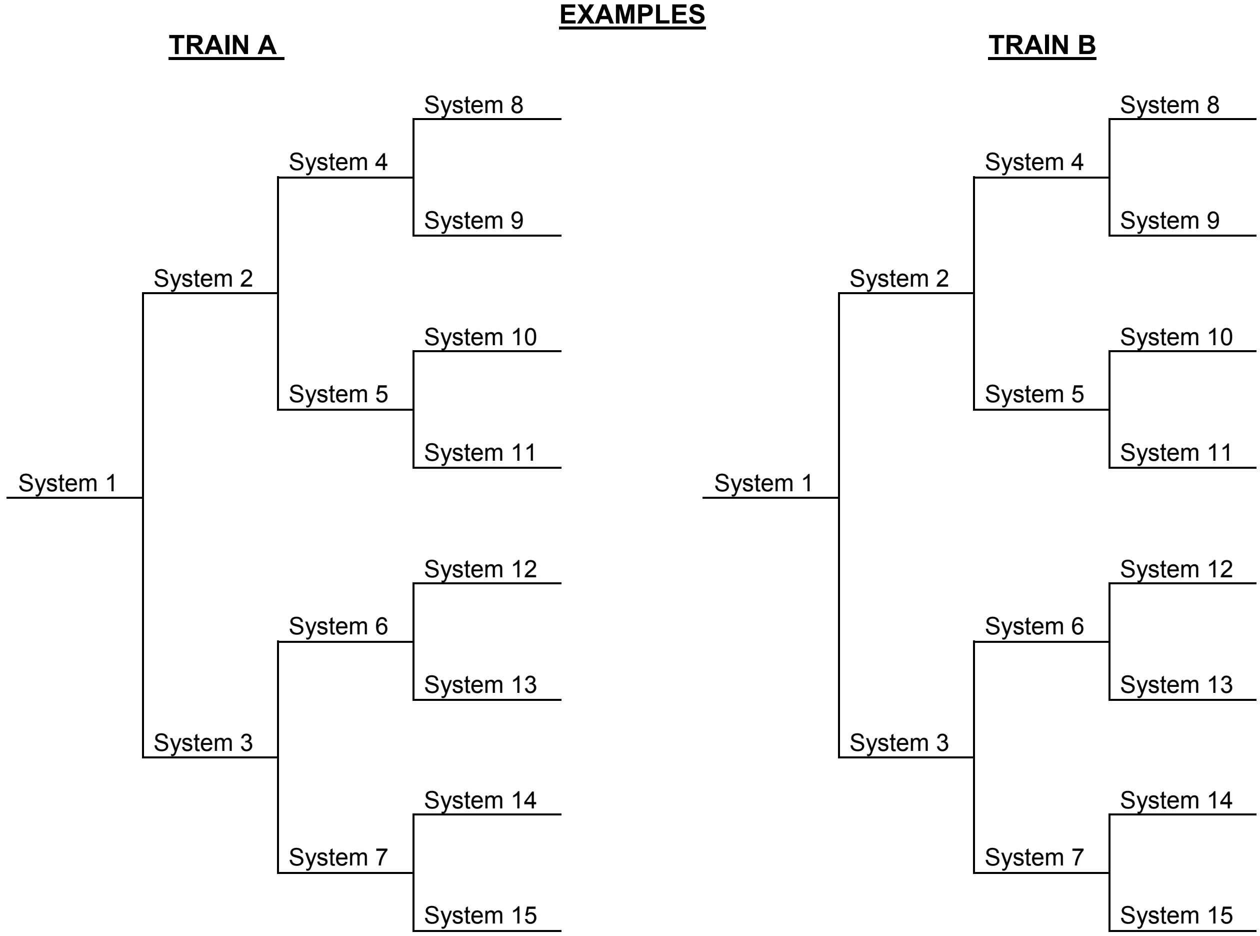
EXAMPLE 3

A LOSF may exist when a SUPPORT SYSTEM is inoperable, and:

A required system redundant to the SUPPORT SYSTEM(S) for the SUPPORTED SYSTEM(S) (a) and (b) above is also inoperable.

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a LOSF may exist in System(s) 2, 4, 5, 8, 9, 10 and 11.

EXAMPLES



Note: Chart reads from left to right, i.e., System 1 is a SUPPORT SYSTEM for System(s) 2 through 15.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

Method 2: TS LCO Function Method 2: TS LCO Function

a. In certain cases, multiple SYSTEM(S) with diverse individual functions are specified under one TS LCO statement; i.e., in one Technical Specification. For these cases, the safety function may be considered to be broader than the individual SYSTEM(S) function – the safety function is the Technical Specification LCO function, not the SYSTEM(S) function (as described in Method 1 above).

b. An example of this is TS 3.5.1, "ECCS—Operating," in which four different systems are included. In this case, the function as stated in the Bases, "…to cool the core during a LOCA," may be the safety function to be considered in the SFDP.

c. If a loss of TS LCO function is determined to exist, the appropriate Conditions and Required Actions for a LOSF may be taken, or alternatively, Method 3 below may be used.

Method 3: Safety Analysis

In this approach, the function of the systems described in the UFSAR accident analyses is considered to be the safety function. If the system in question is not credited in the accident analyses, or if the accident function it performs is intact, then no LOSF exists. However, if the system's function is credited and is lost (i.e., the accident function it performs cannot be met), then the appropriate ACTIONS for a LOSF must be taken.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

B. LOSS OF SAFETY FUNCTION (LOSF) Evaluation

Review the statements below. When a condition is found that applies to the current plant configuration, the evaluation for a LOSF is complete and the LOSF determination provided may be used to perform Step E.3.8.

1. Including the inoperability(s) that resulted in entering this procedure, are all currently existing Tech Spec and/or TRM inoperability(s) confined to a single safety-related division?

   ☐ Yes – No LOSF exists.

   ☐ No – A LOSF may exist. Evaluate which of the following conditions apply:

   - ☐ There are no inoperabilities in any support or supported subsystem/division/train(s) redundant to the affected SSC. No LOSF exists.

     This satisfies Method 1. Note that the redundant subsystem/division/train may be a diverse component or feature. For example, LPCI in conjunction with the ADS system is redundant to HPCS for mitigating a small break LOCA.

   - ☐ The supported system has no redundant subsystem/division/train and is part of an LCO which uses diverse methods for satisfying single failure criteria AND the LCO function is intact. No LOSF exists.

     This satisfies Method 2. Some safety equipment is allowed to have no redundant components if other design features are present which ensures that the safety function will be maintained in the event of a single active failure. For example. Penetrations with only one PCIV are permitted because of the reliability of the closed system (i.e., suppression pool water) or safety system integrity to act as a penetration isolation boundary. Thus, if these PCIVs were to become inoperable, the LCO function would be intact provided the assumed system integrity or closed system conditions are present.

(continued)

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

☐ Inoperable support and/or supported equipment redundant to the affected SSC is part of an LCO containing multiple systems satisfying diverse individual functions AND the LCO function is intact. No LOSF exists.

This satisfies Method 2. Sufficient systems may exist within an LCO such that the LCO function could still be accomplished with redundant equipment inoperable. For example, if the A LPCI and C LPCI pumps were inoperable, there are still a sufficient number of ECCS pumps available to mitigate a LOCA event and provide core cooling.

☐ The inoperable support and supported equipment is part of a system(s) **not** credited in the accident analysis of the Safety Analysis Report (SAR/UFSAR). No LOSF exists.

This satisfies Method 3. A LOSF cannot exist if the function is not assumed in the accident analysis of the SAR/UFSAR. For example, the RCIC function is not credited in the accident analysis; therefore, a loss of the RCIC function would not result in a LOSS OF SAFETY FUNCTION.

☐ The inoperable support and supported equipment is part of a system(s) credited in the accident analysis of the Safety Analysis Report (SAR/UFSAR) AND all associated functions required by the accident analysis are intact. No LOSF exists.

This satisfies Method 3. A LOSF cannot exist if the function assumed in the accident analysis of the SAR/UFSAR can be satisfied. An example of this would be inoperable safety related equipment that is in its accident state (i.e., has fulfilled its accident function).

(continued)

B. LOSS OF SAFETY FUNCTION (LOSF) Evaluation (continued)

☐ The SSC is part of a SUPPORT SYSTEM supporting components that results in a LOSF AND the LOSF is solely due to the inoperability of this single Tech Spec SUPPORT SYSTEM LCO. A LOSF exists; however, the appropriate LCO is the LCO for the SUPPORT SYSTEM. Refer to Section C of this Attachment.

ATTACHMENT 1 (Continued)
LOSS OF SAFETY FUNCTION EVALUATION

☐ A LOSF exists in a supported system AND none of the above conditions apply. Refer to Section C of this Attachment.

C. SUPPORTED SYSTEM LOSF

When a LOSF is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the LOSF exists, consideration must be given to the specific type of function affected.

1. SINGLE SUPPORT SYSTEM INOPERABILITY-

   Per the Bases of LCO 3.0.6, when a LOSF is solely due to a single TS SUPPORT SYSTEM (e.g., loss of a pump suction source due to low tank level or loss of automatic actuation/isolation due to inoperable instrumentation) the appropriate LCO is the LCO for the SUPPORT SYSTEM. Multiple inoperable components within the same SUPPORT SYSTEM LCO is considered a single Tech Spec SUPPORT SYSTEM. The Actions for the SUPPORT SYSTEM LCO adequately address the inoperabilities of that system without reliance upon the Actions of the SUPPORTED SYSTEM.

2. MULTIPLE SUPPORT SYSTEM INOPERABILITY-

   When a LOSF is due to multiple TS SUPPORT SYSTEM inoperabilities, the appropriate LCO is the LCO for the SUPPORTED SYSTEMS.

ATTACHMENT 2

SUPPORTED SYSTEM (S) COMPLETION TIME EXTENSIONS

BACKROUND

TS LCO 3.0.2 requires declaring SUPPORTED SYSTEM(S) inoperable if a SUPPORT SYSTEM inoperability renders the SUPPORTED SYSTEM(S) incapable of performing its required function. However, per LCO 3.0.6, the Conditions and Required Actions of the SUPPORTED SYSTEM(S) do not have to be entered except as directed by the SUPPORT SYSTEM'S Required Actions. Consequently, it is possible to have SUPPORTED SYSTEM(S) inoperable for longer periods of time than their respective Completion Time would allow on their own. Per Technical Specification 5.5.12, the SFDP must include measures to ensure that the SUPPORTED SYSTEM(S) Completion Times are not inappropriately extended.

The following two methods are provided for ensuring Completion Times are not inappropriately extended. METHOD 1 applies to SUPPORTED SYSTEM inoperabilities associated with a single SUPPORT SYSTEM inoperability. METHOD 2 is applicable to SUPPORTED SYSTEM inoperabilities due to multiple SUPPORT SYSTEM inoperabilities.

<u>**METHOD 1**</u>

Single SUPPORT SYSTEM inoperable affecting SUPPORTED SYSTEM(S)

1. With a single SUPPORT SYSTEM inoperable, the affected SUPPORTED SYSTEM(S) Conditions and Required Actions are not required to be entered unless directed by the SUPPORT SYSTEM Required Actions.

2. The method to accomplish this will be in the form of a calculated MAXIMUM OUT OF SERVICE TIME (MOST). The MOST will ensure that a time limit is placed on the inoperable SUPPORTED SYSTEM(S) such that if the SUPPORTED SYSTEM(S) becomes inoperable for reasons other than another SUPPORT SYSTEM inoperability, no extension of time is added to the original MOST. MOST is only used when implementing the SFDP.

3. The MOST is calculated in the following manner:

Support LCO Required Action Completion Time	**+**	**Supported LCO Required Action = MOST Completion Time**
Support Train A, LCO AAA (72hrs)	+	Supported Train A, LCO BBB (72 hrs)=144 hrs
	+	Supported Train A, LCO UUU (72 hrs)=144 hrs
	+	Supported Train A, LCO ZZZ (72 hrs)=144 hrs
	+	Supported Train A, LCO RRR (168 hrs) = 240 hrs

ATTACHMENT 2 (Continued)

SUPPORTED SYSTEM (S) COMPLETION TIME EXTENSIONS

EXAMPLE 1- Single SUPPORT SYSTEM(S)

2A RHRSW Pump is declared inoperable. TS LCO 3.7.1 Conditions and Required Actions are entered. A LOSF evaluation is performed and all B train components are verified to be operable. Therefore, TS LCO 3.0.6 and the SFDP can be implemented. All SUPPORTED SYSTEM(S) have been identified and the calculated MOST are as follows:

SUPPORT / SUPPORTED SYSTEM(S)		LCO CONDITION	COMPLETION TIME	MOST
RHRSW SYSTEM	Support	3.7.1 A.1	7days	
RHR Suppression Pool Cooling	Supported	3.6.2.3 A.1	7days	14 days

EXAMPLE 2- Single SUPPORT SYSTEM(S)

A Division 1 ECCS Drywell Pressure High instrument has become inoperable. TS LCO 3.3.5.1 Conditions and Required Actions are entered. A LOSF evaluation is performed and all Division 2 components are verified to be OPERABLE. Therefore, the TS LCO 3.0.6 and the SFDP can be implemented. All SUPPORTED SYSTEM(S) have been identified and the calculated MOST are as follows:

SUPPORT / SUPPORTED SYSTEM(S)		LCO CONDITION	COMPLETION TIME	MOST
Drywell Pressure High	Support	3.3.5.1 B.3	24 HRS	
	Support	3.3.5.1 E.2	8 Days	
	Support	3.3.6.1 A.1	24 HRS	
ECCS SYSTEM (LPCI&LPCS)	Supported	3.5.1. A.1	7 Days	8 Days
ECCS SYSTEM (LPCI&LPCS)	Supported	3.5.1. C.1	72 HRS	96 HRS
A.C. Sources	Supported	3.8.1. B.4	14 Days	15 Days
Degraded Voltage TD Relay	Supported	3.3.8.1 A.1	1 HRS	25 HRS
ECCS SYSTEM (ADS)	Supported	(Operable)		
PCIV (RCIC)	Supported	(Operable)		

ATTACHMENT 2 (Continued)

SUPPORTED SYSTEM (S) COMPLETION TIME EXTENSIONS

METHOD 2

Multiple SUPPORT SYSTEM(S) become INOPERABLE affecting the same SUPPORTED SYSTEM(S)

There may be some cases where two SUPPORT SYSTEMS for a common SUPPORTED SYSTEM become INOPERABLE simultaneously. In this case, the following method should be used to calculate the MOST.

a. The first SUPPORT / SUPPORTED MOST plus an additional 24 hours; or

b. The subsequent SUPPORT / SUPPORTED MOST as measured from discovery of the first SUPPORT SYSTEM inoperability.

EXAMPLE 1- Multiple SUPPORT SYSTEM(S)

Two SUPPORT SYSTEM(S) become INOPERABLE at different times.

1. Systems B and C support System A.
   System B (SUPPORT SYSTEM) becomes inoperable at T = 0 days.

   - System A (SUPPORTED SYSTEM) Completion Time - 3 days
   - System B (SUPPORT SYSTEM) Completion Time - 3 days
   - System C (SUPPORT SYSTEM) Completion Time - 7 days

2. System B (SUPPORT SYSTEM) with a Completion Time of 3 days, renders System A (SUPPORTED SYSTEM) inoperable. Method 1 is applied, which allows an overall MOST of 6 days for System A (SUPPORTED SYSTEM).

3. At T = 1 day, System C (SUPPORT SYSTEM) becomes inoperable and has a Completion Time of 7 days. System C (SUPPORT SYSTEM) also supports System A (SUPPORTED SYSTEM). System B (SUPPORT SYSTEM) continues to remain inoperable through its Completion Time T = 3 days.

4. Once System C (SUPPORT SYSTEM) becomes inoperable concurrent with System B, Method 2 is applied at T=1, the MOST is as follows:

   Method 2a: Original MOST (System A +B) + 24 hours = 7days, OR

   Method 2b: New MOST (System A + C) = 10 days measured from T = 0.

ATTACHMENT 3

SFDP TRACKING WORKSHEET

INSTRUCTIONS

The Safety Function Determination (SFD) Worksheet is used to document the SUPPORTED SYSTEM(S) of an inoperable SUPPORT SYSTEM, track their MAXIMUM OUT OF SERVICE TIME (MOST), and document whether or not a loss of safety function exists. It is also the mechanism for documenting the reevaluation of safety function determinations that are necessary when subsequent LCO's are entered. Enter the following information on the Worksheet.

1. The noun name of the INOPERABLE SUPPORT SYSTEM / component.

2. SUPPORT SYSTEM Tech Spec Condition / Required Action.

3. Date and time of entry into LCO Conditions and Required Actions for the SUPPORT SYSTEM.

4. Completion time allowed for the Required Action of the SUPPORT SYSTEM Tech Spec.

5. The SFD# will be a sequential number (year/unit/ # e.g. 01/01/001).

6. Enter the noun name of each Tech Spec system supported by the INOPERABLE SUPPORT SYSTEM.

7. For each SUPPORTED SYSTEM, list the Tech Spec Condition / Required Action.

8. Record the allowed completion time for the SUPPORTED SYSTEM Required Action.

9. Perform a cross train check (ATTACHMENT 1/ Method 1 and TABLE 1) to verify OPERABILITY of the inoperable SUPPORTED SYSTEM'S redundant equipment, as well as the support features for the redundant equipment. Indicate yes or no in Block 9. If the affected system has no redundant component mark Block 9 "N/A".

ATTACHMENT 3 (Continued)

SFDP TRACKING WORKSHEET

10. Using ATTACHMENT 1, Section B, determine whether or not a LOSF in the SUPPORTED SYSTEM exists. If safety function has been lost, then enter the appropriate Conditions and Required Actions for that system or component using the guidance in ATTACHMENT 1, Section C.

11. If the safety function has not been lost or LOSF is solely due to a single TS SUPPORT SYSTEM, calculate the MAXIMUM OUT OF SERVICE TIME for the SUPPORTED SYSTEM(S). If ATTACHMENT 2 Method 1 is used, this will be the sum of Block 4 and Block 8. If Method 2 is used, see ATTACHMENT 2.

12. Expiration time: Time determined by either Method 1 or 2 of ATTACHMENT 2 measured from the time in Step 3 (Date/Time Entered) in HR: MIN on the MM/DD/YR.

13. The comment block can be used to record any notes or other references. If a LOSF solely due to a single TS SUPPORT SYSTEM exists and it is desired to defer the Conditions and Required Actions of the SUPPORTED SYSTEM(S), enter "Single support system" in this Block.

14. Preparer sign and date.

15. Sign and date for verification of the SFD, indicating that you concur with the listed results.

16. As subsequent inoperabilities occur, all existing SFD's must be reviewed to determine their validity. Record the new LCO Condition and Required Actions and initial and date indicating either yes, the SFD is still valid, or no the SFD is no longer valid. If the SFD is no longer valid based on the new LCO Conditions and Required Actions, a new SFD must be performed. Record the number of the new SFD and attach to the now invalid SFD. Subsequent SFD's done for the same LCO Conditions and Required Actions will be numbered 01-01-001A, 01-01-001B, etc.

17. The SFD may be closed out when the INOPERABLE SUPPORT SYSTEM and SUPPORTED SYSTEM(S) listed on the SFDP Tracking Sheet are returned to OPERABLE STATUS. Enter the Time and Date when the SUPPORT SYSTEM and SUPPORTED SYSTEM(S) are returned to OPERABLE STATUS and sign the Worksheet.

ATTACHMENT 3 (Continued)

SFDP TRACKING WORKSHEET

SUPPORT SYSTEM INOPERABLE

1. System Name / Component ____________________ 2. Tech Spec Condition / Required Action ________________

3. Date / Time Entered ________________ 4. Completion Time ________________ 5. SFD # _____________

SUPPORTED SYSTEMS / COMPONENTS

6. Supported System Name	7. T.S. Condition / Required Action	8. Completion Time	9. Redundant Inoperability?	10. Loss of Safety Function?	11. M.O.S.T.	12. Expiration Time	13. Comments

14. Prepared by: ________________ sign and date

15. Verified by: ________________ sign and date

16. REVIEW FOR SUBSEQUENT INOPERABILITIES (See Attached Worksheet)

17. SFD CLOSE OUT: The SUPPORT SYSTEMS and SUPPORTED SYSTEM(S) listed above have been returned to OPERABLE status

____
Time / Date / Signature

ATTACHMENT 3 (Continued)

SFDP TRACKING WORKSHEET

SFDP REVIEW FOR SUBSEQUENT INOPERABILITIES		
NEW LCO CONDITION #	ALL OPEN SFDPs VALID (Y / N)	VERIFIED BY (INITIAL / DATE)

TABLE 1

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Guidelines for Performing Cross Train Checks

The following matrix is meant to list possible SUPPORT to SUPPORTED LCO relationships for the purpose of implementing the cross train checks as required by LCO 3.0.6. and 5.5.12.

This matrix does **NOT**:

- Cover all possible combinations or permutations of SUPPORT / SUPPORTED LCO relationships.
- Cover SUPPORT / SUPPORTED relationships for items outside of Tech Spec (i.e., room coolers or snubbers).
- Cover SUPPORT / SUPPORTED relationships for LCOs that are **NOT** applicable in a given MODE.
- Cover Technical Requirement Manual LCOs or features.
- Include Support Features and SUPPORTED SYSTEMS if the Required Actions for the INOPERABLE Support Feature direct the entry into the TS ACTIONS for the SUPPORTED SYSTEM.

The purpose behind this matrix is to provide guidance when assessing a LOSF based on SUPPORTED SYSTEM LCOs, due to inoperability of a SUPPORT SYSTEM LCO.

The following minimum items should be considered when evaluating the redundant train:

- Panel Walkdown
- DEL Review
- Schedule Review
- Timeclock board / LCO’s in effect
- Physical walkdown as needed by the CRS
- Any procedural requirements in effect (i.e., VX fans that are shutdown)
- OOS Review
- Configuration Control Log
- TMOD / PMOD’s
- Operability Evaluations

Each situation should be assessed on its own merit, to determine LCO impact.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.3.1.1	Reactor Protection System (RPS) Instrumentation (Refer to Table 2)	3.1.3	Control Rod OPERABILITY
3.3.5.1	Emergency Core Cooling System (ECCS) Instrumentation (Refer to Table 2)	3.3.8.1 3.5.1 3.5.2 3.7.2 3.8.1 3.8.2	LOP Instrumentation* ECCS – Operating ECCS – Shutdown DGCW System* AC Sources – Operating* AC Sources – Shutdown*
3.3.5.2	Reactor Core Isolation Cooling (RCIC) System Instrumentation (Refer to Table 2)	3.5.3	RCIC System
3.3.6.1	Primary Containment Isolation Instrumentation (Refer to Table 2)	3.3.3.1 3.6.1.3	PAM Instrumentation Primary Containment Isolation Valves (PCIVs)
3.3.6.2	Secondary Containment Isolation Instrumentation (Refer to Table 2)	3.6.4.2 3.6.4.3	Secondary Containment Isolation Valves (SCIVs) Standby Gas Treatment (SGT) System
3.3.7.1	Control Room Air Filtration (CRAF) System Instrumentation	3.7.4	Control Room Air Filtration (CRAF) System
3.3.8.1	Loss of Power (LOP) Instrumentation	3.8.1 3.8.2	AC Sources – Operating* AC Sources – Shutdown*

(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.3.8.2	RPS Electric Power Monitoring	3.3.1.1	RPS Instrumentation*
		3.3.2.1	Control Rod Block Instrumentation
		3.3.4.1	EOC-RPT Instrumentation
		3.3.6.1	Primary Containment Isolation Instrumentation*
		3.3.6.2	Secondary Containment Isolation Instrumentation*
		3.6.1.3	Primary Containment Isolation Valves (PCIVs)
3.6.2.2	Suppression Pool Water Level	3.5.1	ECCS –Operating
		3.5.2	ECCS-Shutdown
		3.5.3	RCIC System
		3.6.2.3	RHR Suppression Pool Cooling
		3.6.2.4	RHR Suppression Pool Spray
3.7.1	Residual Heat Removal Service Water (RHRSW) System	3.4.9	RHR Shutdown Cooling System - Hot Shutdown
		3.6.2.3	RHR Suppression Pool Cooling
3.7.3	UHS	3.7.1	RHRSW System*
		3.7.2	DGCW System*

(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	**Support Feature**	**Supported System TS Number**	**Supported System**
3.8.7 (AC Only)	Distribution System – Operating (AC portion Only)	3.1.7	Standby Liquid Control (SLC) System
		3.3.3.1	Post Accident Monitoring (PAM) Instrumentation
		3.3.3.2	Remote Shutdown Monitoring System
		3.3.6.1	Primary Containment Isolation Instrumentation*
		3.3.7.1	Control Room Air Filtration (CRAF) System Instrumentation*
		3.4.7	RCS Leakage Detection Instrumentation
		3.4.9	RHR Shutdown Cooling System - Hot Shutdown
		3.5.1	ECCS – Operating
		3.6.1.3	Primary Containment Isolation Valves (PCIVs)
		3.6.2.3	Residual Heat Removal (RHR) Suppression Pool Cooling
		3.6.2.4	RHR Suppression Pool Spray
			(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.7 (AC Only) (continued)	Distribution System – Operating (AC portion Only)	3.6.4.2	Secondary Containment Isolation Valves (SCIVs)
		3.6.4.3	Standby Gas Treatment (SGT) System
		3.7.1	Residual Heat Removal Service Water (RHRSW) System*
		3.7.2	DGCW System*
		3.7.4	Control Room Air Filtration (CRAF) System
		3.7.5	Control Room Area Ventilation AC System
		3.8.1	AC Sources – Operating*
		3.8.3	Diesel Fuel Oil and Starting Air*
		3.8.4	DC Sources – Operating*

(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.7 (DC Only)	Distribution Systems – Operating (DC Only)	3.3.3.1	Post Accident Monitoring (PAM) Instrumentation
		3.3.3.2	Remote Shutdown Monitoring System
		3.3.4.1	Anticipated Transient Without SCRAM Recirculation Pump Trip (ATWS-RPT) Instrumentation
		3.3.5.1	ECCS Instrumentation*
		3.3.5.2	RCIC System Instrumentation*
		3.3.6.1	Primary Containment Isolation Instrumentation*
		3.3.6.2	Secondary Containment Isolation Instrumentation*
		3.3.8.1	Loss of Power (LOP) System Instrumentation*
		3.3.8.2	Reactor Protection System (RPS) Electric Power Monitoring*
		3.4.9	Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown
		3.5.1	ECCS – Operating
			(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.7 (continued) (DC Only)	Distribution Systems – Operating (DC Portion Only)	3.5.3	RCIC System
		3.6.1.3	Primary Containment Isolation Valves (PCIVs)
		3.6.2.3	Residual Heat Removal (RHR) Suppression Pool Cooling
		3.6.2.4	RHR Suppression Pool Spray
		3.6.4.3	Standby Gas Treatment (SGT) System
		3.7.1	Residual Heat Removal Service Water (RHRSW) System*
		3.7.2	DGCW System*
		3.7.4	Control Room Air Filtration (CRAF) System
		3.7.5	Control Room Area Ventilation AC System
		3.8.1	AC Sources – Operating*

(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.8 (AC Only)	Distribution Systems – Shutdown (AC Portion Only)	3.3.6.1	Primary Containment Isolation Instrumentation*
		3.3.7.1	Control Room Air Filtration (CRAF) System Instrumentation*
		3.4.10	Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown
		3.5.2	ECCS -Shutdown
		3.6.1.3	Primary Containment Isolation Valves (PCIVs)
		3.6.4.2	Secondary Containment Isolation Valves (SCIVs)
		3.6.4.3	Standby Gas Treatment (SGT) System
		3.7.4	Control Room Area Filtration (CRAF) System
		3.7.5	Control Room Area Ventilation AC System
		3.8.2	AC Sources – Shutdown*
		3.8.3	Diesel Fuel Oil and Starting Air*
			(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.8 (AC Only) (continued)	Distribution Systems – Shutdown (AC Portion Only)	3.8.5	DC Sources – Shutdown*
		3.9.8	Residual Heat Removal (RHR) - High Water Level
		3.9.9	Residual Heat Removal (RHR) - Low Water Level
3.8.8 (DC Only)	Distribution Systems – Shutdown (DC Portion Only)	3.3.5.1	ECCS Instrumentation*
		3.3.6.1	Primary Containment Isolation Instrumentation*
		3.3.6.2	Secondary Containment Isolation Instrumentation*
		3.3.8.1	LOP Instrumentation*
		3.3.8.2	RPS Electric Power Monitoring*
		3.4.10	RHR Shutdown Cooling System - Cold Shutdown
		3.5.2	ECCS - Shutdown
		3.6.1.3	Primary Containment Isolation Valves (PCIVs)
		3.6.4.3	SGT System
		3.7.4	CRAF System
			(continued)

* - System is also a support system.

TABLE 1 (Continued)

SUPPORT – SUPPORTED LCO RELATIONSHIPS

Support Feature TS Number	Support Feature	Supported System TS Number	Supported System
3.8.8 (DC Only) (continued)	Distribution Systems – Shutdown (DC Portion Only)	3.7.5 3.9.8 3.9.9	Control Room Area Ventilation AC System Residual Heat Removal (RHR) - High Water Level Residual Heat Removal (RHR) - Low Water Level

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.1.1 Function 1.a and 1.b (Same instruments used for TLCO 3.3.c)	1(2)C51-N002A/K601A (A1) 1(2)C51-N002E/K601E (A1) 1(2)C51-N002C/K601C (A2) 1(2)C51-N002G/K601G (A2) 1(2)C51-N002B/K601B (B1) 1(2)C51-N002F/K601F (B1) 1(2)C51-N002D/K601D (B2) 1(2)C51-N002H/K601H (B2)	One A1 OR One A2 AND One B1 OR One B2	Function 1.a All Control Rods (3.1.3) Function 1.b No credit taken in accident analysis, no OPERABILITY impact on supported equipment.
3.3.1.1 Function 2.a, 2.b, 2.c, and 2.d (Same instruments used for LCO 3.3.2.1 and TLCO 3.3.c)	1(2)C51-K605GM APRM A (A1) 1(2)C51-K605GP APRM C (A2) 1(2)C51-K605GS APRM E (A1 and A2) 1(2)C51-K605GW Flow Unit A* 1(2)C51-K605HA Flow Unit C* 1(2)C51-K605GN APRM B (B1) 1(2)C51-K605GR APRM D (B2) 1(2)C51-K605GT APRM F (B1 and B2) 1(2)C51-K605GX Flow Unit B* 1(2)C51-K605HB Flow Unit D* * - affects Function 2.b only	One A1 OR One A2 AND One B1 OR One B2	Function 2.a and 2.c All Control Rods (3.1.3) Function 2.b and 2.d No credit taken in accident analysis, no OPERABILITY impact on supported equipment.
3.3.1.1 Function 3	1(2)B21-N023AA (A1) 1(2)B21-N023C (A2) 1(2)B21-N023BA (B1) 1(2)B21-N023D (B2)	A1 OR A2 AND B1 OR B2	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.1.1 Function 4 (Same instruments used for LCO 3.3.6.1 Functions 2.f and 5.a)	1(2)B21-N403A/N703A (A1) 1(2)B21-N403C/N703C (A2) 1(2)B21-N403B/N703B (B1) 1(2)B21-N403D/N703D (B2)	A1 OR A2 AND B1 OR B2	All Control Rods (3.1.3)
3.3.1.1 Function 5	1(2)B21-F022A LS-4 (A1) 1(2)B21-F028A LS-4 (A1) 1(2)B21-F022B LS-4 (A1) 1(2)B21-F028B LS-4 (A1) 1(2)B21-F022C LS-4 (A2) 1(2)B21-F028C LS-4 (A2) 1(2)B21-F022D LS-4 (A2) 1(2)B21-F028D LS-4 (A2) 1(2)B21-F022A LS-2 (B1) 1(2)B21-F028A LS-2 (B1) 1(2)B21-F022C LS-2 (B1) 1(2)B21-F028C LS-2 (B1) 1(2)B21-F022B LS-2 (B2) 1(2)B21-F028B LS-2 (B2) 1(2)B21-F022D LS-2 (B2) 1(2)B21-F028D LS-2 (B2)	Two A1 OR Two A2 AND Two B1 OR Two B2 Note: to generate a trip in a single trip system (e.g., A1), the two instrument signals must be from different MSLs.	All Control Rods (3.1.3)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.1.1 Function 6 (Same instruments used for LCO 3.3.6.1 Function 2.b and LCO 3.3.6.2 Function 2)	1(2)C71-N002A (A1) 1(2)C71-N002C (A2) 1(2)C71-N002B (B1) 1(2)C71-N002D (B2)	A1 <u>OR</u> A2 <u>AND</u> B1 <u>OR</u> B2	All Control Rods (3.1.3)
3.3.1.1 Function 7.a and 7.b	1(2)C11-N013A (A1) 1(2)C11-N012A/N601A (A1) 1(2)C11-N013C (A2) 1(2)C11-N012C/N601C (A2) 1(2)C11-N013B (B1) 1(2)C11-N012B/N601B (B1) 1(2)C11-N013D (B2) 1(2)C11-N012D/N601D (B2)	One A1 <u>OR</u> One A2 <u>AND</u> One B1 <u>OR</u> One B2	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.
3.3.1.1 Function 8	1(2)C71-N006A TSV-1 (A1) 1(2)C71-N006E TSV-2 (A1)* 1(2)C71-N006C TSV-3 (A2)* 1(2)C71-N006G TSV-4 (A2) 1(2)C71-N006B TSV-1 (B1)* 1(2)C71-N006F TSV-3 (B1) 1(2)C71-N006D TSV-2 (B2) 1(2)C71-N006H TSV-4 (B2)* * - Same instrument used for LCO 3.3.4.1	Both A1 <u>OR</u> Both A2 <u>AND</u> Both B1 <u>OR</u> Both B2	All Control Rods (3.1.3)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.1.1 Function 9 (Same instruments used for LCO 3.3.4.1)	1(2)C71-N005A (A1) 1(2)C71-N005C (A2) 1(2)C71-N005B (B1) 1(2)C71-N005D (B2)	A1 <u>OR</u> A2 <u>AND</u> B1 <u>OR</u> B2	All Control Rods (3.1.3)
3.3.1.1 Functions 10 and 11	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.5.1 Function 1.a (Same instruments used for LCO 3.3.5.1 Function 4.a)	1(2)B21-N407A*/N707A 1(2)B21-N407C*/N707C * - Same instrument used for LCO 3.3.5.2 Function 1	2 of 2	LPCS Subsystem (3.5.1, 3.5.2) LPCI A Subsystem (3.5.1, 3.5.2) 0 DGCW Pump (3.7.2, 3.7.b) 0 DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 1.e) Thermal O/L Bypass (3.8.c) for: 1(2)E12-F011A 1(2)E12-F016A 1(2)E12-F017A 1(2)E12-F024A 1(2)E12-F026A 1(2)E12-F027A 1(2)E12-F042A 1(2)E12-F048A 1(2)E12-F052A 1(2)E12-F064A 1(2)E12-F087A 1(2)E21-F005 1(2)E21-F012

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 1.b (Same instruments used for LCO 3.3.5.1 Function 4.b and LCO 3.3.6.1 Function 3.i)	1(2)B21-N048A 1(2)B21-N048C	2 of 2	LPCS Subsystem (3.5.1, 3.5.2) LPCI A Subsystem (3.5.1, 3.5.2) 0 DGCW Pump (3.7.2, 3.7.b) 0 DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 1.e) Thermal O/L Bypass (3.8.c) for: 1(2)E12-F011A 1(2)E12-F016A 1(2)E12-F017A 1(2)E12-F024A 1(2)E12-F026A 1(2)E12-F027A 1(2)E12-F042A 1(2)E12-F048A 1(2)E12-F052A 1(2)E12-F064A 1(2)E12-F087A 1(2)E21-F005 1(2)E21-F012
3.3.5.1 Function 1.c (Same relay is used for LCO 3.8.1 and LCO 3.8.2. See SR 3.8.1.18)	1(2)E12A-K70A	1 of 1	LPCI A Subsystem (3.5.1, 3.5.2)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 1.d	1(2)B21-N413A 1(2)B21-N413C	1 of 2	LPCS Subsystem (3.5.1, 3.5.2) LPCI A Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 1.e	1(2)E21-N004	1 of 1	LPCS Subsystem (3.5.1, 3.5.2) Thermal O/L Bypass (3.8.c) for: 1(2)E21-F011
3.3.5.1 Function 1.f	1(2)E12-N010AA	1 of 1	LPCI A Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 1.g	1(2)E21-N413 1(2)E12-N413A	1 of 1 1 of 1	LPCS Subsystem (3.5.1, 3.5.2) LPCI A Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 1.h	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.5.1 Function 2.a (Same instruments used for LCO 3.3.5.1 Function 5.a)	1(2)B21-N407B*/N707B 1(2)B21-N407D*/N707D * - Same instrument used for LCO 3.3.5.2 Function 1	2 of 2	LPCI B Subsystem (3.5.1, 3.5.2) LPCI C Subsystem (3.5.1, 3.5.2) 1(2)A DGCW Pump (3.7.2, 3.7.b) 1(2)A DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 1.e) Thermal O/L Bypass (3.8.c) for: 1(2)E12-F011B 1(2)E12-F016B 1(2)E12-F017B 1(2)E12-F021

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 2.a (continued)			Thermal O/L Bypass (3.8.c) for: 1(2)E12-F024B 1(2)E12-F026B 1(2)E12-F027B 1(2)E12-F042B 1(2)E12-F042C 1(2)E12-F048B 1(2)E12-F052B 1(2)E12-F064B 1(2)E12-F064C 1(2)E12-F087B
3.3.5.1 Function 2.b (Same instruments used for LCO 3.3.5.1 Function 5.b and LCO 3.3.6.1 Function 3.i)	1(2)B21-N048B 1(2)B21-N048D	2 of 2	LPCI B Subsystem (3.5.1, 3.5.2) LPCI C Subsystem (3.5.1, 3.5.2) 1(2)A DGCW Pump (3.7.2, 3.7.b) 1(2)A DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 1.e) Thermal O/L Bypass (3.8.c) for: 1(2)E12-F011B 1(2)E12-F016B 1(2)E12-F017B 1(2)E12-F021 1(2)E12-F024B 1(2)E12-F026B 1(2)E12-F027B

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 2.b (continued)			Thermal O/L Bypass (3.8.c) for: 1(2)E12-F042B 1(2)E12-F042C 1(2)E12-F048B 1(2)E12-F052B 1(2)E12-F064B 1(2)E12-F064C 1(2)E12-F087B
3.3.5.1 Function 2.c	1(2)E12A-K70B	1 of 1	LPCI B Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 2.d	1(2)B21-N413B 1(2)B21-N413D	1 of 2	LPCI B Subsystem (3.5.1, 3.5.2) LPCI C Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 2.e	1(2)E12-N010BA	1 of 1	LPCI B Subsystem (3.5.1, 3.5.2)
	1(2)E12-N010CA	1 of 1	LPCI C Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 2.f	1(2)E12-N413B	1 of 1	LPCI B Subsystem (3.5.1, 3.5.2)
	1(2)E12-N413C	1 of 1	LPCI C Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 2.g	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 3.a	1(2)B21-N406A/N706A 1(2)B21-N406B/N706B 1(2)B21-N406C/N706C 1(2)B21-N406D/N706D Note: Channels A and B comprise one set of parallel contacts and Channels C and D comprise the other set.	A OR B AND C OR D	HPCS Subsystem (3.5.1, 3.5.2) 1(2)B DGCW Pump (3.7.2, 3.7.b) 1(2)B DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 2.e) Thermal O/L Bypass (3.8.c) for: 1(2)E22-F004 1(2)E22-F012 1(2)E22-F023
3.3.5.1 Function 3.b	1(2)B21-N047A 1(2)B21-N047B 1(2)B21-N047C 1(2)B21-N047D Note: Channels A and B comprise one set of parallel contacts and Channels C and D comprise the other set.	A OR B AND C OR D	HPCS Subsystem (3.5.1, 3.5.2) 1(2)B DGCW Pump (3.7.2, 3.7.b) 1(2)B DG (3.8.1, 3.8.2) Time Delay (3.3.8.1 Function 2.e) Thermal O/L Bypass (3.8.c) for: 1(2)E22-F004 1(2)E22-F012 1(2)E22-F023
3.3.5.1 Function 3.c	1(2)B21-N409A/N709A 1(2)B21-N409B/N709B	2 of 2	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.
3.3.5.1 Function 3.d	1(2)E22-N012A	1 of 1	HPCS Subsystem (3.5.1, 3.5.2)
3.3.5.1 Function 3.e	1(2)E22-N006	1 of 1	HPCS Subsystem (3.5.1, 3.5.2)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 3.f	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.5.1 Function 4.a (Same instruments used for LCO 3.3.5.1 Function 1.a)	1(2)B21-N407A*/N707A (A) 1(2)B21-N407C*/N707C (C) * - Same instrument used for LCO 3.3.5.2 Function 1	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 4.b (Same instruments used for LCO 3.3.5.1 Function 1.b and LCO 3.3.6.1 Function 3.i)	1(2)B21-N048A (A) 1(2)B21-N048C (C)	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 4.c	1(2)B21C-K35A (A)	1 of 1	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 4.d	1(2)B21-N408A/N708A (A)	1 of 1	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 4.e and 3.3.5.1 Function 4.f	1(2)E21-N001 (C) 1(2)E21-N009 (A) 1(2)E12-N016A (A) 1(2)E12-N019A (C)	One Logic System A instrument AND One Logic System C instrument	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 4.g	1(2)B21C-K36A (A) 1(2)B21C-K37A (C)	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 4.h	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.5.1 Function 5.a (Same instruments used for LCO 3.3.5.1 Function 2.a)	1(2)B21-N407B*/N707B (B) 1(2)B21-N407D*/N707D (D) * - Same instrument used for LCO 3.3.5.2 Function 1	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 5.b (Same instruments used for LCO 3.3.5.1 Function 2.b and LCO 3.3.6.1 Function 3.i)	1(2)B21-N048B (B) 1(2)B21-N048D (D)	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.1 Function 5.c	1(2)B21C-K35B (B)	1 of 1	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 5.d	1(2)B21-N408B/N708B (B)	1 of 1	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 5.e	1(2)E12-N016B (B) 1(2)E12-N016C (B) 1(2)E12-N019B (D) 1(2)E12-N019C (D)	One Logic System B instrument AND One Logic System D instrument	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 5.f	1(2)B21C-K36B (B) 1(2)B21C-K37B (D)	2 of 2	ADS Valves (3.5.1) Note: Either Trip System A or Trip System B will actuate ADS valves.
3.3.5.1 Function 5.g	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.5.2 Function 1	1(2)B21-N407A*/N710A 1(2)B21-N407B*/N710B 1(2)B21-N407C*/N710C 1(2)B21-N407D*/N710D Note: Channels A and B comprise one set of parallel contacts and Channels C and D comprise the other set. * - Same instruments used for LCO 3.3.5.1 Functions 1.a, 2.a, 4.a, and 5.a	A OR B AND C OR D	RCIC System (3.5.3) Thermal O/L Bypass (3.8.c) for: 1(2)E51-F010 1(2)E51-F013 1(2)E51-F022 1(2)E51-F045 1(2)E51-F046 1(2)E51-F059 1(2)E51-F360
3.3.5.2 Function 2	1(2)B21-N405A*/N705A* 1(2)B21-N405B/N705B * - Same instruments used for LCO 3.3.2.2	2 of 2	RCIC System (3.5.3)
3.3.5.2 Function 3	1(2)E51-N035A 1(2)E51-N035E	1 of 2	RCIC System (3.5.3) Note: No OPERABILITY impact if RCIC suction is aligned to the Suppression Pool.
3.3.5.2 Function 4	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 1.a (Same instruments used for LCO 3.3.6.1 Function 2.e)	1(2)B21-N402A*/702A (A) 1(2)B21-N402B*/702B (B) 1(2)B21-N402C*/702C (C) 1(2)B21-N402D*/702D (D) * - Same instrument used for LCO 3.3.6.1 Functions 2.a and 4.k, and LCO 3.3.6.2 Function 1	MSIVs: A OR C AND B OR D MSL Drains Outbd: A AND B MSL Drains Inbd: C AND D	1(2)B21-F022A,B,C,D (3.6.1.3) 1(2)B21-F028A,B,C,D (3.6.1.3) Valves and Thermal O/L Bypass 1(2)B21-F019 (3.6.1.3, 3.8.c) 1(2)B21-F067A,B (3.6.1.3, 3.8.c) 1(2)B21-F067C,D (3.6.1.3, 3.8.c) Valves and Thermal O/L Bypass 1(2)B21-F016 (3.6.1.3, 3.8.c)
3.3.6.1 Function 1.b	1(2)B21-N015A (A) 1(2)B21-N015B (B) 1(2)B21-N015C (C) 1(2)B21-N015D (D)	MSIVs: A OR C AND B OR D MSL Drains Outbd: A AND B MSL Drains Inbd: C AND D	1(2)B21-F022A,B,C,D (3.6.1.3) 1(2)B21-F028A,B,C,D (3.6.1.3) Valves and Thermal O/L Bypass 1(2)B21-F019 (3.6.1.3, 3.8.c) 1(2)B21-F067A,B (3.6.1.3, 3.8.c) 1(2)B21-F067C,D (3.6.1.3, 3.8.c) Valves and Thermal O/L Bypass 1(2)B21-F016 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 1.c	A MSL: 1(2)E31-N008A (A) 1(2)E31-N008B (B) 1(2)E31-N008C (C) 1(2)E31-N008D (D) B MSL: 1(2)E31-N009A (A) 1(2)E31-N009B (B) 1(2)E31-N009C (C) 1(2)E31-N009D (D) C MSL: 1(2)E31-N010A (A) 1(2)E31-N010B (B) 1(2)E31-N010C (C) 1(2)E31-N010D (D) D MSL: 1(2)E31-N011A (A) 1(2)E31-N011B (B) 1(2)E31-N011C (C) 1(2)E31-N011D (D)	MSIVs: A OR C AND B OR D MSL Drains Outbd: A AND B MSL Drains Inbd: C AND D	1(2)B21-F022A,B,C,D (3.6.1.3) 1(2)B21-F028A,B,C,D (3.6.1.3) Valves and Thermal O/L Bypass 1(2)B21-F019 (3.6.1.3, 3.8.c) 1(2)B21-F067A,B (3.6.1.3, 3.8.c) 1(2)B21-F067C,D (3.6.1.3, 3.8.c) Valves and Thermal O/L Bypass 1(2)B21-F016 (3.6.1.3, 3.8.c) Note: Supported components must be able to isolate on a high steam flow condition from each MSL to be considered OPERABLE.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 1.d	1(2)B21-N056A (A) 1(2)B21-N056B (B) 1(2)B21-N056C (C) 1(2)B21-N056D (D)	MSIVs: A OR C AND B OR D	1(2)B21-F022A,B,C,D (3.6.1.3) 1(2)B21-F028A,B,C,D (3.6.1.3)
		MSL Drains Outbd: A AND B	Valves and Thermal O/L Bypass 1(2)B21-F019 (3.6.1.3, 3.8.c) 1(2)B21-F067A,B (3.6.1.3, 3.8.c) 1(2)B21-F067C,D (3.6.1.3, 3.8.c)
		MSL Drains Inbd: C AND D	Valves and Thermal O/L Bypass 1(2)B21-F016 (3.6.1.3, 3.8.c)
3.3.6.1 Function 1.e	1(2)E31-N029A/30A/R001A-3 (A) 1(2)E31-N029B/30B/R002A-3 (B) 1(2)E31-N029C/30C/R001C-3 (C) 1(2)E31-N029D/30D/R002C-3 (D)	MSIVs: A OR C AND B OR D	1(2)B21-F022A,B,C,D (3.6.1.3) 1(2)B21-F028A,B,C,D (3.6.1.3)
		MSL Drains Outbd: A AND B	Valves and Thermal O/L Bypass 1(2)B21-F019 (3.6.1.3, 3.8.c) 1(2)B21-F067A,B (3.6.1.3, 3.8.c) 1(2)B21-F067C,D (3.6.1.3, 3.8.c)
		MSL Drains Inbd: C AND D	Valves and Thermal O/L Bypass 1(2)B21-F016 (3.6.1.3, 3.8.c)
3.3.6.1 Function 1.f	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.a (Same instruments used for LCO 3.3.6.1 Function 4.k and LCO 3.3.6.2 Function 1)	1(2)B21-N402A*/704A (A) 1(2)B21-N402B*/704B (B) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Groups 3 and 2 (except WR and VP) Outbd: A <u>AND</u> B	1(2)B33-F020 (3.6.1.3) 1(2)B33-F339A,B (3.6.1.3) 1(2)B33-F341A,B (3.6.1.3) 1(2)B33-F343A,B (3.6.1.3) 1(2)B33-F345A,B (3.6.1.3) 1(2)CM-018A,B (3.6.1.3) 1(2)CM-019A,B (3.6.1.3) 1(2)CM-022A (3.6.1.3) 1(2)CM-025A (3.6.1.3) 1(2)CM-028 (3.6.1.3) 1(2)CM-030 (3.6.1.3) 1(2)CM-032 (3.6.1.3) 1(2)CM-033 (3.6.1.3) 1(2)RE-025 (3.6.1.3) 1(2)RE-029 (3.6.1.3) 1(2)RF-013 (3.6.1.3) A H2/O2 Analyzer (3.3.3.1)
	1(2)B21-N402C*/704C (C) 1(2)B21-N402D*/704D (D) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Groups 3 and 2 (except WR and VP) Inbd: C <u>AND</u> D	1(2)B21-F032A,B (3.6.1.3) 1(2)B33-F019 (3.6.1.3) 1(2)B33-F338A,B (3.6.1.3) 1(2)B33-F340A,B (3.6.1.3) 1(2)B33-F342A,B (3.6.1.3) 1(2)B33-F344A,B (3.6.1.3) 1(2)CM-017A,B (3.6.1.3) 1(2)CM-020A,B (3.6.1.3)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.a (continued)			1(2)CM-021B (3.6.1.3) 1(2)CM-026B (3.6.1.3) 1(2)CM-027 (3.6.1.3) 1(2)CM-029 (3.6.1.3) 1(2)CM-031 (3.6.1.3) 1(2)CM-034 (3.6.1.3) 1(2)IN-031 (3.6.1.3) 1(2)RE-024 (3.6.1.3) 1(2)RE-026 (3.6.1.3) 1(2)RF-012 (3.6.1.3) B H2/O2 Analyzer (3.3.3.1)
	1(2)B21-N402A*/704A (A) 1(2)B21-N402D*/704D (D) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Groups 4 and 2 (WR and VP only) Outbd: A <u>AND</u> D	Valves and Thermal O/L Bypass 1(2)VP-053A,B (3.6.1.3, 3.8.c) 1(2)VP-063A,B (3.6.1.3, 3.8.c) 1(2)WR-029 (3.6.1.3, 3.8.c) 1(2)WR-040 (3.6.1.3, 3.8.c) 1(2)VQ-026 (3.6.1.3) 1(2)VQ-029 (3.6.1.3) 1(2)VQ-036 (3.6.1.3) 1(2)VQ-040 (3.6.1.3) 1(2)VQ-042 (3.6.1.3) 1(2)VQ-043 (3.6.1.3) 1(2)VQ-048 (3.6.1.3, 3.8.c) 1(2)VQ-051 (3.6.1.3, 3.8.c) 1(2)VQ-068 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.a (continued)	1(2)B21-N402B*/704B (B) 1(2)B21-N402C*/704C (C) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Groups 4 and 2 (WR and VP only) Inbd: B AND C	Valves and Thermal O/L Bypass 1(2)VP-113A,B (3.6.1.3, 3.8.c) 1(2)VP-114A,B (3.6.1.3, 3.8.c) 1(2)WR-179 (3.6.1.3, 3.8.c) 1(2)WR-180 (3.6.1.3, 3.8.c) 1(2)VQ-027 (3.6.1.3) 1(2)VQ-030 (3.6.1.3) 1(2)VQ-031 (3.6.1.3) 1(2)VQ-032 (3.6.1.3, 3.8.c) 1(2)VQ-034 (3.6.1.3) 1(2)VQ-035 (3.6.1.3, 3.8.c) 1(2)VQ-047 (3.6.1.3, 3.8.c) 1(2)VQ-050 (3.6.1.3, 3.8.c)
3.3.6.1 Function 2.b (Same instruments used for LCO 3.3.1.1 Function 6 and LCO 3.3.6.2 Function 2)	1(2)C71-N002A (A) 1(2)C71-N002B (B)	Groups 7, 10, and 2 (except WR and VP) Outbd: A AND B	1(2)IN-001B (3.6.1.3) 1(2)IN-075 (3.6.1.3) 1(2)B33-F339A,B (3.6.1.3) 1(2)B33-F341A,B (3.6.1.3) 1(2)B33-F343A,B (3.6.1.3) 1(2)B33-F345A,B (3.6.1.3) 1(2)CM-018A,B (3.6.1.3) 1(2)CM-019A,B (3.6.1.3) 1(2)CM-022A (3.6.1.3) 1(2)CM-025A (3.6.1.3) (continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.b (continued)			1(2)CM-028 (3.6.1.3) 1(2)CM-030 (3.6.1.3) 1(2)CM-032 (3.6.1.3) 1(2)CM-033 (3.6.1.3) 1(2)RE-025 (3.6.1.3) 1(2)RE-029 (3.6.1.3) 1(2)RF-013 (3.6.1.3) A H2/O2 Analyzer (3.3.3.1) Thermal O/L Bypass for: 1(2)E12-F040A,B (3.8.c)
(Same instruments used for LCO 3.3.1.1 Function 6 and LCO 3.3.6.2 Function 2)	1(2)C71-N002C (C) 1(2)C71-N002D (D)	Groups 7, 10, and 2 (except WR and VP) Inbd: C <u>AND</u> D	1(2)B21-F032A,B 1(2)B33-F338A,B (3.6.1.3) 1(2)B33-F340A,B (3.6.1.3) 1(2)B33-F342A,B (3.6.1.3) 1(2)B33-F344A,B (3.6.1.3) 1(2)CM-017A,B (3.6.1.3) 1(2)CM-020A,B (3.6.1.3) 1(2)CM-021B (3.6.1.3) 1(2)CM-026B (3.6.1.3) 1(2)CM-027 (3.6.1.3) 1(2)CM-029 (3.6.1.3) 1(2)CM-031 (3.6.1.3) 1(2)CM-034 (3.6.1.3) 1(2)IN-001A (3.6.1.3) 1(2)IN-017 (3.6.1.3)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.b (continued)			1(2)IN-031 (3.6.1.3) 1(2)IN-074 (3.6.1.3) 1(2)RE-024 (3.6.1.3) 1(2)RE-026 (3.6.1.3) 1(2)RF-012 (3.6.1.3) TIP Ball Valves B H2/O2 Analyzer (3.3.3.1) Thermal O/L Bypass for: 1(2)E12-F049A,B 1(2)E12-F099A,B
(Same instruments used for LCO 3.3.1.1 Function 6 and LCO 3.3.6.2 Function 2)	1(2)C71-N002A (A) 1(2)C71-N002D (D)	Groups 4 and 2 (WR and VP only) Outbd: A AND D	Valves and Thermal O/L Bypass 1(2)VP-053A,B (3.6.1.3, 3.8.c) 1(2)VP-063A,B (3.6.1.3, 3.8.c) 1(2)WR-029 (3.6.1.3, 3.8.c) 1(2)WR-040 (3.6.1.3, 3.8.c) 1(2)VQ-026 (3.6.1.3) 1(2)VQ-029 (3.6.1.3) 1(2)VQ-036 (3.6.1.3) 1(2)VQ-040 (3.6.1.3) 1(2)VQ-042 (3.6.1.3) 1(2)VQ-043 (3.6.1.3) 1(2)VQ-048 (3.6.1.3, 3.8.c) 1(2)VQ-051 (3.6.1.3, 3.8.c) 1(2)VQ-068 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.b (continued) (Same instruments used for LCO 3.3.1.1 Function 6 and LCO 3.3.6.2 Function 2)	1(2)C71-N002B (B) 1(2)C71-N002C (C)	Groups 4 and 2 (WR and VP only) Inbd: B <u>AND</u> C	Valves and Thermal O/L Bypass 1(2)VP-113A,B (3.6.1.3, 3.8.c) 1(2)VP-114A,B (3.6.1.3, 3.8.c) 1(2)WR-179 (3.6.1.3, 3.8.c) 1(2)WR-180 (3.6.1.3, 3.8.c) 1(2)VQ-027 (3.6.1.3) 1(2)VQ-030 (3.6.1.3) 1(2)VQ-031 (3.6.1.3) 1(2)VQ-032 (3.6.1.3, 3.8.c) 1(2)VQ-034 (3.6.1.3) 1(2)VQ-035 (3.6.1.3, 3.8.c) 1(2)VQ-047 (3.6.1.3, 3.8.c) 1(2)VQ-050 (3.6.1.3, 3.8.c)
3.3.6.1 Function 2.c (Same instruments used for LCO 3.3.6.2 Function 3)	1(2)D18-N009A/K609A (A) 1(2)D18-N009B/K609B (B)	Group 4 Outbd: A <u>AND</u> B	Valves and Thermal O/L Bypass 1(2)VQ-026 (3.6.1.3) 1(2)VQ-029 (3.6.1.3) 1(2)VQ-036 (3.6.1.3) 1(2)VQ-040 (3.6.1.3) 1(2)VQ-042 (3.6.1.3) 1(2)VQ-043 (3.6.1.3) 1(2)VQ-048 (3.6.1.3, 3.8.c) 1(2)VQ-051 (3.6.1.3, 3.8.c) 1(2)VQ-068 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.c (continued) (Same instruments used for LCO 3.3.6.2 Function 3)	1(2)D18-N009C/K609C (C) 1(2)D18-N009D/K609D (D)	Group 4 Inbd: C <u>AND</u> D	Valves and Thermal O/L Bypass 1(2)VQ-027 (3.6.1.3) 1(2)VQ-030 (3.6.1.3) 1(2)VQ-031 (3.6.1.3) 1(2)VQ-032 (3.6.1.3, 3.8.c) 1(2)VQ-034 (3.6.1.3) 1(2)VQ-035 (3.6.1.3, 3.8.c) 1(2)VQ-047 (3.6.1.3, 3.8.c) 1(2)VQ-050 (3.6.1.3, 3.8.c)
3.3.6.1 Function 2.d (Same instruments used for LCO 3.3.6.2 Function 4)	1(2)D18-N015A/K615A (A) 1(2)D18-N015B/K615B (B)	Group 4 Outbd: A <u>AND</u> B	Valves and Thermal O/L Bypass 1(2)VQ-026 (3.6.1.3) 1(2)VQ-029 (3.6.1.3) 1(2)VQ-036 (3.6.1.3) 1(2)VQ-040 (3.6.1.3) 1(2)VQ-042 (3.6.1.3) 1(2)VQ-043 (3.6.1.3) 1(2)VQ-048 (3.6.1.3, 3.8.c) 1(2)VQ-051 (3.6.1.3, 3.8.c) 1(2)VQ-068 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.d (continued) (Same instruments used for LCO 3.3.6.2 Function 4)	1(2)D18-N015C/K615C (C) 1(2)D18-N015D/K615D (D)	Group 4 Inbd: C AND D	Valves and Thermal O/L Bypass 1(2)VQ-027 (3.6.1.3) 1(2)VQ-030 (3.6.1.3) 1(2)VQ-031 (3.6.1.3) 1(2)VQ-032 (3.6.1.3, 3.8.c) 1(2)VQ-034 (3.6.1.3) 1(2)VQ-035 (3.6.1.3, 3.8.c) 1(2)VQ-047 (3.6.1.3, 3.8.c) 1(2)VQ-050 (3.6.1.3, 3.8.c)
3.3.6.1 Function 2.e (Same instruments used for LCO 3.3.6.1 Function 1.a)	1(2)B21-N402A*/702A (A) 1(2)B21-N402B*/702B (B) 1(2)B21-N402C*/702C (C) 1(2)B21-N402D*/702D (D) * - Same instrument used for LCO 3.3.6.1 Functions 2.a and 4.k, and LCO 3.3.6.2 Function 1	Group 10 Outbd: A AND B Group 10 Inbd: C AND D	1(2)IN-001B (3.6.1.3) 1(2)IN-075 (3.6.1.3) 1(2)IN-001A (3.6.1.3) 1(2)IN-017 (3.6.1.3) 1(2)IN-074 (3.6.1.3)
3.3.6.1 Function 2.f (Same instruments used for LCO 3.3.1.1 Function 4 and LCO 3.3.6.1 Function 5.a)	1(2)B21-N403A/N703A (A) 1(2)B21-N403B/N703B (B) 1(2)B21-N403C/N703C (C) 1(2)B21-N403D/N703D (D)	Group 7 Outbd: A AND B Group 7 Inbd: C AND D	Thermal O/L Bypass for 1(2)E12-F040A,B (3.8.c) TIP Ball Valves (3.6.1.3) Thermal O/L Bypass for 1(2)E12-F049A,B (3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 2.g	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.6.1 Function 3.a	1(2)E31-N013AA (Div 1/Outbd)	Group 8 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E31-N013BA (Div 2/Inbd)	Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.b	1(2)E51A-K47 (Div 1/Outbd)	Group 8 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E51A-K48 (Div 2/Inbd)	Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.c	1(2)E31-N022A (Div 1/Outbd) 1(2)E31-N022C (Div 1/Outbd)	Group 8 Outbd: 2 of 2	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E31-N022B (Div 2/Inbd) 1(2)E31-N022D (Div 2/Inbd)	Group 8 Inbd: 2 of 2	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
	1(2)E31-N022A (Div 1/Outbd) 1(2)E31-N022C (Div 1/Outbd)	Group 9 Outbd: 1 of 2	Valve and Thermal O/L Bypass 1(2)E51-F080 (3.6.1.3, 3.8.c)
	1(2)E31-N022B (Div 2/Inbd) 1(2)E31-N022D (Div 2/Inbd)	Group 9 Inbd: 1 of 2	Valve and Thermal O/L Bypass 1(2)E51-F086 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 3.d	1(2)E51-N012A (Div 1/Outbd) 1(2)E51-N012C (Div 1/Outbd)	Group 8 Outbd: 2 of 2	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E51-N012B (Div 2/Inbd) 1(2)E51-N012D (Div 2/Inbd)	Group 8 Inbd: 2 of 2	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.e	1(2)E31-N004A/R001C-5 (Div 1/Outbd)	Group 8 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E31-N004B/R002C-5 (Div 2/Inbd)	Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.f	1(2)E31-N005A/6A/R001C-7 (Div 1/Outbd)	Group 8 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E31-N005B/6B/R002C-7 (Div 2/Inbd)	Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.g	1(2)E31-N024A/R001C-9 (Div 1/Outbd)	Group 8 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c)
	1(2)E31-N024B/R002C-9 (Div 2/Inbd)	Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 3.h	1(2)E31-N025A/26A/R001C-11 (Div 1/Outbd) 1(2)E31-N025B/26B/R002C-11 (Div 2/Inbd)	Group 8 Outbd: 1 of 1 Group 8 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E51-F008 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)E51-F063 (3.6.1.3, 3.8.c) 1(2)E51-F076 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.i (Same instruments used for LCO 3.3.5.1 Functions 1.b, 2.b, 4.b and 5.b)	1(2)B21-N048A (Div 1/Outbd) 1(2)B21-N048C (Div 1/Outbd) 1(2)B21-N048B (Div 2/Inbd) 1(2)B21-N048D (Div 2/Inbd)	Group 9 Outbd: 1 of 2 Group 9 Inbd: 1 of 2	Valve and Thermal O/L Bypass 1(2)E51-F080 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)E51-F086 (3.6.1.3, 3.8.c)
3.3.6.1 Function 3.j	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		
3.3.6.1 Function 4.a	1(2)E31-N605A (Div 1/Outbd) 1(2)E31-N605B (Div 2*/Inbd) * - instrument is Div 1 powered The following instruments are common to both trip systems 1(2)E31-N503 1(2)E31-N035 (when RT aligned to FW) 1(2)E31-N015 (when RT aligned to Hotwell) 1(2)E31-K604	Group 5 Outbd: 1 of 1 Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 4.b	1(2)E31-R621A (Div 1/Outbd) 1(2)E31-R621B (Div 2*/Inbd) * - instrument is Div 1 powered	Group 5 Outbd: 1 of 1 Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.c	Heat Exchanger Room A 1(2)E31-N003G/R001B-4 (Div 1/Outbd) 1(2)E31-N003H/R002B-4 (Div 2/Inbd) Heat Exchanger Room B 1(2)E31-N003J/R001B-5 (Div 1/Outbd) 1(2)E31-N003K/R002B-5 (Div 2/Inbd)	Group 5 Outbd: 1 of 1 per area Group 5 Inbd: 1 of 1 per area	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.d	Heat Exchanger Room A 1(2)E31-N001G/2G/R001B-20 (Div 1/Outbd) 1(2)E31-N001H/2H/R002B-20 (Div 2/Inbd) Heat Exchanger Room B 1(2)E31-N001J/2J/R001B-22 (Div 1/Outbd) 1(2)E31-N001K/2K/R002B-22 (Div 2/Inbd)	Group 5 Outbd: 1 of 1 per area Group 5 Inbd: 1 of 1 per area	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 4.e	Pump Room A 1(2)E31-N003A/R001B-1 (Div 1/Outbd) 1(2)E31-N003B/R002B-1 (Div 2/Inbd) Pump Room B 1(2)E31-N003C/R001B-2 (Div 1/Outbd) 1(2)E31-N003D/R002B-2 (Div 2/Inbd) Pump Valve Room 1(2)E31-N003E/R001B-3 (Div 1/Outbd) 1(2)E31-N003F/R002B-3 (Div 2/Inbd)	Group 5 Outbd: 1 of 1 per area Group 5 Inbd: 1 of 1 per area	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.f	Pump Room A 1(2)E31-N001A/2A/R001B-10 (Div 1/Outbd) 1(2)E31-N001B/2B/R002B-10 (Div 2/Inbd) Pump Room B 1(2)E31-N001C/2C/R001B-12 (Div 1/Outbd) 1(2)E31-N001D/2D/R002B-12 (Div 2/Inbd) Pump Valve Room 1(2)E31-N001E/2E/R001B-16 (Div 1/Outbd) 1(2)E31-N001F/2F/R002B-16 (Div 2/Inbd)	Group 5 Outbd: 1 of 1 per area Group 5 Inbd: 1 of 1 per area	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 4.g	1(2)E31-N047A/R001B-6 (Div 1/Outbd)	Group 5 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c)
	1(2)E31-N047B/R002B-6 (Div 2/Inbd)	Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.h	1(2)E31-N045A/46A/R001B-26 (Div 1/Outbd)	Group 5 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c)
	1(2)E31-N045B/46B/R002B-26 (Div 2/Inbd)	Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.i	1(2)E31-N050A/R001B-7 (Div 1/Outbd)	Group 5 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c)
	1(2)E31-N050B/R002B-7 (Div 2/Inbd)	Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.j	1(2)E31-N048A/49A/R001B-30 (Div 1/Outbd)	Group 5 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c)
	1(2)E31-N048B/49B/R002B-30 (Div 2/Inbd)	Group 5 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 4.k (Same instruments used for LCO 3.3.6.1 Function 2.a and LCO 3.3.6.2 Function 1)	1(2)B21-N402A*/704A (Div 1/Outbd) 1(2)B21-N402B*/704B (Div 1/Outbd) 1(2)B21-N402C*/704C (Div 2/Inbd) 1(2)B21-N402D*/704D (Div 2/Inbd) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Group 5 Outbd: 2 of 2 Group 5 Inbd: 2 of 2	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Valve and Thermal O/L Bypass 1(2)G33-F001 (3.6.1.3, 3.8.c)
3.3.6.1 Function 4.l	1(2)C41A-S001/K006A (Div 1/Outbd) 1(2)C41A-S004/K006B (Div 1/Outbd)	Group 5 Outbd: 1 of 1 per pump	Valve and Thermal O/L Bypass 1(2)G33-F004 (3.6.1.3, 3.8.c) Note: Supported components must be able to isolate/actuate on a signal from each SLC pump switch to be considered OPERABLE.
3.3.6.1 Function 4.m	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.1 Function 5.a (Same instruments used for LCO 3.3.1.1 Function 4 and LCO 3.3.6.1 Function 2.f)	1(2)B21-N403A/N703A (A) 1(2)B21-N403B/N703B (B)	Group 6 Outbd: A AND B	Valve and Thermal O/L Bypass 1(2)E12-F008 (3.6.1.3, 3.8.c) 1(2)E12-F023 (3.6.1.3, 3.8.c) 1(2)E12-F053A,B (3.6.1.3, 3.8.c) Thermal O/L bypass for 1(2)E12-F009 when valve is being powered from Div 1 emergency power supply (3.8.c)
	1(2)B21-N403C/N703C (C) 1(2)B21-N403D/N703D (D)	Group 6 Inbd: C AND D	Valve and Thermal O/L Bypass 1(2)E12-F009 (3.6.1.3, 3.8.c) 1(2)E12-F099A,B (3.8.c)
3.3.6.1 Function 5.b	1(2)B33-N018A (Div 1/Outbd)	Group 6 Outbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E12-F008 (3.6.1.3, 3.8.c) 1(2)E12-F023 (3.6.1.3, 3.8.c) 1(2)E12-F053A,B (3.6.1.3, 3.8.c) Thermal O/L bypass for 1(2)E12-F009 when valve is being powered from Div 1 emergency power supply (3.8.c)
	1(2)B33-N018B (Div 2/Inbd)	Group 6 Inbd: 1 of 1	Valve and Thermal O/L Bypass 1(2)E12-F009 (3.6.1.3, 3.8.c) 1(2)E12-F099A,B (3.8.c)
3.3.6.1 Function 5.c	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.2 Function 1 (Same instruments used for LCO 3.3.6.1 Function 2.a and 4.k)	1(2)B21-N402A*/704A (A) 1(2)B21-N402D*/704D (D)	Group 4 Outbd: A <u>AND</u> D	Valve / Thermal O/L Bypass 1(2)VQ-038 (3.6.4.2, 3.8.c) 1(2)VR-04YA (3.6.4.2) 1(2)VR-05YB (3.6.4.2) 1(2)VG-001 (3.8.c)* 1(2)VG-003 (3.8.c)* Unit 1 and Unit 2 SGT subsystems* (3.6.4.3)
	1(2)B21-N402B*/704B (B) 1(2)B21-N402C*/704C (C) * - Same instruments used for LCO 3.3.6.1 Functions 1.a and 2.e	Group 4 Inbd: B <u>AND</u> C	Valve / Thermal O/L Bypass 1(2)VQ-037 (3.6.4.2, 3.8.c) 1(2)VR-04YB (3.6.4.2) 1(2)VR-05YA (3.6.4.2) 1(2)VG-001 (3.8.c)* 1(2)VG-003 (3.8.c)* Unit 1 and Unit 2 SGT subsystems* (3.6.4.3) * - Either Trip logic is capable of starting both SGT subsystems and actuating VG thermal overload bypasses.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.2 Function 2 (Same instruments used for LCO 3.3.1.1 Function 6 and LCO 3.3.6.1 Function 2.b)	1(2)C71-N002A (A) 1(2)C71-N002D (D)	Group 4 Outbd: A AND D	Valve and Thermal O/L Bypass 1(2)VQ-038 (3.6.4.2, 3.8.c) 1(2)VR-04YA (3.6.4.2) 1(2)VR-05YB (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3)
	1(2)C71-N002B (B) 1(2)C71-N002C (C)	Group 4 Inbd: B AND C	Valve and Thermal O/L Bypass 1(2)VQ-037 (3.6.4.2, 3.8.c) 1(2)VR-04YB (3.6.4.2) 1(2)VR-05YA (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3) * - Either Trip logic is capable of starting both SGT subsystems and actuating VG thermal overload bypasses.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.2 Function 3 (Same instruments used for LCO 3.3.6.1 Function 2.c)	1(2)D18-N009A/K609A (A) 1(2)D18-N009B/K609B (B)	Group 4 Outbd: A <u>AND</u> B	Valve and Thermal O/L Bypass 1(2)VQ-038 (3.6.4.2, 3.8.c) 1(2)VR-04YA (3.6.4.2) 1(2)VR-05YB (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3)
	1(2)D18-N009C/K609C (C) 1(2)D18-N009D/K609D (D)	Group 4 Inbd: C <u>AND</u> D	Valve and Thermal O/L Bypass 1(2)VQ-037 (3.6.4.2, 3.8.c) 1(2)VR-04YB (3.6.4.2) 1(2)VR-05YA (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3) * - Either Trip logic is capable of starting both SGT subsystems and actuating VG thermal overload bypasses.

(continued)

TABLE 2

SUPPORT INSTRUMENTATION CROSS-REFERENCE

Tech Spec Function	Instrument (Logic/Trip System)	Logic	Supported Component LCOs
3.3.6.2 Function 4 (Same instruments used for LCO 3.3.6.1 Function 2.d)	1(2)D18-N015A/K615A (A) 1(2)D18-N015B/K615B (B)	Group 4 Outbd: A AND B	Valve and Thermal O/L Bypass 1(2)VQ-038 (3.6.4.2, 3.8.c) 1(2)VR-04YA (3.6.4.2) 1(2)VR-05YB (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3)
	1(2)D18-N015C/K615C (C) 1(2)D18-N015D/K615D (D)	Group 4 Inbd: C AND D	Valve and Thermal O/L Bypass 1(2)VQ-037 (3.6.4.2, 3.8.c) 1(2)VR-04YB (3.6.4.2) 1(2)VR-05YA (3.6.4.2) 1(2)VG-001 (3.8.c) 1(2)VG-003 (3.8.c) Unit 1 and Unit 2 SGT subsystems* (3.6.4.3) * - Either Trip logic is capable of starting both SGT subsystems and actuating VG thermal overload bypasses.
3.3.6.2 Function 5	No credit taken in accident analysis, no OPERABILITY impact on supported equipment.		

TECHNICAL SPECIFICATIONS BASES CONTROL PROGRAM

TABLE OF CONTENTS

1.1 PURPOSE

The purpose of this Program is to provide guidance for identifying, processing, and implementing changes to the Technical Specifications (TS) Bases. This Program implements and satisfies the requirements of TS 5.5.11, "Technical Specifications (TS) Bases Control Program."

This Program is applicable to the preparation, review, implementation, and distribution of changes to the TS Bases. This Program also provides guidance for preparing TS Bases Change Packages for distribution.

1.2 REFERENCES

1. TS 5.5.11, "Technical Specifications (TS) Bases Control Program"
2. 10 CFR 50.4, "Written Communications"
3. 10 CFR 50.59, "Changes, Tests and Experiments"
4. 10 CFR 50.71, "Maintenance of Records, Making of Reports"
5. 10 CFR 50.90, "Application for Amendment of License or Construction Permit"

1.3 DEFINITIONS AND/OR ACRONYMS

1. 10 CFR 50.59 REVIEW - A written regulatory evaluation which provides the basis for the determination that a change does, or does not, require NRC approval pursuant to 10 CFR 50.59. The scope of the evaluation should be commensurate with the potential safety significance of the change, but must address the relevant safety concerns included in the Safety Analysis Report and other owner controlled documents. The depth of the evaluation must be sufficient to determine whether or not NRC approval is required prior to implementation. Depending upon the significance of the change, the evaluation may be brief; however, a simple statement of conclusion is not sufficient.

2. EDITORIAL CHANGE - Editorial changes include correction of punctuation, insignificant word or title changes, style or format changes, typographical errors, or correction of reference errors that do not change the intent, outcome, results, functions, processes, responsibilities, or

performance requirements of the item being changed. Changes in numerical values shall not be considered as editorial changes. Editorial changes do not constitute a change to the TRM and therefore do not require further 10 CFR 50.59 Reviews. If the full scope of this proposed change is encompassed by one or more of the below, then the change is considered editorial.

- Rewording or format changes that do not result in changing actions to be accomplished.
- Deletion of cycle-specific information that is no longer applicable.
- Addition of clarifying information, such as:
    - Spelling, grammar, or punctuation changes
    - Changes to references
    - Name or title references

1.4 PROGRAM DESCRIPTION

1. A Licensee may make changes to the TS Bases without prior NRC approval provided the changes do not require either of the following:

    a. A change in the TS as currently incorporated in the license; or

    b. A change to the Updated Final Safety Analysis Report (UFSAR) or TS Bases that requires NRC approval pursuant to 10 CFR 50.59.

2. Changes that meet the above criteria (i.e., 1.4.1.a or 1.4.1.b) shall be submitted to the NRC pursuant to 10 CFR 50.90 and reviewed and approved by the NRC prior to implementation.

3. The TS Bases shall be maintained consistent with the UFSAR.

4. If a change to the TS Bases is not consistent with the UFSAR, then the cognizant Engineer shall prepare and submit a UFSAR Change Package when the TS Bases Change Request is submitted to Regulatory Assurance (RA) for processing.

5. Changes to the TS Bases that do not require prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e), as modified by approved exemptions.

6 TS Bases changes associated with a TS Amendment shall be

implemented consistent with the implementation requirements of the TS Amendment.

7 RS is responsible for the control and distribution of the TS Bases. In order to prevent distribution errors (i.e., omissions or duplications), RS shall maintain the master TS Bases distribution list.

1.5 PROGRAM IMPLEMENTATION

1. TS Bases Change Requestor identifies the need for a revision to the TS Bases and notifies the RA Licensing Engineer (i.e., hereafter referred to as RA LE). A TS Bases change can be initiated through any Stations' RA. TS Bases Change Requestor notifies their counterparts on the need for a change.

2. RA LE notifies their counterparts of identified need for revision to the TS Bases.

3. RA LE obtains concurrence from RS on the need for a change.

4 RA LE drafts TS Bases changes considering format, rules of usage, and technical adequacy.

5 RS Nuclear Licensing Administrator (i.e., hereafter referred to as RS NLA) reviews the agreed upon TS Bases wording changes for consistency with format, rules of usage, and technical adequacy and provides final concurrence.

6 After concurrence of the TS Bases wording changes is obtained, RS NLA makes an electronic version available in a working directory for use in the preparation of the 10 CFR 50.59 REVIEW and Station Qualified Review (SQR) process. The RS NLA shall ensure that the master electronic TS Bases files are revised per step 14 below upon receiving SQR approval. The Revision number in the footer should be a sequential number (i.e., 1, 2, etc.).

****
* NOTE *
* *
* If the TS Bases changes are applicable to more than one Station, the *
* following steps should be performed concurrently for each Station. *
* *
****

7 TS Bases Change Requestor provides a 10 CFR 50.59 REVIEW for the TS Bases changes in accordance with appropriate plant procedures. An exception to this requirement applies when the changes are being requested in order to reflect an approved NRC Safety Evaluation (SE) associated with a site-specific operating license or TS change. The NRC SE is sufficient to support the changes provided it has been determined that the changes are consistent with and entirely bounded by the NRC SE. A 50.59 review shall be performed for TS Bases changes that reflect generic approval by an NRC SE to determine site-specific applicability. A 10 CFR 50.59 REVIEW is not required for an EDITORIAL CHANGE.

8 TS Bases Change Requestor completes Attachment A, "Technical Specifications Bases Change Request Form," as follows:

a. Identifies the affected sections, and includes a copy of the proposed TS Bases changes;

b. Briefly summarizes the changes including the LCO, Action, or Surveillance Requirement to which the changes apply;

c. Briefly summarizes the reason for the changes and attaches all supporting documentation;

d. Identifies any schedule requirements and proposed implementation date that apply (i.e., describe any time limitations that might apply which would require expedited processing). If the changes are outage related, then checks "yes" and lists the applicable outage identifier;

e. Identifies any known implementation requirements such as procedure changes, UFSAR changes, Passport changes, Reportability Manual revisions, pre-implementation training requirements, etc.;

f. If a 10 CFR 50.59 REVIEW was prepared to support the TS

Bases changes, the Requestor then checks the appropriate box, lists the associated 10 CFR 50.59 REVIEW Number, and attaches the original;

g. If the changes to the TS Bases are the result of an NRC SE and the scope of the changes determined to be consistent with and entirely bounded by the NRC SE, then the Requestor checks the appropriate box and attaches a copy;

h. If the changes to the TS Bases are EDITORIAL CHANGES, the Requestor checks the appropriate box and no 10 CFR 50.59 REVIEW is required;

i. Signs and dates as Requestor and identifies the originating department;

j. Obtains approval to proceed from Department Supervisor (or designee); and

k. Returns Attachment A to the RA LE.

9 RA LE reviews the TS Bases Change Request Form, including supporting documentation, and documents the review by signing Attachment A. The review verifies that the following information or documentation is included:

a. Completed 10 CFR 50.59 REVIEW. If the changes are related to an NRC SE and determined to be entirely bounded by the NRC SE, then only a copy of the SE is required to be attached and no 10 CFR 50.59 REVIEW is required. A 10 CFR 50.59 REVIEW is not required for an EDITORIAL CHANGE;

b. Identification of known documents requiring revisions; and

c. Completed UFSAR Change Request with supporting documentation, in accordance with appropriate plant procedures, if applicable.

10. If the TS Bases change is not an EDITORIAL CHANGE, the RA LE obtains SQR approval of the TS Bases changes by performing the following:

a. Prepares the TS Bases Change SQR package. The SQR package shall include Attachment A (including completed 10 CFR

50.59 REVIEW or NRC SE) and the revised TS Bases pages. Attachment A is provided for the purpose of reviewing and finalizing the implementation requirements and ensuring the necessary actions have been initiated. RA LE shall assign Action Tracking (AT) items, as necessary, to track implementation requirements;

b. Submits the TS Bases Change SQR package to the SQR Committee members for a preliminary review. The SQR composition shall include RA and Operating Departments in all cases; and

c. Resolves preliminary review comments and finalizes the TS Bases Change SQR package.

11. The RAM shall determine the need for Plant Operations Review Committee (PORC) approval. The need for PORC approval shall be documented on Attachment A.

12. RA LE obtains PORC approval, if necessary.

13. RA LE notifies RS NLA of approval of the TS Bases changes by forwarding a copy of the approved SQR/PORC Change package to RS NLA.

14. After approval of the TS Bases changes by SQR/PORC, RS NLA ensures that the controlled master electronic files are updated.

15. RS/RA completes Attachment B, "Technical Specifications Bases Change Instruction Form," as follows:

    a. RS NLA indicates the effective date of the TS Bases changes consistent with the SQR/PORC approval or TS amendment required implementation date. If the TS Bases change is a result of a TS Amendment, the update shall be implemented coincident with implementation requirements of the TS Amendment. Otherwise, the update must be implemented by the date indicated on Attachment B;

    b. RS NLA lists each page to be removed and inserted, including the Affected Page List; and

    c. RA LE provides the updated master file directory for updating Electronic Document Management System (EDMS), if applicable.

16. RS NLA creates a TS Bases Change Package. The TS Bases Change Package shall consist of:

    a. TS Bases Change Instruction Form (Attachment B);

    b. Revised Affected Page List; and

    c. Revised TS Bases pages.

    One RS NLA shall assemble and approve the TS Bases Change Package for distribution and a second RS NLA shall perform a peer check to verify completeness of the TS Bases Change Package.

17. After the RA LE notifies the RS NLA that SQR/PORC approval of the TS Bases changes has been obtained and that all AT items assigned to track implementation requirements have been completed, RS NLA forwards the TS Bases Change Package to the RA LE as notification of the need to update the onsite TS Bases controlled copies and ECF, if applicable. RS NLA also forwards the TS Bases Change Package to RS Administration Department as notification of the need to update the offsite (RS) TS Bases controlled copies and to transmit updates to the offsite (non-RS) TS Bases controlled copies.

18. RA LE forwards the TS Bases Change Package to Station Administration Department as notification of the need to update the onsite TS Bases controlled copies and EDMS, if applicable.

19. Upon completion of updating the onsite TS Bases controlled copies and ECF (if applicable), Station Administration Department Supervisor signs and dates Attachment C and returns Attachment B to the appropriate RS NLA.

20. Upon completion of updating the offsite (RS) TS Bases controlled copies and transmitting updates to the offsite (non-RS) TS Bases controlled copies, RS Administration Department signs and dates Attachment B and returns Attachment B to the appropriate RS NLA.

21. RA LE ensures that the documentation required to be maintained as a quality record is provided to Station Administration Department for the purpose of record retention.

1.6 ACCEPTANCE CRITERIA

Not applicable.

1.7 LCOARS/COMPENSATORY MEASURES

An Issue Report may need to be generated to provide proper tracking and resolution of noted problems associated with the implementation of this Program.

The RAM will be responsible for ensuring that Program failures have been resolved.

1.8 REPORTING REQUIREMENTS

> **NOTE**
>
> TS Bases changes requiring prior NRC approval shall be submitted in accordance with Reference 5.

TS Bases changes not requiring prior NRC approval, as described in Section 1.4 of this Program, shall be submitted to the NRC in accordance with 10 CFR 50.71(e).

1.9 CHANGE CONTROL

Changes to this Program, other than EDITORIAL CHANGES, shall include a 10 CFR 50.59 REVIEW and an SQR. The SQR composition shall include RA Department in all cases. For a change to this Program, PORC approval from all Stations is required. The concurrence shall be that the other Stations are implementing the same changes or that the changes have been reviewed and determined not to be applicable to the other Stations.

ATTACHMENT A
TECHNICAL SPECIFICATIONS BASES CHANGE REQUEST FORM

1. Affected Bases Section(s): ____________________
2. Description of changes: ____________________
   ____
3. Reason for changes (attach all supporting documentation): ____________________
   ____
4. Schedule Requirements:
   Outage Related (check one) ( ) No ( ) Yes, Outage # ________
   Other (explain) ____________________

5. Implementation Requirements (attach additional pages, as necessary):
   Identify the impact of the changes on the following:

Affected	N/A	
( )	( )	UFSAR ____________________
( )	( )	TS ____________________
( )	( )	Technical Requirements Manual ____________________
( )	( )	NRC Safety Evaluation ____________________
( )	( )	Fire Protection Report ____________________
( )	( )	NRC Commitments ____________________
( )	( )	Vendor Documentation ____________________
( )	( )	Special Permits/Licenses ____________________
( )	( )	Procedures ____________________
( )	( )	Environmental Qualification ____________________
( )	( )	Design Basis Documentation ____________________
( )	( )	Engineering Calculations ____________________
( )	( )	Drawings/Prints ____________________
( )	( )	PRA Information ____________________
( )	( )	Programs ____________________
( )	( )	Reportability Manual ____________________
( )	( )	QA Topical Report ____________________
( )	( )	Passport ____________________
( )	( )	Pre-Implementation Training Required ____________________
( )	( )	Maintenance Rule ____________________
( )	( )	Offsite Dose Calculation Manual ____________________
( )	( )	Other ____________________

6. Check one:
   ( ) 10 CFR 50.59 REVIEW Attached, 10 CFR 50.59 REVIEW #: ____________________
   ( ) NRC SE Attached, Changes consistent with and entirely bounded by NRC SE
   ( ) EDITORIAL CHANGE, No 10 CFR 50.59 REVIEW required
7. Requestor: ____________________ / ____________________ / ____________________
   (Signature) (Date) (Department)
8. Requesting Supervisor Approval: ____________________ / ____________________
   (Signature) (Date)
9. PORC Approval Required: ( ) Yes ( ) No
10. Licensing Engineer Review: ____________________ / ____________________
    (Signature) (Date)

ATTACHMENT B
TECHNICAL SPECIFICATIONS BASES CHANGE INSTRUCTION FORM FOR ONSITE/OFFSITE DISTRIBUTION AND FOR UPDATING ECF

Braidwood/Byron/Dresden/LaSalle/QC (circle one) TS Bases Revision # ______

NOTE: This change is effective as of ______________________________ and shall be implemented by __________ . (SQR/PORC or Amendment Implementation Date)
(Date)

Approved for distribution: ____________________________________/______________
(RS NLA Signature) (Date)

Verified: ____________________________________/______________
(RS NLA Signature) (Date)

REMOVE Section	REMOVE Page	INSERT Section	INSERT Page	UPDATE EDMS Section	UPDATE EDMS Page
Affected Page List	All	Affected Page List	All	N/A	N/A

ATTACHMENT B
TECHNICAL SPECIFICATIONS BASES CHANGE INSTRUCTION FORM FOR ONSITE/OFFSITE DISTRIBUTION AND FOR UPDATING ECF

Braidwood/Byron/Dresden/LaSalle/QC (circle one) TS Bases Revision # ______

Station Administration Department:

Onsite Distribution Completed: ______________________/__________________
(Station Admin. Dept. Supr.) (Date)

ECF Update Completed: ______________________/__________________
(Station Admin. Dept. Supr.) (Date)

** Return this sheet to: Regulatory Services
Braidwood/Byron/Dresden/LaSalle/QC (circle one) NLA
Downers Grove

RS Administration Department:

Offsite (RS) Distribution Completed: ______________________/__________________
(RS Admin. Dept.) (Date)

Offsite (non-RS) Distribution Transmitted: ______________________/__________________
(RS Admin. Dept.) (Date)

** Return this sheet to Braidwood/Byron/Dresden/LaSalle/QC (circle one) NLA

Offsite (non-RS) Controlled Copy Holders:

Offsite (non-RS) Distribution Completed: ______________________/__________________
(Signature) (Date)

** Return this sheet to: EXELON GENERATING COMPANY, LLC
ATTN: REGULATORY SERVICES ADMINISTRATION DEPARTMENT
EXECUTIVE TOWERS WEST III
REGULATORY SERVICES DEPARTMENT - SUITE 500
1400 OPUS PLACE
DOWNERS GROVE, IL 60515

Core Operating Limits Report for

LaSalle Unit 1

Cycle 16 Revision 0

Table of Contents

List of Tables

1. References

1. Exelon Generation Company, LLC Docket No. 50-373 LaSalle County Station, Unit 1, License No. NPF-11.

2. NRC Letter from D. M. Crutchfield to All Power Reactor Licensees and Applicants, Generic Letter 88-16; Concerning the Removal of Cycle-Specific Parameter Limits from Tech Specs, October 3, 1988.

3. Nuclear Fuels Letter NFM:MW:01-0106, from A. Giancatarino to J. Nugent, “LaSalle Unit 1 and Unit 2 Rod Block Monitor COLR Setpoint Change," April 3, 2001.

4. GE Nuclear Energy Report NEDC-32694P-A, Revision 0, “Power Distribution Uncertainties for Safety Limit MCPR Evaluations,” August 1999.

5. GE Nuclear Energy Document GE-NE-A1300384-07-01, Revision 1, “LaSalle County Station Power Uprate Project Task 201: Reactor Power/Flow Map”, September 1999.

6. GE Hitachi Nuclear Energy Report, GE-NE-0000-0099-8344-R1, Revision 1, “Exelon Nuclear LaSalle Units 1 and 2 Thermal Power Optimization Task T0201: Operating Power/Flow Map”, November 2009.

7. GNF Report 000N0801-SRLR, Revision 1, “Supplemental Reload Licensing Report for LaSalle Unit 1 Reload 15 Cycle 16,” January 2014.

8. GNF Letter from B. R. Moore to Document Control Desk, Subject: “GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II), NEDC-33270P, Revision 5, May 2013,” MFN 13-029, May 24, 2013 (ADAMS Accession No. ML13148A318)

9. AREVA Report ANP-2914(P), Revision 1, “Mechanical Design Report for LaSalle Units 1 and 2 MUR ATRIUM-10 Fuel Assemblies,” AREVA NP Inc., June 2010.

10. Exelon Transmittal ES1300014, Revision 0, “LaSalle Unit 1 Cycle 16 Final Resolved OPL-3 Parameters,” August 21, 2013.

11. GNF DRF A12-00038-3, Vol. 4, “Scram Times Verses Notch Position,” G. A. Watford, May 22, 1992.

12. GEH Nuclear Energy DRF Section 0000-0151-0765 Rev. 0, “Application of SLO MCPR”, 2/12/13.

2. Terms and Definitions

ARTS	Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement Program
ATRM10	AREVA ATRIUM-10 fuel type
BOC	Beginning of cycle
BWR	Boiling water reactor
CFR	Code of Federal Regulations
COLR	Core operating limits report
CRD	Control rod drive mechanism
DLO	Dual loop operation
ELLLA	Extended load line limit analysis
EOC	End of cycle
EOOS	Equipment out of service
EOR16	End of rated operation for Cycle 16
FFWTR	Final feedwater temperature reduction
FWHOOS	Feedwater heater out of service
GNF	Global Nuclear Fuels - Americas
ICF	Increased core flow
K_P	Power-dependent MCPR Multiplier
L1C16	LaSalle Unit 1 Cycle 16
LHGR	Linear heat generation rate
$LHGRFAC_F$	Flow-dependent LHGR multiplier
$LHGRFAC_P$	Power-dependent LHGR multiplier
LPRM	Local power range monitor
MAPLHGR	Maximum average planar linear heat generation rate
MCPR	Minimum critical power ratio
$MCPR_F$	Flow-dependent MCPR
MELLLA	Maximum extended load line limit analysis
MOC	Middle of Cycle Point for Licensing Purposes
MSIVOOS	Main steam isolation valve out of service
OLMCPR	Operating limit minimum critical power ratio
OOS	Out of service
OPRM	Oscillation power range monitor
PBDA	Period based detection algorithm
PLUOOS	Power load unbalance out of service
PROOS	Pressure regulator out of service
RPTOOS	Recirculation pump trip out of service
RWE	Rod withdrawal error
SLMCPR	Safety limit minimum critical power ratio
SLO	Single loop operation
SRVOOS	Safety-relief valve out of service
TBV	Turbine bypass valve
TBVOOS	Turbine bypass valve out of service
TCV	Turbine control valve
TCVSC	Turbine control valve slow closure
TIP	Traversing in-core probe
TIPOOS	Traversing in-core probe out of service
TSV	Turbine stop valve
3DM	3-D Monicore

3. General Information

Power and flow dependent limits are listed for various power and flow levels. Linear interpolation is to be used to find intermediate values.

Rated core flow is 108.5 Mlbm/hr. Operation up to 105% rated flow is licensed for this cycle. Licensed rated thermal power is 3546 MWth.

For thermal limit monitoring above 100% rated power or 100% rated core flow, the 100% rated power and the 100% core flow values, respectively, can be used unless otherwise indicated in the applicable table.

Table 3-1 defines the three exposure ranges used in the COLR. The end of rated (EOR) exposure is defined as the cycle exposure corresponding to all rods out, 100% power/100% flow, and normal feedwater temperature. The term (EOR – 3715 MWd/ST) means the EOR exposure minus 3715 MWd/ST of exposure. The value of the EOR exposure is based on actual plant operation and is thus determined from projections to this condition made near, but before, the time when the EOR16 – 3715 MWd/ST exposure will be reached. For cycle exposure dependent limits at the exact MOC exposure, the more limiting of the BOC to MOC and the MOC to EOC limits should be used. This can be achieved by applying the MOC to EOC limits to the MOC point as all cycle exposure dependent limits in the MOC to EOC limit sets are the same as, or more limiting than, those in the BOC to MOC limit sets.

Table 3-1 Cycle Exposure Range Definitions
(Reference 7):

Nomenclature	Cycle Exposure Range
BOC to MOC	BOC16 to (EOR16 – 3715 MWd/ST)
MOC to EOC	(EOR16 – 3715 MWd/ST) to EOC16
BOC to EOC	BOC16 to EOC16

4. Average Planar Linear Heat Generation Rate

Technical Specification Sections 3.2.1 and 3.4.1

The MAPLHGR values for the most limiting lattice of each fuel type as a function of average planar exposure are given in Tables 4-1 and 4-2. During single loop operation, these limits are multiplied by the fuel-dependent SLO multiplier listed in Table 4-3. The MAPLHGR values in Tables 4-1 and 4-2 along with the MAPLHGR SLO multipliers in Table 4-3 provide coverage for all modes of operation.

Table 4-1 MAPLHGR for GNF2 Fuel
(Reference 7)

Avg. Planar Exposure (GWd/ST)	MAPLHGR (kW/FT)
0.00	13.78
17.15	13.78
60.78	6.87
63.50	5.50

Table 4-2 MAPLHGR for ATRIUM-10 Fuel
(Reference 7)

Avg. Planar Exposure (GWd/ST)	MAPLHGR (kW/FT)
0	12.81
21.41	12.81
55.42	9.10
63.86	7.30

Table 4-3 MAPLHGR SLO Multiplier for GNF2 and ATRIUM-10 Fuel, BOC to EOC
(Reference 7)

Fuel Type	SLO MAPLHGR Multiplier
GNF2	0.78
ATRIUM-10	0.78

5. Operating Limit Minimum Critical Power Ratio

Technical Specification Sections 3.2.2, 3.3.4.1, 3.4.1, and 3.7.7

5.1. Manual Flow Control MCPR Limits

The steady-state OLMCPRs given in Table 5-2 are the maximum values obtained from analysis of the pressurization events, non-pressurization events, and the Option III stability evaluation. MCPR values are determined by the cycle-specific fuel reload analyses in Reference 7. Table 5-2 is used in conjunction with the ARTS-based power (Kp) and flow ($MCPR_F$) dependencies presented in Tables 5-3, 5-4, and 5-5 below. The OLMCPR is determined for a given power and flow condition by evaluating the power and flow dependent MCPR values and selecting the greater of the two.

5.1.1. Power-Dependent MCPR

The power-dependent MCPR multiplier, K_P, is determined from Table 5-3, and is dependent only on the power level and the Application Group (EOOS). The product of the steady state OLMCPR and the proper K_P provides the power-dependent OLMCPR.

5.1.2. Flow-Dependent MCPR

Tables 5-4 through 5-5 give the $MCPR_F$ limit as a function of the core flow, based on the applicable plant conditions. The $MCPR_F$ limit determined from these tables is the flow-dependent OLMCPR.

5.2. Scram Time

Option A and Option B MCPR analyses and results are dependent upon core average control rod blade scram speed insertion times.

The Option A scram time is the Improved Technical Specification scram speed based insertion time. The core average scram speed insertion time for 20% insertion must be less than or equal to the Technical Specification scram speed insertion time to utilize the Option A MCPR limits. Reload analyses performed by GNF for Cycle 16 Option A MCPR limits utilized a 20% core average insertion time of 0.900 seconds (Reference 10).

To utilize the MCPR limits for the Option B scram speed insertion times, the core average scram speed insertion time for 20% insertion must be less than or equal to 0.694 seconds (Reference 10) (0.672 seconds at notch position 39, Reference 11). See Table 5-1 for a summary of scram time requirements related to the use of Option A and Option B MCPR limits.

If the core average scram insertion time does not meet the Option B criteria, but is within the Option A criteria, the appropriate steady state MCPR value may be determined from a linear interpolation between the Option A and B limits with standard mathematical rounding to two decimal places. When performing the linear interpolation to determine MCPR limits, ensure that the time used for Option A is 0.900 seconds (0.875 seconds to notch position 39, Reference 11). Note that making interpolations using the Table 5-2 data is conservative because the stability based OLMCPR sets the limit in many conditions. The Option A to Option B linear interpolation need not include the stability OLMCPR penalty on the endpoints when the calculation is made. However, the result of the linear interpolation is required to be 1.51 or greater for the steady state OLMCPR due to the OPRM PBDA setpoint (see Section 9 of the COLR and Reference 7).

Table 5-1 Scram Times Required for Option A and Option B Application at Notch Position 39
(References 10 and 11)

Notch Position*	Scram Time Required for Option A Application	Scram Time Required for Option B Application
39	≤ 0.875 sec.	≤ 0.672 sec.

* - The insertion time to a notch position is conservatively calculated using the CRD reed switch drop-out time per Reference 11.

5.3. Recirculation Flow Control Valve Settings

Cycle 16 was analyzed with a maximum core flow runout of 105%; therefore the recirculation pump flow control valves must be set to maintain core flow less than 105% (113.925 Mlbm/hr) for all runout events.

Table 5-2 Operating Limit Minimum Critical Power Ratio (OLMCPR) for ATRIUM-10 and GNF2 Fuel
(Reference 7)

Application Group	DLO/ SLO	Exposure Range	Option A		Option B	
			GNF2	ATRM10	GNF2	ATRM10
Base Case	DLO	BOC-MOC	1.51	1.51	1.51	1.51
		MOC-EOC	1.61	1.53	1.56	1.51
Base Case	SLO	BOC-MOC	1.56	1.51	1.56	1.51
		MOC-EOC	1.63	1.55	1.58	1.52
Base Case + TCVSC + RPTOOS + PROOS	DLO	BOC-MOC	1.58	1.56	1.51	1.51
		MOC-EOC	1.69	1.70	1.59	1.53
Base Case + TCVSC + RPTOOS + PROOS	SLO	BOC-MOC	1.60	1.58	1.56	1.51
		MOC-EOC	1.71	1.72	1.61	1.55
Base Case + TCVSC + TBVOOS (all 5 valves)	DLO	BOC-MOC	1.53	1.51	1.51	1.51
		MOC-EOC	1.65	1.56	1.60	1.53
Base Case + TCVSC + TBVOOS (all 5 valves)	SLO	BOC-MOC	1.56	1.51	1.56	1.51
		MOC-EOC	1.67	1.58	1.62	1.55
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	DLO	BOC-MOC	1.61	1.59	1.51	1.51
		MOC-EOC	1.73	1.74	1.63	1.57
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	SLO	BOC-MOC	1.63	1.61	1.56	1.51
		MOC-EOC	1.75	1.76	1.65	1.59

Table 5-3 Power-Dependent MCPR Multipliers (K_P) for ATRIUM-10 and GNF2 Fuel, DLO and SLO, BOC to EOC, Option A and Option B
(Reference 7)

Application Group	K_P, MCPR Limit Multiplier (as a function of % rated power)						
	0% P	25% P	45% P	60% P	85% P	85.01%P	100% P
Base Case	1.338	1.338	1.191	1.191	1.061	1.061	1.000
Base Case + TCVSC + RPTOOS + PROOS	1.488	1.488	1.378	1.296	1.174	1.097	1.000
Base Case + TCVSC + TBVOOS (all 5 valves)	1.379	1.379	1.228	1.207	1.097	1.097	1.000
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	1.488	1.488	1.378	1.296	1.174	1.097	1.000

Table 5-4 DLO Flow-Dependent MCPR Limits ($MCPR_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, All Application Groups, Option A and Option B
(Reference 7)

Flow (% Rated)	$MCPR_F$
0.0	1.89
30.0	1.70
105.0	1.24

Table 5-5 SLO Flow-Dependent MCPR Limits ($MCPR_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, All Application Groups, Option A and Option B
(References 7 and 12)

Flow (% Rated)	$MCPR_F$
0.0	1.91
30.0	1.72
105.0	1.26

6. Linear Heat Generation Rate

Technical Specification Sections 3.2.3 and 3.4.1

The linear heat generation rate (LHGR) limit is the product of the exposure dependent LHGR limit from Table 6-1 or Table 6-2 and the minimum of: the power dependent LHGR Factor, $LHGRFAC_P$, or the flow dependent LHGR Factor, $LHGRFAC_F$ as applicable. The $LHGRFAC_P$ multiplier is determined from Table 6-3. The $LHGRFAC_F$ multiplier is determined from either Table 6-4 or Table 6-5. The SLO multipliers in Tables 6-4 and 6-5 have been limited to a maximum value of 0.78, the SLO LHGR multiplier for GNF2 and ATRIUM-10 fuel.

Table 6-1 LHGR Limit for GNF2 Fuel
(Reference 8)

Peak Pellet Exposure	UO_2 LHGR Limit
See Table B-1 of Reference 8	

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit
See Table B-2 of Reference 8	

Table 6-2 LHGR Limit for ATRIUM-10 Fuel
(Reference 9)

Peak Pellet Exposure (GWd/ST)	LHGR Limit (kW/ft)
0.0	13.4
16.06	13.4
55.43	9.1
63.87	7.3

Table 6-3 Power-Dependent LHGR Multipliers ($LHGRFAC_P$) for ATRIUM-10 and GNF2 Fuel, DLO and SLO, BOC to EOC
(Reference 7)

Application Group	$LHGRFAC_P$ (as a function of % rated power)					
	0% P	**25% P**	**45% P**	**60% P**	**85% P**	**100% P**
Base Case	0.608	0.608	0.713	0.791	0.922	0.978
Base Case + TCVSC + RPTOOS + PROOS	0.608	0.608	0.713	0.761	0.831	0.978
Base Case + TCVSC + TBVOOS (all 5 valves)	0.608	0.608	0.713	0.791	0.922	0.978
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	0.608	0.608	0.713	0.761	0.822	0.978

Table 6-4 Flow-Dependent LHGR Multipliers ($LHGRFAC_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, Pressurization (1 TCV/TSV Closed or OOS), All Application Groups
(Reference 7)

Flow (% Rated)	DLO $LHGRFAC_F$	SLO $LHGRFAC_F$
0.0	0.110	0.110
30.0	0.410	0.410
67.0	0.78	0.78
89.0	1.000	0.78
105.0	1.000	0.78

Table 6-5 Flow-Dependent LHGR Multipliers ($LHGRFAC_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, No Pressurization (All TCV/TSV In-Service), All Application Groups
(Reference 7)

Flow (% Rated)	DLO $LHGRFAC_F$	SLO $LHGRFAC_F$
0.0	0.250	0.250
30.0	0.550	0.550
53.0	0.78	0.78
75.0	1.000	0.78
105.0	1.000	0.78

7. Rod Block Monitor

Technical Specification Sections 3.3.2.1 and 3.4.1

The Rod Block Monitor Upscale Instrumentation Setpoints are determined from the relationships shown below (Reference 3):

Table 7-1 Rod Block Monitor Setpoints

Rod Block Monitor Upscale Trip Function	Allowable Value
Two Recirculation Loop Operation	$0.66\ W_d + 54.0\%$
Single Recirculation Loop Operation	$0.66\ W_d + 48.7\%$

The setpoint may be lower/higher and will still comply with the rod withdrawal error (RWE) analysis because RWE is analyzed unblocked. The allowable value is clamped with a maximum value not to exceed the allowable value for a recirculation loop drive flow (W_d) of 100%.

W_d – percent of recirculation loop drive flow required to produce a rated core flow of 108.5 Mlbm/hr.

8. Traversing In-Core Probe System

8.1. Description

When the traversing in-core probe (TIP) system (for the required measurement locations) is used for recalibration of the LPRM detectors and monitoring thermal limits, the TIP system shall be operable with the following:

1. movable detectors, drives and readout equipment to map the core in the required measurement locations, and
2. indexing equipment to allow all required detectors to be calibrated in a common location.

The following applies for use with 3DM (Reference 4):

The total number of failed and/or bypassed LPRMs does not exceed 25%. In addition, no more than 14 TIP channels can be OOS (failed or rejected).

Otherwise, with the TIP system inoperable, suspend use of the system for the above applicable calibration functions.

8.2. Bases

The operability of the TIP system with the above 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 normalization of the required detectors is performed internal to the core monitoring software system.

9. Stability Protection Setpoints

Technical Specification Section 3.3.1.3

Table 9-1 OPRM PBDA Trip Setpoints
(Reference 7)

PBDA Trip Amplitude Setpoint (Sp)	Corresponding Maximum Confirmation Count Setpoint (Np)
1.11	14

The PBDA is the only OPRM setting credited in the safety analysis as documented in the licensing basis for the OPRM system.

The OPRM PBDA trip settings are based, in part, on the cycle specific OLMCPR and the power dependent MCPR limits. Any change to the OLMCPR values and/or the power dependent MCPR limits should be evaluated for potential impact on the OPRM PBDA trip settings.

The OPRM PBDA trip settings are applicable when the OPRM system is declared operable, and the associated Technical Specifications are implemented.

10. Modes of Operation

The allowed modes of operation with combinations of equipment out-of-service are as described below (Reference 7).

Table 10-1 Allowed Modes of Operation and EOOS Combinations
(Reference 7)

Equipment Out of Service Options (1) (2) (4) (5)	Short Name
Base Case (Option A or B) (3)	Base
Base Case + SLO (Option A or B)	Base SLO
Base Case + TCVSC + RPTOOS + PROOS (Option A or B)	Combined EOOS 1
Base Case + TCVSC + RPTOOS + PROOS + SLO (Option A or B)	Combined EOOS 1 SLO
Base Case + TCVSC + TBVOOS (all 5 valves) (Option A or B)	Combined EOOS 2
Base Case + TCVSC + TBVOOS (all 5 valves) + SLO (Option A or B)	Combined EOOS 2 SLO
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS (Option A or B)	Combined EOOS 3
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS + SLO (Option A or B)	Combined EOOS 3 SLO

(1) Base case includes 1 SRVOOS + 1 TCV/TSV OOS + FWHOOS/FFWTR + 1 MSIVOOS + 2 TBVOOS + PLUOOS, and also includes 1 TIPOOS (up to 14 TIP channels not available) any time during the cycle, including BOC, and up to 25% of the LPRMs out-of-service. The FWHOOS/FFWTR analyses cover a maximum reduction of 100°F for the feedwater temperature. A nominal LPRM calibration interval of 2000 EFPH (2500 EFPH maximum) is supported for L1C16.

(2) TBVOOS (all 5 valves) is the turbine bypass system out of service which means that 5 TBVs are **not** credited for fast opening and 3 TBVs are **not** credited to open in pressure control. For the 2 TBVOOS condition that is a part of the base case, the assumption is that both of the TBVs do not open on any signal and thus remain shut for the transients analyzed (i.e. 3 TBVs are credited to open in pressure control). The MCFL is currently set at 126.6 and will only allow opening of TBV's #1, #2, #3, and #4 during a slow pressurization event. The MCFL does not use the TBV position feedback signal to know how many TBVs have opened or how far each has opened. The #5 TBV is not available based on the current MCFL setpoint and thus cannot be used as one of the credited valves to open in pressure control.

(3) With all TCV/TSV In-Service, the Base Case should be used with the $LHGRFAC_F$ values from Table 6-5 (Reference 7). With 1 TCV/TSV OOS, the Base Case must be used with the $LHGRFAC_F$ values from Table 6-4. The one Stuck Closed TCV and/or TSV EOOS conditions require power level ≤ 85% of rated. The one MSIVOOS condition is also supported as long as thermal power is maintained ≤ 75% of the rated.

(4) The + sign that is used in the Equipment Out of Service Option / Application Group descriptions designates an "and/or".

(5) All EOOS Options (Reference 7 Application Groups) are applicable to ELLLA, MELLLA, ICF and Coastdown realms of operation with the exception that SLO is not applicable to MELLLA or ICF (References 5 and 6). The MOC to EOC exposure range limit sets are generated by GNF to include application to coastdown operation (Methodology Reference 5).

11. Methodology

The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. XN-NF-81-58 (P)(A), Revision 2 and Supplements 1 and 2, “RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model,” March 1984.
2. ANF-89-98 (P)(A), Revision 1 and Revision 1 Supplement 1, “Generic Mechanical Design Criteria for BWR Fuel Designs,” May 1995.
3. EMF-85-74 (P) Revision 0 Supplement 1(P)(A) and Supplement 2(P)(A), “RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model,” February 1998.
4. XN-NF-85-67 (P)(A) Revision 1, “Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel,” September 1986.
5. NEDE-24011-P-A-20 (Revision 20), “General Electric Standard Application for Reactor Fuel,” December 2013 and the U.S. Supplement NEDE-24011-P-A-20-US, of December 2013.
6. NEDC-33106P-A Revision 2, “GEXL97 Correlation for ATRIUM-10 Fuel,” June 2004.
7. NEDO-32465-A, “BWR Owner’s Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

Core Operating Limits Report for

LaSalle Unit 2

Cycle 15 Revision 1

Table of Contents

List of Tables

1. References

1. Exelon Generation Company, LLC Docket No. 50-374 LaSalle County Station, Unit 2, License No. NPF-18.

2. NRC Letter from D. M. Crutchfield to All Power Reactor Licensees and Applicants, Generic Letter 88-16; Concerning the Removal of Cycle-Specific Parameter Limits from Tech Specs, October 3, 1988.

3. Nuclear Fuels Letter NFM:MW:01-0106, from A. Giancatarino to J. Nugent, "LaSalle Unit 1 and Unit 2 Rod Block Monitor COLR Setpoint Change," April 3, 2001.

4. GNF Report NEDC-32694P-A, Revision 0, "Power Distribution Uncertainties for Safety Limit MCPR Evaluations," August 1999.

5. GE Nuclear Energy Document GE-NE-A1300384-07-01, Revision 1, "LaSalle County Station Power Uprate Project Task 201: Reactor Power/Flow Map", September 1999.

6. GE Hitachi Nuclear Energy Report, GE-NE-0000-0099-8344-R1, Revision 1, "Exelon Nuclear LaSalle Units 1 and 2 Thermal Power Optimization Task T0201: Operating Power/Flow Map", November 2009.

7. GNF Report 0000-0156-1147-SRLR, Revision 1, "Supplemental Reload Licensing Report for LaSalle Unit 2 Reload 14 Cycle 15," January 2013.

8. GNF Report 0000-0156-1147-FBIR-P, Revision 0, "Fuel Bundle Information Report for LaSalle Unit 2 Reload 14 Cycle 15," January 2013.

9. AREVA Report ANP-2914(P), Revision 1, "Mechanical Design Report for LaSalle Units 1 and 2 MUR ATRIUM-10 Fuel Assemblies," AREVA NP Inc., June 2010.

10. Exelon Transmittal ES1200013, Revision 0, "LaSalle Unit 2 Cycle 15 Final Resolved OPL-3 Parameters," August 22, 2012.

11. GNF DRF A12-00038-3, Vol. 4, "Scram Times Verses Notch Position," G. A. Watford, May 22, 1992.

12. GNF Transmittal CFL-EXN-HA2-12-173, transmitting results of DRF Section 0000-0155-9963, "LaSalle Unit 2 Cycle 15 Single LHGR Curve Determination (TSD NF-B483)," December 19, 2012.

13. LaSalle Transmittal SEAG 13-000010, Revision 0, "LaSalle L2C15 OPRM Successive Confirmation Count Setpoint and OPRM Amplitude," January 28, 2013.

14. GNF Report NEDC-33647-P, Revision 2, "GNF2 Fuel Design Cycle-Independent Analyses for Exelon LaSalle County Station Units 1 and 2," February, 2012.

15. GNF DRF Section 0000-0151-0765 Rev. 0, "Application of SLO MCPR", 2/12/13.

2. Terms and Definitions

ARTS	Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement Program
ATRM10	AREVA ATRIUM-10 fuel type
BOC	Beginning of cycle
BWR	Boiling water reactor
CFR	Code of Federal Regulations
COLR	Core operating limits report
CRD	Control rod drive mechanism
DLO	Dual loop operation
ELLLA	Extended load line limit analysis
EOC	End of cycle
EOOS	Equipment out of service
EOR15	End of rated operation for Cycle 15
FFWTR	Final feedwater temperature reduction
FWHOOS	Feedwater heater out of service
GNF	Global Nuclear Fuels - Americas
ICF	Increased core flow
K_P	Power-dependent MCPR Multiplier
L2C15	LaSalle Unit 2 Cycle 15
LHGR	Linear heat generation rate
$LHGRFAC_F$	Flow-dependent LHGR multiplier
$LHGRFAC_P$	Power-dependent LHGR multiplier
LPRM	Local power range monitor
MAPLHGR	Maximum average planar linear heat generation rate
MCPR	Minimum critical power ratio
$MCPR_F$	Flow-dependent MCPR
MELLLA	Maximum extended load line limit analysis
MOC	Middle of Cycle Point for Licensing Purposes
MSIVOOS	Main steam isolation valve out of service
OLMCPR	Operating limit minimum critical power ratio
OOS	Out of service
OPRM	Oscillation power range monitor
PBDA	Period based detection algorithm
PLUOOS	Power load unbalance out of service
PROOS	Pressure regulator out of service
RPTOOS	Recirculation pump trip out of service
RWE	Rod withdrawal error
SLMCPR	Safety limit minimum critical power ratio
SLO	Single loop operation
SRVOOS	Safety-relief valve out of service
TBV	Turbine bypass valve
TBVOOS	Turbine bypass valve out of service
TCV	Turbine control valve
TCVSC	Turbine control valve slow closure
TIP	Traversing in-core probe
TIPOOS	Traversing in-core probe out of service
TSV	Turbine stop valve
3DM	3-D Monicore

3. General Information

Power and flow dependent limits are listed for various power and flow levels. Linear interpolation is to be used to find intermediate values.

Rated core flow is 108.5 Mlbm/hr. Operation up to 105% rated flow is licensed for this cycle. Licensed rated thermal power is 3546 MWth.

For thermal limit monitoring above 100% rated power or 100% rated core flow, the 100% rated power and the 100% core flow values, respectively, can be used unless otherwise indicated in the applicable table.

The thermal limits provided in the COLR support SLO for all analyzed equipment out of service options.

Table 3-1 defines the three exposure ranges used in the COLR. The end of rated (EOR) exposure is defined as the cycle exposure corresponding to all rods out, 100% power/100% flow, and normal feedwater temperature. The term (EOR – 3331 MWd/MTU) means the EOR exposure minus 3331 MWd/MTU of exposure. The value of the EOR exposure is based on actual plant operation and is thus determined from projections to this condition made near, but before, the time when the EOR15 – 3331 MWd/MTU exposure will be reached. For cycle exposure dependent limits at the exact MOC exposure, the more limiting of the BOC to MOC and the MOC to EOC limits should be used. This can be achieved by applying the MOC to EOC limits to the MOC point as all cycle exposure dependent limits in the MOC to EOC limit sets are the same as, or more limiting than, those in the BOC to MOC limit sets.

Table 3-1 Cycle Exposure Range Definitions
(Reference 7)

Nomenclature	Cycle Exposure Range
BOC to MOC	BOC15 to (EOR15 – 3331 MWd/MTU) or BOC15 to (EOR15 – 3022 MWd/STU)
MOC to EOC	(EOR15 – 3331 MWd/MTU) to EOC15 or (EOR15 – 3022 MWd/STU) to EOC15
BOC to EOC	BOC15 to EOC15

4. Average Planar Linear Heat Generation Rate

The MAPLHGR values for the most limiting lattice of each fuel type as a function of average planar exposure are given in Tables 4-1 and 4-2. During single loop operation, these limits are multiplied by the fuel-dependent SLO multiplier listed in Table 4-3. The MAPLHGR values in Tables 4-1 and 4-2 along with the MAPLHGR SLO multipliers in Table 4-3 provide coverage for all modes of operation.

Table 4-1 MAPLHGR for GNF2 Fuel
(Reference 7)

Avg. Planar Exposure (GWd/MTU)/ (GWd/STU)	MAPLHGR (kW/FT)
0.00 / 0.00	13.78
18.91 / 17.15	13.78
67.00 / 60.78	6.87
70.00 / 63.50	5.50

Table 4-2 MAPLHGR for ATRIUM-10 Fuel
(Reference 7)

Avg. Planar Exposure (GWd/MTU)/ (GWd/STU)	MAPLHGR (kW/FT)
0.00 / 0.00	12.81
23.61 / 21.41	12.81
61.10 / 55.42	9.10
70.40 / 63.86	7.30

Table 4-3 MAPLHGR SLO Multiplier for GNF2 and ATRIUM-10 Fuel, BOC to EOC
(Reference 7)

Fuel Type	SLO MAPLHGR Multiplier
GNF2	0.78
ATRIUM-10	0.78

5. Operating Limit Minimum Critical Power Ratio

5.1. Manual Flow Control MCPR Limits

The steady-state OLMCPRs given in Table 5-2 are the maximum values obtained from analysis of the pressurization events, non-pressurization events, and the Option III stability evaluation. MCPR values are determined by the cycle-specific fuel reload analyses in Reference 7. Table 5-2 is used in conjunction with the ARTS-based power and flow dependencies presented in the sections below.

5.1.1. Power-Dependent MCPR

The power-dependent MCPR multiplier, K_P, is determined from Table 5-3, and is dependent only on the power level and the Application Group (EOOS). The product of the steady state OLMCPR and the proper K_P provides the power-dependent OLMCPR.

5.1.2. Flow-Dependent MCPR

Tables 5-4 through 5-5 give the $MCPR_F$ limit as a function of the core flow, based on the applicable plant conditions. The $MCPR_F$ limit determined from these tables is the flow-dependent OLMCPR. Table 5-5, for SLO, was created by adjusting the Table 5-4 limits by the delta of the SLO and DLO SLMCPR values (0.03) as stated in Reference 7 and clarified in Reference 15. The data in Table 5-4 is taken from Reference 7.

5.2. Scram Time

Option A and Option B MCPR analyses and results are dependent upon core average control rod blade scram speed insertion times.

The Option A scram time is the Improved Technical Specification scram speed based insertion time. The core average scram speed insertion time for 20% insertion must be less than or equal to the Technical Specification scram speed insertion time to utilize the Option A MCPR limits. Reload analyses performed by GNF for Cycle 15 Option A MCPR limits utilized a 20% core average insertion time of 0.900 seconds (Reference 10).

To utilize the MCPR limits for the Option B scram speed insertion times, the core average scram speed insertion time for 20% insertion must be less than or equal to 0.694 seconds (Reference 10) (0.672 seconds at notch position 39, Reference 11). See Table 5-1 for a summary of scram time requirements related to the use of Option A and Option B MCPR limits.

If the core average scram insertion time does not meet the Option B criteria, but is within the Option A criteria, the appropriate steady state MCPR value may be determined from a linear interpolation between the Option A and B limits with standard mathematical rounding to two decimal places. When performing the linear interpolation to determine MCPR limits, ensure that the time used for Option A is 0.900 seconds (0.875 seconds to notch position 39, Reference 11). Note that making interpolations using the Table 5-2 data is conservative because the stability based OLMCPR sets the limit in many conditions. The Option A to Option B linear interpolation need not include the stability OLMCPR penalty on the endpoints when the calculation is made. However, the result of the linear interpolation is required to be 1.48 or greater for the steady state OLMCPR due to the OPRM PBDA setpoint (see Section 9 of the COLR and Reference 7).

Table 5-1 Scram Times Required for Option A and Option B Application at Notch Position 39
(References 10 and 11)

Notch Position*	Scram Time Required for Option A Application	Scram Time Required for Option B Application
39	≤ 0.875 sec.	≤ 0.672 sec.

* - The insertion time to a notch position is conservatively calculated using the CRD reed switch drop-out time per Reference 11.

5.3. Recirculation Flow Control Valve Settings

Cycle 15 was analyzed with a maximum core flow runout of 105%; therefore the recirculation pump flow control valves must be set to maintain core flow less than 105% (113.925 Mlbm/hr) for all runout events.

Table 5-2 Operating Limit Minimum Critical Power Ratio (OLMCPR) for ATRIUM-10 and GNF2 Fuel
(Reference 7)

Application Group	DLO/ SLO	Exposure Range	Option A		Option B	
			GNF2	ATRM10	GNF2	ATRM10
Base Case	DLO	BOC-MOC	1.50	1.48 (2)	1.48 (2)	1.48 (2)
		MOC-EOC	1.56	1.53 (3)	1.51	1.48
Base Case	SLO(1)	BOC-MOC	1.59	1.48	1.59	1.48 (2)
		MOC-EOC	1.59	1.56 (3)	1.59	1.51
Base Case + TCVSC + RPTOOS + PROOS	DLO	BOC-MOC	1.58	1.57	1.48	1.48 (2)
		MOC-EOC	1.64	1.68	1.54	1.51
Base Case + TCVSC + RPTOOS + PROOS	SLO(1)	BOC-MOC	1.61	1.60	1.59	1.49
		MOC-EOC	1.67	1.71	1.59	1.54
Base Case + TCVSC + TBVOOS (all 5 valves)	DLO	BOC-MOC	1.53	1.48	1.48	1.48 (2)
		MOC-EOC	1.59	1.53	1.54	1.50
Base Case + TCVSC + TBVOOS (all 5 valves)	SLO(1)	BOC-MOC	1.59	1.51	1.59	1.48
		MOC-EOC	1.62	1.56	1.59	1.53
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	DLO	BOC-MOC	1.61	1.59	1.51	1.48
		MOC-EOC	1.68	1.71	1.58	1.54
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	SLO(1)	BOC-MOC	1.64	1.62	1.59	1.51
		MOC-EOC	1.71	1.74	1.61	1.57

(1) For single loop operation, the OLMCPR is the greater of (a) the OPRM based OLMCPR value of 1.48 or (b) 0.03 greater than the two loop limit. However, a minimum value of 1.59 is required for GNF2 fuel to protect the OLMCPR set by the single loop operation recirculation pump seizure event (Reference 7). The single loop operation recirculation pump seizure event is less limiting than the OPRM setpoint for ATRIUM-10 fuel.

(2) OLMCPR is set to reflect OPRM amplitude setpoint of 1.11 (OLMCPR of 1.48) (References 7 and 13). The OPRM amplitude setpoint and resultant OLMCPR are applicable to both DLO and SLO, without alteration.

(3) As part of the Kp improvement analysis (see Reference 7), a requirement is added that the ATRIUM 10 Option A Base Case MOC-EOC DLO OLMCPR have a minimum value of 1.53. The minimum SLO value needs to be increased by the SLO adder of 0.03 resulting in a value of 1.56.

Table 5-3 Power-Dependent MCPR Multipliers (K_P) for ATRIUM-10 and GNF2 Fuel, DLO and SLO, BOC to EOC, Option A and Option B
(Reference 7)

Application Group	K_P, MCPR Limit Multiplier (as a function of % rated power)						
	0% P	25% P	45% P	60% P	85% P	85.01%P	100% P
Base Case	1.338	1.338	1.191	1.191	1.061	1.061	1.000
Base Case + TCVSC + RPTOOS + PROOS	1.488	1.488	1.378	1.296	1.174	1.097	1.000
Base Case + TCVSC + TBVOOS (all 5 valves)	1.379	1.379	1.228	1.207	1.097	1.097	1.000
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	1.488	1.488	1.378	1.296	1.174	1.097	1.000

Table 5-4 DLO Flow-Dependent MCPR Limits ($MCPR_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, All Application Groups, Option A and Option B
(Reference 7)

Flow (% Rated)	$MCPR_F$
0.0	1.91
30.0	1.72
105.0	1.25

Table 5-5 SLO Flow-Dependent MCPR Limits ($MCPR_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, All Application Groups, Option A and Option B
(References 7 and 15)

Flow (% Rated)	$MCPR_F$
0.0	1.94
30.0	1.75
105.0	1.28

6. Linear Heat Generation Rate

The linear heat generation rate (LHGR) limit is the product of the exposure dependent LHGR limit from Table 6-1 or Table 6-2 and the minimum of: the power dependent LHGR Factor, $LHGRFAC_P$, or the flow dependent LHGR Factor, $LHGRFAC_F$ as applicable. The $LHGRFAC_P$ multiplier is determined from Table 6-3. The $LHGRFAC_F$ multiplier is determined from either Table 6-4 or Table 6-5. The SLO multipliers in Tables 6-4 and 6-5 have been limited to a maximum value of 0.78, the SLO LHGR multiplier for GNF2 and ATRIUM-10 fuel.

Table 6-1 LHGR Limit for GNF2 Fuel
(References 8 and 12)

See Appendix A (1)

Table 6-2 LHGR Limit for ATRIUM-10 Fuel
(Reference 9)

Peak Pellet Exposure (GWd/MTU) / (GWd/STU)	LHGR Limit (kW/ft)
0.0 / 0.0	13.4
17.7 / 16.06	13.4
61.1 / 55.43	9.1
70.4 / 63.87	7.3

(1) The only LHGR limits required to be used to monitor GNF2 fuel for L2C15 are the UO2 pin limits (Reference 12). Gadolinia containing pins are non-limiting in L2C15 for the GNF2 fuel designs.

Table 6-3 Power-Dependent LHGR Multipliers ($LHGRFAC_P$) for ATRIUM-10 and GNF2 Fuel, DLO and SLO, BOC to EOC
(Reference 7)

Application Group	$LHGRFAC_P$ (as a function of % rated power)					
	0% P	25% P	45% P	60% P	85% P	100% P
Base Case	0.608	0.608	0.713	0.791	0.922	1.000
Base Case + TCVSC + RPTOOS + PROOS	0.608	0.608	0.713	0.761	0.831	1.000
Base Case + TCVSC + TBVOOS (all 5 valves)	0.608	0.608	0.713	0.791	0.922	1.000
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS	0.608	0.608	0.713	0.761	0.822	1.000

Table 6-4 Flow-Dependent LHGR Multipliers ($LHGRFAC_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, Pressurization (1 TCV/TSV Closed or OOS), All Application Groups
(Reference 7)

Flow (% Rated)	DLO $LHGRFAC_F$	SLO $LHGRFAC_F$
0.0	0.110	0.110
30.0	0.410	0.410
67.0	0.78	0.78
89.0	1.000	0.78
105.0	1.000	0.78

Table 6-5 Flow-Dependent LHGR Multipliers ($LHGRFAC_F$) for ATRIUM-10 and GNF2 Fuel, BOC to EOC, No Pressurization (All TCV/TSV In-Service), All Application Groups
(Reference 7)

Flow (% Rated)	DLO $LHGRFAC_F$	SLO $LHGRFAC_F$
0.0	0.250	0.250
30.0	0.550	0.550
53.0	0.78	0.78
75.0	1.000	0.78
105.0	1.000	0.78

7. Rod Block Monitor

The Rod Block Monitor Upscale Instrumentation Setpoints are determined from the relationships shown below (Reference 3):

Table 7-1 Rod Block Monitor Setpoints

Rod Block Monitor Upscale Trip Function	Allowable Value
Two Recirculation Loop Operation	$0.66\ W_d + 54.0\%$
Single Recirculation Loop Operation	$0.66\ W_d + 48.7\%$

The setpoint may be lower/higher and will still comply with the rod withdrawal error (RWE) analysis because RWE is analyzed unblocked. The allowable value is clamped with a maximum value not to exceed the allowable value for a recirculation loop drive flow (W_d) of 100%.

W_d – percent of recirculation loop drive flow required to produce a rated core flow of 108.5 Mlbm/hr.

8. Traversing In-Core Probe System

8.1. Description

When the traversing in-core probe (TIP) system (for the required measurement locations) is used for recalibration of the LPRM detectors and monitoring thermal limits, the TIP system shall be operable with the following:

1. movable detectors, drives and readout equipment to map the core in the required measurement locations, and
2. indexing equipment to allow all required detectors to be calibrated in a common location.

The following applies for use with 3DM (References 4, 7):

The total number of failed and bypassed LPRMs does not exceed 25%. In addition, no more than 14 TIP channels can be OOS (failed or rejected).

Otherwise, with the TIP system inoperable, suspend use of the system for the above applicable calibration functions.

8.2. Bases

The operability of the TIP system with the above 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 normalization of the required detectors is performed internal to the core monitoring software system.

9. Stability Protection Setpoints

The OPRM PBDA trip settings are shown in Table 9-1 and were taken from the Reference 13 transmittal.

Table 9-1 OPRM PBDA Trip Setpoints
(References 7 and 13)

PBDA Trip Amplitude Setpoint (Sp)	Corresponding Maximum Confirmation Count Setpoint (Np)
1.11	14

The PBDA is the only OPRM setting credited in the safety analysis as documented in the licensing basis for the OPRM system.

The OPRM PBDA trip settings are based, in part, on the cycle specific OLMCPR and the power dependent MCPR limits. Any change to the OLMCPR values and/or the power dependent MCPR limits should be evaluated for potential impact on the OPRM PBDA trip settings.

The OPRM PBDA trip settings are applicable when the OPRM system is declared operable, and the associated Technical Specifications are implemented.

10. Modes of Operation

The allowed modes of operation with combinations of equipment out-of-service are as described below (Reference 7).

Table 10-1 Allowed Modes of Operation and EOOS Combinations
(Reference 7)

Equipment Out of Service Options (1) (2) (4) (5)	Short Name
Base Case (Option A or B) (3)	Base
Base Case + SLO (Option A or B)	Base SLO
Base Case + TCVSC + RPTOOS + PROOS (Option A or B)	Combined EOOS 1
Base Case + TCVSC + RPTOOS + PROOS + SLO (Option A or B)	Combined EOOS 1 SLO
Base Case + TCVSC + TBVOOS (all 5 valves) (Option A or B)	Combined EOOS 2
Base Case + TCVSC + TBVOOS (all 5 valves) + SLO (Option A or B)	Combined EOOS 2 SLO
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS (Option A or B)	Combined EOOS 3
Base Case + TCVSC + TBVOOS (all 5 valves) + RPTOOS + PROOS + SLO (Option A or B)	Combined EOOS 3 SLO

(1) Base case includes 1 SRVOOS + 1 TCV/TSV OOS + FWHOOS/FFWTR + 1 MSIVOOS + 2 TBVOOS + PLUOOS, and also includes 1 TIPOOS (up to 14 TIP channels not available) any time during the cycle, including BOC, and up to 25% of the LPRMs out-of-service. The FWHOOS/FFWTR analyses cover a maximum reduction of 100°F for the feedwater temperature. A nominal LPRM calibration interval of 2000 EFPH (2500 EFPH maximum) is supported for L2C15.

(2) TBVOOS (all 5 valves) is the turbine bypass system out of service which means that 5 TBVs are not credited for fast opening and 3 TBVs are not credited to open in pressure control. For the 2 TBVOOS condition that is a part of the base case, the assumption is that both of the TBVs do not open on any signal and thus remain shut for the transients analyzed (i.e. 3 TBVs are credited to open in pressure control). The MCFL is currently set at 126.6 and will only allow opening of TBV's #1, #2, #3, and #4 during a slow pressurization event. The MCFL does not use the TBV position feedback signal to know how many TBVs have opened or how far each has opened. The #5 TBV is not available based on the current MCFL setpoint and thus cannot be used as one of the credited valves to open in pressure control.

(3) With all TCV/TSV In-Service, the Base Case should be used with the $LHGRFAC_F$ values from Table 6-5 (Reference 7). With 1 TCV/TSV OOS, the Base Case must be used with the $LHGRFAC_F$ values from Table 6-4. The one Stuck Closed TCV and/or TSV EOOS conditions require power level ≤ 85% of rated. The one MSIVOOS condition is also supported as long as thermal power is maintained ≤ 75% of the rated.

(4) The + sign that is used in the Equipment Out of Service Option / Application Group descriptions designates an "and/or".

(5) All EOOS Options (Reference 7 Application Groups) are applicable to ELLLA, MELLLA, ICF and Coastdown realms of operation with the exception that SLO is not applicable to MELLLA or ICF (References 5 and 6). The MOC to EOC exposure range limit sets are generated by GNF to include application to coastdown operation (Methodology Reference 19).

11. Methodology

The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. XN-NF-81-58 (P)(A), Revision 2 and Supplements 1 and 2, "RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model," March 1984.
2. ANF-524 (P)(A) Revision 2 and Supplements 1 and 2, "ANF Critical Power Methodology for Boiling Water Reactors," November 1990 [XN-NF-524 (P)(A)].
3. ANF-913 (P)(A) Volume 1 Revision 1, and Volume 1 Supplements 2, 3, 4, "COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses," August 1990.
4. XN-NF-84-105 (P)(A), Volume 1 and Volume 1 Supplements 1 and 2; Volume 1 Supplement 4, "XCOBRA-T: A Computer Code for BWR Transient Thermal-Hydraulic Core Analysis," February 1987 and June 1988, respectively.
5. EMF-2209 (P)(A), Revision 3, "SPCB Critical Power Correlation," September 2009.
6. ANF-89-98 (P)(A), Revision 1 and Revision 1 Supplement 1, "Generic Mechanical Design Criteria for BWR Fuel Designs," May 1995.
7. EMF-85-74 (P) Revision 0 Supplement 1(P)(A) and Supplement 2(P)(A), "RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model," February 1998.
8. EMF-CC-074 (P)(A) Volume 4 Revision 0, "BWR Stability Analysis: Assessment of STAIF with Input from MICROBURN-B2," August 2000.
9. ANF-CC-33 (P)(A) Supplement 1 Revision 1 and Supplement 2, "HUXY: A Generalized Multirod Heatup Code with 10 CFR 50, Appendix K Heatup Option," August 1986 and January 1991, respectively.
10. XN-NF-80-19 (P)(A) Volume 4 Revision 1, "Exxon Nuclear Methodology for Boiling Water Reactors: Application of the ENC Methodology to BWR Reloads," June 1986.
11. XN-NF-85-67 (P)(A) Revision 1, "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," September 1986.
12. XN-NF-80-19 (P)(A) Volume 3 Revision 2, "Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX: Thermal Limits Methodology Summary Description," January 1987.
13. XN-NF-80-19 (P)(A) Volume 1 and Supplements 1 and 2, "Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis," March 1983.
14. EMF-2158 (P)(A), Revision 0, "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2," Siemens Power Corporation, October 1999.
15. EMF-2245 (P)(A), Revision 0, "Application of Siemens Power Corporation's Critical Power Correlations to Co-Resident Fuel," August 2000.
16. EMF-2361 (P)(A), Revision 0, "EXEM BWR-2000 ECCS Evaluation Model," May 2001.
17. NEDO-32465-A, "BWR Owner's Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.
18. ANF-1358 (P)(A), Revision 3, "The Loss of Feedwater Heating Transient in Boiling Water Reactors," September 2005.
19. NEDE-24011-P-A-19 (Revision 19), "General Electric Standard Application for Reactor Fuel," May 2012 and the U.S. Supplement NEDE-24011-P-A-19-US of May 2012.
20. NEDC-33106P-A Revision 2, "GEXL97 Correlation for ATRIUM-10 Fuel," June 2004.

Appendix A

Global Nuclear Fuel
A Joint Venture of GE Toshiba & Hitachi

Global Nuclear Fuel

0000-0156-1147-FBIR-NP
Revision 0
January 2013

Non-Proprietary Information-Class I (Public)

FUEL BUNDLE INFORMATION REPORT FOR LASALLE UNIT 2 RELOAD 14 CYCLE 15

Important Notice Regarding Contents of This Report

Please Read Carefully

This report was prepared by Global Nuclear Fuel - Americas, LLC (GNF-A) solely for use by Exelon ("Recipient") in support of the operating license for LaSalle 2 (the "Nuclear Plant"). The information contained in this report (the "Information") is believed by GNF-A to be an accurate and true representation of the facts known by, obtained by or provided to GNF-A at the time this report was prepared.

The only undertakings of GNF-A respecting the Information are contained in the contract between Recipient and GNF-A for nuclear fuel and related services for the Nuclear Plant (the "Fuel Contract") and nothing contained in this document shall be construed as amending or modifying the Fuel Contract. The use of the Information for any purpose other than that for which it was intended under the Fuel Contract, is not authorized by GNF-A. In the event of any such unauthorized use, GNF-A neither (a) makes any representation or warranty (either expressed or implied) as to the completeness, accuracy or usefulness of the Information or that such unauthorized use may not infringe privately owned rights, nor (b) assumes any responsibility for liability or damage of any kind which may result from such use of such information.

Information Notice

This is a non-proprietary version of the document 0000-0156-1147-FBIR-P, Revision 0, which has the proprietary information removed. Portions of the document that have been removed are indicated by an open and closed bracket as shown here [[ ]].

1. Introduction and Summary

This report, which supplements the *Supplemental Reload Licensing Report*, contains thermal-mechanical linear heat generation rate (LHGR) limits for the GNF-A fuel designs to be loaded into LaSalle Unit 2 for Cycle 15 These LHGR limits are obtained from thermal-mechanical considerations only Approved GNF-A calculation models documented in Reference 1 were used in performing this analysis

LHGR limits as a function of exposure for each bundle of the core design are given in Appendix A The LHGR values provided in Appendix A provide upper and lower exposure dependent LHGR boundaries which envelope the actual gadolinia dependent LHGR limits. The LHGRs reported have been rounded to two places past the decimal.

Appendix B contains a description of the fuel bundles. Table B-1 contains a summary of bundle-specific information, and the figures provide the enrichment distribution and gadolinium distribution for the fuel bundles included in this appendix. These bundles have been approved for use under the fuel licensing acceptance criteria of Reference 1.

2. References

1 *General Electric Standard Application for Reactor Fuel*, NEDE-24011-P-A-19, May 2012, and the U S Supplement NEDE-24011-P-A-19-US, May 2012.

Appendix A
UO_2/Gd Thermal-Mechanical LHGR Limits

Bundle Type: GNF2-P10CG2B408-12GZ-120T2-150-T6-4069 (GNF2)

Bundle Number: 4069

Peak Pellet Exposure	UO_2 LHGR Limit
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit [1]
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

[1] Bounding gadolinia LHGR limit for all gadolinium concentrations occurring in this bundle design [[ ]]

UO_2/Gd Thermal-Mechanical LHGR Limits

Bundle Type. GNF2-P10CG2B410-17GZ-120T2-150-T6-4070 (GNF2)

Bundle Number. 4070

Peak Pellet Exposure	UO_2 LHGR Limit
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit [2]
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

[2] Bounding gadolinia LHGR limit for all gadolinium concentrations occurring in this bundle design [[ ]]

UO_2/Gd Thermal-Mechanical LHGR Limits

Bundle Type: GNF2-P10CG2B408-15GZ-120T2-150-T6-4206 (GNF2)

Bundle Number: 4206

Peak Pellet Exposure	UO_2 LHGR Limit
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit [3]
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

[3] Bounding gadolinia LHGR limit for all gadolinium concentrations occurring in this bundle design [[ ]]

UO_2/Gd Thermal-Mechanical LHGR Limits

Bundle Type GNF2-P10CG2B403-16GZ-120T2-150-T6-4205 (GNF2)

Bundle Number 4205

Peak Pellet Exposure	UO_2 LHGR Limit
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit [4]
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

[4] Bounding gadolinia LHGR limit for all gadolinium concentrations occurring in this bundle design [[ ]]

UO_2/Gd Thermal-Mechanical LHGR Limits

Bundle Type GNF2-P10CG2B402-17GZ-120T2-150-T6-4207 (GNF2)

Bundle Number 4207

Peak Pellet Exposure	UO_2 LHGR Limit
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

Peak Pellet Exposure	Most Limiting Gadolinia LHGR Limit [5]
GWd/MT (GWd/ST)	kW/ft
[[	
	]]

[5] Bounding gadolinia LHGR limit for all gadolinium concentrations occurring in this bundle design [[ ]]

Appendix B
Fuel Bundle Information

Table B-1 Bundle Specific Information						
Fuel Bundle	Bundle Number	Enrichment (wt% U-235)	Weight of UO_2 (kg)	Weight of U (kg)	Max k_∞ at 20°C [*]	Exposure at Max k_∞ GWd/MT (GWd/ST)
GNF2-P10CG2B408-12GZ-120T2-150-T6-4069 (GNF2)	4069	[[				
GNF2-P10CG2B410-17GZ-120T2-150-T6-4070 (GNF2)	4070					
GNF2-P10CG2B408-15GZ-120T2-150-T6-4206 (GNF2)	4206					
GNF2-P10CG2B403-16GZ-120T2-150-T6-4205 (GNF2)	4205					
GNF2-P10CG2B402-17GZ-120T2-150-T6-4207 (GNF2)	4207					]]

[*] Maximum lattice k_∞ for the most reactive uncontrolled state plus a [[ ]] adder for uncertainties

[[

]]

Figure B-1 Enrichment and Gadolinium Distribution for EDB No. 4069
Fuel Bundle GNF2-P10CG2B408-12GZ-120T2-150-T6-4069 (GNF2)

[[

]]

Figure B-2 Enrichment and Gadolinium Distribution for EDB No. 4070
Fuel Bundle GNF2-P10CG2B410-17GZ-120T2-150-T6-4070 (GNF2)

[[

]]

Figure B-3 Enrichment and Gadolinium Distribution for EDB No. 4206
Fuel Bundle GNF2-P10CG2B408-15GZ-120T2-150-T6-4206 (GNF2)

[[

]]

Figure B-4 Enrichment and Gadolinium Distribution for EDB No. 4205
Fuel Bundle GNF2-P10CG2B403-16GZ-120T2-150-T6-4205 (GNF2)

[[

]]

Figure B-5 Enrichment and Gadolinium Distribution for EDB No. 4207
Fuel Bundle GNF2-P10CG2B402-17GZ-120T2-150-T6-4207 (GNF2)

TECHNICAL REQUIREMENTS MANUAL
CONTROL PROGRAM

TABLE OF CONTENTS

1.1 PURPOSE

The purpose of this Program is to provide guidance for identifying, processing, and implementing changes to the Technical Requirements Manual (TRM). This Program implements and satisfies the requirements of TRM Section 1.6, "Technical Requirements Manual Revisions."

This Program is applicable to the preparation, review, implementation, and distribution of changes to the TRM. This Program also provides guidance for preparing TRM Change Packages for distribution.

1.2 REFERENCES

1. TRM Section 1.6, "Technical Requirements Manual Revisions"
2. 10 CFR 50.4, "Written Communications"
3. 10 CFR 50.59, "Changes, Tests and Experiments"
4. 10 CFR 50.71, "Maintenance of Records, Making of Reports"
5. 10 CFR 50.90, "Application for Amendment of License or Construction Permit"

1.3 DEFINITIONS AND/OR ACRONYMS

10 CFR 50.59 REVIEW - A written regulatory evaluation which provides the basis for the determination that a change does, or does not, require NRC approval pursuant to 10 CFR 50.59. The scope of the evaluation should be commensurate with the potential safety significance of the change, but must address the relevant safety concerns included in the Safety Analysis Report and other owner controlled documents. The depth of the evaluation must be sufficient to determine whether or not NRC approval is required prior to implementation. Depending upon the significance of the change, the evaluation may be brief; however, a simple statement of conclusion is not sufficient.

EDITORIAL CHANGE - Editorial changes include correction of punctuation, insignificant word or title changes, style or format changes, typographical errors, or correction of reference errors that do not change the intent, outcome, results, functions, processes, responsibilities, or performance requirements of the item being changed. Changes in numerical values shall not be considered as editorial changes. Editorial changes do not constitute a change to the TRM and therefore do not require further 10 CFR 50.59 Reviews. If the full scope of this proposed change is encompassed by one or more of the below, then the change is considered editorial.

- Rewording or format changes that do not result in changing actions to be accomplished.
- Deletion of cycle-specific information that is no longer applicable.
- Addition of clarifying information, such as:
    - Spelling, grammar, or punctuation changes
    - Changes to references
    - Name or title references

1.4 PROGRAM DESCRIPTION

1. A Licensee may make changes to the TRM without prior NRC approval provided the changes do not require NRC approval pursuant to 10 CFR 50.59.

2. Changes that require NRC approval pursuant to 10 CFR 50.59 shall be submitted to the NRC pursuant to 10 CFR 50.90 and reviewed and approved by the NRC prior to implementation.

3. The TRM is part of the Updated Final Safety Analysis Report (UFSAR) by reference and shall be maintained consistent with the remainder of the UFSAR.

4. If a change to the TRM is not consistent with the remainder of the UFSAR, then the cognizant Engineer shall prepare and submit a UFSAR Change Package when the TRM Change Request is submitted to Regulatory Assurance (RA) for processing.

5. Changes to the TRM that do not require prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e), as modified by approved exemptions.

6. Any change to a Station's TRM shall be transmitted, via Attachment D, "Technical Requirements Manual Change Applicability Review Form," to the Regulatory Assurance Managers (RAMs) at each of the other Stations. The RAM will review the TRM change for applicability at their respective Station and document their review on Attachment D.

7. TRM changes associated with a Technical Specifications (TS) Amendment shall be implemented consistent with the implementation requirements of the TS Amendment.

8. RA is responsible for the control and distribution of the TRM. In order to prevent distribution errors (i.e., omissions or duplications), RA shall maintain the master TRM distribution list.

1.5 PROGRAM IMPLEMENTATION

1. TRM Change Requestor identifies the need for a revision and completes Parts 2, 3, 4, and 8 of Attachment A, "Technical Requirements Manual Change Request Form," as follows:

    a. Identifies the affected sections, and includes a copy of the proposed TRM changes;

    b. Briefly summarizes the changes including the TLCO, Action, Surveillance Requirement, or Bases (if applicable) to which the changes apply;

    c. Briefly summarizes the reason for the changes and attaches all supporting documentation:

    d. Signs and dates as Requestor and identifies the originating department; and

    e. Forwards Attachment A to the Regulatory Assurance Licensing Engineer (RA LE).

2. RA LE reviews the change and determines if the change is needed and consistent with the information and level of detail contained in the TRM.

   a. If the change is acceptable, the RA LE signs Part 9 of Attachment A and continues with Step 3 of this Appendix.

   b. If the change is determined to be inappropriate for inclusion in the TRM, the RA LE rejects the change and returns Attachment A to the Requestor with the reason for why the change was denied and exits this Appendix.

3. RA LE assigns a TRM Change Request Number (CR #) and records on Part 1 of Attachment A, "Technical Requirements Manual Change Request Form." The CR # should be a number beginning with the last two digits of the year (e.g., 00-00#).

4. RA LE drafts TRM changes considering format, rules of usage, and technical adequacy. The TRM and its Bases are revised on a section basis; individual page revisions are not performed. The Revision number in the footer should be a sequential number (i.e., 1, 2, etc.).

5. If the TRM change is not an EDITORIAL CHANGE, the RA LE generates an Station Quality Review (SQR) review form for the TRM change by performing the following:

   a Prepares the TRM Change Package. The package shall include Attachment A, the SQR review form, and the revised TRM pages;

   b. The SQR composition shall include RA and Operating Departments in all cases; and

   c. Returns the TRM Change Package to the Requestor for completing the review and resolving review comments.

6. TRM Change Requestor provides a 10 CFR 50.59 REVIEW for the TRM changes in accordance with appropriate plant procedures. An exception to this requirement applies when the changes are being requested in order to reflect an approved NRC Safety Evaluation (SE) associated with a site-specific operating license or TS change. The NRC SE is sufficient to support the changes provided it has been determined that the changes are consistent with and entirely bounded by the NRC SE. A 50.59 review

shall be performed for TRM changes that reflect generic industry approval by an NRC SE to determine site-specific applicability. A 10 CFR 50.59 REVIEW is not required for an EDITORIAL CHANGE.

7. TRM Change Requestor completes Parts 5 through 7 of Attachment A, as follows:

   a. Identifies any schedule requirements and proposed implementation date that apply (i.e., describe any time limitations that might apply which would require expedited processing). If the changes are outage related, then checks "yes" and lists the applicable outage identifier;

   b. Identifies any known implementation requirements such as procedure changes, UFSAR changes, Passport changes, Reportability Manual revisions, pre-implementation training requirements, etc.;

   c. If a 10 CFR 50.59 REVIEW was required to support the TRM changes, the Requestor then checks the appropriate box, lists the associated 10 CFR 50.59 REVIEW Number, and attaches the original;

   d. If the changes to the TRM are the result of an NRC SE and the scope of the changes determined to be consistent with and entirely bounded by the NRC SE, then the Requestor checks the appropriate box and attaches a copy;

   e. If the changes to the TRM are EDITORIAL CHANGES, then the Requestor checks the appropriate box and no 10 CFR 50.59 REVIEW is required;

   f. Obtains required reviews and resolves comments, as applicable, and documents on the SQR review form; and

   g. Returns TRM change package to the RA LE.

8. The RAM (or designee) shall determine the need for Plant Operations Review Committee (PORC) approval. The need for PORC approval shall be documented on Part 10 of Attachment A.

9. RA LE reviews the TRM Change Request Form, including supporting documentation, and documents the review by signing Attachment A. The review verifies that the following information or documentation is included:

   a. Completed 10 CFR 50.59 REVIEW. If the changes are related to an NRC SE and determined to be entirely bounded by the NRC SE, then only a copy of the SE is required to be attached and no 10 CFR 50.59 REVIEW is required. A 10 CFR 50.59 REVIEW is not required for an EDITORIAL CHANGE;

   b. Identification of known documents requiring revisions. RA LE shall assign Action Tracking (AT) items, as necessary, to track implementation requirements; and

   c. Completed SQR review with any comments resulting from the SQR process incorporated, if applicable.

10. The Requestor with RA LE assistance obtains PORC approval, if necessary.

11. After approval of the TRM changes by SQR/PORC, RA LE ensures that the controlled master electronic files are updated.

12. RA LE completes Attachment C, "Technical Requirements Manual Change Instruction Form," as follows:

   a. Indicates the effective date of the TRM changes consistent with the SQR/PORC approval or TS amendment required implementation date. If the TRM change is a result of a TS Amendment, the update shall be implemented consistent with the implementation requirements of the TS Amendment. Otherwise, the update must be implemented by the date indicated on Attachment C;

   b. Lists each page to be removed and inserted, including the Affected Page List; and

   c. Provides the updated master file directory for updating Electronic Document Management System (EDMS), if applicable.

13. RA LE creates a TRM Change Instruction Package. The TRM Change Instruction Package shall consist of:

    1. TRM Change Instruction Form (Attachment C);

    2. Revised Affected Page List; and

    3. Revised TRM pages.

    One RA LE shall assemble and approve the TRM Change Instruction Package for distribution and a second RA LE shall perform a peer check to verify completeness of the TRM Change Instruction Package.

14. After verifying that SQR/PORC approval of the TRM changes has been obtained and that all AT items assigned to track implementation requirements have been completed (or are scheduled to be completed if not necessary for implementation), RA LE forwards the TRM Change Instruction Package to Station Administration Department as notification of the need to update the onsite TRM controlled copies and EDMS, if applicable.

15. RA LE notifies RAMs at each of the other Stations by transmitting Attachment D, "Technical Requirements Manual Change Applicability Review Form."

16. RA LE also forwards the TRM Change Package to LS Administration Department as notification of the need to update the offsite (LS) TRM controlled copies and to transmit updates to the offsite (non-LS) TRM controlled copies.

17. Upon completion of updating the onsite TRM controlled copies and EDMS (if applicable), Station Administration Department Supervisor signs and dates Attachment C and returns Attachment C to the RA LE.

18. Upon completion of updating the offsite (LS) TRM controlled copies and transmitting updates to the offsite (non-LS) TRM controlled copies, RS Administration Department signs and dates Attachment C and returns Attachment C to the RA LE.

19. RA LE ensures that the documentation required to be maintained as a quality record is provided to Station Administration Department for the purpose of record retention.

1.6 ACCEPTANCE CRITERIA

Not applicable.

1.7 COMPENSATORY MEASURES

A Issue Report may need to be generated to provide proper tracking and resolution of noted problems associated with the implementation of this Program.

The RAM will be responsible for ensuring that Program failures have been resolved.

1.8 REPORTING REQUIREMENTS

NOTE

TRM changes requiring prior NRC approval shall be submitted in accordance with Reference 5.

TRM changes not requiring prior NRC approval, as described in Section 1.4 of this Program, shall be submitted to the NRC in accordance with 10 CFR 50.71(e).

1.9 CHANGE CONTROL

Changes to this Program, other than EDITORIAL CHANGES, shall include a 10 CFR 50.59 REVIEW, an SQR, and PORC approval. The SQR composition shall include RA and Operating Departments in all cases.

ATTACHMENT A
TECHNICAL REQUIREMENTS MANUAL CHANGE REQUEST FORM

1. Change Request #: ______________

2. Affected TRM Section(s): ________________________

3. Description of changes: ____
____

4. Reason for changes (attach all supporting documentation): ________________________________
____

5. Schedule Requirements: Outage Related (check one) ( ) No ( ) Yes, Outage # ______
Other (explain) ____

6. Implementation Requirements (attach additional pages, as necessary):
Identify the impact of the changes on the following:

Affected	N/A	
( )	( )	UFSAR ______________________________________
( )	( )	TS/TS Bases______________________________________
( )	( )	NRC Safety Evaluation ______________________________________
( )	( )	Fire Protection Report ______________________________________
( )	( )	NRC Commitments ______________________________________
( )	( )	Vendor Documentation ______________________________________
( )	( )	Special Permits/Licenses ______________________________________
( )	( )	Procedures ______________________________________
( )	( )	Environmental Qualification ______________________________________
( )	( )	Design Basis Documentation ______________________________________
( )	( )	Engineering Calculations ______________________________________
( )	( )	Drawings/Prints ______________________________________
( )	( )	PRA Information ______________________________________
( )	( )	Programs ______________________________________
( )	( )	Reportability Manual ______________________________________
( )	( )	QA Topical Report ______________________________________
( )	( )	Passport______________________________________
( )	( )	Pre-Implementation Training Required ______________________________
( )	( )	Maintenance Rule ______________________________________
( )	( )	Offsite Dose Calculation Manual ______________________________
( )	( )	Other ______________________________________

7. Check one:
( ) 10 CFR 50.59 REVIEW Attached, 10 CFR 50.59 REVIEW #:________________________
( ) NRC SE Attached, Changes consistent with and entirely bounded by NRC SE
( ) EDITORIAL CHANGE, No 10 CFR 50.59 REVIEW required

8. Requestor: ______________________/______________________/______________________
(Signature) (Date) (Department)

9. Regulatory Assurance Approval: ______________________/______________________
(Signature) (Date)

10. PORC Approval Required: ( ) Yes ( ) No

11. Licensing Engineer Review: ______________________/______________________
(Signature) (Date)

ATTACHMENT B
(Deleted)

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ATTACHMENT C
TECHNICAL REQUIREMENTS MANUAL CHANGE INSTRUCTION FORM
FOR ONSITE/OFFSITE DISTRIBUTION AND FOR UPDATING EDMS

LaSalle TRM Revision # ____

NOTE: This change is effective as of ______________________________ and shall be implemented by ___________ . (SQR/PORC or Amendment Implementation Date)
(Date)

Approved for distribution: ______________________________/____________
(RA LE Signature) (Date)

Verified: ______________________________/____________
(RA LE Signature) (Date)

Section	REMOVE Page	INSERT Section	INSERT Page	UPDATE EDMS Section	UPDATE EDMS Page
Affected Page List	All	Affected Page List	All	N/A	N/A

ATTACHMENT C
TECHNICAL REQUIREMENTS MANUAL CHANGE INSTRUCTION FORM
FOR ONSITE/OFFSITE DISTRIBUTION AND FOR UPDATING EDMS

LaSalle Station TRM Revision # ___________________________________

Station Administration Department:

Onsite Distribution Completed: ______________________________/___________________
(Station Admin. Dept. Supr.) (Date)

EDMS Update Completed: ______________________________/___________________
(Station Admin. Dept. Supr.) (Date)

** Return this sheet to: Regulatory Assurance
LaSalle Station

RS Administration Department:

Offsite (LS) Distribution Completed: ______________________/______________________
(LS Admin. Dept.) (Date)

Offsite (non-LS) Distribution Transmitted: _________________/______________________
(LS Admin. Dept.) (Date)

** Return this sheet to: Regulatory Assurance
LaSalle Station

Offsite (non-LS) Controlled Copy Holders:

Offsite (non-LS) Distribution Completed: ____________/______________________
(Signature) (Date)

** Return this sheet to: EXELON GENERATING COMPANY, LLC
ATTN: LICENSING SERVICES ADMINISTRATION DEPARTMENT
4300 WINFIELD ROAD
WARRENVILLE, IL 60555

ATTACHMENT D
TECHNICAL REQUIREMENTS MANUAL CHANGE APPLICABILITY REVIEW FORM

Any change to a Station's Technical Requirements Manual (TRM) shall be transmitted to the Regulatory Assurance Managers (RAMs) at each of the other Stations. The RAM will review the TRM change for applicability at their respective Station. Review of applicability shall be documented on this Attachment and forwarded to the Regulatory Assurance Licensing Engineer(s) at the Station(s) making the change.

LaSalle Station

TRM Section(s)/Title(s): ______________________________

Description of the change:______________________________
____
____

Braidwood RAM Review: ____________/____________
(Signature) (Date)

Change Applicable: ( ) Yes ( ) No

Byron RAM Review: ____________/____________
(Signature) (Date)

Change Applicable: ( ) Yes ( ) No

Dresden RAM Review: ____________/____________
(Signature) (Date)

Change Applicable: ( ) Yes ( ) No

QC RAM Review: ____________/____________
(Signature) (Date)

Change Applicable: ( ) Yes ( ) No

** Return this sheet to: Regulatory Assurance
LaSalle Station

B 2.1 MISCELLANEOUS TEST REQUIREMENTS

B 2.1.a Miscellaneous Test Requirements

BASES

BACKGROUND

In a letter dated March 3, 2000, LaSalle County Station requested a License Amendment to revise the Technical Specifications to a format and content consistent with NUREG-1433 (Ref. 7) and NUREG-1434 (Ref. 8), the Improved Standard Technical Specifications. In developing the Improved Technical Specifications (ITS) for LaSalle, the station reviewed the selection criteria utilized in BWR Owners Group report NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," and applied the criteria to each of the LaSalle Unit 1 and Unit 2 Technical Specifications. Additionally, the station used the selection criteria provided in the NRC Final Policy Statement on Technical Specification Improvements (Ref. 10) to determine which portions of the Technical Specifications would be retained in the ITS. The selection criteria provided in Reference 10 were codified in 10 CFR 50.36 and are as follows:

<u>Criterion 1:</u> Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

<u>Criterion 2:</u> A process variable, design feature, or operating restriction that is an initial condition of a Design Basis Accident (DBA) or transient analyses that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

<u>Criterion 3:</u> A structure, system, or component (SSC) that is part of the primary success path and which functions or actuates to mitigate a DBA or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

<u>Criterion 4:</u> A structure, system, or component which operating experience or probabilistic safety assessment has shown to be significant to public health and safety.

(continued)

BASES

BACKGROUND (continued)	In a Safety Evaluation Report dated March 30, 2001, the NRC staff found that the Technical Specification Amendment to convert the LaSalle Technical Specifications to the ITS complied with applicable laws and was adequate to protect the health and safety of the public. This approval included the relocation of certain Technical Specification requirements to owner controlled documents such as the UFSAR and the TRM.
APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS	This TRM section contains Surveillance Requirements that were relocated from the Technical Specifications because either the test did not meet the NRC criteria for retention in the Technical Specifications, the test was not required to ensure the OPERABILITY of an SSC, or the test contains ITS acceptance criteria details not required to be retained in the Technical Specifications. Although these tests do not directly assure the OPERABILITY of safety related SSCs, a failure of the equipment being tested could potentially affect the ability of a safety related SSC to perform its safety function depending on the nature of the failure. For this reason, the Surveillance Requirements are modified by a Note stating that in the event that a TSR is determined to be not met, immediate action must be taken to evaluate and determine the OPERABILITY of equipment associated with the TSR. The specific purpose, Applicability, and relationship to Technical Specification and TRM Limiting Conditions for Operation for each Surveillance Requirement are discussed below on a TSR by TSR basis. <u>TSR 2.1.a.1</u> <u>Offgas Isotopic Analysis</u> This TSR requires an isotopic analysis of an offgas sample, including quantitative measurements for xenon and krypton. The offgas isotopic analysis for xenon and krypton are not direct measurements related to the limits of LCO 3.4.8, “Reactor Coolant System (RCS) Specific Activity” or LCO 3.7.6, “Main Condenser Offgas.” These analyses are used to routinely monitor and trend offgas activity and are only applicable to plant specific controls and administrative limits. Thus, the analysis requirements of this TSR are not necessary for assuring

(continued)

BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS

TSR 2.1.a.1 Offgas Isotopic Analysis (continued)

RCS specific activity is within required limits and a failure to meet this TSR (i.e., failure to perform the sample within the specified Frequency) does not result in a failure to meet LCO 3.4.8 or LCO 3.7.6.

This TSR is only applicable in MODE 1 because the level of fission products generated in other MODES is much less.

The 31 day Frequency is adequate to trend changes in offgas activity level and is consistent with the Radioactive Gaseous Waste Sampling and Analysis Program requirements of the Offsite Dose Calculation Manual (ODCM).

TSR 2.1.a.2 Control Room Area Ventilation System Smoke Protection

This TSR provides verification that the Control Room Area Filtration (CRAF) subsystems automatically switch to the pressurization mode of operation on detection of smoke in an outside air intake. The CRAF subsystem actuation on detection of smoke in an outside air intake functions to permit continuous occupancy of the control room during an external smoke event. However, this smoke protection mode of the CRAF system is not assumed to mitigate a DBA or transient since smoke intrusion is not a DBA or transient. Furthermore, none of the four NRC Policy Statement criteria are applicable to this requirement. Thus, the smoke protection mode of the CRAF system is not required for CRAF system OPERABILITY.

As stated above, a failure to meet this TSR does not, of itself, result in a failure to meet LCO 3.7.4, “CRAF System.” However, depending on the failure mechanism, a malfunction of the equipment associated with this TSR could result in the inability of the CRAF system to perform its specified safety function. Therefore, upon discovery of a failure to meet this TSR, a determination of the OPERABILITY status of the CRAF system must be

(continued)

BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS

TSR 2.1.a.2 Control Room Area Ventilation System Smoke Protection (continued)

promptly performed. Additionally, the OPERABILITY of instruments required by TLCO 3.3.p, "Fire Detection Instrumentation" must be promptly determined since the smoke detection portion of the equipment tested by this TSR is also required by TLCO 3.3.p.

This TSR is applicable in MODES 1, 2, and 3, during CORE ALTERATIONS, during operations with the potential for draining the reactor vessel, and during handling of irradiated fuel assemblies in the secondary containment. This Applicability is based on the original licensing basis for the CRAF smoke protection mode function.

Operating experience has shown that these components normally pass the TSR when performed at the 24 month frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

TSR 2.1.a.3 Safety Relief Valve (SRV) Low-Low Set Functional Test

This TSR verifies that the SRV low-low set function does not interfere with the OPERABILITY of the Automatic Depressurization System (ADS) by performance of a functional test. The logic channels associated with the low-low set function are electrically interconnected with the ADS logic channels. However, the only possible impact that could prevent ADS operation is a failure in the common portion of the logic. Since this logic is energize to actuate, the non-interference requirement for the ADS function can be adequately demonstrated through a periodic functional test of the low-low set function.

A failure to meet this TSR does not, of itself, result in a failure to meet LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation" or LCO 3.5.1, "ECCS – Operating." However, depending on the failure mechanism, a malfunction of the equipment associated with this TSR could result in the inability of the ADS system

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BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS

TSR 2.1.a.3 Safety Relief Valve (SRV) Low-Low Set Functional Test (continued)

(initiation instrumentation or valves) to perform its specified safety function. Therefore, upon discovery of a failure to meet this TSR, a determination of the OPERABILITY status of the ADS system must be promptly performed.

Since the purpose of this TSR is to ensure that the low-low set function does not interfere with ADS system OPERABILITY, the Applicability for this TSR is when the ADS initiation instrumentation of LCO 3.3.5.1 and the ADS system valves of LCO 3.5.1 are required to be OPERABLE (i.e., MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig). For further discussion regarding the Applicability for ADS system components, refer to the Bases of LCO 3.3.5.1 and LCO 3.5.1.

The 24 month Frequency is based on the need to perform this surveillance under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the surveillance when performed at the 24 month Frequency.

TSR 2.1.a.4 Zero Pressure Control Rod Scram Time

This TSR provides the acceptance criteria for satisfying Technical Specification SR 3.1.4.3 when testing is performed at < 800 psig reactor steam dome pressure. When work that could affect the scram insertion time is performed on a control rod or the Control Rod Drive (CRD) system, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate that the affected control rod is still within acceptable limits. Limits for reactor pressures ≥ 800 psig are found in Technical Specification Table 3.1.4-1.

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BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS

TSR 2.1.a.4 Zero Pressure Control Rod Scram Time (continued)

The scram time limit for reactor pressures < 800 psig are delineated in this TSR. To be within limit, the control rod must scram from fully withdrawn to notch position 05 in $\leq$ 2.04 seconds when tested at 0 psig reactor steam dome pressure. This limit was established based on a high probability of meeting the acceptance criteria at reactor pressures $\geq$ 800 psig. If testing demonstrates the affected control rod does not meet this limit, but is within the 7-second limit of Technical Specification Table 3.1.4-1, Note 2, the control rod can be declared OPERABLE and “slow”.

Specific examples of work that could affect the scram times include (but are not limited to) the following: removal of a CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, or accumulator isolation valves and check valves in the piping required for a scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability of testing the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

TSR 2.1.a.5 Diesel Generator (DG) Fuel Oil Storage Tank Cleaning

This TSR requires the draining, removal of sediment, and cleaning of each DG fuel oil storage tank. The tank cleaning solution should be sodium hypochlorite or equivalent. This TSR is a preventive maintenance type requirement and is not directly related to the limits of LCO 3.8.3, “Diesel Fuel Oil and Starting Air.” The performance of SR 3.8.3.2 (fuel oil testing) and the limits of the Diesel Fuel Oil Testing Program ensure that tank sediment is minimized. Thus, the preventive maintenance requirements of this TSR are not necessary for assuring OPERABILITY of the DG fuel oil storage tank and a

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BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS

TSR 2.1.a.5 Diesel Generator (DG) Fuel Oil Storage Tank Cleaning (continued)

failure to meet this TSR (i.e., sediment in the tank or failure to perform the cleaning within the specified Frequency) does not result in a failure to meet LCO 3.8.3.

Since stored diesel fuel oil supports the operation of the diesel generators, this TSR is only applicable when the associated DG is required to be OPERABLE. This Applicability is consistent with the requirements of LCO 3.8.3.

The 10 year Frequency is based on the original licensing basis of the DG fuel oil storage tank cleaning requirement.

TSR 2.1.a.6 DG Fuel Oil System Pressure Test

This TSR requires pressure testing the portions of the diesel fuel oil system designed to Section III, subsection ND, of the ASME Code. The test should be performed in accordance with ASME Code Section XI, Article IWD-5000. This TSR is a preventive maintenance type requirement and is not directly related to the limits of LCO 3.8.3, "Diesel Fuel Oil and Starting Air." The performance of SR 3.8.3.1 (fuel oil volume verification) once per 31 days ensures that any degradation of the tank wall surface that results in a fuel oil volume reduction is detected and corrected in a timely manner. Thus, the preventive maintenance requirements of this TSR are not necessary for assuring OPERABILITY of the DG fuel oil storage tank and a failure to perform this TSR within the specified Frequency does not result in a failure to meet LCO 3.8.3.

However, if testing demonstrates a failure to meet the TSR acceptance criteria (i.e., a pressure test failure), then depending on the mechanism, the failure could result in the inability of the DG fuel oil system to perform its specified safety function. Therefore, upon discovery of a failure to meet the acceptance criteria of this TSR, a determination of the OPERABILITY status of the DG fuel oil system must be promptly performed.

(continued)

BASES

APPLICABLE DESIGN BASES, APPLICABILITY, and SURVEILLANCE REQUIREMENTS	<u>TSR 2.1.a.6</u> <u>DG Fuel Oil System Pressure Test</u> (continued) Since stored diesel fuel oil supports the operation of the diesel generators, this TSR is only applicable when the associated DG is required to be OPERABLE. This Applicability is consistent with the requirements of LCO 3.8.3. The 10 year Frequency is based on the original licensing basis of the DG fuel oil system pressure test requirement.

REFERENCES

1. UFSAR Section 4.6.3.2.1.5.
2. UFSAR Section 7.3.1.2.2.10.
3. UFSAR Section 9.4.1.1.1.
4. UFSAR Section 9.5.1.2.4.
5. UFSAR Section 9.5.4.
6. 10 CFR 50.36.
7. NUREG-1433, "Standard Technical Specifications, General Electric Plants BWR/4," Revision 1, April 1995.
8. NUREG-1434, "Standard Technical Specifications, General Electric Plants BWR/6," Revision 1, April 1995.
9. NEDO-31466 (and Supplement 1), "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.
10. NRC Final Policy Statement on Technical Specification Improvements, July 22, 1993 (58 FR 39132).
11. NRC Safety Evaluation supporting Amendment No. 147 to Facility Operating License No. 11 and Amendment No. 133 to Facility Operating License No. 18, Commonwealth Edison Company, LaSalle County Station, Units 1 and 2, dated March 30, 2001.

B 3.0 TECHNICAL REQUIREMENTS MANUAL LIMITING CONDITION FOR OPERATION (TLCO) APPLICABILITY

BASES

TLCOs	TLCO 3.0.a through TLCO 3.0.f establish the general requirements applicable to all TLCOs in Sections 2.1 and 3.1 through 3.9 and apply at all times, unless otherwise stated.
TLCO 3.0.a	TLCO 3.0.a establishes the Applicability statement within each individual TLCO as the requirement for when the TLCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Requirement).
TLCO 3.0.b	TLCO 3.0.b establishes that upon discovery of a failure to meet a TLCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of a TLCO are not met. This Requirement establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a TLCO; and b. Completion of the Required Actions is not required when a TLCO is met within the specified Completion Time, unless otherwise specified. There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the TLCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the TLCO is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of

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BASES

TLCO 3.0.b (continued)

Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when a TLCO is met or is no longer applicable, unless otherwise stated in the individual TLCOs.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual TLCO's ACTIONS specify the Required Actions where this is the case. An example of this is in TLCO 3.7.i, "Snubbers."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time conditions exist which may result in TLCO 3.0.c being entered. Individual TLCOs may specify a time limit for performing a TSR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another TLCO becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new TLCO becomes applicable and the ACTIONS Condition(s) are entered.

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BASES (continued)

TLCO 3.0.c

TLCO 3.0.c establishes the actions that must be implemented when a TLCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering TLCO 3.0.c is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that TLCO 3.0.c be entered immediately.

Upon entering TLCO 3.0.c, 1 hour is allowed to implement appropriate compensatory actions and verify the plant is not in an unanalyzed condition or that a required safety function is not compromised. Within 12 hours, Shift Operations Superintendent or designee approval of the compensatory actions and the plan for exiting TLCO 3.0.c must be obtained. The use and interpretation of specified times to complete the actions of TLCO 3.0.c are consistent with the discussion of Section 1.3, Completion Times.

The actions required in accordance with TLCO 3.0.c may be terminated and TLCO 3.0.c exited if any of the following occurs:

a. The TLCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time TLCO 3.0.c is exited.

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BASES

TLCO 3.0.c (continued)

In MODES 1, 2, and 3, TLCO 3.0.c provides actions for Conditions not covered in other Requirements. The requirements of TLCO 3.0.c do not apply in MODES 4 and 5 because the unit is already in the most restrictive Condition. The requirements of TLCO 3.0.c do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual TLCOs sufficiently define the remedial measures to be taken.

TLCO 3.0.d

TLCO 3.0.d establishes limitations on changes in MODES or other specified conditions in the Applicability when an TLCO is not met. It precludes placing the unit in a MODE or other specified condition stated in that Applicability (e.g., Applicability desired to be entered) when the following exist:

a. Unit conditions are such that the requirements of the TLCO would not be met in the Applicability desired to be entered; and

b. Continued noncompliance with the TLCO requirements, if the Applicability were entered, would result in the unit being required to exit the Applicability desired to be entered to comply with the Required Actions.

Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. The provisions of this TLCO should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of TLCO 3.0.d shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the

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BASES

TLCO 3.0.d (continued)

provisions of TLCO 3.0.d shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

Exceptions to TLCO 3.0.d are stated in the individual TLCOs. The exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time. Exceptions may apply to all the ACTIONS or to a specific Required Action of a TLCO.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by TSR 3.0.a. Therefore, changing MODES or other specified conditions while in an ACTIONS Condition, either in compliance with TLCO 3.0.d, or where an exception to TLCO 3.0.d is stated, is not a violation of TSR 3.0.a or TSR 3.0.d for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, TSRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected TLCO.

TLCO 3.0.d is only applicable when entering MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, TLCO 3.0.d is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, or 3. The requirements of TLCO 3.0.d do not apply in MODES 4 and 5, or in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Requirements sufficiently define the remedial measures to be taken.

TLCO 3.0.e

TLCO 3.0.e establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Requirement is to provide an exception to TLCO 3.0.b (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

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BASES

TLCO 3.0.e (continued)	b. The OPERABILITY of other equipment. The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Requirement does not provide time to perform any other preventive or corrective maintenance. An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.
TLCO 3.0.f	TLCO 3.0.f establishes the applicability of each TLCO to both Unit 1 and Unit 2 operation. Whenever a requirement applies to only one unit, or is different for each unit, this will be identified in the appropriate section of the TLCO (e.g., Applicability, TSR, etc.) with parenthetical reference, Notes, or other appropriate presentation within the body of the requirement.

B 3.0 TECHNICAL REQUIREMENTS MANUAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

BASES

TSRs

TSR 3.0.a through TSR 3.0.e establish the general requirements applicable to all Requirements in Sections 2.1 and 3.1 through 3.9 and apply at all times, unless otherwise stated.

TSR 3.0.a

TSR 3.0.a establishes the requirement that TSRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the TLCO apply, unless otherwise specified in the individual TSRs. This TLCO is to ensure that TSRs are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a TSR within the specified Frequency, in accordance with TSR 3.0.b, constitutes a failure to meet a TLCO.

Systems and components are assumed to be OPERABLE when the associated TSRs have been met. Nothing in this TSR, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the TSRs; or

b. The requirements of the TSR(s) are known to be not met between required TSR performances.

TSR do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated TLCO are not applicable, unless otherwise specified.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given TSR. In this case, the unplanned event may be credited as fulfilling the performance of the TSR.

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BASES

TSR 3.0.a (continued)	TSRs, including TSRs invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. TSRs have to be met and performed in accordance with TSR 3.0.b, prior to returning equipment to OPERABLE status. Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable TSRs are not failed and their most recent performance is in accordance with TSR 3.0.b. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.
TSR 3.0.b	TSR 3.0.b establishes the requirements for meeting the specified Frequency for TSRs and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval. TSR 3.0.b permits a 25% extension of the interval specified in the Frequency. This extension facilitates TSR scheduling and considers plant operating conditions that may not be suitable for conducting the TSR (e.g., transient conditions or other ongoing TSR or maintenance activities). The 25% extension does not significantly degrade the reliability that results from performing the TSR at its specified Frequency. This is based on the recognition that the most probable result of any particular TSR being performed is the verification of conformance with the TSRs. As stated in TSR 3.0.b, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required

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BASES

TSR 3.0.b (continued)

Action, whether it is a particular TSR or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of TSR 3.0.b are not intended to be used repeatedly merely as an operational convenience to extend TSR intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

TSR 3.0.c

TSR 3.0.c establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a TSR has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time it is discovered that the TSR has not been performed in accordance with TSR 3.0.b, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete TSRs that have been missed. This delay period permits the completion of a TSR before complying with Required Actions or other remedial measures that might preclude completion of the TSR.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the TSR, the safety significance of the delay in completing the required TSR, and the recognition that the most probable result of any particular TSR being performed is the verification of conformance with the requirements.

When a TSR with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to start of movement of fuel assemblies or control rods, or in accordance with the Diesel Fuel Oil Testing Program, etc.) is discovered to not have been performed when specified, TSR 3.0.c allows for

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BASES

TSR 3.0.c (continued)

the full delay period of up to the specified Frequency to perform the TSR. However, since there is not a time interval specified, the missed TSR should be performed at the first reasonable opportunity.

TSR 3.0.c provides a time limit for, and allowances for the performance of, TSRs that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for TSRs is expected to be an infrequent occurrence. Use of the delay period established by TSR 3.0.c is a flexibility which is not intended to be used as an operational convenience to extend TSR intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed TSR, it is expected that the missed TSR will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the TSR as well as any plant configuration changes required or shutting the plant down to perform the TSR) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the TSR. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed TSR should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed TSRs for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed TSRs will be placed in the station’s Corrective Action Program.

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BASES

TSR 3.0.c (continued)

If a TSR is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then is considered outside the specified limits and the Completion Times of the Required Actions for the applicable TLCO Conditions begin immediately upon expiration of the delay period. If a TSR is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable TLCO Conditions begin immediately upon the failure of the TSR.

Completion of the TSR within the delay period allowed by this TSR, or within the Completion Time of the ACTIONS, restores compliance with TSR 3.0.a.

TSR 3.0.d

TSR 3.0.d establishes the requirement that all applicable TSRs must be met before entry into a MODE or other specified condition in the Applicability.

This TSR ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this TSR should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

However, in certain circumstances, failing to meet a TSR will not result in TSR 3.0.d restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated TSR(s) are not required to be performed per TSR 3.0.a which states that TSRs do not have to be performed on inoperable equipment. When equipment is inoperable, TSR 3.0.d does not apply to the associated TSR(s) since the requirement for the TSR(s) to be performed is removed. Therefore, failing to perform the TSRs within the specified Frequency, on equipment that is

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BASES

TSR 3.0.d (continued)

inoperable, does not result in a TSR 3.0.d restriction to changing MODES or other specified conditions of the Applicability. However, since the TLCO is not met in this instance, TLCO 3.0.d will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

The provisions of TSR 3.0.d shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of TSR 3.0.d shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

The precise requirements for performance of TSRs are specified such that exceptions to TSR 3.0.d are not necessary. The specific time frames and conditions necessary for meeting the TSRs are specified in the Frequency, in the TSR, or both. This allows performance of TSRs when the prerequisite condition(s) specified in a TSR procedure require entry into the MODE or other specified condition in the Applicability of the associated TLCO prior to the performance or completion of a TSR. A TSR that could not be performed until after entering the TLCO Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the TSR may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of TSRs' annotation is found in Section 1.4, Frequency.

TSR 3.0.d is only applicable when entering MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, TSR 3.0.d is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, or 3. The requirements of TSR 3.0.d do not apply in MODES 4 and 5, or in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Requirements sufficiently define the remedial measures to be taken.

(continued)

BASES (continued)

TSR 3.0.e	TSR 3.0.e establishes the applicability of each TSR to both Unit 1 and Unit 2 operation. Whenever a requirement applies to only one unit, or is different for each unit, this will be identified with parenthetical reference, Notes, or other appropriate presentation within the TSR.

This section is no longer used.

B 3.3 INSTRUMENTATION

B 3.3.a Control Rod Drive Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limit to preserve the integrity of the fuel cladding and the reactor coolant pressure boundary (RCPB), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying Allowable Values which establish the threshold for protective system action to prevent exceeding acceptable limits, including Safety Limits (SLs), during Design Basis Accidents (DBAs).

The Control Rod Drive RPS Instrumentation portion of the RPS, as described in the UFSAR, Section 7.2.2.4.10 (Ref. 3), includes sensors, relays, and bypass circuits that are necessary to cause initiation of a reactor scram. The input parameter to the scram logic is from instrumentation monitoring Control Rod Drive (CRD) charging water header pressure. There are four redundant sensor input signals from this parameter. These signals are provided by four pressure transmitters attached to four pressure taps on the charging water headers downstream of the CRD pumps with one transmitter attached to each tap. The channels include trip units that compare measured input signals with pre-established setpoints. When a setpoint is exceeded, the channel outputs an RPS trip signal to the trip logic after an appropriate time delay.

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A1 and A2, B1 and B2), as described in Reference 2. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as one-out-of-two taken

(continued)

BASES

BACKGROUND (continued)

twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds. This 10 second delay on reset is only possible if the conditions that caused the scram have been cleared. This ensures that the scram function will be completed.

Each CRD has an associated hydraulic control unit (HCU). The HCU scram accumulator is pre-charged with high pressure nitrogen. When the CRD pump is activated, the pressurized charging water forces the accumulator piston down to the mechanical stops. The piston is maintained seated against this mechanical stop with normal charging water pressure, typically above 1400 psig. The HCU scram accumulators store sufficient energy to fully insert a control rod at any reactor pressure.

Two scram pilot solenoids are located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each CRD alternately may have a single scram pilot valve with dual solenoid operated pilot assemblies in place of two scram pilot valves. Each scram pilot valve is solenoid operated, with the solenoids normally energized. The scram pilot valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either scram pilot valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the scram pilot valve solenoids for each CRD is controlled by trip System A, and the other solenoid is operated by trip System B. Any trip of trip System A in conjunction with any trip in trip System B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the Scram Discharge Volume (SDV) vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

The actions of the Control Rod Drive RPS Instrumentation are not assumed in any safety or transient analyses. The instrumentation initiates a reactor scram when monitored parameter values exceed the Allowable Values specified by the setpoint methodology and listed in Table T3.3.a-1 to ensure normal scram capability is maintained and inadvertent scrams are avoided.

The OPERABILITY of the Control Rod Drive RPS Instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table T3.3.a-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Control Rod Drive RPS Instrumentation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., charging water pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytic limits, corrected for defined process, calibration, and instrumentation errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)	of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

The OPERABILITY of scram pilot valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this TLCO.

The individual Functions are required to be OPERABLE in the MODES or other conditions specified in the Table that may require an RPS trip to ensure a reliable scram function.

The only MODES specified in Table T3.3.a-1 are MODE 2 and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No Control Rod Drive RPS Instrumentation Functions are required in MODES 3 and 4, since all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. Additionally, In MODE 1, there is sufficient reactor pressure to assure that the control rods will scram even if CRD charging water pressure is low and the scram accumulators begin to depressurize. The control rod scram accumulator OPERABILITY requirements (LCO 3.1.5) ensure that appropriate actions are taken for scram accumulators that have low pressure. Under these conditions, the Control Rod Drive RPS Instrumentation Functions are not required to be OPERABLE. In MODE 5, control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all other control rods remain inserted, no Control Rod Drive RPS Instrumentation Functions are required. In this condition, the required shutdown margin (LCO 3.1.1) and refuel position one-rod-out interlock (LCO 3.9.2) ensure that no event requiring RPS action will occur.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

The specific Applicable Design Bases, TLCO, and Applicability discussions are listed below on a Function by Function basis.

1. Charging Water Header Pressure - Low

CRD charging water pressure to an HCU is normally maintained by a CRD pump. If pump discharge pressure drops for any reason, header pressure at the HCU is maintained by the accumulator and a ball check valve in the charging line between the CRD pump and the accumulator. High leakage through the check valve could potentially cause the accumulator piston to rise off of its mechanical stops as the nitrogen in the accumulator expands to maintain the pressure at the HCU. This results in a reduction of the accumulator's energy and thereby degrades normal scram performance of the CRDs in the absence of sufficient reactor pressure. To prevent this situation, the Charging Water Header Pressure - Low Function is provided to ensure that a reactor scram is initiated before scram capability is compromised during low reactor pressure operations.

Four channels of Charging Water Header Pressure - Low, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

This Function must be enabled in MODE 2 and 5. This is normally accomplished automatically by contacts sensing Reactor Mode Switch position.

The Allowable Value is selected to ensure that a scram signal is generated when the charging header pressure is less than the piston seating pressure of the accumulator.

2. Delay Timer

To meet the power generation design bases of the UFSAR, the RPS setpoints, instrumentation, and controls must be arranged in such a manner as to preclude spurious scrams. An adjustable time-delay relay for each Charging Water

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

2. Delay Timer (continued)

Header Pressure - Low channel protects against an inadvertent scram due to pressure fluctuations in the charging line that may occur during normal plant operations and therefore improves system reliability.

Four channels of Delay Timer, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude the scram function.

This Function must be enabled in MODE 2 and 5. This is normally accomplished automatically by contacts sensing Reactor Mode Switch position.

The Allowable Value was chosen to be long enough to prevent false scrams due to charging header pressure fluctuations but not so long as to impact the ability of the Charging Water Header Pressure – Low scram to perform its assumed function.

ACTIONS

A Note has been provided to modify the ACTIONS related to Control Rod Drive RPS Instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Control Rod Drive RPS Instrumentation channels provide appropriate compensatory measures for separate, inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable Control Rod Drive RPS Instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours is acceptable to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

permit restoration of any inoperable required channel to OPERABLE status. Twelve hours is also consistent with the out of service time allowed by LCO 3.3.1.1 for other Reactor Protection System instrument channels. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases.) If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the Control Rod Drive RPS Instrumentation still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system. Required Actions B.1 and B.2 limit the time the RPS scram logic for any Function would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement). Within the 6 hour allowance, the associated Function must have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

The trip system in the more degraded state should be placed in trip or, alternatively, the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

channels, if the two inoperable channels are in the same RPS Function while the four inoperable channels are all in different RPS Functions). The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is acceptable based on the remaining capability to trip, the low probability of extensive numbers of inoperabilities affecting diverse RPS Functions, and the low probability of an event requiring the initiation of a scram. Additionally, the six hours is consistent with the out of service time allowed by LCO 3.3.1.1 for other Reactor Protection System instrument Functions with the same level of degradation.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the Functions of this Requirement, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

(continued)

BASES

ACTIONS

C.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table T3.3.a-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C, and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the TLCO does not apply. The Completion Times are reasonable, based on operating experience, to reach the specified condition from at power conditions in an orderly manner and without challenging plant systems.

F.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the TLCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.

(continued)

BASES

ACTIONS

F.1 (continued)

Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the TSRs for each Control Rod Drive RPS Instrumentation Function are located in the TSRs column of Table T3.3.a-1.

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains Control Rod Drive RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the average time required to perform channel surveillances. The 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

TSR 3.3.a.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.a.1 (continued)

The 31 day Frequency is based on the original licensing basis of the Control Rod Drive RPS Instrumentation Functions.

TSR 3.3.a.2

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated trip unit, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

TSR 3.3.a.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 48 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has determined that it is acceptable to perform the Surveillance at the 48 month Frequency.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 7.2.1.2.
2. UFSAR Section 7.2.2.3.
3. UFSAR Section 7.2.2.4.10.
4. Technical Specification 3.3.1.1.

B 3.3 INSTRUMENTATION

B 3.3.c Control Rod Block Instrumentation

BASES

BACKGROUND

The Reactor Control Management System (RCMS) is provided for operational manipulation of the control rods and the surveillance of associated equipment. The RCMS instrumentation and controls consist of electrical circuitry, switches, indicators and alarm devices. This system includes the interlocks that inhibit rod movement (rod block) under certain conditions.

The Control Rod Block Instrumentation system is a subsystem of the RCMS, which upon receipt of input signals from other systems and subsystems, inhibits movement of control rods. The system, as described in the UFSAR, Section 7.7 (Ref. 1), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a rod block. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the rod block logic are from instrumentation that monitors neutron flux; scram discharge volume (SDV) water level; reactor recirculation flowrate; as well as SDV water level scram bypass switch position.

TheRCMS hardware is arranged in two-channel redundant system architecture, including RCMS controller channels A and B and RCMS interface units A and B. Each controller channel is a separate hardware assembly running the same software, but running independently of the opposite RCMS controller channel. The two RCMS controller channels exchange sequence enforcement, rod control logic, and other status information with each other to verify the

(continued)

BASES

BACKGROUND (continued)

functional integrity of the opposite RCMS controller channel. Rod Block Monitor rod blocks are redundantly received by input modules installed in each RCMS interface unit. Each channel receives input trip signals from a number of trip channels and each logic channel can provide a separate rod block signal to inhibit rod withdrawal. Rod movement commands from both RCMS controller channels are sent to each RCMS interface. In order to move a rod, each RCMS interface logically ANDs the rod motion commands from both RCMS controller channels. Rod withdrawal is permitted only if the rod motion commands from both RCMS controller channels agree that no rod block condition is present.

Most Control Rod Block Instrumentation Functions are arranged so that some of the signals input to one of the RCMSrod block logic circuits and the remaining signals input to the other logic circuit. For the neutron monitoring equipment (SRM, IRM, and APRM), the instrument grouping used in the rod block circuitry is not the same as that used in the reactor protection system. Half of the total monitors SRM A & C, IRM A, B, E & F, and APRM A, D & E provide inputs to one of the RCMS rod block logic circuits, and the remaining monitors provide input into the other RCMS rod block logic circuit SRM B & D, IRM C, D, G & H, and APRM B, C & F. In contrast, one RPS trip system has SRM A & C, IRM A, C, E & G, and APRM A, C & E and the other trip system has SRM B & D, IRM B, D, F & H and APRM B, D & F. Two recirculation flow units, each providing a high flow and a flow comparator output signal, input to one RCMS rod block logic circuit; the remaining units provide inputs to the other logic circuit. Likewise, one SDV high water level switch provides an input to one rod block logic circuit and the remaining SDV high water level switch provides an input to the other rod block logic circuit.

An exception to this arrangement is the Scram Discharge Volume Switch in Bypass Function. Both rod block logic circuits sense when the Scram Discharge Volume Keylock Switch is placed in bypass defeating the SDV Water Level - High scram Function required by LCO 3.3.1.1.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even during a continuous rod withdrawal.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

The RCMS is an operational control system and has no safety function. As a subsystem of the RCMS, the Control Rod Block Instrumentation system is designed to meet the following design bases:

a. Inhibit control rod withdrawal following erroneous control rod manipulations so that reactor protection system action (scram) is not required.

b. Inhibit control rod withdrawal in time to prevent local fuel damage as a result of erroneous control rod manipulation.

c. Inhibit control rod movement whenever such movement would result in operationally undesirable core reactivity conditions or whenever instrumentation is incapable of monitoring the core response to rod movement.

The OPERABILITY of the Control Rod Block Instrumentation system is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table T3.3.c-1. Each Function must have a required number of OPERABLE channels per Function with their trip setpoints within the specific Allowable Value, where appropriate. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions.

Allowable Values are specified for each Control Rod Block Instrumentation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., neutron flux), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. The analytical limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytical limits, corrected for defined process, calibration, and instrumentation errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

The individual Functions are required to be OPERABLE in the MODES or other conditions specified in the Table that may require a control rod block to mitigate the consequences of an inappropriate control rod manipulation.

The only MODES specified in Table T3.3.c-1 are MODES 1, 2 and 5, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. No Control Rod Block Instrumentation Function is required in MODES 3 or 4, since all control rods are fully inserted and the Reactor Mode Switch Shutdown Position control rod withdrawal block (LCO 3.3.2.1) does not allow any control rod to be withdrawn. Under these conditions the Control Rod Block Instrumentation Functions of this Technical Requirement are not required to be OPERABLE. In MODE 5, control rods withdrawn from a core cell containing no fuel assembles do not affect the reactivity of the core and therefore are not required to have control rod block capability.

The specific Applicable Design Bases, TLCO, and Applicability discussions are listed below on a Function by Function basis.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

1.a Average Power Range Monitor Flow Biased Neutron Flux – Upscale

The APRM channels receive inputs from the LPRMs within the reactor core, which provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. The APRM Flow Biased Neutron Flux – Upscale Function monitors core average neutron flux. The rod block trip setting is varied as a function of recirculation drive flow (i.e., at lower core flows the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced).

The APRM Flow Biased Neutron Flux – Upscale Function is provided to avoid conditions that would require reactor protection system action if allowed to proceed. The rod block trip setpoints are sufficient to avoid both Reactor Protection System (RPS) action (scram) and local fuel damage as a result of a single control rod withdrawal error.

The APRM system is divided into two groups of channels with three APRM inputs to each rod block logic circuit APRMs A, D & E feed one logic circuit, and APRMs B, C & F feed the other logic circuit. There is no requirement to have a certain number of APRMs operable per each rod block logic circuit (like there is for the RPS scram logic) because any one APRM channel can cause a rod block. The APRM system has a limited bypass capability for APRMs which allows one APRM in each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has APRMs A, C & E and the other trip system has APRMs B, D & F.) Four channels of APRM Flow Biased Neutron Flux – Upscale, are required to be OPERABLE to ensure that a control rod block is initiated prior to reaching the APRM Flow Biased Simulated Thermal Power – Upscale RPS trip setpoint (LCO 3.3.1.1, Table 3.3.1.1–1 Function 2.b). In addition, at least 14 Local Power Range Monitor (LPRM) inputs are required from each of the four axial levels at which the LPRMs are located. Each APRM channel receives two independent, redundant flow signals representative of total recirculation drive flow. The total drive flow signals are generated by four flow units, two of which supply signals to the APRMs inputting to RCMS Interface Unit A, while the other two supply signals to the APRMs inputting to C Interface Unit B. Each flow unit signal is provided by summing the flow signals from the two recirculation loops. These redundant flow signals are sensed from four pairs of elbow taps, two on each recirculation loop. No single active component failure can

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

1.a Average Power Range Monitor Flow Biased Neutron Flux – Upscale (continued)

cause more than one of these two redundant signals to read incorrectly. To obtain the most conservative reference signals, the total flow signals from the two flow units (associated with an RCMS logic channel as described above) are routed to a low auction circuit associated with each APRM. Each APRM's auction circuit selects the lower of the two flow unit signals for use as the rod block trip reference for that particular APRM. Each required APRM Flow Biased Simulated Thermal Power – Upscale channel only requires an input from one OPERABLE flow unit, since the individual APRM channel will perform the intended function with only one OPERABLE flow unit input.

Additionally, since any one APRM can cause a rod block, single failure criteria is maintained and an APRM Flow Biased Neutron Flux – Upscale channel may be considered OPERABLE with only one OPERABLE flow unit input.

"W," in the Allowable Value column of Table T3.3.c-1, is the percentage of recirculation loop flow which provides a rated core flow of 108.5 million lbs/hr. The Allowable Value for the APRM Flow Biased Neutron Flux – Upscale Function provides margin to the APRM Flow Biased Simulated Thermal Power – Upscale RPS trip setpoint. A description of the APRM Flow Biased Simulated Thermal Power – Upscale RPS scram Function is provided in the Bases of LCO 3.3.1.1, "RPS Instrumentation."

The APRM Flow Biased Neutron Flux – Upscale Function is required to be OPERABLE in MODE 1 when there is a possibility of generating excessive thermal flux which could result in exceeding limits applicable to high pressure and core flow conditions and is consistent with the MODE requirements of the APRM Flow Biased Simulated Thermal Power – Upscale RPS scram Function required by LCO 3.3.1.1. During MODES 2 and 5, other SRM, IRM and APRM scram and rod block Functions provide protection for fuel cladding integrity.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

1.b Average Power Range Monitor – Inoperative

This signal provides assurance that no control rod will be withdrawn unless the APRM channels are either in service or correctly bypassed. Anytime an APRM mode switch is moved to a position other than "Operate," an APRM module is unplugged, or the APRM has too few LPRM inputs (< 14), an inoperative trip signal will be received by the Control Rod Block Instrumentation system, unless the APRM is bypassed. The APRM system has a limited bypass capability for APRMs which allows one APRM in each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has APRMs A, C & E and the other trip system has APRMs B, D & F.)

Four channels of Average Power Range Monitor – Inoperative are required to be OPERABLE to ensure that no control rod is withdrawn unless the required number of APRMs are OPERABLE to meet the requirements of LCO 3.3.1.1. There is no requirement to have a certain number of APRMs OPERABLE per each rod block logic circuit.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where other APRM Functions are required and is consistent with the MODE requirements of the Average Power Range Monitor – Inop RPS scram Function required by LCO 3.3.1.1.

1.c Average Power Range Monitor – Downscale

This signal provides assurance that no control rod will be withdrawn during power-range operation unless the APRM channels are operating correctly or are correctly bypassed. All unbypassed APRMs must be on scale during reactor operations with the Reactor Mode Switch in the run position. The APRM system has a limited bypass capability for APRMs which allows one APRM in each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has APRMs A, C & E and the other trip system has APRMs B, D & F.)

Four channels of Average Power Range Monitor – Downscale are required to be OPERABLE to ensure that no control rod is withdrawn unless the required number of APRMs are capable of monitoring the core response to control rod movement. There is no requirement to have a certain number of APRMs OPERABLE per each rod block logic circuit.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

1.c Average Power Range Monitor – Downscale (continued)

The Allowable Value is chosen high enough to ensure that the APRMs are registering neutron flux changes in the core.

The Average Power Range Monitor – Downscale Function is required to be OPERABLE in MODE 1 when there is a sufficiently high core neutron flux level to confirm that an APRM indicating downscale is inoperable. During MODES 2 and 5, neutron flux levels can be so low that OPERABLE APRMs may indicate downscale.

1.d Average Power Range Monitor Neutron Flux – High

For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux – High Function is capable of generating a rod block trip signal to avoid conditions that would require RPS action (scram) if continued rod withdrawal in this power range were allowed to proceed.

For most operation at low power levels, the Average Power Range Monitor Neutron Flux – High Function will provide a secondary rod block to the Intermediate Range Monitor – Upscale Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux – High Function will provide the primary rod block trip signal for a corewide increase in power.

The APRM system is divided into two groups of channels with three APRM inputs to each rod block logic circuit APRMs A, D & E feed one logic circuit, and APRMs B, C & F feed the other logic circuit. There is no requirement to have a certain number of APRMs OPERABLE per each rod block logic circuit (like there is for the RPS scram logic) because any one APRM can cause a rod block. The APRM system has a limited bypass capability for APRMs which allows one APRM in each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has APRMs A, C & E and the other trip system has APRMs B, D & F.) Four channels of Average Power Range Monitor Neutron Flux – High are required to be OPERABLE to ensure that a control rod block is initiated prior to reaching the Average Power Range Monitor Neutron Flux – High, Setdown RPS trip setpoint (LCO 3.3.1.1, Table 3.3.1.1–1 Function 2.a). In addition, at least 14 Local Power Range Monitor (LPRM) inputs are required from each of the four axial levels at which the LPRMs are located. A description of the Average Power Range Monitor Neutron Flux – High, Setdown RPS scram Function is provided in the Bases of LCO 3.3.1.1, “RPS Instrumentation.”

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

1.d Average Power Range Monitor Neutron Flux – High (continued)

The Allowable Value was selected to initiate a rod block before the Average Power Range Monitor Neutron Flux – High, Setdown RPS trip setpoint is reached and is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

The Average Power Range Monitor Neutron Flux – High Function must be OPERABLE during MODE 2 when the potential for abnormal operating transients with control rods withdrawn may exist and is consistent with the MODE requirements of the Average Power Range Monitor Neutron Flux – High, Setdown RPS scram Function required by LCO 3.3.1.1. In MODE 1, the Rod Block Monitor (RBM) and Rod Worth Minimizer (LCO 3.3.2.1) protect against control rod withdrawal errors.

2.a Source Range Monitor Detector - not full in

The SRMs provide the operator with information relative to the neutron level at very low flux levels in the core. As such, the SRM indication is used by the operators to monitor the approach to criticality and to determine when criticality is achieved. Additionally, during refueling operations the SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality. The Source Range Monitor Detector - not full in Function assures that no control rod is withdrawn unless all required SRM detectors are correctly inserted when they must be relied on to provide the operator with neutron flux level information. Mechanical switches in the SRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted.

The SRM system is divided into two groups of channels with two SRM input channels into each rod block logic circuit. The system is designed to allow one channel to be bypassed. Each channel can be physically positioned in the core and any one SRM channel can cause a rod block.

This Function must be enabled in MODE 2 when SRM detector count rate is < 100 counts per second (cps) and the IRM channels are on Range 2 or lower, and in MODE 5. This is normally accomplished automatically by detectors and contacts sensing SRM count rate, IRM Range Switch position, and Reactor Mode Switch position.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

2.a Source Range Monitor Detector - not full in (continued)

There is no Allowable Value for this Function.

During startup in MODE 2, three channels of Source Range Monitor Detector - not full in are required to be OPERABLE to ensure that reactor flux level during control rod withdrawal is adequately monitored until the flux level is sufficient to maintain the IRMs on Range 3 or higher. All channels but one are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core and is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. This Function is not required in MODE 2 when SRM count rate is $\geq$ 100 cps and the IRM channels are on Range 3 or higher since the IRM rod block Functions are capable of blocking inappropriate control rod movement in this power range. In MODE 5, two channels of Source Range Monitor Detector - not full in are required to be OPERABLE to provide redundant monitoring of reactivity changes in the reactor core during control rod withdrawal and is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. The SRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

2.b Source Range Monitor – Upscale

During a startup, when SRM count rate is greater than the retract permit setpoint, the SRMs may be withdrawn to maintain their indication within the normal range of their scale. After SRM to IRM overlap is demonstrated (as required by SR 3.3.1.1.6), the SRMs are normally fully withdrawn from the core. Extended operation of the SRMs in high neutron flux fields may result in detector damage. The Source Range Monitor – Upscale Function assures that no control rod is withdrawn unless the SRM detectors are correctly retracted during a reactor startup.

The SRM system is divided into two groups of channels with two SRM input channels into each rod block logic circuit. The system is designed to allow one channel to be bypassed. Each channel can be physically positioned in the core and any one SRM channel can cause a rod block.

This Function must be enabled in MODE 2 when the IRM channels are on Range 7 or lower and in MODE 5. This is normally accomplished automatically by contacts sensing IRM Range Switch position and Reactor Mode Switch position.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

2.b Source Range Monitor – Upscale (continued)

The Allowable Value is selected to be at the upper end of the range over which the SRMs are designed to detect and measure neutron flux.

During startup in MODE 2, three channels of Source Range Monitor – Upscale are required to be OPERABLE to ensure that control rod withdrawal is not permitted if indicated flux level is too high in the operating range of the SRMs. All channels but one are required which is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. This Function is not required in MODE 2 when the IRM channels are on Range 8 or higher since the flux level in this power range would require the full withdrawal of SRMs to prevent an upscale rod block. In MODE 5, two channels of Source Range Monitor – Upscale are required to be OPERABLE consistent with the requirements of LCO 3.3.1.2 for SRM detectors. The SRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

2.c Source Range Monitor – Inoperative

This signal provides assurance that no control rod is withdrawn during low neutron flux level operation unless neutron monitoring capability is available in that all required SRM channels are in service or correctly bypassed. Anytime an SRM mode switch is moved to any position other than “Operate,” the detector voltage drops below a preset level, or an SRM module is unplugged, an inoperative trip signal will be received by the Control Rod Block Instrumentation system, unless the SRM is bypassed. Since only one SRM input may be bypassed, only one SRM may be inoperable without resulting in a control rod block signal.

The SRM system is divided into two groups of channels with two SRM input channels into each rod block logic circuit. Each channel can be physically positioned in the core and any one SRM channel can cause a rod block.

This Function must be enabled in MODE 2 when the IRM channels are on Range 7 or lower and in MODE 5. This is normally accomplished automatically by contacts sensing IRM Range Switch position and Reactor Mode Switch position.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

2.c Source Range Monitor – Inoperative (continued)

There is no Allowable Value for this Function.

During startup in MODE 2, three channels of Source Range Monitor – Inoperative must be OPERABLE to ensure that the required number of SRMs are OPERABLE to meet the requirements of LCO 3.3.1.2. This Function is not required in MODE 2 when the IRM channels are on Range 8 or higher since the SRMs would be fully withdrawn at this flux level and no longer required for monitoring core reactivity changes. In MODE 5, two channels of Source Range Monitor – Inoperative are required to be OPERABLE to provide redundant monitoring of reactivity changes in the reactor core during control rod withdrawal and is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. The SRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

2.d Source Range Monitor – Downscale

This signal provides assurance that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring. All unbypassed SRMs must be on scale during reactor operations with the Reactor Mode Switch in the startup/hot standby or refuel positions.

The SRM system is divided into two groups of channels with two SRM input channels into each rod block logic circuit. The system is designed to allow one channel to be bypassed. Each channel can be physically positioned in the core and any one SRM channel can cause a rod block.

This Function must be enabled in MODE 2 when the IRM channels are on Range 2 or lower and in MODE 5. This is normally accomplished automatically by contacts sensing IRM Range Switch position and Reactor Mode Switch position.

The Allowable Value is chosen high enough to ensure that the SRMs are registering neutron flux changes in the core.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

2.d Source Range Monitor – Downscale (continued)

During startup in MODE 2, three channels of Source Range Monitor – Downscale are required to be OPERABLE to ensure that no control rod is withdrawn unless the required number of SRMs are capable of monitoring the core response to control rod movement. All channels but one are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core and is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. This Function is not required in MODE 2 when the IRM channels are on Range 3 or higher since the IRM rod block Functions are capable of blocking inappropriate control rod movement in this power range. In MODE 5, two channels of Source Range Monitor - Downscale are required to be OPERABLE to provide redundant monitoring of reactivity changes in the reactor core during control rod withdrawal and is consistent with the requirements of LCO 3.3.1.2 for SRM detectors. The SRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

3.a Intermediate Range Monitor Detector – not full in

The IRMs monitor neutron flux levels from the upper range of the SRMs to the lower range of the APRMs. The Intermediate Range Monitor Detector – not full in Function assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available and all required IRM detectors are correctly located in the reactor core. Mechanical switches in the IRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted.

The IRM system is divided into two groups of channels with four IRM inputs to each rod block logic circuit - IRMs A, B, E & F feed one logic circuit and IRMs C, D, G, & H feed the other logic circuit. There is no requirement to have a certain number of IRMs operable per each rod block logic circuit (like there is for the RPS scram logic) because any one IRM channel can cause a rod block. The IRM system has a limited bypass capability for IRMs which allows one IRM in each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has IRMs A, C, E & G and the other trip system has IRMs B, D, F & H.) Six channels of Intermediate Range Monitor Detector – not full in are required to be OPERABLE to ensure that reactor flux level is adequately monitored during control rod withdrawal in this power range. This rod block trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

3.a Intermediate Range Monitor Detector – not full in (continued)

There is no Allowable Value for this Function.

The Intermediate Range Monitor Detector – not full in Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the Rod Worth Minimizer (RWM) and RBM (LCO 3.3.2.1) provide protection against control rod withdrawal errors and the IRMs are not required. The IRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

3.b Intermediate Range Monitor Detector – Upscale

In the range of power monitored by the IRMs the most significant source of reactivity change is due to control rod withdrawal. The IRMs provide a diverse protection function from the RWM, which monitors and controls movement of control rods at low power. The RWM (LCO 3.3.2.1) prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 3). The Intermediate Range Monitor – Upscale Function provides a backup to the Average Power Range Monitor Neutron Flux – High Function in mitigation of a neutron flux excursion and also provides a means to stop rod withdrawal in time to avoid conditions requiring RPS action (scram) in the event that a rod withdrawal error is made during low neutron flux level operations. Additionally, the Intermediate Range Monitor – Upscale Function assures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is correctly upranged during a reactor startup.

The IRM system is divided into two groups of channels with four IRM inputs to each rod block logic circuit – IRMs A, B, E & F feed one logic circuit and IRMs C, D, G & H feed the other logic circuit. There is no requirement to have a certain number of IRMs operable per each rod block logic circuit (like there is for the RPS scram logic) because any one IRM can cause a rod block. The IRM system has a limited bypass capability for IRMs which allows one IRM into each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has IRMs A, C, E & G and the other trip system has IRMs B, D, F & H.) Six channels of Intermediate Range Monitor – Upscale are required to be

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

3.b Intermediate Range Monitor Detector – Upscale (continued)

OPERABLE to ensure that a control rod block is initiated prior to reaching the Intermediate Range Monitor Neutron Flux - High RPS trip setpoint (LCO 3.3.1.1, Table 3.3.1.1–1 Function 1.a). This rod block trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The Allowable Value is selected to be at the upper end of the each IRM range and provides margin to the Intermediate Range Monitor Neutron Flux - High RPS trip setpoint.

The Intermediate Range Monitor – Upscale Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the RWM and RBM (LCO 3.3.2.1) provide protection against control rod withdrawal errors and the IRMs are not required. The IRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

3.c Intermediate Range Monitor – Inoperative

This rod block trip signal assures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available in that all required IRM channels are in service or correctly bypassed. Anytime an IRM Mode switch is moved to a position other than “Operate,” the detector voltage drops below a preset value, or a module is not plugged in, an inoperative rod block trip signal will be received by the Control Rod Block Instrumentation system, unless the IRM is bypassed. The IRM system has a limited bypass capability for IRMs which allows one IRM into each RPS trip system to be bypassed. (The RPS trip systems are divided so that one has IRMs A, C, E & G and the other trip system has IRMs B, D, F & H.)

Six channels of Intermediate Range Monitor – Inoperative are required to be OPERABLE to ensure that no control rod is withdrawn unless the required number of IRMs are OPERABLE to meet the requirements of LCO 3.3.1.1. This rod block trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range. There is no requirement to have a certain number of IRMs OPERABLE per each rod block logic circuit.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

3.c Intermediate Range Monitor – Inoperative (continued)

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where other IRM Functions are required and is consistent with the MODE requirements of the Intermediate Range Monitor – Inop RPS scram Function required by LCO 3.3.1.1.

3.d Intermediate Range Monitor – Downscale

This signal provides assurance that no control rod will be withdrawn during low neutron flux level operations unless the neutron flux is being correctly monitored. The Intermediate Range Monitor – Downscale Function prevents the continuation of a reactor startup if the operator upranges the IRM too far for the existing flux level. Thus, the Intermediate Range Monitor – Downscale Function ensures that all unbypassed IRMs are on scale if control rods are to be withdrawn.

This Function must be enabled in MODE 2 when the IRM channels are on Range 2 or higher and in MODE 5. This is normally accomplished automatically by contacts sensing IRM Range Switch position and Reactor Mode Switch position. This rod block trip is active in all but one of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The Allowable Value is chosen high enough to ensure that the IRMs are registering neutron flux changes in the core.

During startup in MODE 2 and in MODE 5 when a cell with fuel has its control rod withdrawn, six channels of Intermediate Range Monitor – Downscale when core neutron flux level is high enough to maintain IRMs on scale. This Function is not required when the IRM is on its lowest range (Range 1) since neutron flux levels in this power range can be so low that OPERABLE IRMs may indicate downscale. In MODE 1, the RWM and RBM (LCO 3.3.2.1) provide protection against control rod withdrawal errors and the IRMs are not required. The IRMs are automatically bypassed when the Reactor Mode Switch is in the run position.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

4.a Scram Discharge Volume Water Level – High

The SDV receives water displaced from the motion of the Control Rod Drive (CRD) pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore a reactor scram is initiated when the remaining free volume is still sufficient to accommodate the water from a full core scram. The Scram Discharge Volume Water Level – High Function provides a backup to the SDV high water level scram by initiating a rod block and thus limiting further increases in the total water volume that would be discharged by a subsequent scram. SDV water level is measured by two non-indicating float switches, one installed in each of the Scram Discharge Instrument Volumes.

Two channels of Scram Discharge Volume Water Level – High are required to be OPERABLE to ensure that a control rod block is initiated prior to reaching the Scram Discharge Volume Water Level – High RPS trip setpoint (LCO 3.3.1.1, Table 3.3.1.1–1 Function 7.a and 7.b).

The Allowable Value was selected to initiate a rod block before the Scram Discharge Volume Water Level – High RPS trip setpoint is reached and is based on ensuring that there is sufficient volume in the SDV to accommodate the water from a full scram.

This Function is required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

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BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

4.b Scram Discharge Volume Switch in Bypass

The scram discharge high water level trip bypass is controlled by the manual operation of a keylocked switch. This bypass allows the operator to reset the reactor protection system scram relays so that the system can be restored to operation, allowing the operator to drain the scram discharge volume. The Scram Discharge Volume Switch in Bypass Function provides assurance that no control rod will be withdrawn while the Scram Discharge Volume Water Level – High RPS scram Function is out of service.

The SDV scram bypass switch is a single switch with two channels (one from each of the two sets of contacts), each of which inputs into one of the rod block logic circuits.

There is no Allowable Value for this Function.

In MODE 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, one channel of Scram Discharge Volume Switch in Bypass is required to be OPERABLE to ensure that a control rod cannot be withdrawn unless the Scram Discharge Volume Water Level – High RPS scram Function is in service as required by LCO 3.3.1.1. This Function is not required in MODES 1 or 2 since the SDV scram bypass switch can only bypass the Scram Discharge Volume Water Level – High RPS scram Function when the Reactor Mode Switch is in the Shutdown or Refuel positions.

5.a Recirculation Flow Unit – Upscale

The Reactor Recirculation Flow Units provide a flow signal that is representative of total recirculation drive flow. These total flow signals are used as reference signals in the APRM and RBM systems to vary the rod block and scram trip setpoints as a function of total recirculation flow. The Recirculation Flow Unit and Neutron Flux – Upscale Function assures that no control rod is withdrawn unless the Recirculation Flow

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BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

5.a Recirculation Flow Unit – Upscale (continued)

Units, which are necessary for the proper operation of the APRM's and RBM's, are OPERABLE.

There are four channels of Recirculation Flow Unit – Upscale with two channels inputting into each rod block logic circuit. The system is designed to allow one channel to be bypassed. Each flow unit signal is generated by summing the flow signals from the two recirculation loops. These redundant flow signals are sensed from four pairs of elbow taps, two on each recirculation loop. The total flow signal from the two flow units (associated with arod block logic circuit as described above) are routed to low auction circuits associated with each APRM and RBM. Two channels of Recirculation Flow Unit – Upscale, with one channel inputting to each rod block logic circuit, are required to be OPERABLE to ensure at least one OPERABLE flow signal is being provided to the Average Power Range Monitor Flow Biased Simulated Thermal Power – Upscale and Rod Block Monitor Functions required by LCO 3.3.1.1, 3.3.2.1, and TLCO 3.3.c.

The Allowable Value was selected to be high enough to determine that a flow unit is inoperable and is above the maximum possible flow that can be achieved by plant design (flow will be < 105% with the flow control valve fully open).

The Recirculation Flow Unit – Upscale Function is required to be OPERABLE in MODE 1 consistent with the MODE requirements of the Average Power Range Monitor Flow Biased Simulated Thermal Power and Neutron Flux – Upscale and Rod Block Monitor Functions.

5.b Recirculation Flow Unit – Inoperative

This signal provides assurance that no control rod is withdrawn unless the required Recirculation Flow Units necessary for the proper operation of the APRMs and RBMs are in service or correctly bypassed. Anytime a Flow Unit mode switch is moved to any position other than "Operate" or a Flow Unit module is unplugged, an inoperative trip signal will be received by the Control Rod Block Instrumentation system, unless the Flow Unit is bypassed. Since only one Flow Unit input may be bypassed, only one Flow Unit may be inoperable without resulting in a control rod block signal. Although a

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

5.b Recirculation Flow Unit – Inoperative (continued)

control rod block signal will be sent to the rod block logic circuit by a Flow Unit whose mode switch is in “Standby”, that Flow Unit will still provide a valid flow output signal to the auctioneering circuits of the APRMs and RBM.

There are four channels of Recirculation Flow Unit – Inoperative with two channels inputting into each rod block logic circuit. Two channels of Recirculation Flow Unit – Inoperative, with one channel inputting to each rod block logic circuit, are required to be OPERABLE to ensure at least one OPERABLE flow signal is being provided to the Average Power Range Monitor Flow Biased Simulated Thermal Power and Neutron Flux – Upscale and Rod Block Monitor Functions required by LCO 3.3.1.1, 3.3.2.1, and TLCO 3.3.c.

There is no Allowable Value for this Function.

The Recirculation Flow Unit – Inoperative Function is required to be OPERABLE in MODE 1 consistent with the MODE requirements of the Average Power Range Monitor Flow Biased Simulated Thermal Power and Neutron Flux – Upscale and Rod Block Monitor Functions.

5.c Recirculation Flow Unit – Comparator

Each Recirculation Flow Unit compares its total flow signal to the total flow signal of another Flow Unit. Since each Flow Unit is measuring the same process parameters, a difference in the measured total flow could be indicative of a malfunction of one of the Flow Units. The Recirculation Flow Unit – Comparator Function assures that no control rod will be withdrawn unless the difference between the outputs of all unbypassed Flow Units is within limits.

There are four channels of Recirculation Flow Unit – Comparator with two channels inputting into each rod block logic circuit. The position of the Flow Unit bypass switch determines which two Flow Units each channel compares. Two channels of Recirculation Flow Unit – Comparator, with one channel inputting to each rod block logic circuit, are required to be OPERABLE to ensure at least one OPERABLE flow signal is being provided to the Average Power Range Monitor Flow Biased Simulated Thermal Power

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

5.c Recirculation Flow Unit – Comparator (continued)

and Neutron Flux – Upscale and Rod Block Monitor Functions required by LCO 3.3.1.1, 3.3.2.1, and TLCO 3.3.c. Based on the system design, three Recirculation Flow Units must be OPERABLE to provide the required input signals to the two required Recirculation Flow Unit – Comparator channels.

The Allowable Value was selected to be high enough to determine that one of the two flow units is malfunctioning and is above the maximum Flow Unit deviation that can be accounted for by defined process, calibration, and instrumentation errors.

The Recirculation Flow Unit – Comparator Function is required to be OPERABLE in MODE 1 consistent with the MODE requirements of the Average Power Range Monitor Flow Biased Simulated Thermal Power and Neutron Flux – Upscale and Rod Block Monitor Functions.

ACTIONS

A Note has been provided to modify the ACTIONS related to Control Rod Block Instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Control Rod Block Instrumentation channels provide appropriate compensatory measures for separate, inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable Control Rod Block Instrumentation channel.

A.1

Because of the diversity of sensors available to provide rod block trip signals and the redundancy of the Control Rod Block Instrumentation system design, an allowable out of service time of 7 days is permitted for restoring a required channel to OPERABLE status for Functions monitoring neutron flux. However, this out of service time is acceptable provided only one of the associated Function's channels are inoperable (refer to Required Action C.1 Bases). The 7 day completion time is acceptable because, except for SRM MODE 5 requirements, a

(continued)

BASES

ACTIONS

A.1 (continued)

single failure in the remaining OPERABLE channels will not result in a loss of control rod block capability for the Function. This completion time is also acceptable for the SRM MODE 5 requirements because LCO 3.3.1.2, "SRM Instrumentation," and the IRM Functions of this Requirement provide adequate flux monitoring and rod block protection for a control rod withdrawal in MODE 5.

B.1

With one or more required Function 4.a, 4.b, 5.a, 5.b, or 5.c channels inoperable, the associated Function may not maintain control rod block capability. For this reason, Required Action B.1 requires that the inoperable channel(s) be placed in trip within 12 hours. This initiates a control rod withdrawal block, thereby ensuring that the rod block function is met. The Completion Time of 12 hours is acceptable because the withdrawal of control rods has no effect on SDV level or recirculation flow rate; therefore, a loss of control rod block capability in these Functions does not increase the likelihood of a scram. Additionally, the impact on the RPS from a failure of one or more of these instruments is adequately addressed in LCO 3.3.1.1 "RPS Instrumentation."

C.1

If Required Action A.1 is not met and the associated Completion Time has expired, or more than one required channel, for Functions monitoring neutron flux, is inoperable, the inoperable channel(s) must be placed in trip within 1 hour. With multiple channels within the same Function inoperable, control rod block capability may be lost. The 1 hour Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities and is acceptable because it minimizes risk while allowing time for restoration or tripping of inoperable channels.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the TSRs for each Control Rod Block Instrumentation Function are located in the TSRs column of Table T3.3.c-1.

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains Control Rod Block capability. A Function maintains Control Rod Block capability provided there is at least one channel OPERABLE or in trip. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note takes into account the average time required to perform a channel surveillance. Additionally, the 6 hour testing allowance does not significantly reduce the probability that the Control Rod Block Instrumentation system will trip when necessary.

<u>TSR 3.3.c.1</u>

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at lease once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, TSR 3.3.c.1 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and SRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.c.1 (continued)

Frequency is not met per TSR 3.0.b. In this event, the TSR must be performed within 24 hours after entering MODE 2 from MODE 1. Twenty-four hours is based on operating experience and in consideration of providing a reasonable time in which to complete the TSR. A Frequency of 7 days for Functions 2.a-2.d and 3.a, and 31 days for Functions 3.b-3.d, provides an acceptable level of system average unavailability over the Frequency interval and is based on engineering judgment, operating experience, and the reliability of the IRMs and SRMs.

TSR 3.3.c.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at lease once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology

As noted, TSR 3.3.c.2 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required APRM Neutron Flux - High Function cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per TSR 3.0.b. In this event, the TSR must be performed within 24 hours after entering MODE 2 from MODE 1. Twenty-four hours is based on operating experience and in consideration of providing a reasonable time in which to complete the TSR.

The 92 day Frequency of TSR 3.3.c.2 is based on the reliability analysis of Reference 5.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.c.3, TSR 3.3.c.4, and TSR 3.3.c.5

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated trip unit, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 of TSR 3.3.c.4 and TSR 3.3.c.5 requires the APRM and IRM TSRs to be performed within 24 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per TSR 3.0.b. Twenty-four hours is based on operating experience and in consideration of providing a reasonable time in which to complete the TSR. A second Note to TSR 3.3.c.4 and TSR 3.3.c.5 is provided that states that neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 2000 EFPH LPRM calibration against the TIPs (SR 3.3.1.1.8).

The Frequencies of TSR 3.3.c.3, TSR 3.3.c.4 and TSR 3.3.c.5 are based upon the assumption of a 92 day, 184 day, and 24 month calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR Section 7.7.2.
2. USFAR Section 7.2.2.
3. UFSAR Section 15.4.1.
4. NDIT LS-0684, “Analytical Limits for use as inputs in APRM setpoint calculations.”
5. NEDC-30851P-A, Supplement 1, “Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation,” October 1988.

(continued)

BASES

REFERENCES (continued)

6. GENE-770-06-1-A, “Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications,” December 1992.

7. Technical Specification 3.3.1.1.

8. Technical Specification 3.3.1.2.

9. Technical Specification 3.3.2.1.

B 3.3 INSTRUMENTATION

B 3.3.d Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display, in the control room, plant variables that provide information required by the control room operators during accident situations. Regulatory Guide 1.97 (Ref. 5) groups these variables into 5 types; A, B, C, D, and E. Type A variables are those that provide primary information needed to permit operating personnel to perform specific manually controlled safety functions for which no automatic control is provided. Type B variables provide information to the operator to indicate whether or not the station safety functions are being accomplished. Type C variables provide information to indicate the potential or actual breach of fission product barriers. Type D variables provide the operator with indications of the operation of individual safety systems or other systems important to safety. Type E variables are used to determine continually the extent of radioactive releases.

The five groups (types) of variable are placed into three separate Categories (1, 2, or 3) that provide a graded approach to the requirements depending on the importance to safety of the measurement of a specific variable. Category 1 variables are key variables and must meet the highest design and qualification criteria. Variables which provide selective backup information for Type A, B, and C, Category 1 variables are designated Category 2 and 3. Additionally, Type D and E key variables (which have not been included under Category 1) are designated as Category 2.

Instruments measuring Type A and non-Type A, Category 1, variables are governed by LCO 3.3.3.1, “PAM Instrumentation.” Instrumentation measuring some selected Category 2 and 3 variables are governed by this Requirement.

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 5.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

Category 1 PAM instrumentation ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine whether a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to obtain an estimate of the magnitude of any impending threat.

The PAM instrumentation TLCO ensures OPERABILITY of selected Category 2 and 3 variables. These variables provide system operating status and diagnostic information as a backup to the key variables classified as Category 1.

The plant specific Regulatory Guide 1.97 analysis (Ref. 4 and 6) documents the process that categorized the variables. In addition to the categorizations provided in References 4 and 6, the NRC Final Rule for Combustible Gas Control in Containment (Ref. 8) recategorized the drywell oxygen and hydrogen variables as Categories 2 and 3 respectively.

Selected Category 2 and 3 instrumentation are retained in the TRM because they provide backup information to assist operators in minimizing the consequences of accidents. Therefore, these Category 2 and 3 variables are considered important for reducing risk.

TLCO

TLCO 3.3.d only requires one OPERABLE channel or division of each Function listed in Table T3.3.d-1 since RG 1.97 Category 2 and 3 variables are not required to meet single failure criteria (Ref. 5). While only one OPERABLE channel or division of each Function is required in order to present operators with backup and diagnostic information that may assist in determining the status of the unit; the plant design affords two available channels or divisions of drywell hydrogen/oxygen concentration and suppression chamber/drywell air temperature instrumentation that may be used to satisfy the TLCO. In addition to providing the increased flexibility of having an installed spare, providing two divisions allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

(continued)

BASES

TLCO (continued)

The Main Stack and Standby Gas Treatment (SGT) Stack noble gas monitors and the Safety/Relief Valve (S/RV) position indicators only have one available channel to satisfy the TLCO. This is sufficient since other diverse methods of obtaining the information are available (e.g., portable process rad monitor, grab samples, S/RV tailpipe temperature, etc.).

Listed below is a discussion of the specified instrument Functions listed in Table T3.3.d-1.

1. Suppression Chamber Air Temperature

Suppression chamber air temperature is not a Regulatory Guide 1.97 variable, but is retained in the TRM as part of the original licensing basis of the plant. There are two channels of suppression chamber air temperature monitoring available. The channels have a range of 0°F to 450°F, which is adequate to cover normal through post-accident conditions. The signals from the suppression chamber temperature monitoring channels are continuously recorded and displayed on two control room recorders. The PAM Requirement deals specifically with this portion of the instrument channel. One temperature monitoring channel and its associated recorder are required to be OPERABLE.

2. Drywell Air Temperature

Drywell air temperature is a Type D and Category 2 variable provided to assist the operator in assessing the effectiveness of safety systems during an accident. There are four channels of drywell temperature monitoring. They have a range of 0°F to 600°F, which is adequate to cover normal through post-accident conditions. The thermocouples are located so that they form two groups of two sensors to cover each half of the drywell. The signals from the drywell temperature monitoring channels are continuously recorded and displayed on two control room recorders. Two channels of drywell air temperature indication and the associated recorder, on one division, are required to be OPERABLE to ensure that a representative drywell temperature can be monitored post-accident. These instruments are the primary indication of drywell air temperature used by the operator during an accident. Therefore, the PAM Requirement deals specifically with this portion of the instrument channel.

(continued)

BASES

TLCO (continued)

3. Safety/Relief Valve (S/RV) Position Indicators

S/RV position is a Type D and Category 2 variable provided for verification of RCPB integrity and to verify Emergency Core Cooling System (ECCS) functions (e.g., Automatic Depressurization System). In the case of S/RV position, the important information is the position status of the valve. The position indication in the control room consists of open and closed indicating lights for each valve. For Unit 1, these lights are activated by spindle mounted, position acting reed switches mounted on the S/RV. For Unit 2, a Linear Variable Differential Transmitter (LVDT) is used to sense valve position. The signal from the LVDT is sent to a circuit card that compares the signal to predetermined setpoints and in turn actuates the appropriate main control board indicating light(s) (i.e., open, closed, or intermediate indication).

The TLCO requires one channel of valve position indication in the control room to be OPERABLE for each S/RV. A single OPERABLE channel is sufficient to verify the position status of each S/RV since the valve position could be verified redundantly by other means, such as tailpipe temperature, in the event the required channel failed. Additionally, Reference 5 does not require instruments monitoring Category 2 variables to meet single failure criteria. Each S/RV is treated separately and each valve is considered a separate function. Therefore, separate Condition entry is allowed for each inoperable S/RV position indication channel.

4. Main Stack Noble Gas Monitor

Effluent noble gas is a Type C, Type E, and Category 2 variable provided to detect a breach of the primary containment and to monitor for significant radioactive releases for use by operators in assessing the need to invoke site emergency plans. There are three channels of Main Stack Noble Gas monitoring; low range, mid range, and high range, with a combined detection range of 10^{-7} to 10^{5} uCi/cc. The signals from the main stack noble gas monitoring channels are continuously displayed in the main control room.

(continued)

BASES

TLCO

4. Main Stack Noble Gas Monitor (continued)

The three channels meet the range requirements for the variables of Reference 5. The TLCO requires one channel (the high range) of Main Stack Noble Gas Monitor to be OPERABLE. This is acceptable since the low and mid range channels are adequately controlled by the requirements of the Offsite Dose Calculation Manual (ODCM). This instrument is a primary indication of gaseous effluent release used by the operator during an accident. Therefore, the PAM Requirement deals specifically with the monitor and control room indication portion of the high range instrument channel.

5. Standby Gas Treatment (SGT) System Noble Gas Monitor

Effluent noble gas is a Type C, Type E, and Category 2 variable provided to detect a breach of the primary containment and to monitor for significant radioactive releases for use by operators in assessing the need to invoke site emergency plans. There are three channels of SGT System Noble Gas monitoring; low range, mid range, and high range, with a combined detection range of 10^{-7} to 10^{5} uCi/cc. The signals from the SGT noble gas monitoring channels are continuously displayed in the main control room.

The three channels meet the range requirements for the variables of Reference 5. The TLCO requires one channel (the high range) of SGT System Noble Gas Monitor to be OPERABLE. This is acceptable since the low and mid range channels are adequately controlled by the requirements of the ODCM. This instrument is a primary indication of gaseous effluent release used by the operator during an accident. Therefore, the PAM Requirement deals specifically with the monitor and control room indication portion of the high range instrument channel.

6, 7. Drywell Oxygen and Hydrogen Concentration Analyzer

Drywell oxygen concentration is a Type C, Category 2 instrument provided to detect high oxygen concentration conditions that represent a loss of containment inerting. If an inerted containment were to become de-inerted during a significant beyond design-basis accident, then other severe accident management strategies, such as purging and venting, would need to be considered. Drywell hydrogen concentration is a Type C, Category 3 instrument used to assess the

(continued)

BASES

TLCO

6, 7. Drywell Oxygen and Hydrogen Concentration Analyzer (continued)

degree of core damage during a significant beyond design-basis accident and to confirm if random ignition has taken place. Hydrogen concentration is also used in conjunction with oxygen concentration to guide response to severe accident management strategies and procedures.

High hydrogen and oxygen concentrations are each measured by two independent analyzers. Following receipt of a LOCA signal, the analyzers are initiated and continuously record hydrogen and oxygen concentration on two recorders in the control room. The analyzers are designed to operate under accident conditions. The available 0% to 10% range for the hydrogen analyzers and 0% to 20% range for the oxygen analyzers satisfy the intent of Regulatory Guide 1.97. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel. One channel of hydrogen and oxygen concentration and their associated recorder are required to be OPERABLE.

APPLICABILITY

The PAM instrumentation TLCO is applicable in MODES 1 and 2. These variables provide backup information related to the diagnosis and preplanned actions required to mitigate Design Basis Accidents (DBAs). The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate inoperable functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

As noted, Condition A is not applicable to Functions 4 and 5. Conditions D and E provide the appropriate Required Actions when a Function 4 or 5 instrument becomes inoperable.

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days for Function 2 (Required Action A.1) and within 7 days for Functions 1, 3, 6, and 7 (Required Action A.2). The 7 and 30 day Completion Times are based on operating experience and take into account the remaining OPERABLE channel (for Function 2), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

When Function 2 has two required channels that are inoperable, one channel should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the passive nature of the instruments in providing backup information for the key variables. Continuous operation with two required channels inoperable is not desirable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel limits the risk that the PAM Function will be in a degraded condition should an accident occur. As stated in the Note, Condition B is only applicable to Function 2.

(continued)

BASES

ACTIONS (continued)

C.1.1, C.1.2, and C.2

If a channel has not been restored to OPERABLE status within its associated Completion Time of Condition A or B, these Required Actions specify immediate restoration of the channel or initiation of alternate parameter monitoring methods and require preparation of written documentation to be submitted in accordance with the station's Corrective Action Program (CAP). Immediate restoration of the required channel (Required Action C.1.1) is the preferred ACTION since the required channel meets all the performance qualification requirements of Post Accident Monitoring instrumentation. However, if restoration of the required channel is not possible, initiating an alternate method of monitoring (Required Action C.1.2) is acceptable since it restores the operator's ability to monitor the variable during a DBA or severe accident. ACTIONS must continue until the required channel is restored to OPERABLE status or an acceptable alternate method of monitoring is established. The CAP document should discuss, as applicable, the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, and justify the areas in which they are not equivalent. This CAP document should also discuss the cause of the inoperability, identify proposed restorative actions, and provide a schedule for restoring the normal PAM channels to an OPERABLE status. These Required Actions are appropriate in lieu of a shutdown requirement given the likelihood of plant conditions that would require information provided by this instrumentation, and since either another OPERABLE channel is monitoring the Function or an alternative method of monitoring is available.

D.1 and D.2

As noted, Condition D is only applicable to Functions 4 and 5. Since alternate means of monitoring effluent noble gas concentration have been developed and tested, the Required Action is to initiate the preplanned alternate method of monitoring the parameter. These alternate means must be used if the normal PAM channel cannot be restored to OPERABLE status within 72 hours (Required Action D.1). Additionally, Required Action D.2 requires restoration of the required channel to OPERABLE status within 7 days.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

The 72 hour Completion Time is based on providing sufficient time to initiate the alternate monitoring. If it is not possible to initiate the alternate monitoring method and the Completion Time of Required Action D.1 has expired, Condition E must be entered.

The 7 day Completion Time has been determined to be acceptable and takes into account the alternate monitoring method, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

E.1

If any Required Action and associated Completion Time of Condition D is not met, a CAP document must be prepared immediately. The document should discuss the reason for exceeding the Completion Time of the Required Action, identify proposed restorative actions, and provide a schedule for restoring the normal PAM channels to an OPERABLE status.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the following TSRs apply to each PAM instrumentation Function in Table T3.3.d-1 except as specifically identified in the individual TSRs.

The Surveillances are modified by a second Note to indicate that when a Function 2 channel is placed in an inoperable status solely for

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the other required Function 2 channel is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary.

TSR 3.3.d.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the channels required by the TLCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.d.2 and TSR 3.3.d.3

A CHANNEL CALIBRATION is performed every 92 days for Functions 6 and 7, and every 24 months for all other Functions. For Function 3, the CHANNEL CALIBRATION shall consist of verifying that the position indication will conform to the actual valve position. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The 92 day Frequency for CHANNEL CALIBRATION of Functions 6 and 7 is based on operating experience. The 24 month Frequency of all other PAM instrumentation of Table T3.3.d-1 is based on operating experience and consistency with the refueling cycles.

TSR 3.3.d.2 is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure is adequate to perform the test. The 12 hours allowed for the CHANNEL CALIBRATION after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the TSR.

REFERENCES

1. UFSAR Section 7.5.2.1.

2. UFSAR Section 7.7.15.2.6.

3. UFSAR Section 11.5.2.2.

4. UFSAR Appendix B, “Regulatory Guide 1.97 Rev. 2.”

5. Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2, December 1980.

6. NRC Safety Evaluation Report, "Commonwealth Edison Company, LaSalle County Station, Unit Nos. 1 and 2, Conformance to Regulatory Guide 1.97," dated August 20, 1987.

7. Offsite Dose Calculation Manual.

8. 68 FR 54123, “Final Rule – Combustible Gas Control in Containment”, September 16, 2003.

B 3.3 INSTRUMENTATION

B 3.3.e ECCS Discharge Line Keep Fill Alarm Instrumentation

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. The suppression pool provides the required source of water for the ECCS.

One design requirement of the ECCS is that cooling water flow to the reactor pressure vessel (RPV) must be initiated rapidly when the system is called on to perform its function. This quick start system characteristic is provided by quick opening valves, quick start pumps, and a standby a-c power source. The lag between the pump start signal and the initiation of flow into the RPV is minimized by always keeping the ECCS pump discharge lines full. Additionally, if these lines were not full when the systems initiated, the large momentum forces associated with accelerating fluid into dry portions of pipe (water hammer) could cause physical damage to the piping. The ECCS discharge line keep fill system maintains the pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the suppression pool, check valves are provided near the pumps to prevent back flow from emptying the lines into the suppression pool. Operating experience has shown that these valves will leak slightly, producing a small back flow that will eventually empty the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept filled, a water leg pump is provided for each ECCS division. Indication is provided in the control room as to whether these water leg pumps are operating.

(continued)

BASES

BACKGROUND (continued)	The ECCS Discharge Line Keep Fill Alarm Instrumentation consists of pressure switches that monitor fluid pressure in the ECCS discharge lines. A single pressure switch is provided on each of the five ECCS subsystem (LPCS, LPCI A, LPCI B, LPCI C, and HPCS) discharge lines. Each pressure switch provides an output to a main control room alarm (e.g., ESF system status light or control board annunciator) and to alert the operator when the associated discharge line pressure is low.
APPLICABLE DESIGN BASES	The function of the ECCS Discharge Line Keep Fill Alarm Instrumentation is to provide an alarm to alert the operator when the pump discharge piping may not be full of water. While the ECCS will not be prevented from actuating, the presence of this alarm may indicate that the system is not OPERABLE since the pump discharge lines must be maintained full to prevent damage to piping due to a water hammer and to start core cooling at the earliest possible moment. If a valid ECCS Discharge Line Keep Fill Alarm has actuated, the OPERABILITY of the affected ECCS subsystem should be determined by venting the system at the high point vent to verify that the discharge piping is full of water. The ECCS Discharge Line Keep Fill Alarm Instrumentation only performs an alarm function to monitor readiness of the associated safety system. The instrumentation does not perform a safety related prevention or mitigation function nor a post accident instrumentation function.
TLCO	The ECCS Discharge Line Keep Fill Alarm Instrumentation is required to detect conditions which may indicate that an ECCS subsystem is inoperable. There are five channels of ECCS Discharge Line Keep Fill Alarm Instrumentation, one associated with each ECCS subsystem. The discharge line keep fill instrument channel, including the associated control room alarm, for each OPERABLE ECCS subsystem must be OPERABLE to ensure that the associated ECCS subsystem discharge line is being maintained full of water.

(continued)

BASES

TLCO (continued)

Each channel must have its setpoint set within the specified Allowable Value of TSR 3.3.e.2. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., discharge line pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytic limits, corrected for defined process, calibration, and instrument errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

The Allowable Values are based on the head of water between the centerline of the ECCS pump discharge nozzle and the associated system high point vent.

With a discharge line keep fill alarm instrument channel inoperable, monitoring of the status of the ECCS discharge line is degraded; however, the ECCS subsystem may still be OPERABLE provided the discharge piping can be verified full of water by an alternate acceptable means.

(continued)

BASES (continued)

APPLICABILITY

The ECCS Discharge Line Keep Fill Alarm Instrumentation is required to ensure that the operator will be promptly alerted to degradations in the ECCS subsystems required by LCO 3.5.1 “ECCS – Operating,” and LCO 3.5.2, “ECCS – Shutdown.” Therefore, the ECCS Discharge Line Keep Fill Alarm Instrumentation channels are required to be OPERABLE whenever the associated ECCS subsystem is OPERABLE. If an ECCS subsystem is inoperable or not required by LCO 3.5.2, the discharge line keep fill alarm instrumentation channel monitoring that ECCS subsystem is not required to be OPERABLE since these subsystems are not assumed to function to mitigate a LOCA.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS discharge line keep fill alarm instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS discharge line keep fill alarm instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ECCS discharge line keep fill alarm instrumentation channel.

A.1

With an ECCS discharge line keep fill instrumentation channel inoperable, SR 3.5.1.1 is performed every 24 hours to provide periodic assurance that the affected ECCS subsystem discharge line is full of water at a more frequent interval than the routine Frequency of SR 3.5.1.1. The 24 hour interval is adequate, based on operating experience, to detect problems in the affected ECCS discharge line because of the procedural controls governing system operation and the gradual nature of void buildup in the ECCS piping.

(continued)

BASES

ACTIONS

A.1 (continued)

Since the Required Action only specifies "perform," a failure of SR 3.5.1.1 acceptance criteria does not result in the Required Action not met. However, a failure to meet SR 3.5.1.1 renders the associated ECCS subsystem inoperable and the appropriate Conditions of LCO 3.5.1 and LCO 3.5.2 must be entered and the Required Actions taken.

SURVEILLANCE REQUIREMENTS

TSR 3.3.e.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 31 day Frequency is based on the original licensing basis of the ECCS Discharge Line Keep Fill Alarm Instrumentation function.

TSR 3.3.e.2

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated relays, and the sensor. This test verifies the channel responds to the measured parameter

within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	TSR 3.3.e.2 (continued) The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.
REFERENCES	1. USFAR Section 6.3.2.2.5. 2. Technical Specification 3.5.1. 3. Technical Specification 3.5.2.

B 3.3 INSTRUMENTATION

B 3.3.f Emergency Core Cooling System (ECCS) Header Differential Pressure Instrumentation

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. Each of these ECCS subsystems delivers water directly to the fueled region inside of the core shroud.

The HPCS and the LPCS subsystems penetrate on opposite sides of the reactor pressure vessel (RPV) at about the same elevation as the Steam Separators. After entering the RPV the core spray lines immediately split into two headers. Each header passes through the upper core shroud and forms a semi-circular sparger extending halfway inside of the upper core shroud. Sparger nozzles are pointed radially inward and downward from the headers to direct core spray into each fuel assembly. The LPCI subsystem lines penetrate the RPV, traverse the downcomer annulus, and terminate at the core shroud to deliver water directly into the volume enclosed by the core shroud.

Since the ECCS lines traverse through the downcomer annulus, which is at a lower pressure than that inside the core shroud during normal operations, a break in one of these lines would be indicated by a drop in pressure inside of the affected ECCS injection/spray line. Therefore, the integrity of the ECCS lines in the downcomer annulus is monitored by differential pressure switches that compare ECCS discharge line pressure to the pressure in the core shroud either directly or by comparison to another ECCS discharge line penetrating the core shroud. The ECCS Header Differential Pressure Instrumentation consists of three differential pressure switches. One switch measures the differential pressure

(continued)

BASES

BACKGROUND (continued)	between the HPCS spray sparger and the Standby Liquid Control System (SBLC) pressure tap above the core plate to confirm the integrity of the HPCS piping. Another switch compares LPCI B and LCPI C injection line pressures, while the third switch compares the LPCI A injection line pressure to the LPCS spray sparger pressure. Each differential pressure switch provides an output to a main control board alarm to alert the operator of a potential breach in an ECCS line between the inside of the RPV and the core shroud.
APPLICABLE DESIGN BASES	The function of the ECCS Header Differential Pressure Instrumentation is to provide an alarm to alert the operator of a potential compromise of ECCS piping integrity internal to the RPV. While the ECCS will not be prevented from actuating, the presence of this alarm may indicate that the system is not OPERABLE since cooling water would flow out of the break and bypass the core region, potentially invalidating the flow delivery assumptions in the safety analyses of Reference 1. If an ECCS Header Differential Pressure alarm has actuated, the validity of the alarm should be determined since the location of the pressure taps can cause indications to vary under differing RPV temperature and flow conditions (e.g., the differential pressure of the HPCS line varies as a function of core flow and reactor coolant density). If the alarm is determined to be valid, the OPERABILITY of the affected ECCS subsystem should be evaluated to determine if the subsystem is still capable of performing its specified safety function assumed in the accident analysis. The ECCS Header Differential Pressure Instrumentation only performs an alarm function to monitor readiness of the associated safety system during normal plant operations. The instrumentation does not perform a safety related prevention or mitigation function nor a post accident instrumentation function.

(continued)

BASES (continued)

TLCO

The ECCS Header Differential Pressure Instrumentation is required to detect conditions which may indicate that an ECCS subsystem is inoperable. There are three channels of ECCS Header Differential Pressure Instrumentation, one associated with each ECCS division. The ECCS header differential instrument channel, including the associated control room alarm, for each ECCS division must be OPERABLE to ensure that the integrity of the associated ECCS subsystem injection/spray line (between the inside of the RPV and the core shroud) is being maintained.

Each channel must have its setpoint set within the specified Allowable Value of TSR 3.3.f.2. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., discharge line differential pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytic limits, corrected for defined process, calibration, and instrument errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

(continued)

BASES

TLCO (continued)	The Allowable Values were selected to ensure that an ECCS line break between the RPV and the core shroud would be detected during normal plant operations.
APPLICABILITY	During MODES 1, 2, and 3 there is considerable energy in the reactor core and core cooling is required to prevent fuel damage in the event of a break in the primary system piping. In these MODES, LCO 3.5.1 "ECCS – Operating," requires all ECCS subsystems to be OPERABLE. Therefore, all ECCS Header Differential Pressure Instrumentation channels are required to be OPERABLE in MODES 1, 2, and 3, to ensure that the operator will be promptly alerted to degradations in the required ECCS subsystems. In MODES 4 and 5, fewer ECCS subsystems are required to be OPERABLE due to the low temperature and pressure conditions present in these MODES. Similarly, flow delivery requirements for postulated accidents are significantly less than that required in higher MODES. Additionally, the ECCS header differential pressure channels are not capable of providing meaningful detection capability under the temperature, pressure, and flow conditions present in these lower MODES. Therefore, the ECCS Header Differential Pressure Instrumentation is not required to be OPERABLE in MODES 4 and 5.
ACTIONS	A Note has been provided to modify the ACTIONS related to ECCS header differential pressure instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS header differential pressure instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ECCS header differential pressure instrumentation channel.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

With one or more ECCS header differential pressure instrument channels inoperable, the ability to monitor the integrity of the associated ECCS injection/spray lines is degraded. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities affecting all channels, and the low probability of an ECCS line break occurring, 72 hours is provided to restore the inoperable channel (Required Action A.1). Additionally, 72 hours is consistent with the allowed out of service time permitted by Technical Specifications for two inoperable low pressure ECCS pumps (Ref. 3). Alternately, the associated ECCS header pressure may be determined locally within 72 hours and once every 12 hours thereafter (Required Action A.2) allowing plant operation to continue. Local monitoring of ECCS header differential pressure adequately compensates for loss of the main control room alarm function since the most probable mechanism for a breach in an ECCS line would be a slowly propagating imperfection or crack in the piping. The 12 hour interval for local monitoring is appropriate for identifying changes in ECCS injection line pressure and for tracking trends in header differential pressure.

Since the Required Action only specifies “determine,” a local reading in excess of the Allowable Value does not result in the Required Action not met. However, an indicated differential pressure exceeding the Allowable Value may render the associated ECCS subsystem inoperable. In this case, an evaluation should be performed to determine if the affected ECCS subsystem is capable of performing its specified safety function assumed in the accident analysis. If it is concluded that the ECCS subsystem is inoperable, then the appropriate Conditions of LCO 3.5.1 must be entered and the Required Actions taken.

B.1

If the ECCS header differential pressure instrument channel is not restored to OPERABLE status and it is not possible to locally determine ECCS header differential

(continued)

BASES

ACTIONS

B.1 (continued)

pressure within the allowed Completion Time, the integrity of the ECCS injection/spray lines cannot be verified. In this event, the associated ECCS subsystem(s) must be immediately declared inoperable, the appropriate Conditions of LCO 3.5.1 entered, and the Required Actions taken.

SURVEILLANCE REQUIREMENTS

TSR 3.3.f.1

A CHANNEL FUNCTIONAL TEST is performed on each channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 31 day Frequency is based on the original licensing basis of the ECCS Header Differential Pressure Instrumentation function.

TSR 3.3.f.2

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated relays, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 6.3.3.7.7.
2. UFSAR Section 7.6.2.2.5.
3. Technical Specification 3.5.1.

B 3.3 INSTRUMENTATION

B 3.3.g Reactor Core Isolation Cooling (RCIC) System Discharge Line Keep Fill Alarm Instrumentation

BASES

BACKGROUND

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

One design requirement of the RCIC system is that cooling water flow to the reactor pressure vessel (RPV) must be initiated rapidly when the system is called on to perform its function. This quick start system characteristic is provided by quick opening valves and a quick start pump. The lag between the pump start signal and the initiation of flow into the RPV is minimized by always keeping the RCIC pump discharge line full. Additionally, if this line was not full when the system initiated, the large momentum forces associated with accelerating fluid into dry portions of pipe (water hammer) could cause physical damage to the piping. The RCIC discharge line keep fill system maintains the pump discharge line in a filled condition.

RCIC pump suction is provided from the condensate storage tank (CST) or the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC system. Since the RCIC discharge line is elevated above the suppression pool and CST, check valves are provided near the pump to prevent back flow from emptying the lines into the suppression pool or CST. Operating experience has shown that these check valves will leak slightly, producing a small back flow that could eventually empty the discharge piping. To ensure that this leakage from the discharge line is

(continued)

BASES

BACKGROUND (continued)	replaced and the line is always kept filled, a water leg pump is provided for the RCIC system. The suction source for the water leg pump can be manually aligned from either the CST or the suppression pool depending on the alignment of the RCIC pump suction. Indication is provided in the control room as to whether the water leg pump is operating. The RCIC System Discharge Line Keep Fill Alarm Instrumentation consists of a pressure switch that monitors fluid pressure in the RCIC discharge line. The pressure switch provides an output to an ESF system status alarm to alert the operator when the RCIC discharge line pressure is low.
APPLICABLE DESIGN BASES	The function of the RCIC System Discharge Line Keep Fill Alarm Instrumentation is to provide an alarm to alert the operator when the pump discharge piping may not be full of water. While the RCIC system will not be prevented from actuating, the presence of this alarm may indicate that the system is not OPERABLE since the pump discharge line must be maintained full to prevent damage to piping due to a water hammer and to start core cooling at the earliest possible moment. If a valid RCIC System Discharge Line Keep Fill Alarm has actuated, the OPERABILITY of the RCIC system should be determined by venting the system at the high point vent to verify that the discharge piping is full of water. The RCIC System Discharge Line Keep Fill Alarm Instrumentation only performs an alarm function to monitor readiness of the RCIC system. The instrumentation does not perform a safety related prevention or mitigation function nor a post accident instrumentation function.
TLCO	The RCIC System Discharge Line Keep Fill Alarm Instrumentation is required to detect conditions which may indicate that the RCIC system is inoperable. One channel of RCIC System Discharge Line Keep Fill Alarm Instrumentation, including the associated control room alarm, must be OPERABLE to ensure that the RCIC system discharge line is being maintained full of water.

(continued)

BASES

TLCO (continued)	The channel must have its setpoint set within the specified Allowable Value of TSR 3.3.g.2. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions. The nominal setpoint is selected to ensure that the setpoint does not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with the trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. The channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoint is compared to the actual process parameter (e.g., discharge line pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. The analytic limit is derived from the limiting values of the process parameter obtained by analysis or evaluation. The trip setpoint is determined from the analytic limit, corrected for defined process, calibration, and instrument errors. The Allowable Value is then determined, based on the trip setpoint value, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoint and Allowable Value determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (if the channel must function in a harsh environment) are accounted for and appropriately applied for the instrumentation. The Allowable Value is based on the head of water between the centerline of the RCIC pump discharge nozzle and the system high point vent. With the RCIC system discharge line keep fill alarm instrument channel inoperable, monitoring of the status of the RCIC discharge line is degraded; however, the RCIC system may still be OPERABLE provided the discharge piping can be verified full of water by an alternate acceptable means.

(continued)

BASES (continued)

APPLICABILITY	The RCIC System Discharge Line Keep Fill Alarm Instrumentation is required to be OPERABLE when the RCIC system is OPERABLE. RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized, and the OPERABILITY of the RCIC System Discharge Line Keep Fill Alarm Instrumentation ensures that the operator will be promptly alerted to degradations in the RCIC system. If the RCIC system is inoperable or not required to be OPERABLE by LCO 3.5.3, "RCIC System," the discharge line keep fill alarm instrumentation channel monitoring the RCIC system is not required to be OPERABLE since, under these conditions, RCIC is not assumed to function in a reactor isolation event.
ACTIONS	A.1 With the RCIC system discharge line keep fill instrumentation channel inoperable, SR 3.5.3.1 is performed every 24 hours to provide periodic assurance that the RCIC system discharge line is full of water at a more frequent interval than the routine Frequency of SR 3.5.3.1. The 24 hour interval is adequate, based on operating experience, to detect problems in the RCIC discharge line because of the procedural controls governing system operation and the gradual nature of void buildup in the RCIC piping. Since the Required Action only specifies "perform," a failure of SR 3.5.3.1 acceptance criteria does not result in the Required Action not met. However, a failure to meet SR 3.5.3.1 renders the RCIC system inoperable and the appropriate Conditions of LCO 3.5.3 must be entered and the Required Actions taken.
SURVEILLANCE REQUIREMENTS	TSR 3.3.g.1 A CHANNEL FUNCTIONAL TEST is performed on the channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.g.1 (continued)

TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 31 day Frequency is based on the original licensing basis of the RCIC System Discharge Line Keep Fill Alarm Instrumentation function.

TSR 3.3.g.2

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated relays, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
2. UFSAR Section 7.4.1.
3. Technical Specification 3.5.3.

B 3.3 INSTRUMENTATION

B 3.3.h High/Low Pressure Interface Valve Leakage Pressure Monitors

BASES

BACKGROUND

Reactor Coolant System (RCS) Pressure Isolation Valves (PIVs) separate the high pressure RCS from an attached low pressure system. This protects the low pressure piping connected to the RCS. During their lives, these valves can leak varying amounts through either normal operational wear or mechanical deterioration.

LCO 3.4.6, "RCS Pressure Isolation Valve Leakage," allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. Although LCO 3.4.6 provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. Fluid pressure buildup in low pressure portions of connected systems is an indication that the PIVs between the RCS and the connecting systems may be degraded or degrading. Excessive PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could also degrade the ability for low pressure injection to perform its safety function.

PIVs are provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System (LPCS);

c. High Pressure Core Spray System (HPCS); and

d. Reactor Core Isolation Cooling (RCIC) System.

The High/Low Pressure Interface Valve Leakage Pressure Monitors consists of pressure switches that monitor fluid pressure in the connected system pump suction or discharge lines. A single pressure switch is provided on each of

(continued)

BASES

BACKGROUND (continued)	the following locations; HPCS pump suction, LPCS pump discharge, LPCI A pump discharge, LCPI B pump discharge, LPCI C pump discharge, RCIC pump suction, and the common Shutdown Cooling suction line. Each pressure switch provides an output to a main control board alarm to alert the operator when pressure in the associated line is high.
APPLICABLE DESIGN BASES	The function of the High/Low Pressure Interface Valve Leakage Pressure Monitors is to detect high pressure conditions in sections of piping and equipment, which will not normally experience these pressures, since they are isolated from high pressure systems by PIVs. In this way, the instrumentation provides for monitoring the condition of the reactor coolant pressure boundary (RCPB) to detect PIV degradation that has the potential to cause a LOCA outside of containment. While the affected system piping is protected from overpressure by relief valves, the presence of this alarm may indicate that the PIV(s) isolating the high pressure portion of the system from the low pressure portion is not OPERABLE. If a valid High/Low Pressure Interface Valve Leakage Pressure Monitor alarm has actuated, the OPERABILITY of the affected PIV(s) should be evaluated to determine if the valve(s) still meet the leakage requirements of SR 3.4.6.1. Depending on the circumstances, this evaluation may not require the performance of a leak rate test. The High/Low Pressure Interface Valve Leakage Pressure Monitors only perform an alarm function to monitor PIV leakage. The instrumentation does not perform a safety related prevention or mitigation function nor a post accident instrumentation function. Additionally, PIV leakage is not considered in any Design Basis Accident analyses.
TLCO	The High/Low Pressure Interface Valve Leakage Pressure Monitors are required to detect conditions which may indicate that a PIV is inoperable. There are seven High/Low Pressure Interface Valve Leakage Pressure Monitors, one associated with each low pressure section of piping isolated from high pressure systems by PIVs. Seven

(continued)

BASES

TLCO (continued)

High/Low Pressure Interface Valve Leakage Pressure Monitors, including the associated control room alarms, must be OPERABLE to ensure that degradations in PIV isolation integrity are promptly detected to reduce the probability of an intersystem LOCA.

Each monitor must have its setpoint set within the specified Allowable Value of TSR 3.3.h.2. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A monitor is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., discharge line pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., relay) changes state. The analytic limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytic limits, corrected for defined process, calibration, and instrument errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

The Allowable Values were selected to ensure that degradation of PIVs would be detected during normal plant operations.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the High/Low Pressure Interface Valve Leakage Pressure Monitors are required to be OPERABLE because the potential for PIV leakage is greatest when the RCS is pressurized. In MODE 3, PIVs in the RHR flowpath are not isolated when in, or during transition to or from, the RHR shutdown cooling mode of operation; therefore, valve leakage detection capability is not required.

In MODES 4 and 5, the High/Low Pressure Interface Valve Leakage Pressure Monitors are not required to be OPERABLE because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

A Note has been provided to modify the ACTIONS related to high/low pressure interface valve leakage pressure monitors. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable high/low pressure interface valve leakage pressure monitors provide appropriate compensatory measures for separate inoperable monitors. As such, a Note has been provided that allows separate Condition entry for each inoperable high/low pressure interface valve leakage pressure monitor.

A.1 and A.2

With one or more High/Low Pressure Interface Valve Leakage Pressure Monitors inoperable, the ability to monitor the integrity of the associated PIVs is degraded. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

affecting all monitors, and the low probability of gross valve failure occurring, 7 days is provided to restore the inoperable channel (Required Action A.1). Additionally, 7 days is consistent with the allowed out of service time permitted by Technical Specifications for an inoperable low pressure ECCS pump (Ref. 3). Alternately, the pressure in the associated low pressure piping section may be determined locally within 7 days and once every 12 hours thereafter (Required Action A.2) allowing plant operation to continue. Local monitoring of affected piping pressure adequately compensates for loss of the main control room alarm function since PIV leakage is usually on the order of drops per minute and the probability of a rapid gross failure of the valve is extremely low. The 12 hour interval for local monitoring is appropriate for identifying changes and tracking trends in affected system piping pressure.

Since the Required Action only specifies "verify," a local reading in excess of the Allowable Value does not result in the Required Action not met. However, an indicated pressure exceeding the Allowable Value may render the associated PIV(s) inoperable. If it is determined that the affected PIV(s) is leaking in excess of the limits specified in SR 3.4.6.1, then the appropriate Conditions of LCO 3.4.6 must be entered and the Required Actions taken.

SURVEILLANCE REQUIREMENTS

TSR 3.3.h.1

A CHANNEL FUNCTIONAL TEST is performed on each monitor to ensure that the monitor will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.h.1 (continued)

The 31 day Frequency is based on the original licensing basis of the High/Low Pressure Interface Valve Leakage Pressure Monitor function.

TSR 3.3.h.2

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated relays, and the sensor. This test verifies the monitor responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the monitor adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. FSAR Question and Answer 111.86.
2. Technical Specification 3.4.6.
3. Technical Specification 3.5.1.

B 3.3 INSTRUMENTATION

B 3.3.i Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The Automatic Depressurization System (ADS) is designed to provide depressurization of the primary system during a small break loss of coolant accident (LOCA) if High Pressure Core Spray (HPCS) fails or is unable to maintain required water level in the reactor pressure vessel (RPV). ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (Low Pressure Core Spray (LPCS) and Low Pressure Coolant Injection (LPCI)), so that these subsystems can provide core cooling.

ADS may be initiated by either automatic or manual means. Automatic initiation occurs when signals indicating Reactor Vessel Water Level - Low Low Low, Level 1; Drywell Pressure - High or ADS Drywell Pressure Bypass Timer; confirmed Reactor Vessel Water Level - Low, Level 3; and either LPCS or LPCI Pump Discharge Pressure - High are all present, and the ADS Initiation Timer has timed out. Once the Drywell Pressure - High or ADS initiation signals are present, they are individually sealed in until manually reset. Each ADS trip system (trip system A and trip system B) ADS Initiation Timer imposes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The time delay chosen is long enough that the HPCS has time to operate to recover to a level above Level 1, yet not so long that the LPCI and LPCS systems are unable to adequately cool the fuel if the HPCS fails to maintain level. An alarm in the control room is annunciated when either of the timers is running. Resetting the ADS initiation signals resets the ADS Initiation Timers. Either ADS trip system A or trip system B will cause all the ADS valves to open.

It is possible for the operator to inhibit the ADS system with the manual inhibit switches. The operator would make this decision based on an assessment of other plant conditions. One ADS manual inhibit switch is provided for each ADS trip system. A main control room alarm is actuated whenever an ADS manual inhibit switch is placed in the “Inhibit” position.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

The function of the ADS Manual Inhibit Function is to provide the operator a means of disabling automatic ADS initiation capability when plant condition are such that an initiation of ADS could result in core damage.

10 CFR 50.62 (Ref. 4) provides the requirements for reduction of risk from anticipated transient without scram (ATWS) events for light-water-cooled reactors. The regulation requires that boiling water reactors have an alternate rod injection (ARI) system diverse from the Reactor Protection System, a Standby Liquid Control (SLC) system capable of injecting borated water into the RPV, and a system to automatically initiate a recirculation pump trip (RPT) under conditions indicative of an ATWS. A plant specific analysis demonstrated that the requirements imposed by LCO 3.3.4.2, “ATWS-RPT Instrumentation,” and LCO 3.1.7, “SLC System,” adequately meet the criteria of Reference 4. Thus the ADS system, including the ADS Manual Inhibit Function is not assumed in the ATWS analyses of Reference 2. However, guidelines were developed by the BWR Owners Group in response to NUREG-0737 and NEI 91-04 (Ref. 7 and 8) to define strategies for responding to emergencies, including events beyond those postulated in the transient and accident analyses of the UFSAR. These Severe Accident Guidelines (SAGs) implement contingency actions to account for system and component failures beyond those postulated in the UFSAR. One of these contingencies involves the methods for controlling RPV water level under conditions when it cannot be determined that control rod insertion alone will assure that the reactor will remain shutdown under all conditions.

In order to effect a reduction in reactor power under these extraordinary conditions, emergency procedures may direct actions to deliberately lower RPV water level to a level below the automatic initiation setpoint of ADS. Actuation of ADS imposes a severe thermal transient on the RPV and complicates the efforts to maintain RPV water level within the ranges specified in the SAG. Further, rapid and uncontrolled injection of large amounts of relatively cold, unborated water from low pressure injection systems may occur as RPV pressure decreases to and below the shutoff heads of these pumps. Such an

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

occurrence would quickly dilute in-core boron concentration and reduce reactor coolant temperature. When the reactor is not shutdown, or when the shutdown margin is small, sufficient positive reactivity might be added in this way to cause a reactor power excursion large enough to severely damage the core. Therefore, the ADS Manual Inhibit Function is required to purposely prevent ADS initiation under these circumstances.

The ADS initiation instrumentation and ADS valves described in LCO 3.3.5.1, "ECCS Instrumentation," and LCO 3.5.1, "ECCS-Operating," respectively, ensure that the acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 3), will be met following a LOCA assuming the worst case single active component failure in the ECCS. The ADS Manual Inhibit Function is not assumed for ADS operation in any of the accident analyses for which ECCS operation is required, but is designed to aid in the mitigation of an ATWS during severe accident conditions. Since an ATWS event is not a transient for which the actuation of ADS is assumed, the ADS Manual Inhibit Function does not affect the OPERABILITY of the ECCS function of the instrumentation or valves described in LCO 3.3.5.1 and LCO 3.5.1. However, since the ADS Manual Inhibit Function channels have circuitry common to the ADS trip system logic circuits, an inoperability in a manual inhibit instrument channel should be evaluated to determine if it impacts the OPERABILITY of components required by LCO 3.3.5.1. Refer to the Bases of LCO 3.3.5.1 and LCO 3.5.1 for more details.

TLCO

The ADS Manual Inhibit Function is required to allow the operator to prevent ADS initiation during certain plant conditions. There are two channels of ADS Manual Inhibit Function, one associated with each ADS trip system. Both channels of ADS Manual Inhibit Function are required to be OPERABLE to ensure that each ADS trip system can be disabled when conditions warrant to ensure that the ADS valves will not automatically open and cause undesirable effects.

(continued)

BASES (continued)

APPLICABILITY

Critical reactor operation occurs during MODES 1 and 2; therefore, these are the MODES of operation during which an ATWS could occur. During MODE 3, 4, and 5, the reactor is maintained in a subcritical condition and the need for an ATWS mitigation strategy is eliminated. However, since the ADS Manual Inhibit Function can potentially affect the OPERABILITY of components in the ADS initiation trip systems (by disabling the trip system if the Function failed in inhibit), the Applicability of the ADS Manual Inhibit Function is the same as that required for ADS trip system components. Therefore, the ADS Manual Inhibit Function is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable instruments. As such, a Note has been provided that allows separate Condition entry for each inoperable ECCS instrumentation channel.

A.1

Because of the low probability of an event requiring the use of the ADS Manual Inhibit Function and the availability of other methods to electrically inhibit ADS (e.g., resetting the initiation timers or opening the control power breakers), an allowable out of service time of 9 days is acceptable to permit restoration of any inoperable channel to OPERABLE status if both HPCS and Reactor Core Isolation Cooling (RCIC) are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 5 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 9 days to 5 days,

(continued)

BASES

ACTIONS	A.1 (continued) the 5 days begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable channel cannot exceed 9 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 5 days to 9 days, the "time zero" for beginning the 9 day "clock" begins upon discovery of the inoperable channel.
SURVEILLANCE REQUIREMENTS	TSR 3.3.i.1 The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required inhibit logic for a specific channel. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.
REFERENCES	1. UFSAR Section 7.3.1.2.2.4. 2. UFSAR Section 15.8. 3. 10 CFR 50.46. 4. 10 CFR 50.62. 5. Technical Specification 3.3.5.1. 6. Technical Specification 3.5.1. 7. NUREG-0737 Item I.C.1, “Guidance for the Evaluation and Development of Procedures for Transients and Accidents.” 8. NEI 91-04, “Severe Accident Issue Closure Guidelines.”

B 3.3 INSTRUMENTATION

B 3.3.j Primary Containment Isolation Instrumentation

BASES

BACKGROUND

The isolation instrumentation of this Requirement automatically initiates closure of appropriate Reactor Water Cleanup (RWCU) and Residual Heat Removal (RHR) Shutdown Cooling (SDC) system valves. The function of the instrumentation is to provide protection against piping failures in high and moderate energy fluid systems to assure that such failures will not cause the loss of needed functions of safety-related systems. System isolation within the time limits specified for these isolation valves ensures that the temperature of areas within and adjacent to the break location do not exceed their Environmental Qualification (EQ) temperature limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of an RWCU or SDC system isolation. Some channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the isolation logic. The isolation instrumentation shares the same logic circuitry required by LCO 3.3.6.1, “Primary Containment Isolation Instrumentation.” The input parameters to the isolation logic are RWCU system suction flow and SDC system suction flow. Redundant sensor input signals are provided from each such isolation initiation parameter.

The primary containment isolation instrumentation has inputs to the trip logic from the isolation Functions listed below.

Reactor Water Cleanup System Isolation

The RWCU Isolation Function receives input from two channels, each monitoring system suction flow, with each channel in one trip system using one-out-of-one logic. Each of the two trip systems is connected to one of the two valves on the RWCU penetration so that operation of either trip system isolates the penetration.

(continued)

BASES

BACKGROUND

Reactor Water Cleanup System Isolation (continued)

The RWCU Isolation Function isolates the inboard and outboard RWCU suction valves.

RHR Shutdown Cooling System Isolation

The Shutdown Cooling Isolation Function receives input signals from two system suction flow instruments. The outputs from the flow channels are arranged into two one-out-of-one trip systems. One of the two trip systems is connected to the outboard valve associated with the reactor vessel head spray injection penetration, the shutdown cooling return penetration, and the shutdown cooling suction penetration while the other trip system is connected to the inboard valves on the shutdown cooling suction penetration and the shutdown cooling return check valve bypasses.

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation in this Requirement are assumed in the High Energy Line Break (HELB) and Moderate Energy Line Break (MELB) analyses of References 4 and 5. These signals initiate closure of valves to ensure that areas affected by the break do not exceed the EQ temperature, pressure, or humidity limits of the components in those areas.

The RWCU HELB analysis postulates piping breaks in each plant area containing RWCU lines. The analysis conservatively calculated the lowest flowrate that would result from the double-ended guillotine rupture of a 4-inch RWCU line with the plant operating at normal operating temperature and pressure. The analysis demonstrated that leak detection instrumentation would isolate the break prior to exceeding the EQ temperature zone limits of the affected areas. Larger breaks would result in higher flows which would be detected and isolated more rapidly. Per Reference 7, the RWCU HELB analysis does not assume a concurrent loss of offsite power (LOOP).

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)	The MELB analysis postulates that a moderate energy line outside of the primary containment develops a through wall crack which results in spray. The SDC system has been designated a moderate energy fluid system (Ref. 5) and line breaks in this system were evaluated in the MELB analysis. The focus of the MELB analysis is the protection of safe shutdown equipment from spray and flooding resulting from a moderate energy line break. The analysis demonstrated the capability to shutdown the plant and maintain it in a cold shutdown condition assuming a moderate energy line break and a single active component failure. Additionally, the MELB analysis does not assume a concurrent LOOP or other design basis accident or transient. As required by 10 CFR 50, Appendix A, GDC 4 (Ref. 6), the design of the RWCU isolation instrumentation ensures that SSCs important to safety are protected against the dynamic effects of discharging fluids that may result from equipment failures. The SDC isolation instrumentation is retained in the TRM for other reasons and is described below in the individual Function's discussion. The OPERABILITY of the isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table T3.3.j-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each Primary Containment Isolation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., system suction flow), and when

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)	

the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained by analysis or evaluation. The trip setpoints are determined from the analytic limits, corrected for defined process, calibration, and instrument errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for the calibration based errors. These calibration based errors are limited to reference accuracy, instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

Certain RWCU and SDC valves also serve the dual function of automatic Primary Containment Isolation Valves (PCIVs). The PCIVs are required to establish the primary containment boundary during Design Basis Accidents (DBAs). The DBAs for which the consequences are mitigated by PCIVs are a loss of coolant accident and a main steam line break (MSLB). The isolation instrumentation in this Requirement is designed to mitigate the consequences of an RWCU system HELB and a SDC system MELB; therefore, these instrument channels do not affect the OPERABILITY of the PCIV function of the valves described in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)." However, since the isolation instrument channels have circuitry common to PCIV isolation instrumentation, an inoperability in an instrument channel should be evaluated to determine if it impacts the OPERABILITY of components required by LCO 3.3.6.1, “Primary Containment Isolation Instrumentation.” Refer to the Bases of LCO 3.3.6.1 and LCO 3.6.1.3 for more detail.

The individual Functions are required to be OPERABLE in the MODES or other conditions specified in the Table that may require the RWCU or SDC system to be isolated to mitigate the consequences of a high or moderate energy line break.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY (continued)

The specific Applicable Design Bases, TLCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Water Cleanup Isolation – Pump Suction Flow - High

The high suction flow signal is provided to detect a design basis break in the RWCU System. Flowrates less than the design basis break flowrate, and leak flowrates, are detected by the RWCU isolation instrumentation required by LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." The high suction flow signal will also detect breaks in the RWCU System piping located in areas not monitored by area or differential temperature leak detection equipment. The RWCU Differential Flow – High Function of LCO 3.3.6.1 has a 45 second time delay for operational considerations. During this time delay, additional mass will be released from a break causing the temperature in adjacent areas to possibly exceed the EQ temperature limits. Therefore, isolation of the RWCU System is initiated when high suction flow is sensed to prevent exceeding EQ zone limits. This Function is not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from two differential pressure transmitters monitoring suction flow (from the reactor vessel). Two channels of Reactor Water Cleanup Isolation – Pump Suction Flow - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be high enough to avoid spurious isolations during pump and filter/demineralizer swapping, but low enough so that breaks will be isolated prior to allowing the EQ temperature limits to be exceeded.

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY

1. Reactor Water Cleanup Isolation – Pump Suction Flow - High (continued)

The Reactor Water Cleanup Isolation – Pump Suction Flow – High Function is required to be OPERABLE in MODES 1, 2, and 3, since these are the MODES of plant operation in which the RWCU system could contain high energy fluids as defined by Reference 8.

This Function isolates the inboard and outboard RWCU suction valves.

2. Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow - High

High flow in the RHR system could indicate a breach of the nuclear process barrier in the RHR Shutdown Cooling system. The high suction flow signal initiates isolation of the RHR Shutdown Cooling system when an abnormally high flowrate from the vessel is sensed. This Function is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs. Additionally, this Function is not assumed in the MELB analysis of Reference 5. The RHR Shutdown Cooling System isolation on high suction flow supports actions to ensure that the RHR system is isolated to minimize the effects of moderate energy fluid spray caused by a leak in the RHR Shutdown Cooling System.

The high differential flow signals are initiated from two differential pressure switches monitoring suction flow (from the reactor vessel). Two channels of Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was chosen to be high enough to avoid spurious isolations during pump starting, but low enough so that a system break will be detected and isolated.

The Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow - High Function is only required to be OPERABLE in MODE 3 to help mitigate the consequences of a MELB. In MODES 1 and 2, the Reactor

(continued)

BASES

APPLICABLE DESIGN BASES, TLCO, and APPLICABILITY	2. Residual Heat Removal System Shutdown Cooling Isolation – Pump Suction Flow – High (continued) Vessel Pressure - High Function of LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," and administrative controls ensure that this flow path remains isolated to eliminate the possibility of this flow path containing moderate or high energy fluid. In MODES 4 and 5, the probability and consequences of a MELB are eliminated due to the pressure and temperature limitations of these MODES and therefore, the Function is not required. This Function isolates the same valves that are isolate by Group 6 Primary Containment Isolation.
ACTIONS	A Note has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable primary containment isolation instrumentation channel. A.1 Because of the redundancy of the isolation design, an allowable out of service time of 24 hours is acceptable to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). Twenty-four hours is also consistent with the out of service time allowed by LCO 3.3.6.1 for other primary containment isolation instruments that do not have channel

(continued)

BASES

ACTIONS

A.1 (continued)

components common to the Reactor Protection System (RPS). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore the capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic isolation capability being lost for the associated penetration flow path(s). For Functions 1 and 2, this would require one trip system to have one channel OPERABLE or in trip.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table T3.3.j-1. The applicable Condition specified in Table T3.3.j-1 is Function dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

D.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operation may continue if the affected isolation valve(s) is closed. Closing the affected isolation valve(s) accomplishes the function of the inoperable channel(s).

The Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to close the affected isolation valve(s).

E.1 and E.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated). ACTIONS must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the TSRs for each Primary Containment Isolation Instrumentation Function are found in the TSRs column of Table T3.3.j-1.

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the redundant isolation valve in each associated line is OPERABLE and required isolation instrumentation for that redundant valve is OPERABLE. For the purposes of this Surveillance Note, required isolation instrumentation consists of the isolation instrumentation required by this Technical

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Requirement. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the average time required to perform a channel surveillance. The 8 hour testing allowance does not significantly reduce the probability that the isolation valves will isolate the penetration flow path(s) when necessary.

TSR 3.3.j.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the TLCO.

TSR 3.3.j.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.j.2 (continued)

verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is consistent with the CHANNEL FUNCTIONAL TEST Frequencies of similar isolation instrumentation required by LCO 3.3.6.1, “Primary Containment Isolation Instrumentation.”

TSR 3.3.j.3 and TSR 3.3.j.4

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology.

The Frequencies are based on the assumption of a 92 day or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

TSR 3.3.j.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," overlaps this Surveillance to provide complete testing of the assumed function. The 24 month Frequency is based on the need to perform this Surveillance under

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.j.5 (continued)

the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR Section 3.6.2.
2. UFSAR Section 7.3.2.2.3.13.
3. UFSAR Section 7.6.2.2.6.
4. UFSAR Appendix C.
5. UFSAR Appendix J.
6. 10 CFR 50, Appendix A, GDC 4.
7. NDIT LS-0622, “Input for RWCU HELB Analysis.”
8. Branch Technical Position SPLB 3-1 (part of NUREG-0800, Standard Review Plan, Section 3.6.1)
9. Technical Specification 3.3.6.1.
10. Technical Specification 3.6.1.3.

This section no longer used.

B 3.3 INSTRUMENTATION

B 3.3.I Meteorological Monitoring Instrumentation

BASES

BACKGROUND

Meteorological information is required to assess the potential dispersion of radioactive material from, and the radiological consequences of, an accidental release of radioactive material due to a Design Basis Accident (DBA) or other event. The information gathered is used to provide early guidance from the station's emergency organization to local, state, and federal agencies for coping with the emergency and determining when measures should be taken to protect the public health and safety. Meteorological information is also used to assess the annual dose to the public resulting from the routine release of radioactive materials in gaseous effluents to assist in demonstrating that operations are being conducted within the limits of 10 CFR 20. Additionally, this information assures that effluent control equipment is functioning properly, and operating procedures and practices are keeping levels of radioactive material in effluents to unrestricted areas as low as practicable.

A 400 foot meteorological tower erected on the site at approximately the final plant grade of 710' mean sea level (MSL) is instrumented with the Meteorological Monitoring Instrumentation at three different elevations. Wind speed and wind direction are measured at elevations of 33 feet, 200 feet, and 375 feet above ground level. Ambient temperature is measured at the 33 feet level and differential temperatures referenced to 33 feet are measured at 200 feet and 375 feet. Precipitation is also measured nearby. The 375 feet level corresponds to the elevation of the most likely point of airborne release, the plant stack.

The monitoring equipment is placed on booms oriented normal to the general prevailing wind at the site. Sensor signals are brought to an instrument building with controlled environment conditions. The building at the base of the tower houses the recording equipment, signal conditioners, etc., used to process and re-transmit the data to the Main Control Room, Technical Support Center, and Emergency Operations Facility.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

The Meteorological Monitoring Instrumentation system is designed to meet the recommendations of References 4. Additionally, meteorological instrument records retention and maintenance is performed in accordance with Reference 5. Regulatory Guide 1.23 (Ref. 4) recommendations include but are not limited to:

- the capability to measure wind speed, wind direction and ambient air temperature at a minimum of two levels to provide a valid estimation of atmospheric diffusion,
- a tower sited at approximately the same elevation as finished plant grade and in an area where plant structures will have little or no influence on the meteorological instrumentation,
- instrumentation located at 10 meters above ground, at plant vent height, and at stack height to provide a representation of meteorological conditions of potential plant release points,
- data recording capability to assure at least 90% data recovery to generate wind roses and atmospheric dispersion factors (Chi/Q) to provide estimates of airborne concentrations of gaseous effluents and projected offsite radiation doses, and
- sufficient instrument accuracy to ensure that data used in calculations for accident and average annual releases is representative of actual environmental conditions.

The Meteorological Monitoring Instrumentation system is also used to meet the requirements of 10 CFR 50, Appendix E, which requires plans for coping with radiological emergencies. These requirements are implemented by the Generating Station Emergency Plan (GSEP). The GSEP utilizes meteorological information as an input to the Dose Assessment Computer Model for estimating the environmental impact of unplanned releases of radioactivity from the station. Atmospheric stability is a major factor in estimating this impact. Two methods

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	of determining atmospheric stability are used: delta temperature (vertical temperature difference) is the principal method; sigma theta (standard deviation of the horizontal wind direction) is also available for use when delta temperature is not available. The Meteorological Monitoring Instrumentation system only performs a monitoring function to evaluate environmental conditions to provide an assessment of radiological impact due to planned and unplanned releases. The instrumentation does not perform any safety-related prevention, mitigation, or post accident instrumentation function required by the accident analyses of the USFAR.
TLCO	The OPERABILITY of the meteorological monitoring instrumentation is dependent on the OPERABILITY of the individual instrumentation channels specified in Table T3.3.I-1. Each Function must have the required number of OPERABLE channels to ensure that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental releases of radioactive materials to the environment. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. Either the 33 to 200 foot delta temperature channel or the 33 to 375 foot delta temperature channel may be used to meet the channel requirement of Function 3 in Table T3.3.I-1. As noted in Table T3.3.I-1, the Meteorological Monitoring Instrumentation system is shared between Unit 1 and Unit 2. Therefore, a failure to meet the TLCO will result in both Units entering into the applicable Conditions and Required Actions for the inoperable channel.
APPLICABILITY	The potential for a planned or unplanned radioactive material release to the atmosphere exists at all times. For example, a fuel handling accident in the spent fuel pool could occur while performing fuel reconstitution work after a full core offload. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to meteorological monitoring instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable meteorological monitoring instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable meteorological monitoring instrumentation channel.

A.1

With one or more required meteorological monitoring instrument channels inoperable, the ability to monitor atmospheric conditions and determine their effects on a radioactive material release is degraded. Because of the diversity of sensor locations available to provide monitoring signals, an allowable out of service time of seven days is acceptable to permit restoration of any inoperable channel to OPERABLE status. The seven day Completion Time is also based on the original licensing basis of the meteorological monitoring instrumentation.

B.1

If the meteorological monitoring instrument channel is not restored to OPERABLE status, plant operation may continue provided a report is prepared in accordance with the station's Corrective Action Program (CAP). The CAP document shall outline the cause of the inoperability and the plans for restoring the instrument channel to OPERABLE status. The 10 day Completion Time provides an appropriate period of time to develop the recovery plan and is consistent with the original licensing basis reporting requirements for the meteorological monitoring instrumentation.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the TSRs apply to each Function listed in Table T3.3.I-1.

TSR 3.3.I.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of an instrumentation channel has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

CHANNEL CHECK criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare and is consistent with the original licensing basis of the meteorological monitoring instrumentation.

TSR 3.3.I.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific methodology.

The Frequency is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift and is consistent with the recommendations of Reference 4.

REFERENCES

1. UFSAR Section 2.3.3.1.

2. 10 CFR 20.

(continued)

BASES

REFERENCES (continued)	3.	10 CFR 50, Appendix E.
	4.	Regulatory Guide 1.23, “Onsite Meteorological Programs.”
	5.	ANSI/ANS 2.5 (1984).

B 3.3 INSTRUMENTATION

B 3.3.m Explosive Gas Monitoring Instrumentation

BASES

BACKGROUND

Noncondensible off gas is continuously removed from the main condenser by the air ejector during plant operation. These noncondensible gasses consist of activation gasses such as N-16, noble gasses such as krypton from tramp uranium and small fuel cladding leaks, and hydrogen and oxygen from the radiolytic dissociation of water, chemical treatment of the reactor coolant, and air in-leakage. The off gas system is designed to treat these gasses to maintain concentrations within limits.

Hydrogen gas in concentrations of between 4% and 75% is explosive in the presence of oxygen. The off gas system components could be damaged if a hydrogen explosion were to occur within the system. To eliminate this potential hazard, the off gas system uses two methods to reduce hydrogen concentration in the off gas stream; steam dilution and catalytic recombination. The off gas system's catalytic recombiner is used to recombine radiolytically dissociated hydrogen and oxygen as well as excess hydrogen from the use of hydrogen water chemistry treatment. To monitor the proper operation and effectiveness of the recombiner, explosive gas monitoring instrumentation is provided.

The Explosive Gas Monitoring Instrumentation consists of the piping and components, sensors, circuitry, relays, indication, and alarms necessary to determine the partial pressure of hydrogen present in the off gas stream and to provide output and indication of concentration in volume percent. There are two identical Off Gas Hydrogen Analyzer systems (A and B), each capable of monitoring off gas hydrogen concentration. The analyzer has various panel controls allowing for calibration, functional testing, purging, and sampling operations. Each unit draws a sample of the off gas downstream of the recombiner and prior to the hold-up line. The sample passes through an electrochemical cell, which oxidizes hydrogen. An electrode in the cell senses the amount of oxidation occurring and provides an output to the system circuitry which converts the signal to a percent volume concentration. The off gas sample flow then returns to the main condenser. The flow of gas through the system is maintained by

(continued)

BASES

BACKGROUND (continued)	the difference in pressure between the off gas system and the main condenser and is controlled through a series of check valves, manual valves, solenoid valves, and pressure regulators. The output of the analyzer can be read locally and is sent for display on a recorder in the main control room. The system also provides main control room alarms if high hydrogen concentration or other system trouble is sensed. Since the Hydrogen Water Chemistry (HWC) control system injects hydrogen into the reactor coolant system, which will ultimately be removed by the off gas system, the Explosive Gas Monitoring Instrumentation also provides control outputs and interlocks necessary for the operation of this system. These interlocks include a system trip signal when hydrogen concentration exceeds predetermined limits or if neither analyzer is capable of determining hydrogen concentration.
APPLICABLE DESIGN BASES	The off gas system and HWC system are designed to maintain hydrogen below the lower explosive limit ($\leq$ 4% by volume) to eliminate the possibility of an explosion in the off gas treatment system. The hydrogen concentration of gasses from the air ejector is kept below the flammability limit by maintaining adequate process steam flow for dilution. A catalytic recombiner further reduces the hydrogen concentration of the off gas to maintain the gas stream $\leq$ 4% by volume on a dry basis. The HWC system injects oxygen in air into the off gas stream, if necessary, to ensure effective recombination. The recombiner typically reduces hydrogen concentration of the off gas to < 1% by volume. Although the off gas system is designed to remain intact in the event of a hydrogen-oxygen detonation and is excluded as a possible failure mode in the UFSAR accident analyses (Ref. 2), Technical Specification 5.5.9 (Ref. 3) requires that controls be provided to ensure explosive gas mixture limits are maintained. These limits are required

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

to be appropriate for the system design whether or not the system is designed to withstand a hydrogen explosion. This limit is specified in the UFSAR and enforced by TLCO 3.7.e, “Explosive Gas Mixture.”

The Explosive Gas Monitoring Instrumentation is designed to monitor recombiner performance and ensure the hydrogen concentration of the off gas effluent is maintained below the flammability limit to meet the requirements of Technical Specification 5.5.9 and TLCO 3.7.e.

The Explosive Gas Monitoring Instrumentation only performs control, monitoring, and alarm functions to help ensure off gas hydrogen concentration is maintained within limits. The instrumentation does not perform a safety related prevention or mitigation function nor a post accident instrumentation function.

TLCO

The Explosive Gas Monitoring Instrumentation is required to ensure that the limits established by the Explosive Gas and Storage Tank Radioactivity Monitoring Program (Ref. 3) are not exceeded. One channel of Main Condenser Off Gas Treatment System – Hydrogen Monitor, including the associated control room alarm, is required to be OPERABLE to ensure that degradations in the off gas system or HWC system are promptly detected to reduce the probability of a hydrogen-oxygen detonation within the off gas treatment system.

The Hydrogen Monitor channel must have its alarm setpoint set within the specified limits of Reference 3 and TLCO 3.7.e. The actual setpoint is calibrated consistent with the applicable setpoint methodology assumptions. The nominal setpoint is selected to ensure that the setpoint does not exceed the specified limit between CHANNEL CALIBRATIONS. Operation with an alarm setpoint less conservative than the nominal alarm setpoint, but within its specified limit, is acceptable. The monitor is inoperable if its actual alarm setpoint is not within its specified limit.

The alarm setpoint is determined from the specified limit, corrected for defined process, calibration, and instrument errors. The calibration based errors are limited to reference accuracy, instrument drift, errors associated

(continued)

BASES

TLCO (continued)

with measurement and test equipment, and calibration tolerance of loop components. The alarm setpoint determined in this manner provides adequate protection because instrument uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments) are accounted for and appropriately applied for the instrumentation.

System trouble alarms, control system outputs, and HWC system trip signals associated with the Hydrogen Monitor are not part of this TLCO since the primary purpose of this Requirement is to alert the operator of abnormally high hydrogen concentrations in the off gas stream to allow corrective action to be taken. Consequently, the Hydrogen Monitor is required to continuously sample the off gas stream in order to perform its specified function. Therefore, when the monitor's automatic event sequencer activates the hydrogen span gas functional test (a 10 minute period every 24 hours), the monitor is not sampling the process stream and must be considered inoperable. In this event, the TLCO is still met provided the other hydrogen monitor is OPERABLE; otherwise, the monitor's automatic event sequencer should be disabled to ensure continuous OPERABILITY of the monitor (Ref. 4).

APPLICABILITY

The TLCO is applicable when noncondensibles from the main condenser are being processed via the Main Condenser Off Gas System. This occurs whenever the main condenser air ejector is in operation. With the air ejector secured there is no motive force to draw hydrogen from the main condenser into the off gas system and the Requirement is not applicable.

ACTIONS

A.1.1, A.1.2, A.2 and A.3

With the required hydrogen monitor channel inoperable (i.e., no hydrogen monitor channels are OPERABLE), grab samples of the Main Condenser Off Gas Treatment system shall be taken and analyzed to provide periodic hydrogen concentration information. As noted, the frequency of obtaining these grab samples (Required Action A.1.1 and A.1.2) is dependent upon plant conditions and recombiner

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.2 and A.3 (continued)

performance. Off gas system grab samples must be taken every eight hours provided the in-service recombiner temperature is constant and THERMAL POWER is not changing. For the purposes of these Required Actions, recombiner temperature is considered constant if temperature has changed ≤ 20°F within the previous eight hours. Likewise, THERMAL POWER is considered to be unchanged if reactor power has changed by ≤ 1% RTP in the previous eight hours. Steady state reactor power adjustments to compensate for poison changes or fuel burn-up is not considered a THERMAL POWER change. If THERMAL POWER has changed or recombiner temperature does not remain constant, then the sample frequency must be increased to every four hours to detect any changes in off gas hydrogen concentration. This increased sampling frequency must continue until steady state operating conditions are once again achieved (i.e., constant recombiner temperature and unchanging THERMAL POWER for ≥ 8 hours). Additionally, the grab sample must be analyzed and off gas hydrogen concentration determined within four hours of the time the sample was drawn (Required Action A.2). The four and eight hour Completion Time intervals provide periodic information that is adequate to detect changes in off gas hydrogen concentration.

Provided a sample is obtained and analyzed within the applicable Completion Times, the required hydrogen monitor channel may be inoperable for up to 30 days (Required Action A.3). The 30 day Completion Time is based on the original licensing basis for the instrumentation and is acceptable since the sampling and analysis required by Required Actions A.1.1, A.1.2, and A.2 provide appropriate compensatory measures for the inoperable monitor.

B.1

If the required grab samples are not taken and analyzed or the hydrogen monitor channel is not restored to OPERABLE status within the associated Completion Time, a Corrective Action Program (CAP) report must be immediately prepared to resolve the deficiency. The CAP report should address the cause for failing to meet the Completion Time and the plans for restoring compliance with the Required Action or TLCO.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.3.m.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare and is consistent with the requirements of Reference 5. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channel required by the TLCO.

TSR 3.3.m.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel can perform its function in the desired manner. The test also verifies the alarm function and the relative accuracy of the instrument channel. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.m.2 (continued)

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 31 day Frequency is based on the original licensing basis for the Explosive Gas Monitoring Instrumentation and is consistent with the requirements of Reference 5.

TSR 3.3.m.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

As noted, the CHANNEL CALIBRATION must include the use of a 1% hydrogen, balance nitrogen and a 4% hydrogen, balance nitrogen standard gas sample in the performance of the calibration. Other additional hydrogen concentration test gas samples may be used in the calibration of the monitor; however, the two standards specified in the Note must be used in order to meet the TSR.

The Frequency is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis and is consistent with the requirements of Reference 5.

REFERENCES

1. UFSAR Section 11.3.
2. UFSAR Section 15.7.
3. Technical Specification 5.5.9.
4. Letter TSL 94-004, J.P. Schroeder to Shift Control Room Engineers, “Operation of OG Hydrogen Analyzers, 1(2)N62-N009A/B,” March 16, 1994.
5. NUREG 0800, Standard Review Plan, Section 11.3.

B 3.3 INSTRUMENTATION

B 3.3.n Reactor Vessel Water Level Reference Leg Continuous Backfill System

BASES

BACKGROUND

The NRC issued Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," on May 28, 1993 (Ref. 1). The bulletin required all BWRs to address the issue of non-condensable gas buildup in the cold reference leg of reactor pressure vessel (RPV) water level instrumentation.

In light of NRC Bulletin 93-03, BWR Owners' Group (BWROG) De-gas Test results and later BWROG meetings with the NRC, the BWR owners initiated work to install hardware modifications to assure that non-condensable gases will not adversely affect reactor water level instrumentation. Most BWR owners implemented the Continuous Control Rod Drive (CRD) backfill system recommended by the BWROG. LaSalle County Station also installed this modification with changes to the injection point from that proposed by the BWROG.

The principle of operation for the Continuous Backfill System (CBS) is to provide a flow of degassed fluid from the CRD system through a reference leg to each condensing chamber and then from the condensing chamber to the RPV. Tubing is provided from a common CRD pump discharge header to each cold instrument reference leg. Each reference leg has its own Local Flow Station Rack. The continuous backfill system control stations includes flow metering needle valves, flowmeters, filters and isolation valves. All components are located outside to the drywell.

The tie-in for CBS to the instrument reference legs with active instrumentation is inboard of the reference leg root valve and the associated Excess Flow Check Valve (EFCV). For the two reference legs that have safety-related level indication and alarms only, the tie-in to the reference legs is outboard of the reference leg root valve and the associated EFCV. The reference leg with the Upset and Shutdown range level indications does not have or require a continuous backfill system.

(continued)

BASES

BACKGROUND (continued)

The CBS for the four reference legs with active instrumentation are also part of the Primary Containment Isolation boundary. Containment isolation is provided by the isolation check valves on the associated Local Flow Station Rack. Primary Containment Isolation Valves (PCIVs) are governed by LCO 3.6.1.3, "PCIVs."

The other two reference legs with CBS connected, are not part of the Primary Containment isolation boundary. However, all six reference legs' Local Flow Station Racks require isolation valves to form a safety-related/non-safety-related (SR/NSR) boundary between the CRD drive water header and the instrument reference legs. This boundary for four of the racks is provided by the primary containment isolation valves mentioned above. The SR/NSR boundary for the remaining two racks is provided by similar isolation check valves. The SR/NSR boundary isolation check valves are also required to maintain the reference leg(s) full on loss of continuous backfill flow due to loss of CRD flow or malfunction of a Local Flow Station Rack. Table B T3.3.n-1 identifies these isolation check valves along with their corresponding Local Flow Station Rack, reference leg condensing pot, and EFCV.

APPLICABLE DESIGN BASES

The function of the Reactor Vessel Water Level Reference Leg Continuous Backfill System is to provide a constant flow of degassed water to Reactor Vessel water level instrument reference legs to eliminate the potential for non-condensable gas accumulation in the reference legs during reactor operation. During depressurization events, the evolution of dissolved gas in cold reference legs can cause misleading indication to plant operators following accidents or cause certain isolation functions to become inoperable following routine plant shutdowns.

Two types of events have been postulated in which reference leg gases are of concern: a rapid depressurization such as following an automatic depressurization system (ADS) signal or a loss of coolant accident (LOCA), and a slow depressurization typical of a routine plant shutdown. The following paragraphs discuss the periods of concern for each type of event.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

Rapid Depressurization Events

Rapid depressurization events are the result of a LOCA event, can be initiated automatically by the ADS logic (unless the function has been inhibited in accordance with Emergency Procedures) or they can be manually initiated by a plant operator. If high pressure systems have not functioned following a scram or isolation, actuation of ADS on low water level (following a time delay) permits a pressure reduction sufficient to allow low pressure systems to restore RPV level. Following a small or medium size line break inside containment, ADS initiates on concurrent high drywell pressure and low RPV water level to depressurize the RPV. In either case, when pressure is reduced, any gas in the reference legs may evolve out of the reference leg and result in an erroneously high RPV water level signal.

A safety evaluation (Ref. 5) for such events concluded that all safety functions would initiate prior to a pressure reduction below about 450 psig where significant evolution of gas from the reference leg might occur. Therefore, the rapid depressurization does not present a safety issue in terms of the initial plant response. However, because the sensed level would be higher than actual after non-condensable gases have evolved, delayed initiation of some low level trip signals and early initiation of high level trips may occur.

Although all reference legs can be affected by rapid depressurization events, because required safety functions occur before the gas evolution, only reference legs supporting post-accident monitoring channels present a potential concern after rapid depressurization. The higher than actual indicated level could result in the potential for misleading water level indication available to the plant operators and the actual RPV water level may be lower than expected RPV level when restored in accordance with the plant specific Emergency Operating Procedures (EOPs). Unless the bias due to the gas evolution is extremely high (an unlikely event), no concern exists with the restored RPV level and no specific evaluation is necessary.

(continued)

BASES

APPLICABLE DESIGN BASES

Rapid Depressurization Events (continued)

Although the delayed actuation of some safety systems may occur, none are required following rapid depressurization events except in the case of a RPV drain down event while initiating shutdown cooling. Because the frequency of rapid depressurizations is much lower than that for routine shutdowns, the evaluation of drain down events in References 2 and 5 encompasses these events.

The presence of non-condensable gas may result in early initiation of Level 8 trips. However, the consequence of high water level is greatly reduced following RPV depressurization because such trips are only applicable to high pressure makeup systems. Therefore the bias on the Level 8 trips is not an issue related to safety.

Based on the above considerations, a safety concern does not exist with rapid depressurization events and therefore there are no limitations on equipment out-of-service time related to these events.

Slow Depressurization Events

Slow depressurization occurs during routine plant shutdowns. When RPV pressure has been reduced below about 450 psig, industry experience has shown that entrapped reference leg gases can be released leading to erroneous indication. If the entrapped gas evolution is sufficiently large and occurs in multiple reference legs, such erroneous indication can impact the primary containment isolation function. This is of concern when the RPV is placed into the shutdown cooling mode if a RPV drain down event occurs without the isolation function OPERABLE.

Several plant features make the likelihood of this event extremely small. With the continuous backfill system in operation, gas buildup in the reference legs is expected to be eliminated. Plant procedures are used to verify that the system has been functioning prior to initiation of a routine shutdown. If the continuous backfill system is not in operation, a manual backfill of the indication only reference legs can be initiated in accordance

(continued)

BASES

APPLICABLE DESIGN BASES

Slow Depressurization Events (continued)

with plant procedures prior to proceeding with depressurization. In addition, interlocks between the RHR system valves prevent a drain path from being established. Further, multiple reference legs would need to be affected for the isolation function to be lost.

A safety evaluation (Ref. 5) of this case concluded that even without isolation, adequate time was available for an operator to restore RPV level sufficiently to provide core cooling. Nevertheless, Reference 1 specifically requires reference leg backfill to assure the availability of the isolation function following a drain down event.

Reference 2 provides a probabilistic evaluation of core damage frequency due to drain down events and losses of shutdown cooling without implementation of a continuous backfill system or with installed backfill systems inoperable. The results are that the probability of core damage from these events concurrent with the unavailability of the continuous backfill system is extremely small. Consequently, recommended out of service times are based on the risk significance of backfill system failures.

TLCO

The Reactor Vessel Water Level Reference Leg Continuous Backfill System (CBS) is required to be OPERABLE to maintain the instrument reference legs degassified during normal plant operations. The backfill system for each reference leg is considered OPERABLE if the reference leg has proper backfill flow and the associated isolation check valves meet their leakage requirements. Once a minimum backfill flow has been established, periodic monitoring of each reference leg backfill flow is expected to confirm OPERABILITY of the system. If the continuous backfill flow is below the minimum flow, safety related instruments associated with the reference leg may be adversely affected if the backfill system is not restored within the associated Completion Time. OPERABILITY of the CBS prevents level notching and other potential level anomalies as described in NRC Bulletin 93-03 (Ref. 1).

(continued)

BASES (continued)

APPLICABILITY

The Reactor Vessel Water Level Reference Leg Continuous Backfill System is required to be OPERABLE in MODES 1, 2, and 3. This assures that the instrument reference legs will function as required during all cooldowns, whether fast or slow. Non-condensible gases only buildup during hot conditions, so the CBS is not required to be OPERABLE during MODES 4 or 5.

ACTIONS

The Required Actions for loss of normal backfill flow are based on the low significance of the consequences of the continuous backfill system being out-of-service as described in the Applicable Design Bases. The buildup of dissolved gases occurs slowly and thus implementation of compensatory actions for planned shutdowns or cooldowns following an automatic shutdown are adequate to assure safe shutdown without CBS in service for one or more reference legs.

A Note has been added to provide clarification that, for the purposes of this TLCO, separate Condition entry is allowed for each reference leg. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each reference leg with an inoperable backfill system. Complying with the Required Actions may allow for continued operation, and subsequent inoperable backfill lines are governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1 and A.2</u>

If backfill flow is found outside the normal band (e.g., due to drift or filter clogging), then backfill flow must be restored to within limits in eight hours (Required Action A.1). Potential causes of reduced system flow are discussed in Table B T3.3.n-2. Following a loss of CRD drive water pressure or flow there is a potential for loss of water from the associated reference leg(s). The isolation check valves are designed to be low leakage to mitigate the consequences of a loss of CRD drive water pressure/flow; however, to ensure that unacceptable reference leg water loss does not occur, the continuous

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

backfill line should be isolated if flow cannot be restored to normal. Thus, an alternative action to isolate the affected backfill line(s) from the associated reference leg(s) (Required Action A.2) is provided if normal backfill flow cannot be restored within eight hours.

Instrumentation has been analyzed to remain within tolerance with flow less than or equal to 15 lbm/hr (approximately 1.79 gph); therefore, instrumentation on a reference leg without backfill flow or with backfill flow out of limits remains OPERABLE.

The Completion Time of eight hours was chosen because,

1. it is insignificant compared to the time required for gases to build up in the reference legs,
2. it minimizes reference leg water loss due to isolation check valve leakage, and
3. it allows adequate time for minor maintenance or filter changing to restore normal backfill flow.

B.1

If a backfill system supporting a single reference leg is inoperable, the potential exists for a Level 3 RHR isolation channel or one channel of a required post accident monitoring instrumentation function(s) to become inoperable. A single backfill system may be out of service for up to 30 consecutive days to permit restoration of normal backfill flow. If the continuous backfill system is not restored within the specified Completion Time, all water level instruments supported by the reference leg could be affected by gas buildup; therefore, Condition D must be entered and compensatory action taken in accordance with required procedures to assure continued OPERABILITY of the affected instruments.

The 30 day Completion Time limits the period during which an accident might occur concurrently with reference leg gas buildup. This Completion Time is acceptable since gas buildup in a single reference leg typically only affects

(continued)

BASES

ACTIONS

B.1 (continued)

one channel of a required instrumentation function and the redundancy in the plant design ensures that the indication or isolation function is not lost. Additionally, there is no direct safety consequence from gas buildup following a rapid depressurization and the probabilistic evaluation in Reference 2 shows that the core damage frequency with a single backfill system inoperable is extremely small (about $3x10^{10}$ per reactor year).

C.1

If multiple backfill systems are inoperable, the potential exists for redundant post-accident monitoring channels to provide misleading information and the Level 3 RHR isolation Function could become inoperable. This conclusion assumes that gas buildup sufficient to affect instrument OPERABILITY occurs in the reference legs. If the bias introduced into the RPV water level measurement system is not sufficient to make trips inoperable, delayed trips will occur which are bounded by analysis. The loss of continuous backfill to reference legs with independent functions has only slightly more significance than loss of continuous backfill supporting a single reference line.

One or more backfill systems supporting redundant instrumentation channels may be out of service for up to seven days to permit restoration of continuous backfill flow. If the continuous backfill system is not restored to the reference legs within the specified Completion Time, redundant water level instruments supported by the reference legs could be affected by gas buildup; therefore, Condition D must be entered and compensatory action taken in accordance with required procedures.

The seven day Completion Time is judged to be reasonable based on the low probability of a plant depressurization being required during any seven day period combined with the low probability of initiating a drain down event. The probabilistic evaluation in Reference 2 estimates the core damage frequency to be extremely small (core damage

(continued)

BASES

ACTIONS

C.1 (continued)

frequency about $5x10^9$ per reactor year), but higher than the case with a single backfill system inoperable. Additionally, the seven day Completion Time is consistent with LCO 3.3.3.1, “PAM Instrumentation,” regarding post accident monitoring instrumentation channels.

D.1

With the Required Action and associated Completion Time of Condition B or C not met, compensatory measures that meet the intent of Reference 1 must be established. The Completion Time of 24 hours is a reasonable based on the time required to implement these measures per an approved procedure. Once appropriate compensatory measures have been established, plant operation may continue; however, efforts should be made to restore normal continuous backfill as soon as practical.

SURVEILLANCE REQUIREMENTS

TSR 3.3.n.1

Periodic visual verification of the continuous backfill system individual leg flow meters is performed during normal operation to confirm that flow is within the minimum and maximum flow requirements. Reference 6 requires that this verification be performed once per 24 hours.

A Frequency of 24 hours is acceptable since one of the two flow metering valves is set to limit continuous backfill flow to less than or equal to 12 lbm/hr (approximately 1.44 gph) and a trip of a CRD pump or a significant reduction in CRD flow or pressure would be detected from the main control room. The 24 hour Frequency is also based on expected system performance and the time required to produce and adverse affect on reactor water level instrumentation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.n.2

The check valves provided on each backfill flow station rack form a boundary between safety related and non-safety related piping. The CRD pump and associated piping system is non-safety-related and is not seismically qualified. Therefore, these check valves must maintain the inventory of water in each associated reference leg on loss of CRD system pressure. This could occur due to filter clogging or a CRD pump trip, for example. In order to maximize the time available before level instruments begin to drift upscale following a loss of flow, a water leak rate test of each check valve is required to verify leakage is within limits.

The 24 month frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. NRC Bulletin 93-03, dated May 28, 1993, "Resolution of Issues Related to Reactor Water Level Instrumentation in BWRs."

2. G.B. Stramback, BWROG Water Level Project Manager, to Water Level Committee - Out-of-Service Time Task Participants dated October 7, 1993; Out-of-Service Time Report - GENE A00-03647-D-01, dated October 1, 1993.

3. "Final Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors," Federal Register, Vol 58, No. 139, July 22, 1993.

4. LaSalle On-Site Review 93-053, Rev. 1, Add RVWLIS Backfill Isolation Valves to Technical Specifications.

5. LaSalle On-Site Review 93-025, dated May 21, 1993, Degassing effects on level instrumentation during normal or rapid depressurization.

(continued)

BASES

REFERENCES (continued)	6. Letter dated December 10, 1993 from A.T. Gody, Jr. to D.L. Farrar, Issuance of Amendments (TAC NOS. M86897 and M86898).
	7. On-site Review 93-066, dated December 13, 1994, Operability Requirements for Reactor Vessel Water Level Reference Leg Continuous Backfill System, ATR Amendment 2.

Table B T3.3.n-1 (page 1 of 1)
Reference Legs with Continuous Backfill System Connections

LOCAL FLOW STATION RACK	ISOLATION CHECK VALVES	REFERENCE LEG CONDENSING POT	EXCESS FLOW CHECK VALVE
1(2)C11-P002	1(2)C11-F422D[a] 1(2)C11-F423D[a]	1(2)B21-D004A	1(2)B21-F361
1(2)C11-P003	1(2)C11-F422B[a] 1(2)C11-F423B[a]	1(2)B21-D004B	1(2)B21-F359
1(2)C11-P004	1(2)C11-F422G[a] 1(2)C11-F423G[a]	1(2)B21-D004C	1(2)B21-F376
1(2)C11-P005	1(2)C11-F422F[a] 1(2)C11-F423F[a]	1(2)B21-D004D	1(2)B21-F378
1(2)C11-P006	1(2)C11-F422A 1(2)C11-F423A	1(2)B21-D367	1(2)B21-F570
1(2)C11-P007	1(2)C11-F422E 1(2)C11-F423E	1(2)B21-D368	1(2)B21-F571

(a) Check valves are also Primary Containment Isolation Valves and require Type C Local Leak Rate Testing in accordance with Technical Specification SR 3.6.1.1.1 and 10 CFR 50, Appendix J.

Table B T3.3.n-2 (page 1 of 2)
Potential Backfill System Failure Modes

FAILURE	DISCUSSION
Filter Clogging	The most common cause of low backfill flow is expected to be filter clogging. When a filter is clogged, the filter must be isolated so that it can be changed or cleaned. Care must be taken when bringing a filter back on line to assure that inadvertent trips do not occur. Plant procedures specify that some trips may be bypassed if a concern for an inadvertent actuation exists. In general, trips containing a one-out-of-two logic would be of most concern because an inadvertent signal on one reference leg could initiate a trip. The consequence of clogged filters is a possible reduction in continuous backfill flow below the minimum necessary for the elimination of non-condensable gas buildup.
Reference Leg Leakage	Leakage internal to the reference leg can occur if leakage develops through an equalizing valve. Various drain valves, which discharge to closed Reactor Building sumps, also can develop leakage due to a variety of causes including valve packing degradation and seat erosion. In either case, such leakage can prevent the continuous backfill flow from reaching the condensing chamber and negate the benefit of the system. When leakage occurs and can be quantified, the leakage should be eliminated, if possible, or the minimum backfill flow can be increased to compensate for the amount of loss. Leakage through transmitter equalizing valves is not measurable. The consequence of inadequate backfill flow during normal operation is the potential for gas buildup to occur in the reference leg that could result in consequences following an accident as described in the Applicable Design Bases section of this Bases.

(continued)

Table B T3.3.n-2 (page 2 of 2)
Potential Backfill System Failure Modes

FAILURE	DISCUSSION
Control Rod Drive (CRD) Pump Trip	If the CRD pump(s) trip during normal operation, then backfill flow will cease. Although the continuous backfill system is unavailable following this circumstance, the trip of the CRD pump(s) also results in a heatup of the control rod drives and may result in the loss of manual control rod function. A manual scram would be indicated (in accordance with plant procedures), if pumps could not be restored in a reasonably short time, or if multiple CRD scram accumulator pressures fall below 940 psig per Required Action D.1 of LCO 3.1.5, “Control Rod Scram Accumulators.” Because it is expected that a manual scram would be required before significant reference leg gas buildup could occur, this event poses no safety concerns relevant to the events described in the Applicable Design Bases section of this Bases. The potential for backfill check valve leakage following CRD pump trips may be of concern for the long term post-accident monitoring indication. Such leakage represents a potential source of reference leg leakage which can lead to erroneously high indicated level. Features are incorporated into the backfill system design to assure check valve leakage is not of concern. However, the CBS lines should be isolated as soon as practical in accordance with the actions required by this Requirement, if CRD drive water pressure can not be restored within eight hours.

B 3.3 INSTRUMENTATION

B 3.3.o Seismic Monitoring Instrumentation

BASES

BACKGROUND

Seismic Monitoring Instrumentation is required to promptly determine the response to nuclear power plant features important to safety in the event of an earthquake. This capability is required to allow for a comparison of the measured response to that used in the design basis of the plant. Comparison of this data is needed to determine whether the plant can continue to be operated safely as required by 10 CFR 100, Appendix A (Ref. 2).

Reference 2 requires that two earthquake levels be considered in the design of safety related structures, systems and components (SSCs). Consequently, the Seismic Monitoring Instrumentation is designed to monitor for vibratory ground motions exceeding either of these levels. One of these levels, the Operating Basis Earthquake (OBE), is that earthquake which could reasonably be expected to occur at the site during the operating life of the plant. SSCs necessary for continued plant operation without undue risk to the health and safety of the public are designed to remain functional following an OBE. The other earthquake level, the Safe Shutdown Earthquake (SSE), is that earthquake which is based upon the maximum (i.e., most severe) earthquake potential for the area in which the plant is sited. SSCs necessary to assure the integrity of the reactor pressure boundary, the capability to shutdown the reactor (and maintain it in a shutdown condition), and the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures are designed to remain functional following an SSE.

The Seismic Monitoring Instrumentation consists of peak recording accelerographs, triaxial accelerometers, seismic switches, and a central recording panel. All of the system’s sensors and instruments are located in Unit 1. The central recorder panel is located in the Auxiliary Electric Equipment Room (AEER) and has a central recorder for seismic data acquisition and storage, a personal computer, monitor, a printer for display of recorded data, an annunciator instrument that provides local indicator lights and control room indication, and a 30

(continued)

BASES

BACKGROUND (continued)

minute uninterruptible power supply. Lights on the panel indicate whether the system is triggered and whether the OBE or SSE maximum accelerations have been exceeded in any one of the three orthogonal directions in the basement of the containment structure or at elevation 820 feet 6 inches of the containment structure. These directions coincide with the major axes of the analytical model used in the seismic analysis of the plant structure. The central recorder is connected to the containment foundation seismic switch and the triaxial accelerometers.

A seismic switch is located at the containment foundation and alerts the operator when a predetermined acceleration for that location has been exceeded by actuating an annunciator on the main control board.

There are four triaxial accelerometers which input to the central recorder, each of which measures the absolute acceleration as a function of time in three orthogonal directions. The accelerometers transmit tridirectional acceleration data to the central recorder and send a signal to a trigger mechanism internal to the recorder when a very low "g" level acceleration threshold (0.01 g) has been exceeded. This internal trigger initiates the recording function for all the accelerometers.

These accelerometers are located in the free field (a concrete pad near the lake screen house), in the basement of the reactor building (elevation 673 feet 4 inches), at elevation 820 feet 6 inches near the top of the containment structure, and in the auxiliary electric equipment room.

Passive monitoring is provided by four triaxial peak-recording accelerographs which record the absolute peak acceleration in three orthogonal directions coinciding with the major axes of the analytical model of the structure. These accelerographs are located on the standby gas treatment system at elevation 820 feet 6 inches, on the 1A RHR heat exchanger service water cooling inlet piping, on the HPCS diesel generator control panel, and on the main control board.

During a ground motion event, where the acceleration exceeds the seismic trigger setpoint, seismic data is stored in the central recorder

(continued)

BASES

BACKGROUND (continued)

which can be later viewed and printed by means of the personal computer, monitor, and printer located at the panel. The recorded seismic data is then used to facilitate the analysis of structural loads during the seismic event.

APPLICABLE DESIGN BASES

The function of the Seismic Monitoring Instrumentation is to monitor seismic activity above the OBE threshold, and to record seismic data for comparison to design bases spectra. The instrumentation is designed to meet the requirements of 10 CFR 100, Appendix A and the recommendations of Regulatory Guide 1.12 (Ref. 2 and 3).

For LaSalle County Station, the site response spectra are horizontal ground accelerations of 10% and 20% of gravity, for an OBE and an SSE respectively. The vertical ground acceleration is assumed to be two-thirds of the respective horizontal acceleration. SSCs designated Seismic Category I are designed to remain functional following an SSE.

When an earthquake occurs, it may not be known immediately how severe the effects of the earthquake are on plant equipment. The triaxial accelerometers provide time-history data on the seismic input to containment, data on the frequency, amplitude, and phase relationship of the seismic response of the containment structure, and data on the seismic input to other Seismic Category I SSCs. The peak recording accelerographs record peak event acceleration information that can be used to supplement the data gathered by the triaxial accelerometers.

After the seismic event has terminated, the Seismic Monitoring Instrumentation provides an immediate indication of whether the triaxial accelerometers experienced ground accelerations in excess of OBE or SSE levels via the indicating lights on the central recording panel. However, to determine the effect on plant safety related SSCs, a structural response-seismic computer model must be used to compare the accelerometer data to the spectra response assumed in the design basis for the plant. The computer program evaluates the time-history data and computes the maximum response accelerations at various points of the model. The observed response spectra for the reactor building foundation and the 820 foot 6 inch elevation can be compared

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	with the computed response spectra. Agreement between the observed response spectra and the computed response spectra from the time-history inputs demonstrates the adequacy of the analytical model. The magnitude of actual forces at various structural positions can then be compared to design values to authenticate the capability of the plant to continue operation without undue risk to the health and safety of the public. If an evaluated acceleration exceeds an SSE threshold value, the reactor should be shut down. The Seismic Monitoring Instrumentation only provides information regarding seismic activity during a seismic event and is not considered in any design basis accident or transient nor does it provide any function to mitigate an accident or its consequences.
TLCO	Seismic Monitoring Instrumentation is required to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. The Seismic Monitoring Instrumentation listed in Table T3.3.o-1, including the associated main control room alarm, must be OPERABLE to ensure that the capability of detecting and comparing the observed spectra response of a seismic event to that used in the design basis for the plant is maintained. As noted in Table T3.3.o-1, Function 3.b provides the required main control room alarm function and has an adjustable setpoint. Table T3.3.o-1 is also modified by a note stating that all the seismic instrumentation and sensors are located in Unit 1. Thus, the Seismic Monitoring Instrumentation system is shared between Unit 1 and Unit 2 and a failure to meet the TLCO will result in both Units entering into the applicable Conditions and Required Actions for the inoperable instrument.
APPLICABILITY	The potential for a seismic event exists at all times. For example, an earthquake could occur while moving irradiated fuel in the secondary containment with the core fully offloaded. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to seismic monitoring instruments. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable seismic monitoring instrumentation provide appropriate compensatory measures for separate inoperable instruments. As such, a Note has been provided that allows separate Condition entry for each inoperable seismic monitoring instrument.

A.1

With one or more seismic monitoring instruments inoperable, the ability to monitor vibratory ground motion and determine its effects on safety related SSCs is degraded. Because of the diversity of sensor locations available to provide monitoring signals, an allowable out of service time of 30 days is acceptable to permit restoration of any inoperable instrument to OPERABLE status. The 30 day Completion Time is also based on the original licensing basis of the seismic monitoring instrumentation.

B.1

If the seismic monitoring instrument is not restored to OPERABLE status, plant operation may continue provided a report is prepared in accordance with the station’s Corrective Action Program (CAP). The CAP document shall outline the cause of the inoperability and the plans for restoring the instrument to OPERABLE status. The 10 day Completion Time provides an appropriate period of time to develop the recovery plan and is consistent with the original licensing basis reporting requirements for the seismic monitoring instrumentation.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

This Condition is only entered if the sensed vibratory motion is determined to have resulted from a seismic event. Other vibratory events (e.g., severe thunderstorms, bumping of equipment, or plant equipment vibration in the vicinity of the detector) can occasionally cause invalid actuations of the seismic trigger. In these cases, the ACTIONS of this Condition are not appropriate since they specify the compensatory measures, such as assessment and analysis of effects on plant equipment, required following a seismic event. If the central recorder panel has initiated due to an invalid trigger actuation, the panel should be reset as soon as practicable to restore its ability to respond to a valid seismic event. In addition, Condition A should be entered due to the inoperability of the Table T3.3.o-1 instruments feeding the central recorder as a result of the invalid actuation until the central recorder panel is reset and the system restored to standby.

If a valid seismic event having a vibratory ground motion of 0.01 g or greater occurs at the site, actuated instruments must be restored to a ready status to permit monitoring of any subsequent ground motion. Additionally, the data collected from the instruments must be reviewed against the dynamic stress assumptions in the plant design basis.

Some seismic instruments (e.g., peak recording accelerographs), once actuated, are not capable of recording a subsequent event, rendering them inoperable until they have been reset or replaced. Since seismic events are typically followed by several aftershocks, it is necessary to return actuated instruments to an OPERABLE status within 24 hours (Required Action C.1) to assure that the severity of subsequent aftershocks can be evaluated. Seismic monitoring instrument calibration may also be affected by the sudden ground motion of an earthquake. An instrument’s calibration may have shifted outside of allowable limits, depending on the severity of the seismic event. Therefore, Required Action C.2 requires that a CHANNEL CALIBRATION per TSR 3.3.o.3 be performed on each actuated instrument within five days of the initiating event to verify that the affected instruments are still properly calibrated.

In order to validate the analytical model and to determine the magnitude of the stresses that were applied to safety related SSCs during the event, the data from the seismic monitoring instruments must be retrieved and analyzed (Required Action C.3). The information derived from this analysis must be incorporated into a Corrective Action Program (CAP) report per Required Action C.4. The CAP document

(continued)

BASES

ACTIONS

C.1, C.2, C.3, and C.4 (continued)

shall describe the magnitude and frequency spectrum of the event and describe the effect of the event on safety related SSCs at the station. The data analysis and CAP document must be completed within 10 days of the initiating event.

Condition C is modified by a Note requiring Required Actions C.2, C.3 and C.4 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the seismic event. Restoration of instrument OPERABILITY alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected safety-related SSCs. Additionally, the Note ensures that the calibration of actuated seismic instrumentation has not been affected by the event.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the TSRs, the TSRs for each Seismic Monitoring Instrumentation Function are located in the TSRs column of Table T3.3.o-1.

TSR 3.3.o.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one instrument to a similar parameter on other instruments. It is based on the assumption that instruments monitoring the same parameter should read approximately the same value. Significant deviations between the instruments could be an indication of excessive instrument drift or something even more serious. A CHANNEL CHECK will detect gross instrument failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff, based on a combination of the instrument uncertainties, including indication and readability. If an instrument is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based on operating experience that demonstrates instrument failure is rare and is consistent with the recommendations of Reference 4. The CHANNEL CHECK supplements less formal, but more frequent, checks of instruments during normal operational use of the displays associated with the instruments required by the TLCO.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.o.2

A CHANNEL FUNCTIONAL TEST is performed on each required instrument to ensure that the instrument channel will perform the intended function. A successful test of the required contact(s) of an instrument channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 184 days is based on the original licensing basis for the Seismic Monitoring System and is consistent with the recommendations of Reference 4.

TSR 3.3.o.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the instrument responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the instrument adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology.

The Frequencies are based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR Section 3.7.4.
2. 10 CFR 100, Appendix A.
3. Regulatory Guide 1.12, “Instrumentation for Earthquakes.”
4. NUREG 0800, Standard Review Plan, Section 3.7.4.

B 3.3 INSTRUMENTATION

B 3.3.p Fire Protection Instrumentation

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment.

The Fire Protection Instrumentation system provides the station's fire detection capability and consists of fire detection sensors installed in various locations throughout the plant, remote alarm panels, and an interface to the Plant Process Computer (PPC). Several different types of sensors are used to determine the existence and location of fires and combustion byproducts. Detector types include heat, smoke (ionization and photoelectric), and flame (ultraviolet).

Heat detectors sense a high temperature and/or rate of rise temperature condition and provide automatic actions including alarms and actuations of fire suppression equipment. The rate of rise

(continued)

BASES

BACKGROUND (continued)

temperature portion of the detector may be reset at local control panels after the condition has cleared. Under high temperature conditions a fusible link melts to provide the alarm and/or actuation signal. The high temperature condition cannot be reset and once the link has melted, the detector must be replaced.

Two types of smoke detectors are utilized in the Fire Protection Instrumentation system, ionization and photoelectric. A fire ionizes the molecules of a substance during its combustion. This electron imbalance of the combustion byproduct gases is not visible, but can be detected by ionization detectors. This type of detector can provide early warning of a fire and allow for detection prior to the occurrence of significant damage. Ionization detectors are used for both alarm and actuation functions. Conversely, photoelectric smoke detectors utilize a beam of light focused across an area onto a photoelectric cell. As long as the light is striking the cell with the proper intensity, the activation switch is kept open. If the light source is interrupted for a predetermined time limit (as would be the case with smoke), then the switch closes and causes an alarm to alert plant personnel of a fire in the affected area.

Flame detectors sense light in the ultraviolet wave spectrum. These wavelengths are too short to be visible to the human eye and are generally associated with high intensity flames. One disadvantage to flame detectors is that they can be actuated by other sources of ultraviolet light such as arc welding, gamma radiation and sunlight. This places limits on the areas where the detectors can be used. Currently, flame detectors are only used on the refuel floor.

Actuated detectors initiate alarms in the local area and on the PPC Fire Detection Display (FDD) via the Fire Alarm Control Panel (FACP) located in the Auxiliary Electric Equipment Room (AEER). Some detectors also actuate fire suppression or fire containment systems. In addition to providing remote alarm capability to control room operators, the FACP provides for electrical supervision of the detector circuits and will actuate a trouble alarm to alert the control room operators in the event of an instrument or circuit malfunction.

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BASES (continued)

APPLICABLE DESIGN BASES

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Fire Protection Instrumentation system is an integral part of the FPP.

The concept of defense-in-depth is used in safety related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Fire Protection Instrumentation provides a means to detect fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions with or without offsite power. For other safety related systems, the Fire Protection Instrumentation ensures that a fire will be detected in sufficient time to allow action to be taken to prevent a loss of function of such systems, even though loss of redundancy within a system may occur as a result of the fire.

The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire. The Fire Protection Instrumentation system is designed to meet the requirements of GDC 3 and National Fire Protection Association (NFPA) Standard 72E-1974. Additionally, the Fire Protection Instrumentation system function is not assumed in any accident or transient analyses of the UFSAR.
TLCO	Fire Protection Instrumentation ensures that adequate warning capability is available for the prompt detection of fires. This capability is required in order to detect and locate fires in their early stages. The Fire Protection Instrumentation listed in Table T3.3.p-1 (Unit 1) and T3.3.p-2 (Unit 2), including the associated visual and audible alarm on the FDD, must be OPERABLE to promptly detect fires to reduce the potential for damage to safety related equipment. As noted in the Tables, an exception to the OPERABILITY of instruments located within the primary containment is allowed during Type A Containment Leak Rate Testing or when the primary containment is inerted (i.e., < 4% oxygen). Due to high drywell pressure and airflow conditions during a Type A leak rate test, the fire protection instrumentation inside the drywell will generate false alarms. Since the Type A leakage test is performed very infrequently and combustible loading in the containment is administratively controlled, the probability of a fire occurring during the test is extremely low. Consequently, it is acceptable for these instruments to be inoperable without additional compensatory measures during the short period of time required to perform the test. In addition, when the containment is inerted, the oxygen content of the containment atmosphere is too low to support combustion. For this reason, fire protection instruments, specified in Tables T3.3.p-1 and T3.3.p-2 which are located within the primary containment, are not required to be OPERABLE during the performance of Type A leakage testing required by Technical Specification SR 3.6.1.1.1 or when the containment is inerted.

(continued)

BASES (continued)

APPLICABILITY

Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from damage due to the effects of a fire in order to assure that they will be able to perform their required functions. Therefore, Fire Protection Instrumentation monitoring these systems, or the areas containing these systems, must be OPERABLE whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated Fire Protection Instrumentation monitoring the area is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to fire protection instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable fire protection instrumentation channels provide appropriate compensatory measures for separate inoperable instruments. As such, a Note has been provided that allows separate Condition entry for each inoperable fire protection instrument.

A.1, A.2, A.3.1, and A.3.2

In the event that a portion of the fire protection instrumentation system is inoperable, unless the inoperability is due solely to a loss of the FDD, increasing the frequency of fire watch patrols in the affected areas is required to provide detection capability until the inoperable instrument is restored to OPERABILITY. Upon discovery of the inoperability of a required instrument, a fire watch patrol must be established within one hour (Required Action A.1) and the affected area inspected at least once per hour (Required Action A.2) to ensure that any fire will be promptly detected and reported to the control room. The acceptable methods for performing a fire watch patrol (e.g., use of cameras, extent of inspection area, maximum inspection interval, etc.) are delineated in the applicable station implementing procedure.

(continued)

BASES

ACTIONS

A.1, A.2, A.3.1, and A.3.2 (continued)

The inoperable instrument must be restored to OPERABLE status within 14 days (Required Action A.3.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the instrument per Required Action A.3.2. The CAP report should describe the cause of the instrument inoperability and the plan for restoring the instrument to an OPERABLE status.

Since it may be impractical to perform a fire watch inspection of the primary containment due to plant conditions, Condition A is modified by a Note stating that the Condition is only applicable to instruments located outside primary containment. Condition B provides other compensatory action options when fire protection instruments located inside primary containment are inoperable.

The Completion Times of one hour and 14 days are based on the original licensing basis for fire protection instruments located outside of the primary containment.

B.1.1, B.1.2.1, B.1.2.2, B.2.1, and B.2.2

As Noted in the Condition, Condition B is only applicable to required fire protection instruments located inside primary containment. Since the drywell may be inaccessible, Required Action B.1.1 requires that primary containment air temperature be monitored once per hour to detect a fire inside the primary containment. Because a fire generates large quantities of heat, a large unexplained increase in containment air temperature may be indicative of a fire. Air temperature is to be monitored at the locations listed in the Bases of Technical Specification SR 3.6.1.5.1. An air temperature in excess of the acceptance criteria of SR 3.6.1.5.1 may require action in accordance with LCO 3.6.1.5, "Drywell Air Temperature," but is not necessarily an indication of a fire. The excessive temperature should only be interpreted as a fire if no other explanation for the temperature rise can be given and other

(continued)

BASES

ACTIONS

B.1.1, B.1.2.1, B.1.2.2, B.2.1, and B.2.2 (continued)

indications (e.g., actuation of other OPERABLE smoke detectors or indication of fire induced shorts in control circuits) support the conclusion of a fire. Alternatively, a fire watch patrol may be established within one hour (Required Action B.1.2.1) and the affected area inspected at least once per eight hours (Required Action B.1.2.2). However, these actions would only be able to be performed if the drywell was accessible. The acceptable methods for performing a fire watch patrol (e.g., use of cameras, extent of inspection area, maximum inspection interval, etc.) are delineated in the applicable station implementing procedure. If the fire protection instruments located inside primary containment are inoperable solely due to a loss of the FDD, this Condition is not applicable. Fire protection instrumentation inoperability caused by a loss of the FDD is addressed in Condition C of this Requirement.

The inoperable instrument must be restored to OPERABLE status within 14 days (Required Action B.2.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the instrument per Required Action B.2.2. The CAP report should describe the cause of the instrument inoperability and the plan for restoring the instrument to an OPERABLE status.

The Completion Times of one hour, eight hours, and 14 days are based on the original licensing basis for fire protection instruments located inside of the primary containment.

C.1, C.2.1, and C.2.2

When required fire protection instrumentation is rendered inoperable solely due to a failure of the FDD, monitoring of the affected zone(s) on the FACP in the AEER is required to maintain detection capability until the instruments are restored to an OPERABLE status.

Failure of the FDD means that although the FACP is receiving and processing instrument signals, the FDD in the main control room is no longer capable of initiating alarms. This loss of FDD function only applies to the ability of the FDD to initiate audible and visual PPC trouble and fire alarms in the main control room. This loss of function does not apply to the ability to acknowledge or reset alarms from the

(continued)

BASES

ACTIONS

C.1, C.2.1, and C.2.2 (continued)

main control room (i.e., the ability to acknowledge and reset alarms at the FDD is not required for Fire Protection Instrumentation OPERABILITY). The loss of FDD function could be due to a loss of the communication link from the FACP, a loss of the PPC, a problem with a single digital input to the PPC, or other similar malfunction.

The loss of the FDD is a less severe degradation than a loss of the other portions of the Fire Protection Instrumentation system because the instrumentation is still monitoring the fire hazard zone, communicating to the FACP, and capable of automatically initiating any associated automatic fire suppression systems. Therefore, establishing continuous monitoring of the FACP in the AEER within 1 hour (Required Action C.1) is an acceptable compensatory measure to ensure that any fire or instrument trouble will be promptly detected and reported to the main control room. Continuous monitoring consists of a dedicated operator, stationed in the AEER, capable of responding to an audible or visual alarm on the FACP and reporting the alarm to the main control room. If any instrumentation impacted by the loss of the FDD is not capable of generating alarms at the FACP, then the compensatory measures of this Condition are not appropriate and Condition A or Condition B of this Requirement, as applicable, must be entered for the affected instrumentation.

The inoperable instrument must be restored to OPERABLE status within 14 days (Required Action C.2.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the instrument per Required Action C.2.2. The CAP report should describe the cause of the instrument inoperability and the plan for restoring the instrument to an OPERABLE status.

The Completion Times of one hour and 14 days are consistent with the original licensing basis for fire protection instruments.

SURVEILLANCE REQUIREMENTS

TSR 3.3.p.1

A CHANNEL FUNCTIONAL TEST is performed on each required refuel floor ultraviolet detector channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.p.1 (continued)

state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 184 days is based on the original licensing basis for the Fire Protection Instrumentation and is consistent with the recommendations of Reference 7.

TSR 3.3.p.2

Supervisory circuits required by NFPA Standard 72D-1975 associated with the refuel floor ultraviolet detectors must be tested to determine if the circuits are OPERABLE. A circuit is OPERABLE if it is capable of generating an FDD trouble alarm upon a loss of circuit continuity to the detector. This test is typically accomplished by interrupting the circuit path between the detector and the remote fire panel by opening test switches or lifting leads and verifying that the circuit trouble alarm actuates.

The Frequency of 184 days is based on the original licensing basis for the Fire Protection Instrumentation and is consistent with the recommendations of Reference 6.

TSR 3.3.p.3

A CHANNEL FUNCTIONAL TEST is performed on each required fire protection instrument channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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BASES

SURVEILLANCE REQUIREMENTS

TSR 3.3.p.3 (continued)

The TSR is modified by a Note which states that the surveillance is only required to be performed during MODE 4 or 5 entries exceeding 24 hours for detectors which are not accessible during plant operation. Several fire detectors are located in areas which may not be accessible in MODES 1, 2, and 3 due to radiological or habitability conditions. Performing the test on these detectors only when conditions permit is acceptable based on the reliability of the instruments and the continuous monitoring of the detectors by the supervisory circuits.

The Frequency of 12 months is consistent with the recommendations of NFPA 72-1996 (Ref. 8, 9, and 10).

TSR 3.3.p.4

Supervisory circuits required by NFPA Standard 72D-1975 associated with each required fire protection instrument must be tested to determine if the circuits are OPERABLE. A circuit is OPERABLE if it is capable of generating an FDD trouble alarm upon a loss of circuit continuity to the detector. This test is typically accomplished by interrupting the circuit path between the detector and the remote fire panel by opening test switches or lifting leads and verifying that the circuit trouble alarm actuates.

The TSR is modified by a Note which states that the surveillance is only required to be performed during MODE 4 or 5 entries exceeding 24 hours for supervisory circuits with detectors which are not accessible during plant operation. Several fire detectors are located in areas which may not be accessible in MODES 1, 2, and 3 due to radiological or habitability conditions. Performing the test on the supervisory circuits of these detectors only when conditions permit is acceptable based on the reliability of the circuits and the low probability of a fire occurring in these unoccupied spaces.

The Frequency of 12 months is consistent with the recommendations of NFPA 72-1996 (Ref. 8, 9, and 10).

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.
6. NFPA 72D – 1975.
7. NFPA 72E – 1974.
8. NFPA 72-1996.
9. Letter from D.J. Roberts to T.J. O'Connor, "Fire Protection Surveillance Frequencies (DG99-000028)", dated January 11, 1998.
10. Letter from D.J. Roberts to T.J. O'Connor, "Fire Protection Surveillance Frequencies (DG99-000145)", dated February 12, 1999.

B 3.3 FEEDWATER FLOW INSTRUMENTATION

B 3.3.q Feedwater Flow Instrumentation

BASES

BACKGROUND

10 CFR 50, Appendix K, paragraph I.A, "Sources of heat during the LOCA," requires that emergency core cooling system (ECCS) evaluation models assume that the reactor has been operating continuously at a power level at least 1.02 times the licensed power level to allow for instrumentation error. A change to this paragraph, which became effective on July 1, 2000, allows a lower assumed power level, provided the proposed value has been demonstrated to account for uncertainties due to power level instrumentation error.

The Leading Edge Flow Meter (LEFM) is an advanced ultrasonic system that accurately determines the mass flow rate of feedwater in nuclear power plants. The technology underlying the LEFM ultrasonic instruments and the factors affecting their performance are described in a topical report, Reference 7, and a supplement to this topical report, Reference 8. The exact amount of the uprate allowable under a revision to 10CFR50 Appendix K depends not only on the accuracy of the LEFM outputs but also on the uncertainties in other inputs to the thermal power calculation.

Utilization of the LEFM system at LSCS will result in reduced uncertainty in FW flow measurement, which reduces the total power level measurement uncertainty. The core thermal power measurement uncertainty will be a maximum of 0.346%.

The ECCS evaluation models and other plant safety analyses currently assume a two percent thermal power uncertainty. Utilization of the LEFM system thus supports an increase in RTP up to 1.654% (i.e., 2% - 0.346%), based on the reduction in thermal power uncertainty. This increase in RTP corresponds to 3546.7 MWt, which is rounded down to the requested 3546 MWt, or approximately 1.65%.

EGC has evaluated the effects of a bounding 1.7% increase in RTP using an approach developed by General Electric-Hitachi (GEH) Nuclear Energy and approved by the NRC, Reference 6.

(continued)

BASES

APPLICABLE DESIGN BASES

The basic function of the Leading Edge Flow Meter (LEFM) is to interface with the main feedwater system through a flow-metering device, ultrasonic transducers and pressure transmitters to provide Feedwater Mass Flow (Mlb/hr), Volume Flow (Cu Ft/Sec) and Temperature (° F) signals to the Plant Process Computer (PPC).

The system features automatic self-checking. A continuously operating on-line test is provided to verify that the digital circuits are operating correctly and within the specified accuracy range. Operating outside this range results in failure messages which are sent to the PPC and monitored in the control room.

The LEFM is only operable in normal mode. In normal mode the LEFM compares LEFM A CPU results to LEFM B CPU results to achieve the low uncertainty. LEFM/PPC interface communication link is redundant and therefore only one link is required for the system to be operable.

In maintenance mode, the LEFM system has better accuracy than the venturi and therefore at power levels $\leq$ 3489 MWt, the LEFM can be used as an input to the Core Monitoring Software System (CMSS).

In failed mode, the operator must use the venturi.

The ratio between the existing feedwater venturi flow measurement and the LEFM system flow measurement will be continuously monitored. LSCS does not calibrate the feedwater flow venturi to the LEFM CheckPlus measurement; however, when the LEFM becomes inoperable, a correction factor based on this ratio may be applied to the feedwater venturi flow measurement. This will ensure accuracy of the core thermal power calculation while relying on the feedwater flow venturi input.

(continued)

BASES

TLCO

The Leading Edge Flow Meter (LEFM) Instrumentation must remain OPERABLE to ensure accurate feedwater flow is utilized when calculating reactor power (Core Monitoring Software System (CMSS)) above 3489MWth. Utilizing the LEFM reduces the uncertainty in total feedwater flow measurement thereby reducing the total power level uncertainty and allowing the increase in rated thermal power.

The LEFM system Operability is defined as:

- LEFM System Status is ‘NORMAL’.
- A and/or B LEFM CPU link indicates ‘UP’.

APPLICABILITY

The LEFM system is required to provide accurate information to the plant process computer for calculating rated thermal power. Based on feedwater flow uncertainties, rated thermal power can be increased to >3489 MWt. The LEFM must be Operable when rated thermal power is >3489 MWt.

ACTIONS

<u>A.1</u>

When the LEFM becomes inoperable, restore the required instruments to OPERABLE status in 72 hours. During the allowed outage time for the LEFM, power will be calculated using the existing feedwater flow nozzles with the option of applying a correction factor. Although the feedwater flow nozzle measurements may drift slightly during this period due to fouling, fouling of the nozzles results in a higher than actual indication of feedwater flow. This condition results in an overestimate of the calculated calorimetric power level, which is conservative, as the reactor will actually be operating below the calculated power level. A sudden de-fouling event during the 72 hour inoperability period is unlikely and significant sudden de-fouling would be detected by a change in secondary plant parameters.

<u>B.1</u>

If the Required Action and associated Completion Time of Condition A is not met, then immediately initiate an orderly power reduction to ≤3489 MWt.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>TSR 3.3.q.1</u> The Frequency of 12 hours is based upon LEFM self generated internal checks. The system features automatic self-checking. A continuously operating on-line test is provided to verify that the digital circuits are operating correctly and within the specified accuracy range. The LEFM system status will change if this monitoring reveals problems with the instrumentation. Due to the interface between the LEFM and PPC, the plant process computer will provide a computer alarm message to the Control Room if the status of the LEFM instrumentation changes.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix K

2. Cameron Measurement Systems – Caldon® Ultrasonics Engineering Report: ER-746 Rev. 1a, Bounding Uncertainty Analysis for Thermal Power Determination at LaSalle Unit 2 Using the LEFM CheckPlus™. (December 2009)

3. Cameron Measurement Systems – Caldon® Ultrasonics Engineering Report: ER-790 Rev. 0, An Evaluation of the Impact of 55 Tube Permutit Flow Conditioners on the Meter Factor of an LEFM CheckPlus™. (December 2009)

4. Cameron Measurement Systems – Caldon® Ultrasonics Engineering Report: ER-755 Rev. 0, Review of LEFM Impact on Venturi Discharge Coefficient. (July 2009)

5. Letter to NRC, "Request for License Amendment Regarding Measurement Uncertainty Recapture Power Uprate," January 27, 2010

6. NEDC 32938P-A, "Licensing Topical Report: Generic Guidleines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization, " dated May 2003

7. Cameron Topical Report ER-80P, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM ✓™ System,' Rev.0, dated March 1997.

8. Cameron Topical Report ER-157P, "Supplemental to Topical Report ER 80-P: Basis for Power Uprates with an LEFM ✓™ or an LEFM CheckPlus™ System," Rev. 5, dated October 2001.

9. ASME PTC 19.1-1998, "Test Uncertainty, Instruments and Apparatus," American Society of Mechanical Engineers, 1998

10. ISA-RP67.04.02-2000, "Methodologies for Determination of SetPoints for Nuclear Safety-Related Instrumentation, "Instrumentation, Systems, and Automation Society, January 1, 2000.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.a Structural Integrity

BASES

BACKGROUND

General Design Criterion (GDC) 36, 39, 42, and 45, of Appendix A to 10 CFR Part 50 (Ref. 4) require that systems be designed to permit appropriate periodic inspection of important component parts to assure system integrity and capability. Additionally, GDC 32, 37, 40, 43, and 46, require systems to be designed to permit appropriate periodic pressure testing to assure the structural and leaktight integrity of their components.

The systems and components required to meet these GDC requirements have been designated as American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI, Class 1, 2 or 3. Components which are part of the reactor coolant pressure boundary (RCPB) are classified as ASME Code Class 1. Other safety related pressure vessels, piping, pumps, and valves are classified as ASME Code Class 2 or 3. Examples of Code Class 2 systems are; residual heat removal systems, portions of control rod drive systems, and engineered safety features not part of Code Class 1 systems. Examples of Code Class 3 systems are component cooling water systems.

In meeting the GDC requirements above, the applicable systems and components are designed to provide access to permit inservice inspections (ISI) in accordance with Section XI of the ASME Code (Ref. 6), and are included in the station's ISI program. The station's ISI program is based on the requirements of 10 CFR 50.55a.

To ensure that no deleterious defects develop during service in ASME Code Class 1, 2, or 3 system components, selected welds and weld heat-affected zones are inspected periodically throughout the life of the plant. In addition, Code Class 1, 2, and 3 systems receive visual inspections while the systems are pressurized in order to detect leakage or evidence of leakage, signs of mechanical or structural distress, and corrosion.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

Regulatory Guide 1.26 and 10 CFR 50.55a provide specific guidance for determining the quality standards (i.e., designated ASME Code Class) applicable to systems and components in the plant.

10 CFR 50.55a (Ref. 3) requires that certain pressure-retaining components of the RCPB be classified as ASME Code Class 1. The Class 1 system boundary includes all pressure vessels, piping, pumps, and valves which are part of the reactor coolant system, or connected to the reactor coolant system, up to and including:

a. The outermost containment isolation valve in system piping that penetrates the primary containment,
b. The second of two valves normally closed during normal reactor operation in system piping that does not penetrate primary containment, and
c. The Reactor Coolant System (RCS) safety and relief valves.

Regulatory Guide 1.26 (Ref. 5) provides guidance in the classification of systems and components as ASME Code Class 2 and 3. Systems or portions of systems important to safety that are designed for emergency core cooling, post accident containment heat removal, post accident fission product removal, reactor shutdown, or residual heat removal should be classified as ASME Code Class 2. An ASME Code Class 3 classification should be given to systems or portions of systems designed for heat removal from the spent fuel pool as well as cooling or seal water systems designed for the functioning of components and systems important to safety (e.g., reactor recirculation pumps, diesel generators, and control room ventilation). Additionally, systems that contain or may contain radioactive material (e.g., radwaste systems) and whose postulated failure would result in conservatively calculated potential offsite doses in excess of 0.5 Rem to the whole body should be classified as ASME Code Class 3.

All systems and components at the station were evaluated against the requirements and recommendations of References 3 and 5, including any applicable exceptions contained therein, and classified to the appropriate ASME Code Class.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	These components were incorporated into the station's ISI program as required by subsection (g) of Reference 3. The ISI program consists of a preservice inspection plan, which was completed during initial plant startup, and an inservice inspection plan. The conduct of periodic inspections and leakage and hydrostatic testing of Class 1, 2, and 3 components in accordance with the requirements of Section XI of the ASME Code provides reasonable assurance that evidence of structural degradation or loss of leaktight integrity occurring during service will be detected in time to permit corrective action before the safety function of a component is compromised. Compliance with the ISI program ensures that the General Design Criterion of Reference 4 are met.
TLCO	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. If the structural integrity of a component is found to be not in conformance with the Code, then, in addition to taking the actions specified by this TLCO, an evaluation of the component's OPERABILITY, as required by it's applicable LCO or TLCO, should be performed.
APPLICABILITY	The components monitored by the Inservice Inspection and Testing Programs have functions required for shutting down the reactor, maintaining the shutdown condition, and mitigating the consequences of an accident. Therefore, their structural integrity is required anytime there is fuel in the reactor (i.e., MODES 1, 2, 3, 4, and 5).
ACTIONS	A Note has been provided to modify the ACTIONS related to ASME Code Class 1, 2, and 3 components. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also

(continued)

BASES

ACTIONS (continued)

specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for nonconforming ASME Code Class 1, 2, and 3 components provide appropriate compensatory measures for separate nonconforming components. As such, a Note has been provided that allows separate Condition entry for each nonconforming component.

A.1 and A.2

If the structural integrity of an ASME Code Class 1 component is found to be not in conformance with the requirements of the Code, then the component must be restored to within limits prior to increasing Reactor Coolant System (RCS) temperature to > 50°F above the minimum temperature required by Nil Ductility Temperature (NDT) considerations (Required Action A.1). Since pressure retaining components of the RCPB are designated as Class 1, the Completion Time helps ensure that the nonconformance will be corrected prior to initiating a substantive heatup of the RCS which would result in a worsening of the structural degradation of the component due to thermal stresses. An evaluation of the OPERABILITY of the system containing the nonconforming component should also be performed.

Alternately, the nonconforming component may be isolated from the rest of the system (Required Action A.2). In order to meet Required Action A.2, the component must be isolated in a manner such that a structural failure of the nonconforming component will not impact the remaining portions of the system. If the affected system is rendered inoperable due to the isolation of the nonconforming component, then the applicable Conditions and Required Actions of the system's Specification or Requirement must also be entered.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the structural integrity of an ASME Code Class 2 component is found to be not in conformance with the requirements of the Code, then the component must be restored to within limits prior to increasing RCS temperature to > 200°F (Required Action B.1). Since most emergency core cooling and accident mitigation systems are designated as Class 2, the Completion Time helps ensure that these systems will be capable of performing their safety functions in the MODES in which they are required. With RCS temperature ≤ 200°F, the probability and consequences of an accident requiring these systems is reduced due to the low pressure and temperature conditions present. Therefore, the risk associated with a nonconforming Class 2 component is small under these conditions. In either case, an evaluation of the OPERABILITY of the system containing the nonconforming component should be performed.

Alternately, the nonconforming component may be isolated from the rest of the system (Required Action B.2). In order to meet Required Action B.2, the component must be isolated in a manner such that a structural failure of the nonconforming component will not impact the remaining portions of the system. If the affected system is rendered inoperable due to the isolation of the nonconforming component, then the applicable Conditions and Required Actions of the system's Specification or Requirement must also be entered.

C.1 and C.2

If the structural integrity of an ASME Code Class 3 component is found to be not in conformance with the requirements of the Code, then the component must be restored to within limits immediately (Required Action C.1). An evaluation of the OPERABILITY of the system containing the nonconforming component should also be performed. Alternately, the nonconforming component may be isolated from the rest of the system (Required Action C.2). In order to meet Required Action C.2, the component must be isolated in a manner such that a

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

structural failure of the nonconforming component will not impact the remaining portions of the system. If the affected system is rendered inoperable due to the isolation of the nonconforming component, then the applicable Conditions and Required Actions of the system's Specification or Requirement must also be entered.

The Completion Time is appropriate since immediate restoration or isolation of the nonconforming component should not pose a significant impact on station operation due to the fact that most Class 3 systems are support systems for equipment important to safety and typically have redundancy or alternate backup systems.

SURVEILLANCE REQUIREMENTS

TSR 3.4.a.1

The structural integrity of ASME Code Class 1, 2, and 3 components is ensured by the successful completion of the Inservice Inspection and Testing Programs and by visual inspections of components for evidence of deterioration or breach of integrity. This ensures that the structural integrity of these components will be maintained in accordance with the provisions of the Program. Testing and Frequency are consistent with the requirements of References 3 and 6.

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

REFERENCES

1. UFSAR Section 5.2.4.
2. UFSAR Section 6.6.
3. 10 CFR 50.55a.

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BASES

REFERENCES (continued)	4.	10 CFR 50, Appendix A.
	5.	Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants."
	6.	ASME Code, "Rules for Inservice Inspection of Nuclear Power Plant Components," 2001 Edition through the 2003 Addenda, including the December of 2003 Erratum.

B 3.4 REACTOR COOLANT SYSTEM

B 3.4.b Reactor Coolant System (RCS) Chemistry

BASES

BACKGROUND

Water chemistry controls in Boiling Water Reactors (BWR) are applied to mitigate the corrosive environments inherent in BWR operation. The original goal of BWR water chemistry specifications was primarily to control conductivity and chloride levels to prevent the occurrence of transgranular stress corrosion cracking (TGSCC) of stainless steels, a well known degradation mechanism for materials exposed to chlorinated environments. However, early testing techniques did not fully reveal the severity of the oxidizing nature of the BWR environment or the long incubation period for intergranular stress corrosion cracking (IGSCC) initiation and subsequent growth in weld or furnace sensitized stainless steel. Also, the contribution of the high tensile residual stresses that could be produced by welding and grinding was not well understood. These factors have led to a series of IGSCC events. Since the recognition of IGSCC in BWR structural materials, a number of remedies have been qualified that address the materials, tensile stress, and environmental aspects of this phenomenon.

BWR components are susceptible to damage due to IGSCC and other types of corrosion. Costs including extended outages and increased radiation exposure, associated with the inspection and repair of IGSCC in recirculation piping and vessel internals in the nuclear industry have been significant. In addition, damage is often detected by inspection, and discovery of cracking increases the inspection program, which adds additional inspection-related costs. Alternative chemistry regimes such as hydrogen water chemistry (HWC) and other alternatives like noble metal chemical application (NMCA) are expected to provide improvements in the mitigation of IGSCC of reactor internals.

Corrosion potential, more commonly called electrochemical corrosion potential (ECP) is a measure of the thermodynamic tendency for a material to undergo a corrosion reaction. In a BWR, the ECP is also a measure of the electrochemical driving force for IGSCC. The

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BASES

BACKGROUND (continued)

presence of oxygen or hydrogen peroxide (due to the radiolysis of water in the core region) substantially increases ECP. The ECP of structural materials in the BWR environment operating under normal water chemistry conditions is sufficiently high to provide the electrochemical driving force for IGSCC. Laboratory investigations have revealed that lowering the ECP of sensitized stainless steel by the injection of hydrogen into the BWR feedwater plus reducing coolant conductivity will mitigate IGSCC of BWR piping. This augmented hydrogen injection process is referred to as HWC.

The primary detrimental side effect of HWC is the increase in main steam line radiation levels. The radiation is due to the presence of short-lived activation products, primarily N-16, that are produced in the core. As the coolant becomes less oxidizing, the chemical forms of N-16 shift from primarily nitrate, which is non-volatile, to more volatile forms, such as nitrogen oxides and ammonia. Under the reducing conditions produced by HWC, more of the N-16 partitions to the steam resulting in significantly higher steam activity levels.

To help mitigate the side effects of HWC, a second process, referred to as NMCA, is employed. Very simply. noble metals such as platinum, palladium, and rhodium are used to catalyze the recombination of oxygen and hydrogen peroxide with oxygen. The plant is treated by injecting a solution of these metals into the reactor water during a shutdown to MODE 4 at a temperature of 248°F to 347°F for 48 hours. All residual chemicals are removed subsequent to the treatment. The noble metals deposit on all wetted surfaces throughout the whole core. When noble metals are deposited on a surface, and an excess amount of hydrogen is added to the coolant, their catalytic action removes all of the oxygen at the surface, thus allowing the protection of the reactor internal components with lower levels of hydrogen injection. NMCA has several benefits compared to HWC treatment alone including reduced hydrogen injection rates and a return to normal water chemistry operation dose rates (i.e., eliminates the up to 4 to 5 fold increase in steam turbine radiation fields associated with HWC). These benefits eliminate administrative controls needed to deal with increased operating dose, decrease personnel exposure during operation, and reduce localized shielding requirements.

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BASES (continued)

APPLICABLE DESIGN BASES

Nuclear station management is charged with generating safe, reliable, and low-cost electric power. Management is periodically faced with a choice of either keeping a unit available to produce power to meet short-term system demands or maintaining good control of chemistry to help assure the long-term integrity of the reactor and reactor coolant system, including fuel, balance of plant (BOP), and turbines. To effectively deal with these concerns, a chemistry program has been implemented to ensure compliance with regulatory commitments and established industry guidelines for system/materials integrity, while meeting the economic demand of power generation. Operation with off-normal chemistry may result in long-term loss of unit availability. Such losses can be minimized by limiting the magnitude and duration of off-normal chemistry. The goal of water chemistry control is to extend the operating life of the reactor and reactor coolant system, BOP components, and turbines while simultaneously controlling costs to retain economic viability of the nuclear power generation investment.

IGSCC can limit the service life of susceptible materials and components in BWR water environments. Discovery of IGSCC in core shrouds of several plants indicates that cracking may be present in other reactor internal components. The importance of the role of the BWR environment in the IGSCC process has been recognized for some time. Laboratory studies have also shown that certain impurities in the water, such as sulfate and chloride, can accelerate initiation of IGSCC and promote high crack growth rates. The localized corrosion potential also influences the initiation and growth of IGSCC. Recognizing this, the station has implemented industry guidelines via the water chemistry control program to establish a proactive position on water chemistry for mitigating IGSCC while maintaining fuel integrity and controlling radiation fields. This TLCO is an integral part of the water chemistry control program.

Elevated impurity concentrations and potential gradients in a crevice can initiate IGSCC in otherwise resistant material, such as non-sensitized stainless steel or low carbon grades of stainless steel. In crevice geometries, the oxidizing nature of the BWR concentrates impurities

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BASES

APPLICABLE DESIGN BASES (continued)

and changes the water in the crevice to an acid pH. Under these severe localized conditions, IGSCC can initiate and propagate even in non-sensitized material if a sufficient tensile stress is present. Although a number of different parameters are monitored as part of the water chemistry control program to detect and control changes in impurity levels, the requirements for RCS chemistry in this TLCO specifically address the following important parameters: coolant conductivity, chloride concentration, and coolant pH (during noble metal chemical application).

Conductivity

Statistical analyses of IGSCC cracking trends, especially of creviced components have shown that the reactor conductivity history in a given reactor is a useful indicator of the relative probability of the time to detectable cracking in a component when compared to like components in other reactors. All anions in the water contribute to the coolant's conductivity. Conductivity provides a good and prompt measure of the quality of the reactor water. When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity are also within their normal range. High values of conductivity typically correlate with high concentrations of aggressive anions. Recognizing this, guidelines have been established to limit conductivity levels of the reactor coolant.

Chlorides

Research has clearly demonstrated that a fundamentally important chemistry parameter is the thermodynamic activity of strong acid anions, such as chlorides, that are stable in the highly reducing crack tip environment. These anions are drawn into the crack by the potential difference between the crack tip and mouth, and depress the crack tip pH. Laboratory studies have demonstrated that chloride accelerates the initiation of IGSCC and promotes high crack growth rates.

Aside from being one of the most potent promoters of IGSCC in sensitized stainless steel, chloride also promotes TGSCC of annealed stainless steel plus pitting and crevice

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BASES

APPLICABLE DESIGN BASES

Chlorides (continued)

corrosion. Chloride increases can occur during periods of significant condenser in-leakage, or as a result of chlorine-bearing organic ingress during radwaste recycle. Chlorides generally accelerate all forms of corrosion, thus the concentration of chlorides in the reactor coolant must be monitored and controlled.

pH

The pH and conductivity of a pure solution of an acid or base can be related based on physical chemistry. This relationship can provide a fundamental insight into the nature of a contaminant in BWR water. For example, if the reactor water conductivity increases and the pH drops, ingress of an acid is indicated. Such behavior is expected during a resin intrusion incident, exhaustion of the anion resin in the condensate polishers during cooling water in-leakage, or ingress of a halogenated hydrocarbon contaminant. Likewise, if the reported pH and conductivity are high, ingress of a contaminate that is basic is indicated.

However, extreme caution should be exercised in measuring and interpreting variations in pH in the BWR cycle. Measurement accuracy in most BWR streams is generally suspect because of the dependence of the instrument reading on ionic strength of the sample solution. Two instruments calibrated according to appropriate procedures employing standard buffer solutions at a pH of 7 and 10 can differ by as much as a unit when measurements are made on a BWR process stream which has low conductivity (i.e., low ionic strength).

RCS Chemistry limits, actions, and monitoring requirements specified in this TLCO are in conformance with Reference 2 and provide reasonable assurance that the reactor coolant pressure boundary components will be adequately protected, during operation, from conditions that could lead to stress corrosion of the materials and loss of structural integrity of a component. RCS Chemistry limits are not assumed as initial conditions in any accident or transient analyses of the UFSAR.

(continued)

BASES (continued)

TLCO

Control of BWR water chemistry increases plant availability by reducing IGSCC in cooling system piping and reactor internals. The water chemistry limits of Tables T3.4.b-1 and T3.4.b-2 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 higher limit on chlorides is permitted during MODE 1. During MODES 4 and 5, or with the reactor vessel defueled, the temperature necessary for stress corrosion to occur is not present so higher concentrations of chlorides are not considered harmful during these periods. Soluble iron could increase significantly due to NMCA-related chemistry, but is benign to stress corrosion cracking. A conductivity increase due to soluble iron may be subtracted prior to evaluating against the conductivity limits.

During a NMCA, higher conductivity limits are permitted, without causing significant detriment to stress corrosion cracking of reactor materials in contact with reactor coolant, for a maximum of 48 hours for the injection of noble metal chemicals in MODE 3 and for a maximum of 24 hours after the end of the injection (cleanup period) with the plant being in MODE 4 as rapidly as the cooldown rate limits permit after the end of the injection.

Conductivity data is generally more reliable than pH data because of the difficulty of accurately determining pH at low ionic strengths. For this reason, pH is only required to be monitored during the injection and cleanup periods of a NMCA when conductivity levels are higher, thus, the limits of Table T3.4.b-2 are only applicable during NMCA treatment injection and cleanup periods.

APPLICABILITY

The potential for IGSCC initiation and subsequent growth exists at all times. For example, an RCS chemistry limit violation could result from impure reactor makeup water, contamination of the condenser hotwell (with subsequent transfer to the reactor vessel), or Reactor Water Cleanup (RWCU), condensate, or Spent Fuel Pool filter demineralizer exhaustion. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A.1

If conductivity or chloride concentration exceeds the limits of Table T3.4.b-1 in MODE 1, the parameter is in a range in which data or engineering judgement indicate that significant degradation may occur in the short term, thereby warranting a prompt correction of the abnormal condition.

72 hours is permitted to restore the chemistry parameter(s) to within limits. Methods available to the operator for correcting the off-normal condition include operation of the RWCU system and placing fresh RWCU or condensate filter demineralizers in service.

Because the effects of abnormal water chemistry are dependent on both the severity and duration of the off-normal condition, an additional Completion Time for the cumulative amount of time the TLCO is not met in MODE 1 is provided. RCS chemistry in excess of the limits is only permitted for 336 hours in the past 365 days. Once this Completion Time has been exceeded, Condition B must be entered. Any subsequent violations of RCS chemistry limits in MODE 1 will result in immediate entry into Condition B until the number of hours in excess of the limit drops below 336 in the last year.

The Completion Times are considered reasonable based on industry data and engineering judgement.

B.1

If the Required Action and associated Completion Time of Condition A is not met, then the plant must be placed in a MODE or other specified condition in which the limit does not apply. To achieve this status, the plant must be brought to MODE 2 within 6 hours. The major benefit of reducing power is to reduce the concentrating effect within the reactor vessel and provide time for the cleanup system to reestablish the purity of the reactor coolant. Once MODE 2 is achieved, other limits in Table T3.4.b-1 become applicable. Although conductivity limits in MODE 2

(continued)

BASES

ACTIONS

B.1 (continued)

are higher, chloride concentration limits are more restrictive. Depending on the progress of the impurity cleanup, RCS chemistry parameters may exceed the limits for MODE 2. In this case, Condition D should be immediately entered.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner without challenging plant systems.

C.1

If conductivity is in excess of 10 μmho/cm (at 25°C) or chlorides are in excess of 0.5 ppm in MODE 1, the parameter is in a range in which data or engineering judgement indicate that it is inadvisable to continue to operate the plant. Therefore, the plant must be placed in a MODE or other specified condition in which the limit does not apply. To achieve this status, the plant must be brought to MODE 2 within 12 hours. The major benefit of reducing power is to reduce the concentrating effect within the reactor vessel and provide time for the cleanup system to reestablish the purity of the reactor coolant. Once MODE 2 is achieved, other limits in Table T3.4.b-1 become applicable. Depending on the progress of the impurity cleanup, RCS chemistry parameters may exceed the limits for MODE 2. In this case, Condition D should be immediately entered.

The Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

D.1

If conductivity or chloride concentration exceed the limits of Table T3.4.b-1 in MODES 2 or 3, the parameter is in a range in which data or engineering judgement indicate that significant degradation may occur in the short term, thereby warranting a prompt correction of the abnormal condition.

48 hours is permitted to restore the chemistry parameter(s) to within limits. Methods available to the operator for correcting the off-normal condition include operation of the RWCU system and placing fresh RWCU or condensate filter demineralizers in service.

The Completion Time is considered reasonable based on industry data and engineering judgement.

E.1

If the Required Action and associated Completion Time of Condition D is not met, then the plant must be placed in a MODE or other specified condition in which the limit does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The major benefit of placing the plant in Cold Shutdown is to reduce the temperature-dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant. Once MODE 4 is achieved, other limits in Table T3.4.b-1 become applicable. Depending the severity of the chemistry limit violation and the progress of the impurity cleanup, RCS chemistry parameters may exceed the limits for MODE 4. In this case, Condition F and Condition G, as applicable, should be immediately entered.

The Completion Times are reasonable, based on operating experience, to reach the required plant conditions in an orderly manner without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

F.1

If chloride concentration exceeds the limit of Table T3.4.b-1 in MODES 4 and 5, or with the reactor vessel defueled, the parameter is in a range in which data or engineering judgement indicate that significant degradation may occur in the short term, thereby warranting a prompt correction of the abnormal condition.

24 hours is permitted to restore the chloride concentration to within limits. Methods available to the operator for correcting the off-normal condition include operation of the RWCU system, Fuel Pool Cooling (FC) system, placing fresh RWCU, condensate, or FC filter demineralizers in service, or initiating a feed and bleed operation using high quality makeup water.

The Completion Time is considered reasonable based on industry data and engineering judgement.

G.1

If conductivity exceeds the limit of Table T3.4.b-1 in MODES 4 and 5, or with the reactor vessel defueled, the parameter is in a range in which data or engineering judgement indicate that significant degradation may occur in the short term, thereby warranting a prompt correction of the abnormal condition.

72 hours is permitted to restore conductivity to within limits. Methods available to the operator for correcting the off-normal condition include operation of the RWCU system, Fuel Pool Cooling (FC) system, placing fresh RWCU, condensate, or FC filter demineralizers in service, or initiating a feed and bleed operation using high quality makeup water.

The Completion Time is considered reasonable based on industry data and engineering judgement.

(continued)

BASES

ACTIONS (continued)

H.1

If RCS chemistry exceeds the limits of Table T3.4.b-2 while in MODE 3, the parameter is outside of the range expected to occur during NMCA treatment and may be indicative of the ingress of other undesired ionic species. Action must be immediately initiated to place the plant in MODE 4. The major benefit of placing the plant in Cold Shutdown is to reduce the temperature-dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant.

Once MODE 4 is achieved, other limits in Table T3.4.b-2 become applicable. Depending the severity of the chemistry limit violation and the progress of the impurity cleanup, RCS chemistry parameters may exceed the limits for MODE 4. In this case, Condition I should be immediately entered.

I.1 and I.2

If RCS chemistry exceeds the limits of Table T3.4.b-2 while in MODES 4 and 5, or with the reactor vessel defueled, the parameter is outside of the range expected to occur during NMCA treatment and may be indicative of the ingress of other undesired ionic species.

RCS chemistry parameters must be restored to limits within 72 hours of the time NMCA treatment commenced (Required Action I.1). Methods available to the operator for correcting the off-normal condition include operation of the RWCU system, Fuel Pool Cooling (FC) system, placing fresh RWCU, condensate or FC filter demineralizers in service, or initiating a feed and bleed operation using high quality makeup water.

Additionally, Required Action I.2 requires that a Corrective Action Program (CAP) report be prepared if the out of specification parameter is conductivity or pH. The CAP report should outline the cause of the chemistry excursion and the plans for restoring RCS chemistry to within limits.

(continued)

BASES

ACTIONS (continued)

J.1

Chloride is one of the most potent promoters of corrosion in stainless steel. If the concentration of chlorides exceeds 0.5 ppm for greater than 24 hours (Required Action F.1) or exceeds 0.5 ppm 72 hours after the commencement of NMCA treatment (Required Action I.1) in MODES 4 and 5, or with the reactor vessel defueled, the effect on RCS materials must be determined. Besides continuing efforts to restore chloride concentration to within limit, an engineering evaluation is required to determine if RCS operation can continue. The evaluation must verify the structural integrity of the reactor coolant pressure boundary (RCPB) remains acceptable and must be completed if operation of the plant in MODES 2 or 3 is desired. The Completion Time ensures that stresses are not applied to the RCS until the effects of the chlorides on stress corrosion susceptible components are verified to be acceptable.

Condition J is modified by a Note requiring Required Action J.1 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limit. Restoration alone per Required Action F.1 or I.1 is insufficient because higher than expected material degradation may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

TSR 3.4.b.1

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. If conductivity is within its normal range, chlorides and other impurities are also within their normal ranges. Therefore, with the continuous recording conductivity monitor inoperable, additional samples must be analyzed to ensure that chlorides are not exceeding the limit.

To ensure RCS chemistry is within its normal range, a dip or flow through conductivity measurement must be taken once every 4 hours while in MODES 1, 2, or 3, and once every 24 hours at all other times. The 4 and 24 hour

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.4.b.1 (continued)

intervals provide periodic information that is adequate to detect significant changes in conductivity. The more frequent monitoring interval provides the operator with a warning mechanism so he can investigate and remedy the condition before reactor water limits are reached.

TSR 3.4.b.2

Periodic samples of the coolant are taken to verify RCS conductivity and chloride concentration are within limits. These samples also serve as a reference for calibration of continuous reading monitors and are considered adequate to assure accurate readings of the monitors.

The Frequency of 72 hours is adequate to ensure that RCS chemistry parameters remain within limits and takes into account less formal, but more frequent, checks of RCS chemistry parameters.

With conductivity greater than 1.0 μmho/cm (at 25°C), chloride concentration cannot be assured to be within limits; therefore, more frequent checks of conductivity and chloride concentration must be made to ensure RCS chemistry remains within limits. Under these conditions, the RCS must be sampled and analyzed for chlorides and conductivity once per 8 hours.

TSR 3.4.b.3

Periodic samples of the coolant are taken to verify RCS pH is within limits. The Frequency of 72 hours is adequate to ensure that RCS chemistry parameters remain within limits and takes into account less formal, but more frequent, checks of RCS chemistry parameters.

Since pH limits are only applicable during periods of NMCA treatment, the TSR is modified by a NOTE stating that the sample is only required during the injection and cleanup periods of a NMCA treatment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.4.b.4

Performance of the CHANNEL CHECK once every 7 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly. The CHANNEL CHECK of the continuous conductivity monitor is performed by comparing its reading to a standardized flow-thru reference cell.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency of 7 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of the channel in any 7 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the channels.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. If conductivity is within its normal range, chlorides and other impurities are also within their normal ranges. With conductivity greater than 1.0 μmho/cm (at 25°C), coolant impurities cannot be assured to be within limits; therefore, more frequent checks of conductivity monitor accuracy must be made to ensure that impurity excursions will be quickly detected. Under these conditions, a CHANNEL CHECK of the continuous conductivity monitor must be performed once every 24 hours.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 5.2.3.2.1.

2. Regulatory Guide 1.56, “Maintenance of Water Purity in Boiling Water Reactors.”

3. EPRI TR-103515-R2, “BWR Water Chemistry Guidelines: 2000 Revision,” Final Report, February 2000.

B 3.5 EMERGENCY CORE COOLING SYSTEM (ECCS)

B 3.5.a ECCS Corner Room Watertight Doors

BASES

BACKGROUND

Nuclear power plant structures, systems, and components (SSCs) important to safety are designed to withstand, without loss of capability to perform their safety functions, the most severe flood conditions that can reasonably be postulated to occur at the site as a result of severe hydrometeorological conditions, seismic activity, or interior piping and storage tank ruptures. Requirements for plant flood control from external sources are governed by 10 CFR 50, Appendix A, General Design Criterion (GDC) 2, "Design Basis for Protection Against Natural Phenomena." Requirements for plant flood control from internal sources are governed by Reference 4.

The station's internal flood control efforts are directed towards three sources that could conceivably introduce large amounts of water into the plant below grade level. These sources result from;

1. a failure of water lines connected directly to the lake which would permit the entering of lake water into the plant via gravity,
2. a failure of a water line directly connected to the lake which, if the associated pump were to remain on, would result in water flowing into the plant, and
3. a failure of the suppression pool.

The flood control measures utilized at the station include; floodwalls, watertight piping penetration sleeves, waterproofing materials, waterstops, watertight bulkhead doors, an alarm and indication system for key sumps, and abnormal operating procedures to mitigate the effects of flooding.

APPLICABLE DESIGN BASES

The ECCS corner room watertight doors and penetration seals are an integral part of the station's interior flood control measures. These rooms on the 673' elevation of the Reactor Building have watertight walls erected up to an elevation of 686' 7" Mean Sea Level (MSL). The doors and piping penetrating these walls are likewise designed

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	to be watertight and the room sumps are separated to ensure that only the equipment in one room can be affected by a failure of a door or seal during a flooding event. Thus, these areas will be protected in the highly unlikely event of a suppression pool rupture. The ECCS corner room watertight doors provide an alarm in the main control room, after a short time delay, whenever a door is opened. A rupture of the suppression pool is not assumed in the accident analysis of the UFSAR. The ECCS subsystems are assumed to perform their specified safety functions without requiring protection from this event. Therefore, the ECCS corner room watertight doors and penetrations seals do not impact the OPERABILITY of any ECCS components required by LCO 3.5.1, “ECCS – Operating,” or LCO 3.5.2, “ECCS – Shutdown.”
TLCO	To ensure that the ECCS subsystems are protected from the effects of internal flooding due to a suppression pool rupture, the ECCS corner room watertight doors and penetration seals must be OPERABLE. Penetration seals are considered OPERABLE if there are no unsealed openings and no indications of degradation or damage to rubber seals or boots. Watertight doors are considered OPERABLE provided the door seals can create a leak tight barrier and the door is closed and secured (except during normal entry and exit from the room). OPERABLE doors must be secured by at least one lug to ensure that the door will remain in place during and following a seismic event. Additionally, watertight doors may be considered OPERABLE when held open for inspection or transportation of material through the door provided a dedicated individual is stationed at the door to assure closure upon completion of the activity and the door is not otherwise inoperable.
APPLICABILITY	The ECCS corner room watertight doors and penetration seals are required to protect ECCS equipment in the Reactor Building corner rooms from the effects of a suppression pool rupture. Therefore, this TLCO is applicable in MODES 1, 2 and 3, and MODES 4 and 5 when the associated ECCS subsystem is required to be OPERABLE consistent with the applicability requirements of LCO 3.5.1 and LCO 3.5.2.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS corner room watertight doors and penetration seals. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable watertight doors and penetration seals provide appropriate compensatory measures for separate inoperable rooms. As such, a Note has been provided that allows separate Condition entry for each inoperable corner room. A room is considered inoperable upon the discovery of an inoperable door or penetration seal within the room. The discovery of a subsequent inoperable door or seal within the same room does not result in a separate Condition entry. Once a room has been declared inoperable, all inoperable doors and seals within the room must be restored to OPERABLE status before another Condition entry for that room can be made.

A.1

If one or more ECCS corner room watertight doors or penetration seals are inoperable, action must be taken to restore the doors and seals to an OPERABLE status within 14 days. The 14 day Completion Time is reasonable based on the low probability of a suppression pool rupture occurring and the time required to complete the Required Action.

B.1

If the Required Action and associated Completion Time of Condition A is not met, the ECCS equipment in the affected corner room remains unprotected from an internal flooding event. In this case, the affected ECCS subsystems must be conservatively declared inoperable until flood protection is restored.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.5.a.1

Verifying that each watertight door in each ECCS corner room is closed, except when the door is open for entry and exit, ensures that the infiltration of water from a suppression pool rupture does not occur. The 31 day Frequency has been shown to be adequate based on operating experience and is considered acceptable in view of the existing alarms and administrative controls on door status.

TSR 3.5.a.2

Visual inspection of the watertight door seals and room penetration seals provides an indication of physical damage or abnormal deterioration that could potentially degrade the leak tightness of the seal.

The presence of physical damage or deterioration does not necessarily represent a failure of this TSR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the seal (ability to perform its design function).

While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR Section 3.4.1.
2. 10 CFR 50, Appendix A, GDC 2.
3. Regulatory Guide 1.102, “Flood Protection for Nuclear Power Plants.”
4. NUREG 0800, Standard Review Plan, Section 3.4.1.
5. Technical Specification 3.5.1.
6. Technical Specification 3.5.2.

B 3.5 EMERGENCY CORE COOLING SYSTEM (ECCS)

B 3.5.b Safety Relief Valve (SRV) System Low-Low Set (LLS) Function

BASES

BACKGROUND

There are 13 total SRVs, of which 7 have an Automatic Depressurization System (ADS) function (SRVs “C”, “E”, “R”, “U”, “D”, “S”, and “V”) and 7 that have a Low-Low Setpoint (LLS) function (SRVs “C”, “E”, “P”, “U”, “D”, “S”, and “K”). The seven ADS SRVs are supplied by the ADS accumulator backup compressed gas system (nitrogen bottle banks). Of these, five SRVs (SRVs “C”, “D”, “E”, “S”, “U”) have both ADS and LLS functions. For these five SRVs, the logic channels associated with the LLS function are interconnected with the ADS logic channels. In addition, the ADS and LLS functions for these five SRVs utilize a common pneumatic supply.

The seven SRVs ("C", "E", "P", "U", "D", "S", and "K") associated with the LLS relief logic are set to three ranges of valve operation (low, medium, or high). One SRV accomplishes the low range LLS function, another SRV accomplishes the medium range LLS function, and the remaining five SRVs accomplish the high range LLS function. The low range LLS function is normally accomplished by SRV “U” and the medium range LLS function is normally accomplished by SRV “S”. The LLS function modifies the "reopen" and "reclose" setpoints of the low and medium ranges SRVs so they are lower than the other SRV setpoints. Failure of the low and medium range LLS function has the potential to adversely impact ADS operability.

APPLICABLE DESIGN BASES

The LLS relief logic functions to minimize the containment design load by reducing the number of relief valves that reopen following a reactor isolation event. The two LLS valves (SRVs “U” and “S”) are the same valves used for the lowest SRV pressure group. Therefore, since the valves will already have opened from their original pressure relief signals, the LLS logic acts to hold them open past their normal reclose point until the pressure decreases to a predetermined "low-low" setpoint and acts to lower their opening setpoint. Therefore SRVs “U” and “S” will open sooner and will remain open longer than the other safety/relief valves. This extended relief capacity assures that no more than one valve will reopen a second time (Ref: UFSAR 7.3.1.2.2.10).

(continued)

BASES (continued)

TLCO

The "B" solenoid of five SRVs (SRVs "C", "D", "E", "S", and "U") is actuated by Division 2 ADS and Division 2 LLS. This means that on a loss of the non safety-related pneumatic supply system, the ADS accumulator for each of these SRVs could be required to provide the pneumatic supply to support SRV operation when either the relief, LLS or ADS function is actuated.

Due to the “B” solenoid being common to both Division 2 ADS and LLS, a scenario exists that if the Division 2 LLS function of the low and medium LLS SRVs (SRVs “U” and “S”) were unavailable the capability of LLS to limit the number of SRVs experiencing subsequent actuations would be removed. With more SRVs experiencing subsequent actuations, the available compressed gas in the bottle banks and ADS accumulators could be exhausted while controlling reactor pressure leaving insufficient compressed gas to support subsequent ADS operation of the remaining SRVs.

Ensuring that the LLS function of the Low and Medium LLS SRVs are available whenever ADS is required in accordance with TS 3.5.1 mitigates the consequences of this scenario.

APPLICABILITY

The ADS function of six SRVs is required to be OPERABLE in MODES 1, 2 and 3 except when reactor steam dome pressure is ≤ 150 psig as defined by Tech Spec 3.5.1. In order to ensure the ADS function is OPERABLE during all analyzed scenarios, the LLS function of the low and medium LLS SRVs shall be OPERABLE when the ADS function is required.

ACTIONS

A.1 and A.2

The ACTION for an inoperable required Division 2 LLS function (low or medium) requires immediate entry into TS 3.5.1 Condition G for ADS accumulator backup compressed gas system inoperable and immediate action to restore the required function(s) to an OPERABLE status. Inoperability of the low or medium Division 2 LLS function will result in more LLS SRV actuations leaving an insufficient compressed gas volume to support subsequent ADS SRV operation. The immediate action to restore OPERABILITY of the low or medium Division 2 LLS function is to implement either EC# 366749 (Unit 1) or EC# 367087 (Unit 2).

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.5.b.1

A Note has been provided to TSR 3.5.b.1 to defer the first performance of the required functional test until no later than L1R14 for Unit 1 and L2R13 for Unit 2.

This TSR verifies that the Division 2 LLS function will not interfere with the OPERABILITY of ADS by performance of a functional test. This functional test verifies that the Division 2 LLS logic will arm during an event resulting in multiple SRV actuations and that the Division 2 LLS logic properly controls the opening and closing of the low and medium LLS SRVs. Performance of this surveillance ensures that the LLS/ADS Division 2 pneumatic interface will not adversely impact the ADS function.

The 24-month Frequency is based on:

- The need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.
- The low probability associated with the scenario of concern (small break LOCA in HPCS concurrent with a LOOP, the low or medium LLS SRV out-of-service, and a singe failure disabling the Division 2 LLS function of the other medium or low LLS SRV).

REFERENCES

1. UFSAR Section 7.3.1
2. TS Bases 3.5.1
3. Letter from U. S. NRC to Exelon Generation Company, LLC, "LaSalle Station Units 1 and 2 Issuance of Amendments to Technical Specification 3.5.1, "Emergency Core Cooling Systems (ECCS) Operating," March 19, 2010

B 3.6 CONTAINMENT SYSTEMS

B 3.6.a Main Steam Isolation Valve (MSIV) Alternate Leakage Treatment (ALT) Paths

BASES

BACKGROUND

Amendment 112 and 97 to Facility Operating Licenses NPF-11 and NPF-18, for Units 1 and 2 respectively, approved the deletion of the MSIV Leakage Control System (MSIV-LCS) and increased the allowed MSIV leakage rate. The MSIV leakage rate is maintained by Technical Specification SR 3.6.1.3.10. The basis for the deletion of the MSIV-LCS and increasing the allowed MSIV leakage rate was submitted to the NRC by Reference 5 and supplemented by References 7, 9, 10, 11, 12, 13, and 14. The NRC approved the amendments for both Units 1 and 2 in Reference 15. The primary basis for the license amendments is Reference 16.

The original MSIV-LCS was designed to handle up to 100 scfh, and thus was limited in its capabilities for leakage in excess of 100 scfh. The MSIV-LCS routed MSIV leakage back to the secondary containment to be released through the Standby Gas Treatment System (SGT). The basis for deletion of the MSIV-LCS required establishing an alternate means of "treating" MSIV leakage.

The proposed “treatment” path for the MSIV leakage to the environment was analyzed in order to provide a dose assessment. Based on this dose assessment, the option chosen by LaSalle and the preferred method in the Topical Report (Ref. 16) is the isolated condenser method, which consists of establishing an open pathway for the leakage past the MSIVs to the main condenser through the main steam line drains.

The approved MSIV Alternate Leakage Treatment (ALT) path for LaSalle is as follows:

1. Four main steam lines from their respective MSIV to their respective drain lines.

2. A 2" drain line connected to each steam line.

(continued)

BASES

BACKGROUND (continued)

3. A 12" drain header, receiving leakage from each of the four 2" drain lines.

4. A 3" line routed from the 12" drain header and branching into a 1" normal operating orifice drain line and a 3" start-up drain line as follows:

   a. An operating 1" drain line with an orifice connected to the condenser at elevation 696'7" (condenser bottom is 690'7") and a normally open motor-operated globe valve.

   b. A start-up 3" drain line (no orifice) connected to the condenser at elevation 676'7" and a normally closed motor-operated globe valve.

There are two identical ALT Paths (as described above) available to route MSIV leakage to the main condenser; however, only one of these paths is necessary to meet the dose assessment assumptions.

During normal plant operation, the operating drains (1(2)B21-F071 and 1(2)B21-F073) are open and the start-up drains are closed. For the ALT Path mode of operation, the two operating drain valves remain open and one of the start-up drains (1(2)B21-F070 or 1(2)B21-F072) is opened. This alignment provides an initial flow path, although restricted, until a start-up drain is open.

APPLICABLE DESIGN BASES

The function of the MSIV ALT Paths is to provide a reliable flow path for leakage past the MSIVs during accidents involving potential core degradation such as the Design Basis Accident (DBA) Loss of Coolant Accident (LOCA) to minimize offsite and control room dose. The dose calculations were based on a leakage rate of 400 scfh and on the size (interior diameter) and length of the piping in the MSIV ALT Paths. The assumed condenser mixing model is based on the effective condenser volume and includes only that volume above the main steam drain line inlet point (Ref. 5, 7, and Appendix C of Ref. 16).

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

The radiological dose model took credit for the path from the reactor vessel, through the 26" main steam lines, through either of the two drain lines downstream of the outboard MSIVs (both paths were analyzed), to the main condenser with leakage from the turbine seals. The radiological dose model showed the difference between the two ALT paths to be insignificant. No credit is taken in the radiological dose model for the two operating drain lines being open.

The ALT Path to the main condenser has high reliability, because LaSalle has redundant, seismically qualified ALT paths to the main condenser. With two independent seismically qualified ALT paths, mechanical failure of a single valve in one ALT drain path does not prevent routing MSIV leakage through the other full capacity path to the condenser. Even in the unlikely event of a failure of all three power sources, two offsite power sources and the safety-related Diesel Generator, a restricted flow path through the operating drain orifices to the main condenser will exist. LaSalle start-up drain stop valves (1(2)B21-F070, 1(2)B21-F072) also have local reach rod operators outside of the heater bay shield walls to allow manual operation if required.

In evaluating the reliability of the ALT Path, the boundary isolation and flowpath valves fell into four categories:

Category 1 – Remote manual motor-operated valves powered from ESS Division 2 busses.

All seven of these valves and motor operators, (1(2)B21-F418A, 1(2)B21-F418B, 1(2)B21-F070/72, 1(2)B21-F071/73, and 1(2)B21-F020) were originally seismically qualified. They were reclassified as non-safety related; however, they are powered from their original power sources, ESS Division 2 busses and thus have a reliable source of power.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

Category 2 – Local manual valves that remain in their normal operating (closed) position in the ALT path mode of leakage treatment.

Local manual valves used as boundary valves are seismically qualified and remain in their normal locked closed operating positions and require no operator action to establish an ALT Path.

Category 3 – EHC operated valves.

The Main Steam High Pressure Turbine Main Stop Valves (1(2)B21-MSV-1, 2, 3, and 4) are operated utilizing EHC pressure and fail closed upon loss of electrical power to EHC, loss of EHC pressure, or upon Turbine Trip. The Main Steam Bypass Valves (1(2)B21-MSBPV1, 2, 3, 4, and 5) are also operated utilizing EHC pressure and fail closed upon loss of electrical power to EHC or loss of EHC pressure. These valves were evaluated and determined to be seismically rugged.

Category 4 – Dual acting, quick closing MSIVs.

The dual acting, quick closing MSIVs are safety-related valves and are seismically qualified.

The piping and piping supports are also highly reliable, because the piping and piping supports within the ALT boundary are seismically qualified. The majority of the piping and piping supports within the boundary were originally seismically analyzed. The remaining portions not originally seismically qualified were analyzed and subsequently modified during L1R07 per DCP 9500167 for Unit 1 and during L2R07 per DCP 9500168.

In addition, the motor-operated valves (MOVs) utilized as either boundary valves or ALT path control valves are included in the plant Inservice Testing (IST) program and are required to be stroke tested once per fuel cycle.

(continued)

BASES (continued)

TLCO

This TLCO establishes availability requirements to maintain the MSIV ALT Paths functional in the same MODES in which the primary containment and MSIVs are required to be OPERABLE by Technical Specifications LCO 3.6.1.1 and LCO 3.6.1.3.

The piping and valves forming the boundary for and providing a flow path to the main condenser are part of the MSIV Alternate Leakage Treatment (ALT) Paths required by this TLCO and must be functional. Additionally, the ALT Path boundary valves and portions of the ALT Path piping are common to both ALT Paths; therefore, a failure in one of these components renders both ALT Paths non-functional.

APPLICABILITY

The MSIV ALT Paths are required to be functional in order to remain within the assumptions used in the dose calculations (Ref. 5 and 7). The dose calculations only pertain to the release due to MSIV leakage; therefore, the Applicability for this TLCO is the same as LCO 3.6.1.3, “Primary Containment Isolation Valves (PCIVs),” which is MODES 1, 2, and 3.

ACTIONS

A.1

With either MSIV ALT Path MOV, 1(2)B21-F070 or 1(2)B21-F072, not functional, the non-functional MOV must be restored within 30 days. Non-functional means inability of the MOV to operate using the control switch in the control room. In this condition, the remaining functional ALT Path is adequate to perform the required MSIV leakage treatment function. However, the overall system reliability is reduced because a single failure in the functional ALT Path could result in the leakage treatment function not being adequately performed. The Completion Time is based on the MSIV-LCS Technical Specification allowed outage time that was deleted by License Amendments 112 and 97 for Units 1 and 2, respectively, and is therefore conservative.

(continued)

BASES

ACTIONS (continued)

B.1

If both MSIV ALT path MOVs, 1(2)B21-F070 and 1(2)B21-F072 are non-functional, at least one must be restored to a functional status within 7 days. The reduced Completion Time is considered acceptable since there is a secondary means of repositioning MOVs by local manual operation, the low probability of a DBA during this period, operating experience and allows sufficient time to restore one of the MSIV ALT path MOVs.

C.1

If either the 1(2)B21-F070 or 1(2)B21-F072 MOV is non-functional longer than 30 days, or both the 1(2)B21-F070 and 1(2)B21-F072 MOVs are non-functional for more than 7 days, then the ability to establish at least one MSIV ALT Path by local valve operation needs to be evaluated; this can include local manual operation of MOVs 1(2)B21-F070 or 1(2)B21-F072. The Completion Time of 72 hours is acceptable because local operation is normally available.

D.1

If no MSIV ALT path can be established or if there is a loss of both MSIV ALT paths for reasons other than the loss of the 1(2)B21-F070 and 1(2)B21-F072 MOVs, (e.g., failure of a MSIV ALT path boundary isolation valve to remain closed or loss of condenser) then a compensatory means needs to be available to limit radioactive release during a DBA LOCA or similar event. Examples of compensatory methods are given in Appendix E of Reference 16. These include, but are not limited to, flooding of the main steam lines upstream or downstream of the MSIVs, Reactor Pressure Vessel depressurization to the suppression pool, and pressurization of piping between the MSIVs with nitrogen or water.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.6.a.1

Verifying the correct alignment for each manual, power operated, and automatic valve in each ALT path provides assurance that the proper flow path will exist for the MSIV leakage treatment function. This TSR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in an incorrect position, and yet considered in the correct position, provided it can be realigned to its correct position from the main control room. This is acceptable because the ALT Path is a manually initiated system.

This TSR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This TSR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency is consistent with similar surveillance requirements in Technical Specifications and is therefore acceptable.

TSR 3.6.a.2

The motor-operated valves utilized as either boundary valves or ALT path control valves have been included in the plant IST program. These valves are listed in Tables T3.6.a-1 (Unit 1) and Table 3.6.a-2 (Unit 2). They are required to be stroke tested once per fuel cycle in accordance with the Inservice Testing Program (Ref. 9).

TSR 3.6.a.3

The inspections of the MSIV ALT Path boundary piping and associated snubbers and supports is done in accordance with LTS-600-11, “Safety Related Snubber Visual Examination,” which lists the requirements for performing visual inspections of snubbers per Section XI of the ASME Boiler and Pressure Vessel Code. The piping is also included as part of the LaSalle In-Service Inspection (ISI) Program.

Per Attachment A, Section B of Reference 5, the lines in the leakage path downstream of the MSIVs are required to receive inspections in accordance with the station’s ISI Program for ASME Section XI, Class II piping. All maintenance and modifications on these lines must be performed as for Class II piping. Additionally, drawings

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.6.a.3 (continued)

and documentation have been updated with the current configurations to ensure that future modifications maintain acceptable seismic performance for all leakage path lines, consistent with the Sargent & Lundy seismic qualification walkdown.

The MSIV ALT Path boundary piping systems are classified as Seismic Category I per USFAR Table 3.2-1, but are not safety-related. The testing requirements for hydraulic and mechanical snubbers is specified by TLCO 3.7.i, "Snubbers." However, snubbers installed on nonsafety-related systems are excluded from this testing program unless their failure or failure of the system on which they are installed, would have an adverse effect on safety-related systems. Therefore, the testing requirements of TLCO 3.7.i do not apply to the snubbers in the MSIV ALT Paths; consequently, these snubbers only require a visual inspection in accordance with this TSR.

REFERENCES

1. Design Changes: M01-1-95-167 and M01-1-95-166 for Unit 1 and DCPs 9500168 and 95–169 for Unit 2.

2. Onsite Review 95-061, Rev. 0, dated 8/15/95.

3. Onsite Review 95-061, Rev. 1, dated 8/28/95.

4. Onsite Review 96-026, Rev. 0.

5. G.G. Benes letter to the U.S. NRC dated August 28, 1995; Request for Application for Amendment of LaSalle Technical Specifications and Exemption to Appendix J of 10CFR50, to eliminate the MSIV Leakage Control System and increase allowed MSIV Leakage.

6. R.M. Latta letter to D.L. Farrar dated November 16, 1995; Request for Additional Information - LaSalle County Station, Units 1 and 2.

7. G.G. Benes letter to the U.S. NRC dated December 15, 1995; Supplement to August 28, 1995 Request for Application for Amendment to Facility Operating Licenses NPF-11 and NPF-18.

(continued)

BASES

REFERENCES (continued)

8. M.D. Lynch letter to D.L. Farrar dated February 1, 1996; Request for Additional Information on Pending License Amendments to Remove the MSIV-LCS, LaSalle County Station, Units 1 and 2.

9. G.G. Benes letter to the U.S. NRC dated February 5, 1996; Response to NRC Staff Request for Additional Information (RAI) regarding the MSIV-LCS Alternate Leakage Treatment (ALT) Path.

10. G.G. Benes letter to the U.S. NRC dated February 9, 1996; Supplement to August 28, 1995 Request for Application for Amendment to Facility Operating Licenses NPF-11 and NPF-18.

11. G.G. Benes letter to the U.S. NRC dated February 28, 1996; Response to NRC Staff Request for Additional Information (RAI) regarding the MSIV-LCS Alternate Leakage Treatment (ALT) Path.

12. G.G. Benes letter to the U.S. NRC dated March 4, 1996; Response to revise the Exemption Request regarding the MSIV-LCS Alternate Leakage Treatment (ALT) Path submittal.

13. G.G. Benes letter to the U.S. NRC dated March 28, 1996; Providing additional information discussed during March 26, 1996 conference call regarding the MSIV-LCS Alternate Leakage Treatment (ALT) Path submittal.

14. G.G. Benes letter to the U.S. NRC dated April 3, 1996; Providing additional information discussed during March 13, 1996 conference call regarding the MSIV-LCS Alternate Leakage Treatment (ALT) Path submittal.

15. M.D. Lynch letter to D.L. Farrar dated April 5, 1996, issuance of License Amendments 112 and 97, Units 1 and 2 respectively, to delete the MSIV-LCS and increase the MSIV leakage limits.

16. General Electric Topical Report NEDC-31858P, Revision 2, dated September 1993, "BWROG Report for Increasing MSIV Leakage Rate Limits and Elimination of Leakage Control System.

17. OSR 98-152, Amend the Administrative Technical Requirements, dated May 27, 1998, for License Amendments 112 and 97, for Units 1 and 2, respectively.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.b Suppression Chamber – Drywell Vacuum Breaker Position Indication

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are four vacuum breakers located outside the primary containment which form an extension of the primary containment boundary. The vacuum relief valves are mounted in special piping between the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell-drywell boundary. Each vacuum breaker is a self actuating valve with one vacuum breaker in each line. Each vacuum breaker is provided with redundant position indication which is indicated in the main control room.

The position indication for each vacuum breaker consists of four limit switches, two open limit switches and two closed limit switches. One pair of limits switches (one open and one closed) receives power from a safety related Division 1 AC electrical bus, while the remaining pair is powered by a safety related Division 2 AC electrical bus. The limit switches provide signals to position indicating lights in the main control room and provide an alarm when the vacuum breaker is not fully closed.

APPLICABLE DESIGN BASES

The purpose of the vacuum breaker position indication is to assure that the vacuum breakers are closed prior to an accident in order to prevent a steam bypass path. With a vacuum breaker not closed, communication between the drywell and suppression chamber airspace exists, and, as a result, there is the potential for primary containment overpressurization due to this bypass leakage if a Loss of Coolant Accident (LOCA) were to occur. Design Basis Accident (DBA) analyses assume the vacuum breakers to be

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	closed initially and to remain closed and leak tight until the suppression pool is at a positive pressure relative to the drywell. This assurance is provided by the position indication and alarm function which alerts the control room operator that the vacuum breaker is open. The Suppression Chamber – Drywell Vacuum Breaker Position Indication instruments have only an indication and alarm function and there are no automatic or interlock functions associated with these instruments. As such, these instruments do not impact the OPERABILITY of the vacuum relief system required by LCO 3.6.1.6, "Suppression Chamber – Drywell Vacuum Breakers."
TLCO	Two sets of control room position indication, including the associated control room alarm, on each OPERABLE Suppression Chamber – Drywell Vacuum Breaker must be OPERABLE to provide assurance that the vacuum breakers are closed. This ensures that there is no excessive bypass leakage should a LOCA occur. Position indication is not required to be OPERABLE if the associated vacuum breaker is inoperable since the Required Actions of LCO 3.6.1.6 require that an inoperable vacuum breaker (that is open or cannot be verified closed) be manually isolated to ensure that a steam bypass path does not exist.
APPLICABILITY	A primary system rupture that purges the drywell of air and fills the drywell free airspace with steam could occur in MODES 1, 2, and 3. In order to maintain the primary containment pressure within the limits of the accident analyses, the steam must be directed to the suppression pool and not bypass the suppression chamber downcomers. The Suppression Chamber – Drywell Vacuum Breaker Position Indication is required to be OPERABLE in these MODES to verify that the vacuum breakers are closed during the event until the drywell is at a negative pressure relative to the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breaker position indication OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to suppression chamber – drywell vacuum breaker position indication. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable suppression chamber – drywell vacuum breaker position indication provides appropriate compensatory measures for separate inoperable position indicators. As such, a Note has been provided that allows separate Condition entry for each inoperable position indication.

A.1

With one or more required position indicators inoperable, the indicator must be restored to OPERABLE status (Required Action A.1) within 14 days. Alternatively, the position of the vacuum breaker may be verified by alternate means (Required Action A.2) within 14 days and once every 14 days thereafter. Either the redundant OPERABLE position indicator or local position indication may be used as the alternate means of determining valve position.

The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

B.1

If the required position indication has not been restored to OPERABLE and the position of the valve cannot be determined (i.e., Required Action and associated Completion Time of Condition A not met), then the associated vacuum breaker must be declared inoperable immediately and the Applicable Conditions and Required Actions of LCO 3.6.1.6 entered.

(continued)

BASES

ACTIONS	B.1 (continued) Once the vacuum breaker has been declared inoperable and LCO 3.6.1.6 declared not met, this TLCO is met and Condition A and B may be exited for the inoperable position indications associated with the inoperable vacuum breaker.
SURVEILLANCE REQUIREMENTS	TSR 3.6.b.1 A CHANNEL FUNCTIONAL TEST is performed on each required position indicator to ensure that the indication can perform its function in the desired manner. The test also verifies the alarm function and the relative accuracy of the position indication. The 92 day Frequency is based on the original licensing basis of the Suppression Chamber – Drywell Vacuum Breaker Position Indication and is consistent with the vacuum breaker functional test requirements of SR 3.6.1.6.2.
REFERENCES	1. UFSAR Section 6.2.1.

B 3.6 Containment Systems

B 3.6.c Primary Containment Hydrogen Mixing Subsystem

BASES

BACKGROUND

The revised 10CFR50.44 [Ref. 1], Combustible Gas Control for Nuclear Power plants, no longer defines a design-basis LOCA hydrogen release, and eliminated the requirements for hydrogen control systems to mitigate such a release, provided the containment is inerted. 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. LaSalle's Technical Specification was amended (Amendments 158 (Unit 1) and 172 (Unit 2)) [Ref. 2] to eliminate the hydrogen recombiner system.

Revised 10CFR 50.44(b)(1), Mixed Atmosphere, requires that containments must have a capability of ensuring a mixed atmosphere. To meet this requirement the Primary Containment Hydrogen Mixing Subsystem is required to provide mixing of the drywell head and control rod drive area immediately below the reactor pressure vessel. A complete description of the Primary Containment Hydrogen Mixing Subsystem is presented in UFSAR Section 6.2.5. [Ref. 3]

(continued)

BASES

BACKGROUND (continued)

NUREG-0519, Section 6.2.5.1 Containment Hydrogen Recombiner Evaluation, identifies that “the combustible gas control system is and extension of the containment boundary following a loss-of-coolant accident, we (NRC) have required and the applicant agreed to demonstrate that an adequate leak tight integrity is assured…” TSR 3.6.c.2 requirements satisfy this commitment.

APPLICABLE DESIGN BASES

The function of the mixing subsystem is to ensure that local concentrations with greater than 4% hydrogen cannot occur within the primary containment following a LOCA. The atmospheres of both drywell proper and suppression chamber area, each of which is a single compartment, are well mixed. The mixing is achieved by natural convection processes. Natural convection occurs as a result of the temperature difference between the bulk gas space in the vessel and the containment wall. The momentum of steam emitted from the point of rupture enhances the natural convective action. There are two interior subcompartments where gases may not achieve thorough mixing with the bulk containment atmosphere. The drywell head area, which is for reactor vessel refueling purposes, is one such subcompartment. The other is the control rod drive area immediately below the reactor pressure vessel. The physical arrangements and/or location of the monitoring system and the hydrogen recombiner system are such that concentrations above the 4% limit of combustible gases will not occur. The atmosphere between the drywell and suppression pools will be mixed during the depressurization phase of the LOCA. The hydrogen mixing fans will also serve to affect mixing between these two compartments. The hydrogen mixing fans will take suction on the drywell and discharge to the suppression pool. This will in turn cause the atmosphere from the suppression pool to circulate into the drywell via the vacuum breaker lines. The oxygen and hydrogen monitoring systems will alert the

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

operator of the concentration within these subcompartments and the positions of the effluent and suction points of the recombiner will preclude the building of concentrations above the limit in these areas as well as the drywell and wetwell proper.

Refer to TRM Sections TLCO 3.3.d and B 3.3.d [Ref. 4]; Post Accident Monitoring (PAM) Instrumentation for actions and bases associated with the drywell hydrogen and oxygen concentration analyzers.

TLCO

This TLCO establishes availability requirements to maintain the Primary Containment Hydrogen Mixing Subsystem paths functional. The piping and valves forming the boundary for and providing a flow path to the mixing fans are part of the Primary Containment Hydrogen Mixing Subsystem required by this TLCO and must be functional.

APPLICABILITY

In MODES 1 and 2, two Primary Containment Hydrogen Mixing Subsystems are required to provide atmosphere-mixing of the drywell head area, control rod drive area immediately below the reactor pressure vessel, and the atmosphere between the drywell and suppression pools during the depressurization phase of the LOCA.

In MODE 3, both the hydrogen production rate and the total hydrogen production after a LOCA would be less that that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the Primary Containment Hydrogen Mixing Subsystems is low. Therefore, the Primary Containment Hydrogen Mixing Subsystems are not required in MODE 3.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, Primary Containment Hydrogen Mixing Subsystems are not required in these MODES.

ACTIONS

A.1

With one Primary Containment Hydrogen Mixing Subsystem inoperable, the inoperable Primary Containment Hydrogen Mixing Subsystem must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE Primary Containment Hydrogen Mixing Subsystem is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE mixing subsystem could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent hydrogen accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of TLCO 3.0.d are not applicable. As a result, a MODE change is allowed when one mixing subsystem is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE mixing subsystem, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

(continued)

ACTIONS (continued)

B.1 and B.2

With two primary containment hydrogen mixing subsystems inoperable, the ability to perform the hydrogen mixing function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen mixing capabilities are provided by the Primary Containment Vent and Purge System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen mixing function does not exist. In addition, the alternate hydrogen mixing system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen mixing system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen mixing system. If the ability to perform the hydrogen mixing function is maintained, continued operation is permitted with two hydrogen mixing subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen mixing subsystems to be inoperable because the hydrogen mixing function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.c.1

Performance of a system functional test for each Primary Containment Hydrogen Mixing Subsystems ensures that the fans are OPERABLE and can attain and sustain the necessary airflow for mixing. In particular, this SR requires verification that the airflow is $\geq$125 scfm.

Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.c.2

This SR requires that the hydrogen mixing subsystem boundary be leak rate tested with the Primary Containment and be in compliance with the Primary Containment Leakage Rate Testing Program. The impact of the failure to meet this SR must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50.44, Federal Register / Vol.68, No. 179 / Tuesday, September 16, 2003 / Rules and Regulations.

2. NRC letter from Mr. S. Sands to Mr. C. Crane, LaSalle County Station Units 1 and 2, Issuance of Amendments to Technical Specifications to Eliminate Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors, dated April 22, 2005.

3. UFSAR, Section 6.2

4. UFSAR, Section 6.2.5.

5. TRM Sections TLCO 3.3.d and B 3.3.d

6. NUREG-0519:
   - 6.2.5 Combustible Gas Control
   - 6.2.5.1 Containment Hydrogen Recombiner Evaluation

B 3.7 PLANT SYSTEMS

B 3.7.a Residual Heat Removal Service Water (RHRSW) System - Shutdown

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for removal of heat due to the decay of fission products following reactor shutdown. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode of the RHR System. The RHRSW System also provides cooling water to the RHR pump seal coolers which are required for RHR pump operation during the shutdown cooling mode in MODE 3.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of two pumps (together capable of providing a nominal flow of 7400 gpm), a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with one or two pumps (depending on the decay heat load) operating to maintain safe shutdown conditions. The two subsystems are separated from each other so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the UFSAR, Section 9.2.1, Reference 1.

The RHRSW and the Diesel Generator Cooling Water subsystems are subsystems to the Core Standby Cooling System (CSCS) — Equipment Cooling Water System (ECWS). The CSCS — ECWS consists of three independent piping subsystems corresponding to essential electrical power supply Divisions 1, 2, and 3. The CSCS — ECWS subsystems take suction from the service water tunnel located in the Lake Screen House. The RHRSW subsystems are manually initiated. Cooling water is then pumped from the service water tunnel by the RHRSW pumps to the supported system and components (RHR heat exchangers and RHR pump seal coolers). After removing heat from its supported systems and components, the water from the RHRSW subsystem is

(continued)

BASES

BACKGROUND (continued)	discharged to the CSCS Pond (i.e., the Ultimate Heat Sink) through a discharge line that is common to the corresponding divisional discharge from the other unit. The discharge line terminates in the discharge structure at an elevation above the normal CSCS Pond level. The system is initiated manually from the control room. In addition, the Division 2 RHRSW subsystem may be initiated manually from the remote shutdown panel in the auxiliary electric equipment room. If operating during a loss of offsite power, the system is automatically load shed to allow the diesel generators to automatically power only that equipment necessary to reflood the core but may be manually restarted following power restoration.
APPLICABLE DESIGN BASES	Decay heat removal by the RHRSW System with the RHR system in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the UFSAR safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The MODE 4 and 5 RHR shutdown cooling subsystem requirements and Applicable Safety Analyses are discussed in LCO 3.4.10, “RHR Shutdown Cooling System – Cold Shutdown,” LCO 3.9.8, “RHR – High Water Level,” and LCO 3.9.9, “RHR – Low Water Level.”
TLCO	Each RHRSW subsystem associated with an RHR subsystem required OPERABLE by LCO 3.4.10, LCO 3.9.8, or LCO 3.9.9, is required to be OPERABLE to provide the required redundancy necessary to ensure that the core decay heat removal function is maintained, assuming the worst case single active failure occurs coincident with the loss of offsite power. An RHRSW subsystem is considered OPERABLE when: a. the required number of pumps necessary to remove decay heat are OPERABLE; and b. An OPERABLE flow path is capable of taking suction from the CSCS service water tunnel and transferring the water to the associated RHR heat exchanger.

(continued)

BASES

TLCO (continued)

With both pumps in the RHRSW subsystem OPERABLE, the subsystem is capable of removing decay heat under all possible power history and time after shutdown conditions. However, at some point following a plant shutdown, the decay heat load of the reactor core will be low enough such that only one pump in the RHRSW subsystem is necessary to adequately keep the core cooled. Under these conditions, an RHRSW subsystem with only one OPERABLE pump is considered to be OPERABLE provided the required cooling capacity of the subsystem is verified (by calculation or demonstration) to be capable of maintaining or reducing temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the subsystem cooling capability.

An adequate suction source is not addressed in this TLCO since the minimum net positive suction head and the maximum suction source temperature are covered by the requirements specified in TLCO 3.7.c, "Ultimate Heat Sink (UHS) – Shutdown."

APPLICABILITY

In MODES 4 and 5, the RHRSW subsystems associated with RHR subsystems required to be OPERABLE by Technical Specifications must be OPERABLE to remove decay heat to maintain coolant temperature below 200°F.

In MODES 1, 2, and 3, this TLCO is not applicable. Operations of the RHR system in shutdown cooling mode is not allowed with reactor vessel pressure greater than or equal to the RHR cut-in permissive pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal above this pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS – Operating") do not allow placing the RHR shutdown cooling subsystem into operation. The requirements for RHRSW system decay heat removal capability in MODE 3 below the cut-in pressure are discussed in LCO 3.7.1, "RHRSW System."

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to RHRSW subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RHRSW subsystems provide appropriate compensatory measures for separate inoperable RHRSW subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHRSW subsystem.

A.1

If one or more RHRSW subsystems are inoperable, the associated RHR shutdown cooling subsystem supported by the affected RHRSW loop cannot perform its intended function and must be immediately declared inoperable. In accordance with LCO 3.0.2, this requires entering into the Applicable Conditions and Required Actions for LCO 3.4.10, LCO 3.9.8, or LCO 3.9.9.

SURVEILLANCE REQUIREMENTS

TSR 3.7.a.1

Verifying the correct alignment for each manual, power operated, and automatic valve in each RHRSW subsystem flow path provides assurance that the proper flow paths will exist for RHRSW operation. This TSR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in an incorrect position, and yet considered in the correct position, provided it can be realigned to its correct position. This is acceptable because the RHRSW System is a manually initiated system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	TSR 3.7.a.1 (continued) This TSR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This TSR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.
REFERENCES	1. UFSAR Section 9.2.1.

B 3.7 PLANT SYSTEMS

B 3.7.b Diesel Generator Cooling Water (DGCW) System - Shutdown

BASES

BACKGROUND

The DGCW System is designed to provide cooling water for the removal of heat from the standby diesel generators, low pressure core spray (LPCS) pump motor cooling coils, and Emergency Core Cooling System (ECCS) cubicle area cooling coils that support equipment required for a safe reactor shutdown following a design basis accident (DBA) or transient.

The DGCW System consists of three independent cooling water headers (Divisions 1, 2, and 3), and their associated pumps, valves, and instrumentation. The pump and header for the Division 1 DGCW subsystem is common to both units (and supplies cooling to equipment on both units). The other divisions have independent pumps and suction headers.

The Division 1 DGCW subsystem services its associated Diesel Generator (DG) and ECCS cubicle area coolers, and the LPCS pump motor cooler. The Division 2 DGCW subsystem services its associated DG and ECCS cubicle area cooler. The Division 3 DGCW subsystem services the High Pressure Core Spray (HPCS) DG and its associated ECCS cubicle area cooler. The opposite unit Division 2 DGCW subsystem services its associated DG for support of systems required by both units.

The DGCW and the Residual Heat Removal Service Water (RHRSW) subsystems are subsystems to the Core Standby Cooling System (CSCS) — Equipment Cooling Water System (ECWS). The CSCS — ECWS consists of three independent piping subsystems corresponding to essential electrical power supply Divisions 1, 2, and 3. The CSCS — ECWS subsystems take a suction from the service water tunnel located in the Lake Screen House. Each DGCW pump auto-starts upon receipt of a diesel generator (DG) start signal when power is available to the pump's electrical bus or on start of ECCS cubicle area coolers. The Division 1 DGCW pump also auto-starts upon receipt of a start signal for the LPCS pump. Cooling water is then pumped from the service

(continued)

BASES

BACKGROUND (continued)	water tunnel by the DGCW pumps to the supported systems and components (i.e., the DGs, LPCS pump motor cooler, and the ECCS cubicle area coolers). After removing heat from these systems and components, the water from the DGCW subsystem is discharged to the CSCS pond (i.e., the Ultimate Heat Sink) through a discharge line that is common to the corresponding divisional discharge from the other unit. The discharge line terminates in the discharge structure at an elevation above the normal CSCS Pond level. A complete description of the DGCW System is presented in the UFSAR, Section 9.2.1 (Ref. 1).
APPLICABLE DESIGN BASES	The ability of the DGCW System to provide adequate cooling to the DGs, LPCS pump motor cooling coils and ECCS cubicle area cooling coils is an implicit assumption in the UFSAR. The ability to provide onsite emergency AC power is dependent on the ability of the DGCW System to cool the DGs.
TLCO	The required Division 1, 2, and 3, and opposite unit's Division 2 DGCW subsystems must to be OPERABLE to ensure the effective operation of the required DGs, the LPCS pump motor (when required), and the required ECCS equipment supported by the ECCS cubicle area coolers during an accident or event. The OPERABILITY of each DGCW subsystem is based on having an OPERABLE pump and an OPERABLE flow path capable of taking suction from the CSCS water tunnel and transferring cooling water to the associated diesel generator, LPCS pump motor cooling coils, and ECCS cubicle area cooling coils, as required. An adequate suction source is not addressed in this TLCO since the minimum net positive suction head of the DGCW pump and the maximum suction source temperature are covered by the requirements specified in TLCO 3.7.c, "Ultimate Heat Sink (UHS) - Shutdown."

(continued)

BASES (continued)

APPLICABILITY

Each DGCW subsystem is required to be OPERABLE in MODES 4 and 5 whenever its associated DG is required to be OPERABLE by LCO 3.8.2, “AC Sources – Shutdown.” The DGCW subsystems supporting the DG(s) required to be OPERABLE in MODES 4 and 5 provide assurance that:

a. systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

b. systems needed to mitigate a fuel handling accident are available;

c. systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The DGCW requirements for MODES 1, 2, and 3 are covered in LCO 3.7.2, “DGCW System.”

ACTIONS

A Note has been provided to modify the ACTIONS related to DGCW subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable DGCW subsystems provide appropriate compensatory measures for separate inoperable DGCW subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable DGCW subsystem.

(continued)

BASES

ACTIONS (continued)

A.1

If one or more required DGCW subsystems are inoperable, the associated DG(s) and ECCS components supported by the affected DGCW loop, including LPCS pump motor cooling coils or ECCS cubicle area cooling coils, as applicable, cannot perform their intended function and must be immediately declared inoperable. In accordance with LCO 3.0.2, this also requires entering into the Applicable Conditions and Required Actions for LCO 3.8.2, "AC Sources – Shutdown," and LCO 3.5.2, "ECCS - Shutdown," as appropriate.

SURVEILLANCE REQUIREMENTS

TSR 3.7.b.1

Verifying the correct alignment for manual, power operated, and automatic valves in each required DGCW subsystem flow path provides assurance that the proper flow paths will exist for DGCW subsystem operation. This TSR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position, and yet be considered in the correct position provided it can be automatically realigned to its accident position, within the required time. This TSR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This TSR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

TSR 3.7.b.2

This TSR ensures that each required DGCW subsystem pump will automatically start to provide required cooling to the associated DG, LPCS pump motor cooling coils, and ECCS cubicle area cooling coils, as applicable, when the associated DG starts and the respective bus is

(continued)

BASES

SURVEILLANCE REQUIREMENTS	TSR 3.7.b.2 (continued) energized. For the Division 1 DGCW subsystem, this TSR also ensures the DGCW pump automatically starts on receipt of a start signal for the unit LPCS pump. These starts may be performed using actual or simulated initiation signals. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.
REFERENCES	1. UFSAR Section 9.2.1.

B 3.7 PLANT SYSTEMS

B 3.7.c Ultimate Heat Sink (UHS) – Shutdown

BASES

BACKGROUND

The UHS (i.e., the Core Standby Cooling System (CSCS) Pond) consists of the volume of water remaining in the cooling lake following the failure of the main dike. This water has a depth of approximately 5 feet and a top water elevation established at 690 feet. The volume of the remaining water in the cooling lake is sufficient to permit a safe shutdown and cooldown of the station for 30 days with no water makeup for both accident and normal conditions (Regulatory Guide 1.27, Ref. 3).

The CSCS Pond provides a source of water to the service water tunnel from which the Residual Heat Removal Service Water (RHRSW), Diesel Generator Cooling Water (DGCW), and Fire Protection (FP) system pumps take suction. The service water tunnel is filled from the CSCS Pond by six inlet lines which connect to the circulating water pump forebays. Prior to entering the service water tunnel inlet pipes, the water is strained by the Lake Screen House traveling screens to prevent large pieces of debris from entering the system and blocking flow or damaging equipment. However, because the traveling screens are not safety related, a 54-inch bypass line around the screens is provided to assure a continuous supply of CSCS Pond water to the service water tunnel. This bypass line is isolated by a normally closed manual valve.

Additional information on the design and operation of the CSCS Pond is provided in UFSAR, Sections 9.2.1 and 9.2.6 (Refs. 1 and 2). The excavation slopes of the CSCS Pond and flume are designed to be stable under all conditions of emergency operation while providing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

APPLICABLE DESIGN BASES

The volume of the CSCS pond is sized to permit the safe shutdown and cooldown of the units from full power for 30 days with no additional makeup water source available under both normal and accident conditions (Ref. 1). In MODES 4 and 5, significantly less energy is required to be removed by the RHRSW and DGCW systems. Consequently, the UHS has considerable margin for maintaining the units in a safe shutdown condition for 30 days in these MODES.

(continued)

BASES (continued)

TLCO	OPERABILITY of the UHS is based on a maximum water temperature (as specified in the UFSAR) being supplied to the plant and a minimum pond water volume. To help ensure the volume of water available in the CSCS pond is sufficient to maintain adequate long term cooling, sediment deposition (in the intake flume and in the pond) must be ≤ 1.5 ft and CSCS pond bottom elevation must be ≤ 686.5 ft.
APPLICABILITY	In MODES 4 and 5, and during the movement of irradiated fuel in the secondary containment, the CSCS pond is required to be OPERABLE to ensure a sufficient supply of water is available to maintain the plant in a safe shutdown condition following a failure of the cooling lake embankment. The CSCS pond requirements for MODES 1, 2, and 3 are addressed in LCO 3.7.3, “UHS.”
ACTIONS	<u>A.1</u> If the CSCS pond is inoperable, due to sediment deposition > 1.5 ft (in the intake flume, CSCS pond, or both) or the pond bottom elevation > 686.5 ft, action must be taken to restore the inoperable UHS to an OPERABLE status within 90 days. The 90 day Completion Time is reasonable based on the low probability of an accident occurring during that time, historical data corroborating the low probability of continued degradation (i.e., further excessive sediment deposition or pond bottom elevation changes) of the CSCS pond during that time, and the time required to complete the Required Action. A high sedimentation or high pond bottom elevation affects only the volume of water available for cooling and not the water temperature. Because of the inherent margin in CSCS pond size with the unit in MODE 4 or 5, the RHRSW and DGCW systems are still capable of performing their specified heat removal function for an extended period of time. Therefore, entry into Condition A does not affect the OPERABILITY of the RHRSW or DGCW systems in these MODES.

(continued)

BASES

ACTIONS (continued)

B.1

If the CSCS pond is determined to be inoperable for reasons other than Condition A (e.g., inoperable due to the temperature of the cooling water supplied to the plant from the CSCS pond exceeding the UFSAR limit), the required RHRSW and DGCW subsystems may not be capable of performing their intended function and must be immediately declared inoperable. Additionally, the required RHRSW and DGCW subsystems must also be conservatively declared inoperable if the CSCS pond sediment level or bottom elevation cannot be restored within limits in 90 days.

SURVEILLANCE REQUIREMENTS

TSR 3.7.c.1

Verification of the temperature of the water supplied to the plant from the CSCS pond ensures that the heat removal capabilities of the RHRSW System and DGCW System are within the assumptions of the UFSAR. To ensure that the maximum specified water temperature supplied to the plant is not exceeded, the temperature during normal plant operation must be verified every 24 hours. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

TSR 3.7.c.2

This TSR helps ensure adequate long term cooling can be maintained, by verifying the sediment level in the intake flume and the CSCS pond is $\leq$ 1.5 feet. This limit is consistent with Technical Specification SR 3.7.3.2, and is conservative in MODES 4 and 5. Sediment level is determined by a series of sounding cross-sections compared to as-built soundings. The 24 month Frequency is based on historical data and engineering judgement regarding sediment deposition rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	TSR 3.7.c.3 This TSR ensures adequate long term cooling can be maintained, by verifying the CSCS pond bottom elevation is $\leq$ 686.5 feet. This limit is consistent with Technical Specification SR 3.7.3.3 and is conservative in MODES 4 and 5. The 24 month Frequency is based on historical data and engineering judgement regarding pond bottom elevation changes.
REFERENCES	1. UFSAR Section 9.2.1. 2. UFSAR Section 9.2.6. 3. Regulatory Guide 1.27, Revision 1, March 1974.

B 3.7 PLANT SYSTEMS

B 3.7.d Liquid Holdup Tanks

BASES

BACKGROUND	10 CFR 50.34a contains provisions that require nuclear power plant operators to design and install equipment to assure that releases of radioactive materials to unrestricted areas is kept “as low as reasonably achievable” (ALARA). To this end, the liquid radwaste system is designed so that liquid radwastes discharged from the site will have radioactivity concentrations well within the limits specified in 10 CFR 20 and meet the design objectives of 10 CFR 50, Appendix I (Ref. 5). Each liquid radwaste stream terminates in a sample tank. Since the liquid radwaste system operates on a batch basis, this arrangement allows each treated batch to be sampled when appropriate to assure that the treatment was effective. If the sample indicates that the waste needs further processing, it is recycled either through the same treatment or through a subsystem providing a higher degree of treatment. If the treated waste water is not needed for recycle, the water is sent to the discharge tank and held until a discharge batch is accumulated. Each batch is sampled to verify that its activity level is within limits for discharge. A system bypass allows connection to portable waste treatment equipment. This enables the efficient processing of liquid radwaste through the use of state of the art radwaste processing technology. The liquid radwaste system, via the discharge tanks, is the only flow path from a unit to the environment for radioactive liquids during normal operations. However, during special plant maintenance or operating activities such as chemical cleaning, it may be necessary to process or collect radioactive liquid in an outside temporary tank. This Requirement provides the limitations that must be adhered to during such an activity.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES	This Requirement implements the requirements of Offsite Dose Calculation Manual (ODCM) Surveillance Requirement 12.3.1.B.4 and Technical Specification (TS) 5.5.9.b for the Explosive Gas and Storage Tank Radioactivity Monitoring Program. It also implements, in part, TS 5.5.4.b for the Radioactive Effluent Controls Program. The requirements for the content of TS 5.5.4 and 5.5.9 concerning radioactive effluents are contained in 10 CFR 50.36a (Ref. 3). Reference 3 requires licensees to maintain control over radioactive material in liquid effluents to unrestricted areas, produced during normal reactor operations, to levels that are ALARA. Reference 5 contains the numerical guidance to meet the ALARA requirement and the dose values specified are small percentages of the implicit and explicit limits in 10 CFR 20. As a secondary control, the instantaneous release concentrations required by these TSs were chosen to help maintain annual average releases of radioactive material in liquid effluents to within the dose values specified in Reference 5. For the purposes of these TSs, 10 CFR 20 is used as a source of reference values only. These TS requirements allow operational flexibility, compatible with considerations with health and safety, which may temporarily result in release rates which, if continued for the calendar quarter, would result in radiation doses higher than specified in Reference 5. However, these releases are within the implicit and explicit limits of 10 CFR 20 which references Appendix B, Table 2, Column 2 concentrations. The referenced concentrations are based on an annual dose of 50 mrem total effective dose equivalent. Since an instantaneous release concentration corresponding to a dose rate of 500 mrem/year has been shown to be acceptable as a TS limit for liquid effluents and has not had a negative impact on the ability of the station to operate within the design objectives of Reference 5, the Nuclear Regulatory Commission determined it is acceptable to set the instantaneous limits associated with liquid release rates to 10 times the concentration values of 10 CFR 20, Appendix B, Table 2, Column 2 (Ref. 7). This liquid effluent concentration limit is codified in ODCM section 12.3.1 and is applicable to outside temporary liquid holdup tanks.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	The limitations specified in ODCM 12.3.1 provide additional assurance that the levels of radioactive materials in bodies of water outside the site will result in exposure within: 1. the Section II.A design objectives of Reference 5 to an individual, and 2. the limits of 10 CFR 20.1301 to the population. In addition, the ODCM limit is associated with 40 CFR 141 which specifies concentration limits at the nearest downstream potable water supply.
TLCO	Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks contents, the resulting concentration of radioactive material released from the site will be less than or equal to 10 times the concentration values in 10 CFR 20, Appendix B, Table 2, Column 2 for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration shall be limited to the concentration specified in ODCM Table 12.3.1-1. In accordance with Technical Specification 5.5.9.b, an outside temporary tank is defined as any outside tank that is not surrounded by a liner, dike, or wall capable of holding the tank contents and that does not have tank overflows and surrounding area drains connected to the Liquid Waste Management System.
APPLICABILITY	The potential for having an uncontrolled release of the contents of outside temporary tanks exists at all times. Activities which could add radioactive material to an outside temporary tank are not dependent on the MODE of plant operation. Therefore, this TLCO is applicable even when fuel is not loaded into the core.
ACTIONS	A Note has been provided to modify the ACTIONS related to outside temporary liquid holdup tanks. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or

(continued)

BASES

ACTIONS (continued)

variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for outside temporary tanks provide appropriate compensatory measures for each tank having quantities of radioactive materials greater than the limit. As such, a Note has been provided that allows separate Condition entry for each tank.

A.1 and A.2

If it is determined that an outside temporary tank contains radioactive material in a quantity in excess of the limits specified in ODCM 12.3.1.A, further additions of radioactive liquid to the tank must be suspended immediately (Required Action A.1). Recirculating the tank contents to eliminate stratification or to obtain a more representative sample is not considered an addition of radioactive material to the tank. In addition, Required Action A.2 requires that the contents of the affected tank be reduced to within limits within 48 hours. This may be accomplished by diluting the tank contents or by processing the contents through a treatment system to remove the radioactive material from the process stream. Processing the tank contents through a treatment system and returning the stream to the tank is not considered adding radioactive material to the tank, even if the return stream still contains residual radioactive material.

The Completion Time of 48 hours to restore the activity level of the tank to within limits provides a reasonable time for the tank contents to be diluted or cleaned up using normal, temporary, or vendor supplied waste processing systems.

SURVEILLANCE REQUIREMENTS

TSR 3.7.d.1

This Surveillance is performed to ensure that radioactive material concentrations in outside temporary tanks remain within limits when radioactive liquids are being added to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.d.1 (continued)

the tank. The 7 day Frequency is adequate to trend changes in radionuclide content when material is being added to the tank. A second sample Frequency of once within 7 days following the completion of material addition to the tank is specified to ensure that the final quantity of radioactive material within the tank is known upon completion of the evolution.

To meet the TSR Frequency during addition of radioactive material to the tank, a sample of the tank contents must be taken within the last 7 days (plus the extension allowed by TSR 3.0.b) prior to the start of the addition. If the tank is empty prior to the start of the addition, a sample cannot be obtained and the TSR would be immediately not met upon commencement of the addition. To eliminate this conflict, the TSR is modified by a Note which allows the Surveillance to not be performed prior to the start of material addition to the tank provided the tank is empty at the beginning of the addition. Per the Note, the sample is not required to be taken until 7 days after the start of the addition to the empty tank. A tank is considered empty if the level of the tank is too low to obtain a dip or grab sample of the tank contents.

REFERENCES

1. UFSAR Section 11.2.
2. 10 CFR 50.34a.
3. 10 CFR 50.36a.
4. 10 CFR 20.
5. 10 CFR 50, Appendix I.
6. Technical Specifications 5.5.4 and 5.5.9.
7. Letter from R.R. Assa (NRC) to D.L. Farrar (ComEd), Issuance of Revised 10 CFR 20 Technical Specifications for LaSalle Unit 1 and Unit 2, December 30, 1993.
8. Offsite Dose Calculation Manual.

B 3.7 PLANT SYSTEMS

B 3.7.e Explosive Gas Mixture

BASES

BACKGROUND

Noncondensible off gas is continuously removed from the main condenser by the air ejector during plant operation. These noncondensible gasses consist of activation gasses such as N-16, noble gasses such as krypton from tramp uranium and small fuel cladding leaks, and hydrogen and oxygen from the radiolytic dissociation of water, chemical treatment of the reactor coolant, and air in-leakage. The off gas system is designed to treat these gasses to maintain concentrations within limits.

Hydrogen gas in concentrations of between 4% and 75% is explosive in the presence of oxygen. The off gas system components could be damaged if a hydrogen explosion were to occur within the system. To eliminate this potential hazard, the off gas system uses two methods to reduce hydrogen concentration in the off gas stream; steam dilution and catalytic recombination. The off gas system's catalytic recombiner is used to recombine radiolytically dissociated hydrogen and oxygen as well as excess hydrogen from the use of hydrogen water chemistry treatment.

When the Hydrogen Water Chemistry (HWC) control system is in operation, it injects hydrogen into the reactor coolant system, which reduces both radiolytic hydrogen and radiolytic oxygen to near zero. Ultimately, the excess hydrogen from the HWC system is removed by the off gas system. Because of the absence of radiolytic oxygen in the off gas stream, the HWC system adds oxygen in air to the stream to increase the effectiveness of the recombiner. Thus, the proper operation of the HWC system also helps ensure that off gas hydrogen concentration is maintained within limit.

APPLICABLE DESIGN BASES

The off gas system and HWC system are designed to maintain hydrogen below the lower explosive limit ($\leq$ 4% by volume) to eliminate the possibility of an explosion in the off gas treatment system. The hydrogen concentration of gasses from the air ejector is kept below the flammability

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	limit by maintaining adequate process steam flow for dilution. A catalytic recombiner further reduces the hydrogen concentration of the off gas to maintain the gas stream ≤ 4% by volume on a dry basis. The HWC system injects oxygen in air into the off gas stream, if necessary, to ensure effective recombination. The recombiner typically reduces hydrogen concentration of the off gas to < 1% by volume. Although the off gas system is designed to remain intact in the event of a hydrogen-oxygen detonation and is excluded as a possible failure mode in the UFSAR accident analyses (Ref. 2), Technical Specification 5.5.9 (Ref. 3) requires that controls be provided to ensure explosive gas mixture limits are maintained. These limits are required to be appropriate for the system design whether or not the system is designed to withstand a hydrogen explosion. This limit is specified in the UFSAR and enforced by this TLCO. The design of the Main Condenser Off Gas Treatment System and the Hydrogen Water Chemistry System meets the control requirements of Reference 3.
TLCO	The concentration of hydrogen in the Main Condenser Off Gas Treatment System must be maintained ≤ 4% by volume in order to reduce the probability of a hydrogen-oxygen detonation within the system. The limiting value of 4% by volume is based on the lower explosive limit (LEL) of hydrogen in dry air. This limit is conservative in the non-dry portions of the off gas system (i.e., from the discharge of the air ejector to the outlet of the off gas condenser) since the LEL of hydrogen in moist air is higher than 4% by volume. Thus, the limit ensures the absence of an explosive mixture throughout the entire off gas treatment system.
APPLICABILITY	The TLCO is applicable when noncondensibles from the main condenser are being removed during Main Condenser Air Ejector System operation. With the air ejector secured there is no motive force to draw hydrogen from the main condenser into the off gas system and the Requirement is not applicable.

(continued)

BASES (continued)

ACTIONS	A.1 When the hydrogen concentration of the off gas stream exceeds 4% by volume, action must be taken to reduce the concentration. The hydrogen concentration must be reduced to within the limit of the TLCO within 48 hours. The Completion Time of 48 hours provides sufficient time for the operator to take action (which may include swapping off gas treatment trains) in a controlled manner to reduce hydrogen concentration and is acceptable based on the fact that the off gas system is designed to contain a hydrogen-oxygen detonation.
SURVEILLANCE REQUIREMENTS	TSR 3.7.e.1 This Surveillance is performed to ensure that hydrogen concentration remains within limit during normal operations. The 24 hour Frequency is adequate to trend changes in the hydrogen concentration and takes into account indications available in the control room.
REFERENCES	1. UFSAR Section 11.3. 2. UFSAR Section 15.7. 3. Technical Specification 5.5.9.

B 3.7 PLANT SYSTEMS

B 3.7.f Sealed Source Contamination

BASES

BACKGROUND

Radioactive sources are used in a number of applications at the site including fire detection instrumentation, security explosimeters, and calibration of radiation detection equipment. Many of these sources are encased in a capsule or protective cover strong enough to prevent dispersion of the radioactive material to the outside environment. Sources constructed in this manner are termed “sealed sources”, and although they are a radiation hazard, they are designed so as not to be a contamination hazard. This TRM Requirement deals specifically with these types of sources.

Sealed sources may contain special nuclear material, source material, or byproduct material as defined by 10 CFR 30 (Ref. 2). 10 CFR 30 also delineates the requirements for the licensing of sealed sources. Sealed sources with very low concentrations of radioactive material are exempt from the requirements of Reference 2.

Damage to a sealed source can result in the undesired spread of contamination. For this reason, sealed sources are periodically tested for leakage and external contamination. 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 (e.g., sealed sources within radiation monitoring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism

APPLICABLE DESIGN BASES

The Nuclear Regulatory Commission (NRC) requires, with certain exceptions, that during use, sealed sources be tested periodically for possible leakage of radioactive material at intervals not to exceed six months. The NRC does not require periodic leak testing of in use sealed

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	sources if the source contains only; 1) hydrogen-3, 2) radioactive material with a half-life of less than 30 days, 3) radioactive material in the form of gas, 4) less than 100 microcuries (μCi) of beta or gamma emitting material, or 5) less than 5 μCi of alpha emitting material. 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 conservative limitation ensures that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Unsealed sources are exempt from this Requirement because, by virtue of the way they are constructed, radioactive material can spread beyond the source. To ensure that these sources do not pose a contamination risk, their handling is administratively controlled and their containers, as well as any surfaces on which they are used, are periodically surveyed for contamination.
TLCO	To ensure that an undesirable spread of contamination from a damaged source does not occur, sealed sources containing greater than 100 μCi of beta and/or gamma emitting material, or greater than 5 μCi of alpha emitting material, must be verified to have less than 0.005 μCi of removable contamination when tested in accordance with their applicable Surveillance Requirements. Sealed source means any radioactive material to be used as a source of radiation which has been constructed in such a manner as to prevent the escape, under normal conditions, of the radioactive material.
APPLICABILITY	The potential for damage to a sealed source and the unplanned release of the radioactive material housed within the capsule or container exists at all times. Sealed sources are used in applications, such as calibration of instruments, which are independent of reactor operations. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to Sealed Source Contamination. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for contaminated sealed sources provide appropriate compensatory measures for each separate contaminated source. As such, a Note has been provided that allows separate Condition entry for each source.

A.1, A.2.1, A.2.2, and A.3

Whenever a sealed source is discovered to have $\geq$ 0.005 μCi of removable contamination it must be immediately withdrawn from use to minimize the spread of the contamination. Action must also be initiated to either decontaminate and repair the source (Required Action A.2.1) or dispose of the source in accordance with NRC regulations (Required Action A.2.2). 10 CFR 20.2001 delineates the requirements for disposal of radioactive material. Any State and Local requirements for the transport and disposal of radioactive material must likewise be followed. It should be emphasized that the need for disposing of or restoring the integrity of the source is important in preventing the inadvertent spread of contamination. Good radiological practices dictate that repair or disposal efforts continue even after the TLCO is met following decontamination of the affected source.

In addition to the above actions, a Corrective Action Program (CAP) report must be initiated per Required Action A.3 upon discovery of a contaminated sealed source. The CAP report should describe the cause of the contamination and the plan for decontaminating, repairing, or disposing of the source.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The four TSRs of this TLCO are modified by two Notes. The first Note states that sealed sources which are continuously enclosed within a shielded mechanism need not be tested unless they are removed from the mechanism. For the purposes of the TSRs, these sources are considered to be stored. This is acceptable since the probability of damage to one of these sources is extremely low due to the extra protection provided by the shielded mechanism. An example of this type of source is the Ni-63 source located in some security explosimeters. Note 2 to the TSRs excludes startup sources and fission detectors from the testing requirements the TSRs if they have been previously subjected to a core flux. This exception is provided to maintain personnel dose as low as reasonably achievable (ALARA) and is acceptable based on the administrative controls in place for storing and handling irradiated startup sources and fission detectors.

Each sealed source tested in accordance with these TSRs must be tested by either the licensee or by persons specifically authorized by the NRC or an Agreement State.

TSR 3.7.f.1

Sealed sources which are in use must be tested for leakage and contamination to verify the source is undamaged. Sealed sources containing radioactive material with half-lives $\leq$ 30 days (excluding hydrogen-3) and sources containing only gaseous radioactive material are exempt from this TSR. This exception is consistent with NRC requirements. The test method must have a detection sensitivity of at least 0.005 μCi per test sample.

The Frequency of 184 days is based on the original licensing basis for sealed source contamination and is consistent with NRC requirements.

TSR 3.7.f.2

Sealed sources and fission detectors which are stored must be tested for leakage and contamination to verify the source is undamaged prior to placing it in use or transferring it to another licensee. The test method

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.f.2 (continued)

must have a detection sensitivity of at least 0.005 μCi per test sample.

As noted in the TSR, the source or detector is only required to be tested if it has not been tested within the previous 184 days. This is consistent with NRC requirements and also ensures that TSR 3.7.f.1 will be met when a sealed source is placed into use.

TSR 3.7.f.3

Sealed sources and fission detectors which are stored must be tested for leakage and contamination to verify the source is undamaged prior to placing it in use if it has been transferred without a certificate indicating the last test date. The testing may be performed at any time after receipt of the source or detector but prior to its use. Once tested in accordance with this TSR, further testing of the stored source or detector is conducted in accordance with TSR 3.7.f.2. The test method must have a detection sensitivity of at least 0.005 μCi per test sample.

TSR 3.7.f.4

Sealed startup sources and fission detectors must be tested for leakage and contamination to verify the source is undamaged prior to use which will subject it to a core flux and also following any repair or maintenance to the source or detector. This TSR ensures that startup sources and fission detector are intact prior to irradiation which will prevent further testing of their integrity. Additionally, the TSR ensures that maintenance performed on the source or detector did not result in a breach of the structural integrity of the source or detector. The Frequency of 31 days prior to core flux irradiation or installation in the core and 31 days following maintenance or repairs is based on the original licensing basis for sealed source contamination.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 20.
2. 10 CFR 30.
3. 10 CFR 70.39.
4. Regulatory Guide 10.11, “Guidance for the Preparation of Applications for Radiation Safety Evaluation and Registration of Sealed Sources Containing Byproduct Material.”
5. ANSI N542-1977.
6. Memo from M. Rumick to G. Powell/A. Schnapp, “Exemption from Leak Testing of Smoke Detectors and Devices Containing Tritium,” June 29, 1995.
7. Memo from T.J. Kovach, “NSHP Recommendations on Inventory and Leak Testing of Sources,” October 18, 1985.

B 3.7 PLANT SYSTEMS

B 3.7.g Area Temperature Monitoring

BASES

BACKGROUND

10 CFR 50, Appendix A, General Design Criterion (GDC) 4 requires that structures, systems, and components (SSCs) important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents (LOCAs). Additionally, 10 CFR 50.49 (Ref. 3) requires that a program be established for the environmental qualification (EQ) of this equipment. The station's EQ Program implements these requirements.

Under the EQ Program, plant areas containing safety-related electrical equipment are divided into three types of zones based on the environmental conditions that occur within these areas as a result of various plant events. These zone classifications are the harsh environment, normal environment, and controlled environment. Harsh environments are defined as those areas of the plant which experience environmental conditions resulting from a postulated LOCA inside containment, a high-energy line break (HELB), or an instrument line break outside containment. Normal environments are those areas in the auxiliary building maintained at room, or ambient outdoor conditions by a non-safety-related HVAC system during routine plant operations. Abnormal conditions may occur in some of these areas due to loss of the HVAC system. Controlled environments are defined as those areas of the plant housing safety-related equipment and served by redundant safety-related HVAC systems or those areas where the safety-related equipment is redundant and each redundant part is served by a separate safety-related HVAC system that maintains the temperature and humidity in accordance with the equipment operating requirements.

Each of these zones experiences normal service conditions and may experience accident or abnormal environmental conditions. Normal service conditions are defined as those that exist during routine plant operations and along

(continued)

BASES

BACKGROUND (continued)	with the zone in which they are located, form the basis for the EQ service life of components that fall under the requirements of Reference 3. These normal service conditions extend over a range of values which can be expected to occur at various times during the operating life of the plant.
APPLICABLE DESIGN BASES	Regulatory Guide 1.89 describes the method for complying with the regulations with regard to design verification (i.e., qualification) of Class IE equipment for service in light-water-cooled nuclear power plants. The requirements delineated include principles, procedures, and methods of qualification which confirm the adequacy of the equipment design for the performance of Class IE functions under normal, abnormal, design-basis-event, post-design-basis-event, and containment-test conditions. Environmental qualification testing of instrumentation, control, and electrical equipment important to safety at the station meets the requirements of Reference 6 which is an accepted standard in Regulatory Guide 1.89. To ensure that the assumptions used to determine the EQ service life of components, in conjunction with this testing, remain valid, the normal service conditions in the affected areas must be monitored. This Requirement provides this assurance. The normal service environmental conditions identified in Table T3.7.g-1 are the expected minimum/maximum ambient temperature conditions that may occur in these areas during normal plant operations. A more refined or more detailed analysis may be performed for specific components or groups of components to establish more realistic environmental limitations than the expected limits specified in the Table. Therefore, the temperature limits specified in Table T3.7.g-1 do not represent the OPERABILITY limits for equipment in that area, but rather, represent the point at which the continued OPERABILITY of equipment must be reverified by analysis since the bounding assumptions of the original analysis may have been exceeded. Typically, it is expected that the analysis will determine that the affected equipment remains OPERABLE, however, its EQ service life may have

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	been shortened if the ambient temperature exceeds the upper limit. The lower temperature limit does not affect the EQ service life of affected components, but rather, ensures that equipment is operating within its design limits. Equipment operating in ambient conditions lower than the limit specified in the Table should be evaluated to ensure that the component can operate satisfactorily under the existing environmental conditions.
TLCO	The area temperature limitations in Table T3.7.g-1 ensure that safety-related equipment will not be subjected to continuous temperatures in excess of the assumptions made in their environmental qualification. Prolonged exposure to temperature extremes may degrade equipment and eventually lead to a loss of OPERABILITY. Therefore, to ensure these assumptions remain valid, the temperature limits of the Table must not be exceeded by more than 30°F or for a period in excess of 8 hours.
APPLICABILITY	Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be able to perform their required functions under the environmental conditions that may be present during the event. Therefore, Area Temperature Monitoring limits are applicable whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and monitoring of temperature in the area is not required.
ACTIONS	A Note has been provided to modify the ACTIONS related to Area Temperature Monitoring. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions

(continued)

BASES

ACTIONS (continued)

for excessive temperature in plant areas provide appropriate compensatory measures for each separate area experiencing elevated temperatures. As such, a Note has been provided that allows separate Condition entry for each area. For the purposes of this Note, an area consists of a single contiguous space which experiences approximately the same temperature throughout the space. For example, area A.5 of Table T3.7.g-1 may be considered to be four separate areas since each corner room can experience significantly different environmental conditions based on equipment status and configuration.

A.1, A.2, and A.3

Operation with an area temperature in excess of 30°F beyond the limits specified in Table T3.7.g-1 must be corrected so that the affected components' environment is returned to a condition that has been verified by analysis. The 4 hour Completion Time reflects the sense of urgency of restoring the temperature to within the analyzed range. This is necessary because temperatures in excess of 30°F beyond the analyzed range for an extended period of time can have a significant impact on the EQ service life of affected components resulting in premature failure or failure under accident conditions. The impact of less severe violations (i.e., temperatures beyond the range by ≤ 30°F for ≤ 8 hours) are considerably smaller and are evaluated under the station's normal EQ evaluation program.

Condition A is modified by a Note requiring Required Actions A.1, A.2 and A.3 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the analysis of the effects of the excursion outside the allowable limits, to document the problem to determine appropriate corrective actions, and to restore temperature to the analyzed range. Restoration of temperature to ≤ 30°F beyond the allowable range alone is insufficient because higher than analyzed thermal stresses may have occurred and may have had a significant effect on component EQ service life.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Operation outside the area temperature limits for a period of > 8 hours should be corrected so that the affected components' environment is returned to a condition that has been verified by analysis. However, most violations will not be severe and the impact on component EQ service life will be small. Therefore, the Required Actions require immediate preparation of a report in accordance with the station's Corrective Action Program (CAP) and performance of an analysis to demonstrate the continued OPERABILITY of equipment in the affected area within 30 days. The CAP document should outline the cause of the temperature limit violation and the plans for restoring the temperature to within limits. The analysis shall determine the effect of the temperature excursion on the component(s), the basis for its continued OPERABILITY, and any actions (which may include component replacement) necessary to confirm the components' OPERABILITY. The 30 day Completion Time provides an appropriate period of time to complete the analysis and is consistent with the original licensing basis reporting requirements for area temperature violations.

Condition B is modified by a Note requiring Required Actions B.1 and B.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the analysis of the effects of the excursion outside the allowable limits and to document the problem to determine appropriate corrective actions. Restoration of area temperature alone is insufficient because higher than analyzed thermal stresses may have occurred and may have had an effect on component EQ service life.

SURVEILLANCE REQUIREMENTS

TSR 3.7.g.1

Verification of area temperatures ensures that the required limits are satisfied. The 24 hour Frequency has been shown to be acceptable based on operating experience. Furthermore, the 24 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal area temperature or a degradation of area HVAC equipment.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 3.11.
2. 10 CFR 50, Appendix A, GDC 4.
3. 10 CFR 50.49.
4. Regulatory Guide 1.89, “Qualification of Class IE Equipment for Nuclear Power Plants.”
5. NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment.”
6. IEEE-323-1974.

B 3.7 PLANT SYSTEMS

B 3.7.h Structural Integrity of Class I Structures

BASES

BACKGROUND

Initial construction of the structures, systems, and components of the plant, including where the facility is sited, was done in accordance with GDC 2 and 10 CFR 100 (Ref. 4 and 5). Reference 4 requires that safety-related portions of systems be designed to withstand the effects of natural phenomena without a loss of capability to perform their safety functions. To protect these systems against external hazards such as earthquakes, tornadoes, and hurricanes, the structures surrounding safety related systems were built and designed to meet Class I, Seismic Category I requirements.

The reactor siting criteria of 10 CFR 100 (Ref. 5) requires the consideration of the geologic characteristics of the proposed site, such that, there is reasonable assurance that the nuclear power plant can be operated at the proposed site without undue risk to the health and safety of the public. To accomplish this, detailed studies of the subsurface soil were made during initial construction to evaluate the performance of Class I structural foundations and their underlying earthworks over their anticipated loading conditions during the life of the plant.

Maintaining the integrity of the Class I structures at the station is important to the continued safe operation of the facility. To help assure this integrity, a subsurface monitoring program has been established to ensure that the assumptions which were made concerning the stability of Class I structural foundations remain valid. The subsurface instrumentation used at the station consists of settlement monuments located in the main plant area and the lake screen house. The monuments, which are simply points of known elevation on existing structures, typically consist of a scribe mark at the top of a column base plate or an "X" marked in a concrete floor or wall slab. Settling of Class I structures is determined by measuring the elevation of these monuments using first-order surveying techniques from benchmarks

(continued)

BASES

BACKGROUND (continued)	not affected by station loading. A total of 10 settlement monuments are located throughout the various plant structures. Settlement monuments are also provided on the cooling lake dike to monitor the vertical movement of the soil mass in the dike.
APPLICABLE DESIGN BASES	Geotechnical parameters are used in analyzing the design of Class I structure foundations and underlying earthworks. Geotechnical parameters needed for this analysis include, but are not limited to, those used to evaluate the bearing capacity of foundation materials, lateral earth pressures against walls, the stability of cuts and slopes in soil and rock, and those needed to estimate the expected settlement of structures. Reference 7 requires plans for continued geological monitoring after initial construction to detect occurrences that could detrimentally affect the facility. These occurrences could be produced by the presence of local adverse anomalies or discontinuities such as cavities, sinkholes, fissures, faults, brecciation, and lenses or pockets of unsuitable material, not detected during the initial site survey. These occurrences could result in unacceptable settlement of structures causing reductions in their structural integrity, consequently resulting in degradation of the ability of safety systems to perform their design function. In order to assure that settlement does not exceed predicted and allowable settlement values, a program has been established to conduct a survey of the site. Historical plant settlement readings indicate that all the main plant structures have stabilized. Therefore, the limits established in the settlement monitoring program are based solely on changes in settlement values between successive measurements. This allowable settlement value is based on the original settlement predictions. In establishing this value, an assumption is made that systems and components within these structures have been designed to withstand the stresses which would develop due to predicted total and differential settlement.

(continued)

BASES (continued)

TLCO	The integrity of Class I structures must be maintained to ensure that safety related systems housed within these structures will be able to perform their specified safety function under all postulated conditions. The integrity of these structures is assured by verifying that foundation settlement is within limits and by assuring that construction and future modifications to these structures meets the applicable code requirements for Class I structures. The structures applicable to this TLCO are the Seismic Category I structures listed in Table 3.2-1 of the USFAR (Ref. 3). This includes the Lake Screen House since the concrete portions of this building contain Category I safety systems and is designed to withstand Seismic Category I loads. Several Seismic Category II structures listed in Reference 3 contain Class I structural components. The shear walls for the Turbine, Radwaste, and Off-gas Filter buildings are interconnected with the shear walls in the Reactor, Diesel Generator, and Auxiliary buildings. All of these sheer walls are considered to act together to resist lateral loads applied to these buildings. Therefore, the sheer walls for these building are Seismic Category I and are also applicable to this TLCO. If the structural integrity of a Class I structure applicable to this Requirement is compromised, the OPERABILITY of safety systems housed within or supported by the affected structure should be evaluated.
APPLICABILITY	The need for a safety system to perform its specified function can occur at anytime; consequently, the Class I structures supporting and protecting these systems are required at all times. For example, fuel handling in the spent fuel pool could occur during performance of fuel reconstitution work after a full core offload. During this evolution, several safety systems including the Standby Gas Treatment and Control Room Area Filtration systems are required to be OPERABLE by Technical Specifications. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A.1

If the settlement of a Class I structure exceeds 0.01 feet since the previous reading, then the structural integrity of the structure may be in jeopardy. Therefore, action must be immediately initiated to prepare a Corrective Action Program (CAP) report to resolve the unexpected settlement. The CAP report must outline the cause of the excessive settlement, the action that will be taken, and the plans and schedule for restoring the integrity of the affected Class I structure.

Condition A only provides remedial action for the excessive settlement of Class I structures; therefore, if the structural integrity of a Class I structure is compromised for any other reason, TLCO 3.0.c must be entered immediately.

SURVEILLANCE REQUIREMENTS

TSR 3.7.h.1

The total settlement of each Class I structure and the differential settlement between Class I structure must be determined by measurement and calculation to the nearest 0.01 foot every 24 months. To ensure that all required Class I structures are monitored, the following points must be surveyed:

- AB2; Inside of Auxiliary Building to Unit 2 Reactor Building Airlock, 710’ at column J-17,
- RB1; Unit 1 Reactor Building 710’ on 300° containment tendon buttress,
- RB2; Unit 2 Reactor Building 710’ on 60° containment tendon buttress,
- OG1; Filter Removal Area of the Off-gas Filter Building 710’ at column AD-12, and

either;
- TB1; Turbine Building 710’ at column V-2, or
- TB2; Turbine Building 710’ at column S-16, and

either;
- NE Lake Screen House; at column A-7, or
- SE Lake Screen House; at column A-1, or
- SE of Lake Screen house on the wing wall.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.h.1 (continued)

Each of the points surveyed must be verified to be within the limit of $\leq$ 0.01 feet from the previous reading as specified in the settlement monitoring program.

The Frequency of 24 months is acceptable based on historical data which shows that the main plant structures have stabilized and the low probability of a subsurface event (e.g., soil liquefaction, ground subsidence, etc.) that could result in unacceptable settling of structures. However, a reading in excess of 0.01 feet from the previous reading indicates unexpected structure settlement and, in this event, the Frequency is increased to 31 days until the structure has stabilized (i.e., a subsequent reading is $\leq$ 0.01 feet from the previous reading).

TSR 3.7.h.2

If excessive settlement is detected during the performance of TSR 3.7.h.1, then evaluations and corrective actions are taken in accordance with Condition A to restore foundation stability. To assure that plant safety is maintained, a report outlining the results of actions taken, including settlement and differential settlement plots versus time and comparison of allowable and actual settlement readings, must be submitted to the Plant Operations Review Committee (PORC) within 24 months of observing excessive settlement. The PORC will review this report to determine if the margin of plant safety is being appropriately maintained. Reports must be submitted to the PORC every 24 months until it has been determined that the affected structure has stabilized (i.e., a subsequent reading is $\leq$ 0.01 feet from the previous reading). At least one report required by this TSR must be submitted after settlement has been determined to have stabilized.

(continued)

BASES (continued)

REFERENCES

1. UFSAR Section 2.5.4.10.1.2.
2. UFSAR Section 2.5.4.13.
3. UFSAR Table 3.2-1.
4. 10 CFR 50, Appendix A, GDC 2.
5. 10 CFR 100.23.
6. Regulatory Guide 1.132.
7. NUREG 0800, Standard Review Plan, Section 2.5.5.

B 3.7 PLANT SYSTEMS

B 3.7.i Snubbers

BASES

BACKGROUND

Nuclear power plant components and supports are subjected to combinations of loadings derived from plant and system operating conditions, natural phenomena, postulated plant events, and site related hazards. Section III of the American Society of Mechanical Engineers (ASME) Code provides specific sets of design and service stress limits that apply to the pressure retaining or structural integrity of components and supports when subjected to these loadings.

Load-bearing members classified as component supports are essential to safety since they retain components in place during the loadings associated with normal and upset plant conditions under the stress of specified seismic events, thereby permitting system components to function properly. They also prevent excessive component movement during the loadings associated with emergency and faulted plant conditions combined with the specified seismic event, thus helping to mitigate the consequences of system damage. Eight different types of component supports are utilized at the station; rigid supports, variable spring supports, constant supports, snubbers, struts, guides, anchors, and pipe whip restraints. This Requirement deals specifically with snubbers.

When piping systems were initially designed, snubber locations were selected based on the routing of the system and physical considerations. The piping system was then analyzed and the results reviewed to determine if the snubber locations selected were satisfactory. If the dynamic analysis of the system showed that the piping was overstressed or equipment loads were above allowables, then snubbers were added and existing snubber locations altered as necessary. Another analysis was made to verify the new dynamic support arrangement. If the piping or equipment loads were still above the allowables, the process was repeated until all stresses and loads were acceptable. The snubber loads were then used to select the snubber size and the design drawings and specifications made.

(continued)

BASES

BACKGROUND (continued)

To the extent possible, adequate provisions were made in locating the snubbers for accessibility for inspection, testing, and repair or replacement. Specific criteria were not employed beyond those normally employed for equipment accessibility. Good engineering practice and piping arrangement experience established the accessibility requirements for the snubbers.

APPLICABLE DESIGN BASES

The specific design and service loading conbinations used for the design of supports in safety-related systems provides assurance that, in the event of an earthquake or other service loadings due to postulated events or system operating transients, the resulting combined stresses imposed on system components will not exceed allowable stress and strain limits for the materials of construction. Limiting stresses under such loading combinations provides a conservative basis for the design of support components to withstand the most adverse combination of loading events without loss of structural integrity or supported component OPERABILITY.

Piping systems at LaSalle Station are designed to three basic allowable limits depending on the probability of the applied loading. These limits are normal, upset, and faulted. Normal loads are those that piping systems are expected to be subject to during day-to-day operation, such as weight, pressure, and normal thermal expansion. Upset loads are those loads that are considered occasional or infrequent loads, that the piping system is expected to withstand during its service lifetime without requiring repair, such as water hammer, relief valve discharge, or operational basis earthquake (OBE). Faulted loads are those associated with the most extreme and lowest probability events such as loss of coolant accidents, and safe shutdown earthquake (SSE). Faulted limits have been established to allow significant damage and deformation to the piping and pipe support without a loss of intended safety function. There is a fourth category set of limits applicable to LaSalle Station known as OPERABILITY or functional limits. Functional limits are, as the name implies, limits that ensure reasonable assurance that the

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	systems intended function will be able to be performed under any set of design basis loading. These values vary on the pipe material type and temperature. However, the relative values are nearly constant, that is, functional limits are always approximately twice faulted limits (i.e., the system will remain functional when subjected to double the assumed faulted stress). The original design of the piping systems is very conservative and generally contains large margins below design allowable limits. The method used when the piping systems were originally designed was crude and inefficient when compared to today's standards. After the completion of the original design of the LaSalle piping systems, there was a snubber reduction program initiated at the station. Many snubbers were consequently removed, but the effort still resulted in piping systems with ample margin in the Code allowable stresses. Also, beyond the conservatisms described above, the LaSalle seismic analyses used to generate the plant seismic curves was crude and very conservative (i.e., circa 1968-69). Therefore, although snubbers are needed to maintain the OPERABILITY of the systems they support, there is substantial margin to OPERABILITY limits and an evaluation of the effects of a loss of one or more snubbers may demonstrate that the supported system remains capable of performing its specified safety function. The design of snubbers applicable to this Requirement satisfies the relevant portions of General Design Criterion 1, 2, and 4 of Appendix A to 10 CFR 50.
TLCO	Snubbers are required to be 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 event or other event initiating dynamic loads. All safety-related snubbers are required snubbers for this TLCO. Additionally, snubbers installed on non-safety-related systems are required snubbers for this TLCO if their failure, or failure of the system on which they are installed, would have an adverse effect on any safety-related system.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, this TLCO applies since safety-related systems supported by snubbers are required to mitigate the consequences of a design basis accident to protect the reactor core and prevent the release of radioactive material to the environment. In MODES 4 and 5, only selected safety-related systems are necessary to ensure adequate coolant inventory and sufficient heat removal capability, or to mitigate the effects of a fuel handling accident. Therefore, only snubbers on systems required to be OPERABLE in MODES 4 and 5 are required to be OPERABLE in these MODES.
ACTIONS	A Note has been provided to modify the ACTIONS related to snubbers. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable snubbers provide appropriate compensatory measures for separate, inoperable snubbers. As such, a Note has been provided that allows separate Condition entry for each inoperable snubber. A second Note has been added to ensure that appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable snubber. As a result of the snubber reduction program effort to remove unnecessary snubbers from piping systems, it is highly unlikely that a piping system would meet design code allowable limits if a snubber were removed from an OPERABLE system. However, an evaluation using the criteria in Section III, Appendix F of the ASME Code, based on historical evaluations, demonstrated that a failed snubber would not impact the ability of the parent system to perform its specified safety function. Therefore, per Reference 7, a single failed or removed snubber does not render the associated piping system inoperable. If a system is discovered to have more than one inoperable snubber, the system should be considered inoperable until an engineering evaluation to determine system OPERABILITY is performed.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

With one or more required snubbers inoperable, the ability of the affected piping system(s) to withstand dynamic loadings due to seismic events or system operating conditions is degraded. The inoperable snubber must be replaced or restored to OPERABLE within 72 hours (Required Action A.1). Required Action A.2 requires an engineering evaluation be performed on the attached component to determine if the component is acceptable for continued operation. The Completion Time of 72 hours is based on the original licensing basis for snubbers and is considered acceptable based on the amount of time required to restore snubber OPERABILITY and perform the required engineering evaluation.

Condition A is modified by a Note requiring Required Action A.2 to be completed when the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the failed snubber on the piping system. Restoration alone per Required Action A.1 is insufficient because excessive stresses on the attached piping or components may have occurred, affecting their ability to meet their designed service. The Note is only applicable when the Condition is entered due to a functional failure of a snubber since a functional inoperability could result in excessive component and piping stresses that must be evaluated. Snubbers inoperable for other reasons would not result in excessive stresses. For example, if a snubber was made inoperable due to removal for testing and the testing determined it to be functioning properly, no excessive stresses would be suspected and an engineering evaluation would not be required.

B.1

If the Required Action and associated Completion Time of Condition A is not met, the components and piping supported by the inoperable snubber remain susceptible to experiencing increased stress. In this case, the attached system must be conservatively declared inoperable until the required system snubber(s) are restored OPERABLE or the engineering evaluation of Required Action A.2 confirms the continued OPERABILITY of the system.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.7.i.1

Maintaining snubbers OPERABLE requires compliance with the testing requirements of the Augmented Inservice Inspection Program of TRM 5.0.d. Permanent or other exemptions from the surveillance program may be granted by the Nuclear Regulatory Commission if a justifiable basis for exemption is presented, and, if applicable, snubber life destructive testing was performed to qualify the snubber for the applicable design conditions at either the completion of their fabrication or at a subsequent date. The required Frequency is specified by the Augmented Inservice Inspection Program.

REFERENCES

1. UFSAR Section 3.9.3.4.
2. FSAR Question and Answer 111.38.
3. 10 CFR 50, Appendix A.
4. NUREG-0800, Standard Review Plan, Section 3.9.3.
5. ASME Code, Section III, Appendix F.
6. ASME OM Code, Appendix A, Subsection ISTD, “Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants,” 1999 Addenda.
7. Engineering Change 334581, “TRM 3.7.i 72 Hour Provision Acceptability Evaluation.”
8. Letter to J. Rommel from R. Hall, “Position on System Operability for Snubber Testing,” dated December 19, 2001.

B 3.7 PLANT SYSTEMS

B 3.7.j Fire Suppression Water System

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety-related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety-related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment.

The fire protection water distribution system is capable of supplying cooling lake water to the plant fire hydrants, the water sprinkler and deluge systems, and the hose valve stations under all conditions. The system is normally kept pressurized by one of two fire protection jockey pumps. Each pump has a 75 gpm capacity. They are only used for system pressurization. If a system demand occurs, the intermediate pump is automatically activated. This pump has a 225 GPM capacity. If the system demand exceeds the capacity of this pump, the pressure decreases in the fire protection system, thereby automatically

(continued)

BASES

BACKGROUND (continued)	starting a diesel fire pump. If system demand is in excess of the capability of a single fire pump or if there is a pump failure, the second fire pump will engage automatically. Each fire pump has a capacity of 2500 gpm. The fire hydrant system is supplied by separate header connections to each of the two fire pumps. The system consists of a 14-inch ring header surrounding the main plant buildings with strategic placement of the fire hydrants, located no more than 250 feet apart. The common yard loop is sectionalized, permitting independence of each unit if desired. The underground piping consists of welded carbon steel piping buried below the frost line. The lateral to each hydrant can be isolated by a key-operated valve, and a section of the loop can be isolated by a post-indicating valve. Multiple headers from the outside fire loop are brought into the building complex to feed the standpipe, deluge, and sprinkler systems. The fire hose stations, deluge systems, and sprinkler systems associated with the fire suppression water system are discussed in the Bases of TLCO 3.7.k, “Deluge and Sprinkler Systems,” and TLCO 3.7.m, “Fire Hose Stations.”
APPLICABLE DESIGN BASES	The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Fire Suppression Water System is an integral part of the FPP.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

The concept of defense-in-depth is used in safety-related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Fire Suppression Water System provides a means to suppress and extinguish fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions, with or without offsite power.

The fire pumps take suction from the seismically designed Core Standby Cooling Water System (CSCS) tunnel in the lake screen house. This tunnel has multiple intakes from the cooling lake; however, a failure in the fire protection system cannot affect the ultimate heat sink. Both diesel-driven fire pumps are located in the lake screen house and take suction directly from the water tunnel. The diesel-driven fire pumps are located at opposite ends of the lake screen house in rooms enclosed by 3-hour fire enclosures and are protected by automatic sprinkler systems which alarm in the control room upon actuation. As a backup to the diesel driven fire pumps, water can be supplied from the service water system.

A single failure of a fire pump in the fire protection system does not prevent the system from performing its design function. Two fire pumps are provided with one being sufficient for any plausible demand. If one pump fails to start, the other pump starts and provides water to the fire protection system. The plant is encircled by a 14-inch ring header

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	which feeds the fire protection system inside the station. If a pipe rupture occurs, the affected portion of piping can be isolated and water can still be supplied. The fire protection system forms several loops in the plant, permitting portions of the system to be valved-out, thereby assuring continued water supply for the balance of the station. This installation conforms to National Fire Protection Association (NFPA) Standard 24, "Standard for Outside Protection." The sizing basis for the diesel driven fire pumps is in accordance with Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards, which assume one pump out of service, a break in the shortest pipe run, the largest sprinkler system operating, and an additional 500 gpm for fire hoses. Following an automatic start, the diesel engine can be shut down only by the local control panel pushbutton or by the emergency shutdown devices which operate only to prevent destruction of the engine. This installation conforms to NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." Additionally, the threads on all fire protection equipment are compatible with the local fire department equipment. The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire. The Fire Suppression Water System is designed to meet the requirements of GDC 3 and NFPA Standards. Additionally, the Fire Suppression Water System is not assumed in any accident or transient analyses of the UFSAR.
TLCO	The OPERABILITY of the Fire Suppression Water System ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located.

(continued)

BASES

TLCO (continued)

The Fire Suppression Water System is considered OPERABLE when:

a. Two diesel driven fire pumps, each with a 2500 gpm capacity, with their discharge aligned to the fire suppression header, are OPERABLE; and

b. An OPERABLE flowpath is capable of taking water from the CSCS water tunnel and transferring water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves and the last valve ahead of; the water flow alarm device on each sprinkler, the deluge valve on each deluge or spray system, and each hose standpipe required to be OPERABLE by TLCO 3.7.k and TLCO 3.7.m.

Portions of the Fire Suppression Water System are shared between Unit 1 and Unit 2; therefore, a failure to meet the TLCO may result in both Units entering into the applicable Conditions and Required Actions for the inoperable component.

APPLICABILITY

The potential for a fire exists at all times. For example, a fire could occur while moving irradiated fuel in the secondary containment with the core fully offloaded. Therefore, this TLCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1

Required Action A.1 is intended to handle the inoperability of one diesel driven fire pump or one Fire Suppression Water System water supply. A Completion Time of 7 days is allowed to restore the pump or water supply to OPERABLE status. With the plant in this condition, the remaining OPERABLE pump and water supply are adequate to perform the fire protection function; however, the overall reliability of the system is reduced. The Completion Time is based on the original licensing basis for the Fire Suppression Water System and takes into account the redundant water supply capability and the low probability of a fire occurring during this period.

(continued)

BASES

ACTIONS

A.1 (continued)

Alternatively, if the Fire Suppression Water System cannot be restored to OPERABLE status within the specified Completion Time, plant operation may continue provided a report is prepared in accordance with the station's Corrective Action Program (CAP) (Required Action A.2). The CAP document shall outline the cause of the inoperability and the plans for restoring the pump or water supply to OPERABLE status. The 7 day Completion Time provides an appropriate period of time to develop the recovery plan and ensures that a degradation of the Fire Suppression Water System for a period greater than 7 days due to a loss of one pump or water supply has been evaluated.

Condition A is not appropriate if certain portions of the distribution piping becomes inoperable since the 14-inch ring header, including the branch feeds into the buildings, are common to both water supplies. In these situations, Condition B should be entered and its Required Action taken.

B.1

In the event the Fire Suppression Water System becomes inoperable, prompt corrective measures must be taken since the system provides the major fire suppression capability of the plant. Thus, whenever portions of the system become inoperable for reasons other than Condition A (e.g., two inoperable water supplies or portions of the common distribution piping inoperable), a backup suppression water supply must be established within 24 hours. The backup protection should provide an equivalent level of fire suppression capability to the affected portions of the system. For example, if Condition B was entered due to a loss of both diesel driven fire pumps, station Service Water would normally be aligned in accordance with operating instructions as the backup water supply since it is capable of providing equivalent suppression capability. The 24 hour Completion Time is based on the original licensing basis of the Fire Suppression Water System.

(continued)

BASES

ACTIONS

B.1 (continued)

A Note has been provided in Condition B related to Fire Suppression Water System components. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Fire Suppression Water System components provide appropriate compensatory measures for separate inoperabilities. As such, a Note has been provided that allows separate Condition entry for each discovery of a Fire Suppression Water System inoperability.

C.1

If the Required Action and associated Completion Time of Condition B are not met, the affected unit(s) must be placed in a MODE which lowers the consequences of a fire. To achieve this status, the unit(s) must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.1

This TSR, along with TSR 3.7.j.2, verifies that the diesel driven fire pump battery cell parameters are consistent with IEEE-450 (Ref. 8), which recommends regular battery inspections (at least one per month) including specific gravity and electrolyte level of pilot cells. The cells selected as pilot cells are those whose electrolyte specific gravity approximate the state of charge of the entire battery. The limit specified for electrolyte level (i.e., above the plates) is based on manufacturers recommendations and is consistent with the guidance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.1 (continued)

in IEEE-450. This limit ensures that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. Reference 8 recommends that electrolyte level readings should be made only with the battery on float charge.

TSR 3.7.j.2

This TSR, along with TSR 3.7.j.1, verifies that the diesel driven fire pump battery cell parameters are consistent with IEEE-450 (Ref. 8), which recommends regular battery inspections (at least one per month) including specific gravity and electrolyte level of pilot cells. The cells selected as pilot cells are those whose electrolyte specific gravity approximate the state of charge of the entire battery. The limit specified for specific gravity for each pilot cell is $\geq$ 1.200. This value is characteristic of a charged cell with adequate capacity. According to IEEE-450, the specific gravity readings are based on a temperature of 77°F (25°C). The specific gravity readings are corrected for actual electrolyte temperature. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation; however, in accordance with Reference 8, level correction is not required for the diesel driven fire pump batteries.

TSR 3.7.j.3

Verifying battery terminal voltage helps to ensure the batteries are capable of performing their intended function. The voltage requirements are based on the nominal design voltage of the battery and are conservative when compared with the initial voltages assumed in the battery sizing calculations. The 31 day Frequency is based on the original licensing basis for the diesel driven fire pump batteries.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.j.4

This TSR provides verification that the level of fuel oil in the day tank is at or above the level at which the low level alarm is annunciated. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for diesel driven fire pump operation. Reference 6 requires that sufficient fuel oil for eight hours of fire pump operation be maintained in the day tank. To meet the NFPA requirement, 275 gallons of usable fuel oil is needed. The actual tank volume equals the usable tank volume plus the unusable tank volume. Operation with the day tank fuel oil level below the NFPA limit, but above the TSR limit, is acceptable since the pump will be able to provide fire suppression water for an extended period of time for a large spectrum of fire events. The diesel driven fire pump is inoperable if the day tank level is < 170 gallons of usable fuel. Station fire protection personnel should be promptly notified if the contents of a fuel oil day tank are below the NFPA minimum recommended level.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

TSR 3.7.j.5

This Surveillance demonstrates that each required fuel oil transfer pump operates and manually transfers fuel oil from its associated storage tank to the diesel driven fire pump day tank(s). Each diesel fire fuel oil transfer pump has the ability to transfer fuel oil to both fire pump day tanks; therefore, this TSR is met provided the day tank can receive fuel oil from one of the fuel oil transfer pumps. This Surveillance provides assurance that the fuel oil transfer pump(s) is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for fuel transfer systems are OPERABLE.

The Frequency for this TSR is based on the original licensing basis for the diesel driven fire pump fuel oil transfer system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.j.6

This TSR helps to ensure the availability of the diesel driven fire pumps to mitigate fires by verifying that the diesel fire pump will start from ambient conditions and run for a minimum of 30 minutes on recirculation flow. Ambient conditions for the fire pump means that the diesel engine has been at rest for a period of time (i.e., the engine is cool enough to allow checking the engine radiator coolant level). The 31 day Frequency is consistent with the recommendations of NEIL.

TSR 3.7.j.7

This TSR verifies that each normally open fire protection suppression water system valve that is not locked, sealed, or otherwise secured, is open. The TSR helps to ensure that fire suppression capability is adequate to minimize potential damage to safety-related equipment. This TSR does not involve any testing or valve manipulation. Rather, it involves verification that those fire suppression water system valves capable of being mispositioned are in the correct position. This TSR does not apply to valves that are locked, sealed, or otherwise secured in the open position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Surveillance specifies the minimum requirements to ensure that the fire suppression water system is OPERABLE; but, it does not satisfy all verifications needed for insurance purposes. NEIL requires periodic verification of locked, as well as unlocked, valves. However, these additional verifications are beyond what is necessary for assuring the OPERABILITY of the Fire Suppression Water System and are not required by this TSR.

The 92 day Frequency is consistent with the flowpath verification requirements of NEIL.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.j.8

The tests of new fuel prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s). The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 9);

b. Verify in accordance with the tests specified in ASTM D975-06b (Ref. 9) that the sample has: 1) an absolute specific gravity at 60°F of ≥ 0.83 and ≤ 0.89 (or an API gravity at 60°F of ≥ 27 and ≤ 39) when tested in accordance with ASTM D1298-99 (Ref. 9); 2) a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes when tested in accordance with ASTM D445-97 (Ref. 9); and 3) a flash point of ≥ 125°F when tested in accordance with ASTM D93-99c (Ref. 9); and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-93 (Ref. 9) or a water and sediment content within limits when tested in accordance with ASTM D2709-96e (Ref. 9). The clear and bright appearance with proper color test is only applicable to fuels that meet the ASTM color requirement (i.e., ASTM color 5 or less).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the TSR since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed within 31 days following addition of the new fuel oil to the fuel oil storage tank(s) to establish that the other properties specified in Table 1 of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.8 (continued)

ASTM D975-06b (Ref. 9) are met for new fuel oil when tested in accordance with ASTM D975-06b (Ref. 9), except that the analysis for sulfur may be performed in accordance with ASTM D1552-95 (Ref. 9), ASTM D2622-98 (Ref. 9), ASTM D4294-98 (Ref. 9) or ASTM D5453-06 (Ref. 9). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on diesel engine operation. This Surveillance ensures the availability of high quality fuel oil for the diesel driven fire pumps.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D5452-98 (Ref. 9). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate concentration is unlikely to change between Frequency intervals.

TSR 3.7.j.9

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are conservative when compared with the initial voltages assumed in the battery sizing

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.9 (continued)

calculations. Verifying that the voltage has not decreased by more than 2.8 volts from the value observed during the original test when the battery was first installed provides assurance that significant battery degradation has not occurred. The 92 day Frequency is based on the original licensing basis for the diesel driven fire pump battery and battery charging system.

TSR 3.7.j.10

The quarterly inspection of specific gravity, and electrolyte level (TSR 3.7.j.11) for each connected cell is consistent with IEEE-450 (Ref. 8). The term "connected cell" excludes any battery cell that may be jumpered out. The limit specified for specific gravity for each connected cell is ≥ 1.200. This value is characteristic of a charged cell with adequate capacity. In addition, the specific gravity of each connected cell is verified to not have decreased by > 0.05 since the last performance of this TSR. Verifying that the specific gravity of each connected cell is within 0.05 of the value observed during the previous test helps ensures that no significant degradation of battery capacity has occurred. According to IEEE-450, the specific gravity readings are based on a temperature of 77°F (25°C). The specific gravity readings are corrected for actual electrolyte temperature. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation; however, in accordance with Reference 8, level correction is not required for the diesel driven fire pump batteries.

TSR 3.7.j.11

The quarterly inspection of specific gravity (TSR 3.7.j.10), and electrolyte level for each connected cell is consistent with IEEE-450 (Ref. 8). The term "connected cell" excludes any battery cell that may be jumpered out. The limit specified for electrolyte level (i.e., above

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.11 (continued)

the plates) is based on manufacturers recommendations and is consistent with the guidance in IEEE-450. This limit ensures that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. Reference 8 recommends that electrolyte level readings should be made only with the battery on float charge.

TSR 3.7.j.12

Cycling each testable valve in the fire suppression water system flowpath through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. For the purposes of this TSR, testable valves are those valves that can be accessed during plant operations at power. Valves which cannot be accessed during power operations (e.g., due to radiological conditions) are tested in accordance with TSR 3.7.j.17. The 12 month Frequency is consistent with the recommendations of NEIL.

TSR 3.7.j.13 and TSR 3.7.j.14

Visual inspection of the battery and its terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. Verifying that the terminal connections are tight ensures that connection resistance is minimized. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance TSR. The presence of visible corrosion does not necessarily represent a failure of the TSR, provided visible corrosion is removed during performance of the Surveillance.

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BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.j.13 and TSR 3.7.j.14 (continued)

The 18 month Frequency for the Surveillances is based on the original licensing basis for the diesel-driven fire pump batteries.

TSR 3.7.j.15

Inspecting the diesel engine of each fire pump ensures that the diesel driven fire pumps maintain a high level of reliability and availability when needed for fire suppression service. The type and frequency of inspections are determined by the manufacturers recommendations for the engine's class of service and takes into account both the hours of engine operation and the time since the last inspection.

TSR 3.7.j.16

The Fire Suppression Water System is required to actuate automatically to perform its design function. This TSR demonstrates that, with the required simulated system initiation signals, the pumps start and any automatic valves in the flowpath actuate to their required positions. The pumps are verified to start sequentially on decreasing Fire Water Suppression System header pressure in order to maintain fire suppression water system pressure $\geq$ 118 psig. This periodic Surveillance is also performed to verify that the fire pumps will develop the flowrates required by the Applicable Design Bases. The flowrate ensures that adequate fire suppression water flow is available to meet NFPA and NEIL requirements. The pump flowrates are verified against a system pressure that is adequate to overcome elevation head and piping friction losses in the system to ensure that sufficient water flow is provided to all suppression devices (e.g., sprinklers, hose stations, etc.).

The Frequency of 18 months is based on the original licensing basis for the diesel-driven fire pumps.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.j.17

Cycling each testable valve in the fire suppression water system flowpath through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. This TSR verifies those testable valves that cannot be accessed during plant operations at power (e.g., due to radiological conditions). Valves which can be accessed during power operations are tested in accordance with TSR 3.7.j.12.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

TSR 3.7.j.18

A flow test of the Fire Suppression Water System is performed to determine the available fire water flow through the system and to evaluate the performance of the system by comparison with recognized standards. Faults which can be disclosed by the flow test include, but are not limited to, tuberculated fire mains, partially closed or inoperative valves, and the presence of silt or other foreign material in the fire mains. The test is conducted in accordance with Chapter 5, Section 11 of Reference 10.

The Frequency of 36 months is based on the original licensing basis for the Fire Suppression Water System.

REFERENCES

1. UFSAR Section 9.5.1
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.

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BASES

REFERENCES (continued)

6. NFPA 20 – 1974.

7. NFPA 24 – 1973.

8. IEEE Standard 450, 1995.

9. ASTM Standards; D4057-95; D975-06b; D1298-99; D445-97; D93-99c; D4176-93; D2709-96e; D1552-95; D2622-98; D4294-98; D5452-98, D5453-06.

10. Fire Protection Handbook, 14th Edition, National Fire Protection Association

B 3.7 PLANT SYSTEMS

B 3.7.k Deluge, Spray and Sprinkler Systems

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment. The Deluge, Spray and Sprinkler Systems covered in this Requirement consist of manual deluge systems, pre-action spray and sprinkler systems, and wet pipe sprinkler systems.

Manual deluge systems are operated locally or from the main control room by switches which open the deluge valve. These systems are used to protect charcoal adsorbers in plant ventilation systems. Manual systems are used instead of automatic systems to prevent a false initiation signal from causing damage to the charcoal beds. Local action is required in all cases since the manual isolation valve upstream of each deluge valve is maintained closed to prevent charcoal degradation due to water leakage through the deluge valve and out the open deluge nozzles.

(continued)

BASES

BACKGROUND (continued)	Pre-Action spray and sprinkler systems employ a deluge-type valve, with the piping between the deluge valve and nozzles pressurized with air (at approximately 20-40 psig), from a small compressor mounted on the pipe near the deluge valve. Multiple detectors in the area sense combustion products and operation of any one detector will actuate the deluge valve to charge the line. The spray nozzles are located above the area served and are held shut by vials containing a volatile liquid. Heat near the vial causes the liquid to expand and break the vial, thus localizing the spray to the area that has the fire, thereby minimizing damage to unaffected areas. Wet Pipe Sprinkler Systems are filled with water up to the sprinkler heads. For a Wet Pipe Sprinkler System, the sprinkler head serves as a heat detector. A fusible link or vial melts or bursts allowing the sprinkler head to open and water to impinge on the deflector head. The Wet Pipe Sprinkler System is the type used generally in most plant areas. It is less complex and provides immediate fire suppression in the affected area when a sprinkler head is activated by heat. Actuation of any Sprinkler, Deluge or Pre-action system causes an alarm to sound locally and in the main control room.
APPLICABLE DESIGN BASES	The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Deluge, Spray and Sprinkler Systems are an integral part of the FPP. The concept of defense-in-depth is used in safety related systems to achieve a high degree of plant nuclear safety. This concept is also

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Deluge and Sprinkler Systems provide a means to suppress and extinguish fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions with or without offsite power.

Manual Deluge systems are provided for the charcoal adsorbers in the standby gas treatment system, control room emergency makeup filters, auxiliary electric room (AEER) supply air filters, and control room supply air filters. The manual Deluge systems are operated locally or from the control room, (the normally closed manual isolation valves upstream of the deluge valve require local actions to initiate water flow in all cases) except those protecting the AEER supply air filters, which are operated locally or outside the auxiliary electric equipment room. Each charcoal adsorber is also provided with temperature sensors which alarm in the control room due to abnormally high temperatures.

The cable spreading rooms, the diesel generator corridors, and the concealed cable space over the laboratories for LaSalle County Station are each equipped with automatic pre-action spray and Sprinkler systems actuated by ionization detectors. Ionization detectors are installed on or near the ceilings. The ionization detectors installed in the concealed cable space over the laboratories are installed above the suspended

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

ceiling. These detectors are sensitive enough to alarm at the very inception of a fire when combustion products are first being released. Actuation of one ionization detector causes an alarm locally and in the control room and trips the deluge valve, filling the system with water.

Pre-action spray and Sprinkler heads are located adjacent to each cable tray. A heat source is then required for the spray and sprinkler head to actuate and flood the tray. This system is also air supervised; and damage to the system or actuation of a spray and sprinkler head actuates an alarm both in the AEER and in the control room. If for some reason the ionization detection system was not in service or failed to function, the heat of a fire would melt the fusible links energizing an alarm both in the AEER and in the control room by releasing the supervisory air pressure maintained in the dry pipe.

Wet pipe sprinkler systems are initiated by heat responsive sprinkler heads located in the hazard area. The emergency diesel generator (DG) fuel storage tank rooms, DG day tank rooms, and railroad access area are protected by wet pipe sprinkler systems. All sprinkler systems are provided with alarm check valves to give an alarm in the main control room when the sprinkler system goes into operation. Tamper switches and/or locks are provided for the fire protection isolation valves on each of the pre-action Spray and Sprinkler, and Deluge systems.

The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire.

The Deluge, Spray and Sprinkler Systems are designed to meet the requirements of GDC 3 and National Fire Protection Association (NFPA) Standards 13 and 15, with any deviations documented and justified (Ref. 8). Additionally, the Deluge, Spray and Sprinkler Systems are not assumed in any accident or transient analyses of the UFSAR.

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BASES (continued)

TLCO

The Deluge, Spray and Sprinkler Systems ensure that adequate fire suppression capability is available to confine and extinguish fires occurring in portions of the facility where safety-related equipment is located. The Deluge, Spray and Sprinkler Systems listed in Table T3.7.k-1 (Unit 1) and T3.7.k-2 (Unit 2) must be OPERABLE to reduce the potential for damage to safety-related equipment.

The Tables are modified by a footnote indicating that TSR 3.7.k.3, TSR 3.7.k.4, and TSR 3.7.k.5 are not applicable to Deluge, Spray and Sprinkler Systems associated with plant ventilation equipment. Refer to the Bases of these TSRs for further information regarding these exceptions.

APPLICABILITY

Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from damage due to the effects of a fire in order to assure that they will be able to perform their required functions. Therefore, Deluge, Spray and Sprinkler Systems protecting this equipment, or the areas containing this equipment, must be OPERABLE whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated Deluge, Spray or Sprinkler System protecting the area is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to Deluge, Spray and Sprinkler systems. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Deluge, Spray and Sprinkler systems provide appropriate compensatory measures for separate inoperable systems. As such, a Note has been provided that allows separate Condition entry for each inoperable Deluge, Spray or Sprinkler system.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, A.3.1, and A.3.2

In the event that a Deluge, Spray or Sprinkler system is inoperable, increasing the frequency of fire watch patrols in the affected area is required to provide early detection and response capability until the inoperable system is restored to OPERABILITY. Upon discovery of the inoperability of a required Deluge, Spray or Sprinkler system, an hourly fire watch patrol must be established with the first inspection of the affected area completed within one hour (Required Action A.1). Because of the possibility of a fire affecting redundant safety systems, Required Action A.2 requires the establishment of a continuous fire watch with backup suppression equipment within one hour if the DG corridor system becomes inoperable while the corridor contains cable trays with inoperable fire wrap. If all of the DG corridor cable trays have OPERABLE fire wrap, then the hourly fire watch patrol of Required Action A.1 is sufficient to minimize the fire risk. Backup suppression equipment must be adequate to extinguish fires from possible sources (i.e., Class A, B, and/or C) in the affected area and includes, but is not limited to, fire hose stations, wheeled or handheld extinguishers, and manual actuation of the inoperable suppression system. The acceptable methods for performing a continuous fire watch and a fire watch patrol (e.g., use of cameras, extent of inspection area, maximum inspection interval, etc.) are delineated in the applicable station implementing procedure.

The inoperable Deluge, Spray or Sprinkler system must be restored to OPERABLE status within 14 days (Required Action A.3.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the system per Required Action A.3.2. The CAP report should describe the cause of the inoperability and the plan for restoring the system to an OPERABLE status.

The Completion Times of one hour and 14 days are based on the original licensing basis for Deluge, Spray and Sprinkler systems.

SURVEILLANCE REQUIREMENTS

TSR 3.7.k.1

This TSR verifies that each normally open Deluge, Spray and Sprinkler system valve in the water flowpath is in the open position. The TSR helps to ensure that fire suppression capability for the protected area is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.k.1 (continued)

adequate to minimize potential damage to the associated equipment. This TSR does not involve any testing or valve manipulation. Rather, it involves verification that those Deluge, Spray and Sprinkler system valves capable of being mispositioned are in the correct position.

The 92 day Frequency is consistent with the flowpath verification requirements of Nuclear Electric Insurance Limited (NEIL).

TSR 3.7.k.2

Cycling each testable valve in the Deluge, Spray and Sprinkler systems flowpath through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. For the purposes of this TSR, testable valves are those valves that can be accessed during plant operations at power. Valves which cannot be accessed during power operations (e.g., due to radiological conditions) are tested in accordance with TSR 3.7.k.6. The 12 month Frequency is consistent with the recommendations of NEIL.

TSR 3.7.k.3

The Deluge, Spray and Sprinkler Systems (except manual Deluge systems) are required to actuate automatically to perform their design function. This TSR demonstrates that, with the required simulated system initiation signal, the automatic valves in the system flowpath actuate to their required positions. As noted by footnote (a) to Tables T3.7.k-1 and 3.7.k-2, this TSR is not applicable to Deluge, Spray and Sprinkler systems protecting plant ventilation equipment since performance of this test could result in a water discharge that would damage the equipment or charcoal filter media.

The Frequency of 18 months is based on the original licensing basis for the Deluge, Spray and Sprinkler systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.k.4 and TSR 3.7.k.5

Pre-action Spray and Sprinkler and Deluge system headers route fire suppression water to the open deluge nozzles or sprinkler/spray heads following actuation of the system. Since these portions of the system are not normally pressurized with fire water, any degradation in the distribution headers or open deluge nozzles may not be readily detected (i.e., not evidenced by water leakage). For this reason TSR 3.7.k.4 requires a visual inspection of the integrity of the Deluge, Spray and Sprinkler headers, and TSR 3.7.k.5 requires verification that deluge nozzles are unobstructed. These TSRs require inspection of piping, pre-action spray and sprinkler heads, deluge spray nozzles, and hangers for signs of degradation or any other obvious conditions that could alter coverage of the Deluge, Spray or Sprinkler system.

As noted by footnote (a) to Tables T3.7.k-1 and 3.7.k-2, TSR 3.7.k.4 is not applicable to piping housed within ventilation system charcoal beds and TSR 3.7.k.5 is not applicable to Deluge, Spray and Sprinkler systems protecting plant ventilation equipment. These systems are exempted due to the difficulty in gaining access to the piping and is considered acceptable since the inaccessible portions of the Deluge, Spray and Sprinkler systems are maintained dry and are located within ventilation ducting. Consequently, the probability of nozzle blockage, header corrosion, or other conditions which could impact the ability of the system to perform its function is small.

The 24 month Frequency is based on a historical review of system performance. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

TSR 3.7.k.6

Cycling each testable valve in the Deluge, Spray and Sprinkler systems flowpath through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. This TSR verifies those testable valves that cannot be accessed during

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BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.k.6 (continued)

plant operations at power (e.g., due to radiological conditions). Valves which can be accessed during power operations are tested in accordance with TSR 3.7.k.2.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.
6. NFPA 13 – 1976
7. NFPA 15 – 1973
8. NUREG – 0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.

B 3.7 PLANT SYSTEMS

B 3.7.I CO_2 Systems

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment. The CO_2 Systems specified in this Requirement are low pressure, total flooding, extended discharge systems for the five diesel generator (DG) rooms.

The carbon dioxide systems consist of a common 10-ton refrigerated liquid CO_2 storage unit and associated piping, headers and valves to each of the five DG rooms. An internal refrigeration system on the storage unit maintains temperature within a range of 3°F to 6°F with a resulting pressure of approximately 295 psi to 305 psi allowing the gas to be stored at a lower pressure. This lowers the probability of leaks and allows for less expensive storage and piping systems. Additionally, the CO_2 storage unit provides carbon dioxide for automatic fire suppression in the main generator alterex housings, manual fire

(continued)

BASES

BACKGROUND (continued)

suppression hose reels, and purge gas for the main generators; however, these functions are not part of this Requirement. Audible and visual predischarge alarms warn that the CO_2 flooding system is about to actuate so that personnel may leave the area. Manual actuation switches are also provided. Actuation of the CO_2 flooding system automatically shuts down the local fans and closes the local dampers.

APPLICABLE DESIGN BASES

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The CO_2 Systems are an integral part of the FPP.

The concept of defense-in-depth is used in safety related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the CO_2 Systems provide a means to suppress and extinguish fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions with or without offsite power.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

The maximum potential for fire affecting safety-related equipment at the station is in the DG rooms, diesel day tank rooms, and diesel fuel storage rooms. A rupture of a day tank, storage tank, or the main fuel line to a DG could release significant quantities of #2 diesel fuel. If a high energy source of ignition is present, such as an electrical short, the fuel would be ignited and a major plant fire would ensue. To mitigate this fire hazard, the diesel day tank and storage tank rooms are protected by automatic sprinkler systems and the DG rooms are protected by the CO_2 systems. Refer to TLCO 3.7.k, “Deluge and Sprinkler Systems,” for Applicable Design Bases for these sprinkler systems.

An automatic carbon dioxide total flooding extended discharge system is provided for each of the five DG rooms. The CO_2 is stored in a common 10 ton refrigerated storage unit whose capacity is based on two consecutive timed applications to three DG rooms, two complete main generator purge cycles, plus a reserve supply for hose reel use. Each system is actuated by a fixed temperature rise detector system. CO_2 release is delayed and an audible alarm sounded to allow personnel who may be in these rooms ample time to escape. The DG rooms have independent ventilation systems, with no cross connection to the other DG systems. These ventilation systems are of the once through type, therefore, auxiliary smoke removal systems are not needed. The activation of the CO_2 system automatically stops the ventilation system fans and closes the electro-thermal link fire dampers. The CO_2 system may also be manually actuated by either of two pushbutton stations for each DG room. Automatic or manual actuation of the CO_2 system automatically sounds an alarm in the main control room and in the vicinity of the hazard area. Once the CO_2 is released into the room, the design concentration for extinguishing the fire is achieved within one minute. A wet standpipe hose reel is provided outside the main entrance of the DG rooms to supply backup protection.

The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	The CO_2 Systems are designed to meet the requirements of GDC 3 and National Fire Protection Association (NFPA) Standard 12, with any deviations documented and justified (Ref. 6). Additionally, the CO_2 Systems are not assumed in any accident or transient analyses of the UFSAR.
TLCO	The CO_2 Systems ensure that adequate fire suppression capability is available to confine and extinguish fires occurring in portions of the facility where safety-related equipment is located. The CO_2 Systems for the Division 1, Division 2, Division 3, and opposite Unit Division 2 DG rooms must to be OPERABLE to reduce the potential for damage to safety-related equipment.
APPLICABILITY	Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from damage due to the effects of a fire in order to assure that they will be able to perform their required functions. Therefore, CO_2 Systems protecting the areas containing this equipment, must be OPERABLE whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated CO_2 System protecting the area is not required.
ACTIONS	A Note has been provided to modify the ACTIONS related to carbon dioxide systems. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable CO_2 systems provide appropriate compensatory measures for separate inoperable systems. As such, a Note has been provided that allows separate Condition entry for each inoperable CO_2 system.

(continued)

BASES

ACTIONS (continued)

A.1, A.2.1, and A.2.2

In the event that a CO_2 system is inoperable, increasing the frequency of fire watch patrols in the affected area is required to provide early detection and response capability until the inoperable system is restored to OPERABILITY. Upon discovery of the inoperability of a required CO_2 system, an hourly fire watch patrol must be established with the first inspection of the affected area completed within one hour (Required Action A.1). The acceptable methods for performing a fire watch patrol (e.g., use of cameras, extent of inspection area, maximum inspection interval, etc.) are delineated in the applicable station implementing procedure.

The inoperable CO_2 system must be restored to OPERABLE status within 14 days (Required Action A.2.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the system per Required Action A.2.2. The CAP report should describe the cause of the inoperability and the plan for restoring the system to an OPERABLE status.

The Completion Times of one hour and 14 days are based on the original licensing basis for CO_2 systems.

SURVEILLANCE REQUIREMENTS

TSR 3.7.I.1

This TSR provides verification that the level of CO_2 in the storage tank is above the level necessary to ensure that adequate carbon dioxide is available for extinguishing a DG room fire. The 7 day Frequency is adequate to assure that a sufficient supply of CO_2 is available, since facility operators would be aware of any large uses of carbon dioxide during this period. In addition, the Frequency is consistent with the inspection requirements of Reference 6.

TSR 3.7.I.2

Verifying adequate CO_2 storage tank pressure ensures that the assumptions concerning gas flow and application rate remain valid. With pressure below the limit, design CO_2 concentration may not be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.I.2 (continued)

achieved within the time interval specified in Reference 6. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

TSR 3.7.I.3

This TSR verifies that each normally open CO_2 system valve in the flowpath is in the open position. The TSR helps to ensure that fire suppression capability for the protected area is adequate to minimize potential damage to the associated equipment. This TSR does not involve any testing or valve manipulation. Rather, it involves verification that those CO_2 system valves capable of being mispositioned are in the correct position.

The 92 day Frequency is consistent with the flowpath verification requirements of Nuclear Electric Insurance Limited (NEIL).

TSR 3.7.I.4

The CO_2 Systems are required to actuate automatically to perform their design function. This TSR demonstrates that, with the required simulated system initiation signal, the automatic valves in the system flowpath actuate to their required positions. The Frequency of 18 months is based on the original licensing basis for the CO_2 systems and satisfies the testing requirements of Reference 6.

TSR 3.7.I.5

The puff test verifies the nozzles in each CO_2 system are unobstructed. A satisfactory test ensures that carbon dioxide will flow from the system through the nozzle. It is not intended for the puff test to verify the actual flowrate of gas through the nozzle. Rather, the test verifies the nozzle is open and may be performed by use of streamers, plastic bags, or other devices which would indicate that the nozzle flowpath is not blocked.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.7.I.6

The CO_2 Systems are required to actuate automatically to perform their design function. This TSR demonstrates that, with the required simulated system initiation signal, the active CO_2 components associated with the VD dampers in the system flowpath actuate to their required positions. The Frequency of 48 months is based on the original licensing basis for the CO_2 systems and satisfies the testing requirements of Reference 7. TSR 3.7.I.4 does not include surveillances associated with the operation and testing of the VD dampers.

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.
6. NFPA 12 – 1973.
7. EC 362093

B 3.7 PLANT SYSTEMS

B 3.7.m Fire Hose Stations

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment. The Fire Hose Stations covered in this Requirement provide manual fire fighting capability for areas containing safety-related equipment.

The Fire Protection standpipe and fire hose system at the station is classified as a Class II wet standpipe system. This class of system is defined as a small hose system for use primarily by the building occupants (i.e., on-site Fire Brigade) whose standpipes are filled with water and maintained pressurized at all times. A continuous pressure of approximately 160 psig is provided for the standpipe system by one of two redundant Fire Protection Jockey Fire Pumps. The Jockey Pumps ensure that fire water pressure is immediately available to the manual hose stations for fire fighting and prevent system water hammer

(continued)

BASES

BACKGROUND (continued)

when the Intermediate Jockey Fire Pump or Diesel Fire Pumps automatically start. The Fire Hose Stations consist of hose racks placed throughout the plant containing either 50 or 100 feet of 1-½ inch fire hose and variable flow nozzles. When needed for fire suppression, the fire hose is removed from the rack by the station Fire Brigade and pressurized by opening the Fire Hose Station isolation valve connected to the wet standpipe system. The variable flow nozzle can then be adjusted to provide the appropriate water flow and spray pattern to the fire.

APPLICABLE DESIGN BASES

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Fire Hose Stations are an integral part of the FPP.

The concept of defense-in-depth is used in safety related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Fire Hose

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	Stations provide a means to manually suppress and extinguish fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions, with or without offsite power. Manual fire hose stations serve all areas of the plant except portions of the steam and radwaste pipe tunnels and the primary containment. The pipe tunnels do not contain combustibles. Hoses are normally brought into the primary containment during outages and, in addition, the primary containment has a spray system that can be used as a deluge system. Fire hoses stations, depending on their location, provide the primary means of fire suppression for the surrounding area. Fire hose stations are also provided as backup suppression capability for areas served by sprinkler and deluge systems. If an automatic sprinkler system fails to actuate, nearby fire hose stations could be used by the station Fire Brigade to bring the fire under control and extinguish it. The adjustable nozzles provided on each fire hose station allow the user to create a variety of flow patterns (e.g., fog or solid stream) making the fire hose stations suitable for extinguishing Class A, B, or C fires. The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire. The Fire Hose Stations are designed to meet the requirements of GDC 3 and National Fire Protection Association (NFPA) Standard 14, with any deviations documented and justified (Ref. 8). Additionally, the Fire Hose Stations are not assumed in any accident or transient analyses of the UFSAR.
TLCO	The Fire Hose Stations ensure that adequate manual fire suppression capability is available to confine and extinguish fires occurring in portions of the facility where safety-related equipment is located. The Fire Hose Stations listed in Table T3.7.m-1 (Unit 1) and T3.7.m-2 (Unit 2) must to be OPERABLE to reduce the potential for damage to safety-related equipment.

(continued)

BASES (continued)

APPLICABILITY	Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from damage due to the effects of a fire in order to assure that they will be able to perform their required functions. Therefore, Fire Hose Stations protecting the areas containing this equipment must be OPERABLE whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated Fire Hose Station(s) protecting the area is not required.
ACTIONS	A Note has been provided to modify the ACTIONS related to fire hose stations. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable fire hose stations provide appropriate compensatory measures for separate inoperable hose stations. As such, a Note has been provided that allows separate Condition entry for each inoperable fire hose station. <u>A.1, A.2, A.3.1, and A.3.2</u> In the event that a required fire hose station is inoperable, backup suppression capability must be established to ensure that a fire in the affected area(s) can be quickly extinguished. Backup suppression capability is established by staging additional lengths of fire hose at an OPERABLE hose station. The additional hose must be of sufficient length to allow the OPERABLE hose station to serve all areas covered by the inoperable hose station and have a diameter greater than or equal to the diameter of the inoperable hose station to ensure an adequate supply of water can be provided. The backup fire

(continued)

BASES

ACTIONS	A.1, A.2, A.3.1, and A.3.2 (continued) hose may either be staged at the OPERABLE hose station or physically routed to the affected area. If the inoperable hose station is the primary means of fire suppression for the affected areas, then the additional fire hose must be staged within 1 hour (Required Action A.1). For LaSalle, all of the fire hose stations listed in the Tables, with the exception of FB 164, FB 156, and F 364, provide the primary means of fire suppression in their respective areas. Thus, for fire hose stations FB 164, FB 156, and F 364, Required Action A.2 requires that the additional fire hose be staged at an OPERABLE hose station within 24 hours. This is acceptable, since these hose stations are not the primary means of fire suppression in the areas they serve. The inoperable fire hose station must be restored to OPERABLE status within 14 days (Required Action A.3.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the hose station per Required Action A.3.2. The CAP report should describe the cause of the inoperability and the plan for restoring the hose station to an OPERABLE status. The Completion Times of 1 hour, 24 hours, and 14 days are based on the original licensing basis for fire hose stations.
SURVEILLANCE REQUIREMENTS	TSR 3.7.m.1 Visually inspecting each hose station ensures that the required hose, nozzle, and fittings are at the station and in a ready for use state to ensure they will function when required. For the purposes of this TSR, accessible hose stations are those stations that can be accessed during plant operations at power. Hose stations which cannot be accessed during power operations (e.g., due to radiological conditions) are inspected in accordance with TSR 3.7.m.2. The 92 day Frequency is consistent with the recommendations of Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards. (continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.m.2

Visually inspecting each hose station ensures that the required hose, nozzle, and fittings are at the station and in a ready for use state to ensure they will function when required. This TSR verifies those stations that cannot be accessed during plant operations at power (e.g., due to radiological conditions). Hose stations which can be accessed during power operations are inspected in accordance with TSR 3.7.m.1.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

TSR 3.7.m.3 and TSR 3.7.m.4

Each required fire hose must be periodically removed from its rack and its entire length, including couplings and gaskets, inspected for signs of degradation. The inspection ensures that there is no evidence of mildew, rot, chemical damage, abrasion, or other deficiencies which could impact the integrity of the fire hose during use. Additionally, the couplings and gaskets are inspected to ensure a leak tight fit to the standpipe and nozzle can be obtained. Gaskets or hoses discovered to have unacceptable levels of degradation must be replaced prior to reconnecting the hose to the fire protection standpipe and reracking the hose onto the hose station. This TSR satisfies the inspection requirements of Reference 7.

The 24 month Frequency is based on a historical review of system performance. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.m.5

A flow test of each required hose station is performed to ensure the availability of fire water flow through the system and to verify the OPERABILITY of the hose station. Faults which can be disclosed by the flow test include, but are not limited to, tuberculated fire protection standpipes, inoperative valves, and the presence of silt or other foreign material in the standpipes. The test is conducted by partially opening the hose station isolation valve, verifying water flow out of the valve, and confirming, by a qualitative determination, that no evidence of flow blockage exists.

The Frequency of 36 months is based on the original licensing basis for the Fire Hose Stations.

TSR 3.7.m.6

Performing a hydrostatic test of each required fire hose ensures that the hose will be able to perform its function when required. A hydrostatic test will reveal any hose deterioration not disclosed by visual inspection. The test must be conducted at a pressure at least 50 psig higher than the maximum operating pressure of the fire main but not less than 150 psig.

The test must be performed initially within 5 years after the purchase date of the hose. The second hydrostatic test of the hose is to be performed between 5 and 8 years following the purchase date. All subsequent tests are performed at 2 year intervals. The Frequency specified is consistent with the requirements of NFPA Standard 1962.

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.

(continued)

BASES

REFERENCES (continued)

6. NFPA 14 – 1974.

7. NFPA 1962 – 1979.

8. NUREG–0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.

B 3.7 PLANT SYSTEMS

B 3.7.m Fire Hose Stations

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment. The Fire Hose Stations covered in this Requirement provide manual fire fighting capability for areas containing safety-related equipment.

The Fire Protection standpipe and fire hose system at the station is classified as a Class II wet standpipe system. This class of system is defined as a small hose system for use primarily by the building occupants (i.e., on-site Fire Brigade) whose standpipes are filled with water and maintained pressurized at all times. A continuous pressure of approximately 160 psig is provided for the standpipe system by one of two redundant Fire Protection Jockey Fire Pumps. The Jockey Pumps ensure that fire water pressure is immediately available to the manual hose stations for fire fighting and prevent system water hammer

(continued)

BASES

BACKGROUND (continued)

when the Intermediate Jockey Fire Pump or Diesel Fire Pumps automatically start. The Fire Hose Stations consist of hose racks placed throughout the plant containing either 50 or 100 feet of 1-½ inch fire hose and variable flow nozzles. When needed for fire suppression, the fire hose is removed from the rack by the station Fire Brigade and pressurized by opening the Fire Hose Station isolation valve connected to the wet standpipe system. The variable flow nozzle can then be adjusted to provide the appropriate water flow and spray pattern to the fire.

APPLICABLE DESIGN BASES

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Fire Hose Stations are an integral part of the FPP.

The concept of defense-in-depth is used in safety related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Fire Hose

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	Stations provide a means to manually suppress and extinguish fires in plant areas containing systems necessary to achieve and maintain safe plant shutdown conditions, with or without offsite power. Manual fire hose stations serve all areas of the plant except portions of the steam and radwaste pipe tunnels and the primary containment. The pipe tunnels do not contain combustibles. Hoses are normally brought into the primary containment during outages and, in addition, the primary containment has a spray system that can be used as a deluge system. Fire hoses stations, depending on their location, provide the primary means of fire suppression for the surrounding area. Fire hose stations are also provided as backup suppression capability for areas served by sprinkler and deluge systems. If an automatic sprinkler system fails to actuate, nearby fire hose stations could be used by the station Fire Brigade to bring the fire under control and extinguish it. The adjustable nozzles provided on each fire hose station allow the user to create a variety of flow patterns (e.g., fog or solid stream) making the fire hose stations suitable for extinguishing Class A, B, or C fires. The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire. The Fire Hose Stations are designed to meet the requirements of GDC 3 and National Fire Protection Association (NFPA) Standard 14, with any deviations documented and justified (Ref. 8). Additionally, the Fire Hose Stations are not assumed in any accident or transient analyses of the UFSAR.
TLCO	The Fire Hose Stations ensure that adequate manual fire suppression capability is available to confine and extinguish fires occurring in portions of the facility where safety-related equipment is located. The Fire Hose Stations listed in Table T3.7.m-1 (Unit 1) and T3.7.m-2 (Unit 2) must to be OPERABLE to reduce the potential for damage to safety-related equipment.

(continued)

BASES (continued)

APPLICABILITY

Equipment and systems required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from damage due to the effects of a fire in order to assure that they will be able to perform their required functions. Therefore, Fire Hose Stations protecting the areas containing this equipment must be OPERABLE whenever the associated equipment is required to be OPERABLE. If a system or piece of equipment is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated Fire Hose Station(s) protecting the area is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to fire hose stations. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable fire hose stations provide appropriate compensatory measures for separate inoperable hose stations. As such, a Note has been provided that allows separate Condition entry for each inoperable fire hose station.

<u>A.1, A.2, A.3.1, and A.3.2</u>

In the event that a required fire hose station is inoperable, backup suppression capability must be established to ensure that a fire in the affected area(s) can be quickly extinguished. Backup suppression capability is established by staging additional lengths of fire hose at an OPERABLE hose station. The additional hose must be of sufficient length to allow the OPERABLE hose station to serve all areas covered by the inoperable hose station and have a diameter greater than or equal to the diameter of the inoperable hose station to ensure an adequate supply of water can be provided. The backup fire

(continued)

BASES

ACTIONS

A.1, A.2, A.3.1, and A.3.2 (continued)

hose may either be staged at the OPERABLE hose station or physically routed to the affected area. If the inoperable hose station is the primary means of fire suppression for the affected areas, then the additional fire hose must be staged within 1 hour (Required Action A.1). For LaSalle, all of the fire hose stations listed in the Tables, with the exception of FB 164, FB 156, and F 364, provide the primary means of fire suppression in their respective areas. Thus, for fire hose stations FB 164, FB 156, and F 364, Required Action A.2 requires that the additional fire hose be staged at an OPERABLE hose station within 24 hours. This is acceptable, since these hose stations are not the primary means of fire suppression in the areas they serve.

The inoperable fire hose station must be restored to OPERABLE status within 14 days (Required Action A.3.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the hose station per Required Action A.3.2. The CAP report should describe the cause of the inoperability and the plan for restoring the hose station to an OPERABLE status.

The Completion Times of 1 hour, 24 hours, and 14 days are based on the original licensing basis for fire hose stations.

SURVEILLANCE REQUIREMENTS

TSR 3.7.m.1

Visually inspecting each hose station ensures that the required hose, nozzle, and fittings are at the station and in a ready for use state to ensure they will function when required. For the purposes of this TSR, accessible hose stations are those stations that can be accessed during plant operations at power. Hose stations which cannot be accessed during power operations (e.g., due to radiological conditions) are inspected in accordance with TSR 3.7.m.2. The 92 day Frequency is consistent with the recommendations of Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.m.2

Visually inspecting each hose station ensures that the required hose, nozzle, and fittings are at the station and in a ready for use state to ensure they will function when required. This TSR verifies those stations that cannot be accessed during plant operations at power (e.g., due to radiological conditions). Hose stations which can be accessed during power operations are inspected in accordance with TSR 3.7.m.1.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

TSR 3.7.m.3 and TSR 3.7.m.4

Each required fire hose must be periodically removed from its rack and its entire length, including couplings and gaskets, inspected for signs of degradation. The inspection ensures that there is no evidence of mildew, rot, chemical damage, abrasion, or other deficiencies which could impact the integrity of the fire hose during use. Additionally, the couplings and gaskets are inspected to ensure a leak tight fit to the standpipe and nozzle can be obtained. Gaskets or hoses discovered to have unacceptable levels of degradation must be replaced prior to reconnecting the hose to the fire protection standpipe and reracking the hose onto the hose station. This TSR satisfies the inspection requirements of Reference 7.

The 24 month Frequency is based on a historical review of system performance. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.m.5

A flow test of each required hose station is performed to ensure the availability of fire water flow through the system and to verify the OPERABILITY of the hose station. Faults which can be disclosed by the flow test include, but are not limited to, tuberculated fire protection standpipes, inoperative valves, and the presence of silt or other foreign material in the standpipes. The test is conducted by partially opening the hose station isolation valve, verifying water flow out of the valve, and confirming, by a qualitative determination, that no evidence of flow blockage exists.

The Frequency of 36 months is based on the original licensing basis for the Fire Hose Stations.

TSR 3.7.m.6

Performing a hydrostatic test of each required fire hose ensures that the hose will be able to perform its function when required. A hydrostatic test will reveal any hose deterioration not disclosed by visual inspection. The test must be conducted at a pressure at least 50 psig higher than the maximum operating pressure of the fire main but not less than 150 psig.

The test must be performed initially within 5 years after the purchase date of the hose. The second hydrostatic test of the hose is to be performed between 5 and 8 years following the purchase date. All subsequent tests are performed at 2 year intervals. The Frequency specified is consistent with the requirements of NFPA Standard 1962.

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.

(continued)

BASES

REFERENCES (continued)	6.	NFPA 14 – 1974.
	7.	NFPA 1962 – 1979.
	8.	NUREG–0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.

B 3.7 PLANT SYSTEMS

B 3.7.n Safe Shutdown Lighting

BASES

BACKGROUND

The general purpose of the lighting systems is to provide sufficient lighting of desired quality in all areas of the station, indoors and outdoors, for normal, essential, and emergency conditions. AC station lighting is the normal lighting system used throughout the plant. The normal AC lighting cabinets are energized from the non-ESF (Engineered Safety Features) 480-volt motor control centers.

AC emergency (or standby) station lighting is provided for station operation during a loss of normal AC auxiliary power. It is limited to the lighting required for the control and maintenance of ESF equipment (such as the ESF switchgear, emergency cooling equipment, control equipment, etc.) and for the access routes to this equipment. It represents approximately 7.5% of all station lighting. It is energized from the 480-Volt ESF motor control centers and thus receives power from the diesel generators when, and if, the sources of normal AC auxiliary power fail. The control room emergency lighting system is similar to the normal lighting system except that the source of AC power is supplied from the engineered safety features power distribution system. These lights are normally in service at all times.

8-hour balance of plant and safe shutdown battery emergency lighting units are provided in various locations in sufficient quantity to provide supplemental lighting for maintenance and supervision of both BOP and safe shutdown equipment. The battery emergency lighting system in the control room consists of battery operated lighting units located strategically within the control room. The units are normally de-energized and operated automatically upon failure of the ESF or non-ESF AC lighting systems. This Requirement deals specifically with the 8-hour safe shutdown battery emergency lighting units described in the Applicable Design Bases.

(continued)

BASES

BACKGROUND (continued)

The DC emergency lighting system in the control room consists of incandescent lighting fixtures installed in a manner similar to the normal lighting system. The system is normally de-energized and is automatically energized from the 125-volt battery system upon loss of AC power to the ESF 480-volt buses. DC emergency lighting in the remainder of the plant is limited to incandescent lamp fixtures at stairwells and at exit points of various areas of the plant, outside of the control room.

In the event of a loss of normal onsite and offsite power, provision is made for automatically shedding all but approximately 10% of the normal lighting load so as to avoid excessive loading of the standby diesel-generator system. These lighting circuits can then be manually re-energized by operator action when load conditions permit. Essential lighting in the ESF divisional (safety-related) areas is supplied from its respective diesel-generator feeds. The control room lighting is supplied equally from Unit 1 and Unit 2, (on a 50/50 basis). In addition, provision is made for automatic transfer of approximately 2.5% of the normal lighting system to the 125-volt battery system in the event of a loss of AC supply so as to provide emergency lighting for essential areas in the plant. The emergency lighting system includes the main control room, safety-related equipment and control areas, standby AC equipment areas, and access and exit routes.

As a supplement to the station battery supplied emergency lighting system, additional self-contained, battery operated emergency lighting units of a portable or semiportable type are provided where required. These are equipped with 4-hour battery supplies.

APPLICABLE DESIGN BASES

On May 23, 1980, the Nuclear Regulatory Commission (NRC) issued a Memorandum and Order (CL1-80-21) which stated: “The combination of the guidance contained in Appendix A to Branch Technical Position, ASB 9.5-1 and the requirements set forth in this proposed rule define the essential elements for an acceptable fire protection program at nuclear power plants docketed for Construction Permits prior to July 1, 1976, for demonstration of compliance with General Design Criterion (GDC) 3 of Appendix A to 10 CFR Part 50.” On October 27, 1980, the

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	NRC approved this rule concerning fire protection. The rule and its Appendix R were developed to establish the minimum acceptable fire protection requirements necessary to resolve certain areas of concern in contest between the NRC and licensees of plants operating prior to January 1, 1979. Although this fire protection rule and Appendix R do not apply to LaSalle, the station agreed to install self-contained 8-hour battery-pack emergency lighting in all areas of the plant which could be manned to bring the plant to a safe cold shutdown condition (Ref. 6). These safe shutdown Emergency Lighting Battery Packs (ELBPs) are wired directly to the ESF and non-ESF power sources and switch on automatically if AC power fails. A sufficient number of ELBPs are installed throughout the plant so that the requirements of Section III.J of 10 CFR 50 Appendix R are satisfied. The battery pack units were designed to provide illumination of safe shutdown equipment and access/egress routes in the event that the normal station lighting system is disabled by a fire. The Safe Shutdown Lighting system conforms to applicable NRC positions and industry standards and is not assumed in any accident or transient analyses of the UFSAR.
TLCO	The OPERABILITY of 8-hour DC emergency lighting units (ELBPs) installed to satisfy Section III.J of 10 CFR 50 Appendix R ensures adequate illumination in areas needed for operation of safe shutdown equipment and access and egress routes thereto. These design features provide illumination to enable operators to reach the necessary areas, including the remote shutdown panels, and perform shutdown functions so the reactor can be safely shutdown in the event of a fire emergency. To be considered OPERABLE, the ELBP must be capable of illuminating automatically upon a loss of normal area lighting and illuminate the required area or equipment for a minimum of 8 hours. Factors affecting OPERABILITY include, but are not limited to, dead batteries, substantially miss-aimed lamps, burned-out bulbs, and objects significantly obstructing the illumination path (e.g., scaffolding, temporary shielding, etc.).

(continued)

BASES (continued)

APPLICABILITY

The purpose of the Safe Shutdown Lighting system is to provide illumination so that operators can safely bring the plant to MODE 4 in the event of a fire which disables the normal station lighting system. Since a fire can occur at any time, the ELBPs of the Safe Shutdown Lighting system are required to be OPERABLE whenever the plant is in MODES of operation higher than MODE 4. Therefore, this TLCO is applicable in MODES 1, 2, and 3.

ACTIONS

A Note has been provided to modify the ACTIONS related to Safe Shutdown Lighting ELBPs. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable DC emergency lights provide appropriate compensatory measures for separate, inoperable lights. As such, a Note has been provided that allows separate Condition entry for each inoperable DC emergency light.

A.1, A.2.1, and A.2.2

In the event that an Appendix R emergency light is inoperable, backup or portable lighting is required to be established within 1 hour to provide illumination capability until the inoperable unit is restored to service (Required Action A.1). Backup lighting may be provided by placing a backup OPERABLE emergency lighting unit in the field or by crediting the existence of portable lighting provided in accordance with Section 5.1.4 of Nuclear Engineering Standard NES-MS-05.4.

The inoperable DC emergency light must be restored to OPERABLE status within 14 days (Required Action A.2.1). Alternately, a report can be prepared in accordance with the station's Corrective Action Program (CAP) within 14 days of the discovery of the inoperability of the light per Required Action A.2.2. The CAP report should describe the cause of the inoperability and the plan for restoring the light to an OPERABLE status.

(continued)

BASES

ACTIONS

A.1, A.2.1, and A.2.2 (continued)

The Completion Times of 1 hour and 14 days are based on the original licensing basis for DC emergency lights.

SURVEILLANCE REQUIREMENTS

TSR 3.7.n.1

To ensure that ELBPs installed to satisfy Reference 3 will function when required, a “quick check” of the lighting unit should be periodically performed. As a minimum, a “quick check” should consist of a visual integrity inspection, lens condition check, an electrolyte level check (for maintenance type batteries), a circuitry check, and a state of charge check. For lamps that are inaccessible at power, alternate test methods may be used to verify the lamps are functional (e.g., use of an ammeter to verify lamp energized). Allowing alternate “quick check” methods are acceptable since access to these areas is typically restricted for ALARA and personnel safety. Therefore, the probability of lamp misalignment, broken lenses, or other lamp problems is low.

The 92 day Frequency was determined to be acceptable based on historical failure rates, operating experience, and engineering judgment (Ref. 5).

TSR 3.7.n.2

Each DC emergency lighting unit required by the TLCO must be demonstrated to be OPERABLE by performance of an 8 hour discharge test or by an acceptable alternate method. An example of an acceptable alternate testing method is the internal ohmic measurement check (i.e., conductance test) recommended by EPRI Report TR-106826, “Emergency Lighting Battery Unit Maintenance and Application Guide.”

The 18 month Frequency was determined to be acceptable based on historical failure rates, operating experience, and engineering judgment (Ref. 5).

REFERENCES

1. UFSAR Section 9.5.3.

2. 10 CFR 50, Appendix A, GDC 3.

(continued)

BASES

REFERENCES (continued)

3. 10 CFR 50, Appendix R.
4. NES-MS-05.4, “Appendix R Emergency Lighting Program.”
5. Nuclear Fire Protection Information Transmittal 91-089, June 20, 1991.
6. NUREG–0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.
7. EPRI Report TR-106826, “Battery Performance Monitoring by Internal Ohmic Measurements for Emergency Lighting Batteries.”

B 3.7 PLANT SYSTEMS

B 3.7.o Fire Rated Assemblies

BASES

BACKGROUND

General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50 (Ref. 3) requires that structures, systems and components (SSCs) important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials are required to be used wherever practical throughout the plant, particularly in locations such as the containment and control room. GDC 3 also requires that fire detection and suppression systems have sufficient capacity and capability to minimize the adverse effect of fire on safety-related SSCs. Additionally, these fire protection systems should be built to ensure that their failure, rupture, or inadvertent operation does not significantly impair the capability of safety-related SSCs to perform their required functions.

The Fire Protection System and Program at LaSalle utilizes materials, instrumentation, suppression systems, and barriers to prevent a fire from starting; to quickly detect any fires and annunciate them locally and remotely; to quickly suppress a fire by use of automatic fire protection equipment; to prevent the spread of a fire by use of fire barriers; to minimize the size of a fire and limit its damage; and to provide fire fighting capability for manual fire extinguishment. The Fire Rated Assemblies covered in this Requirement consist of fire resistant walls, floors, ceilings, doors, windows, dampers, fire wrap, and seals.

The station layout is arranged to isolate safety-related systems from unacceptable fire hazards. This is accomplished by either distance or a barrier. Due to structural and shielding requirements, many walls have a fire rating in excess of 3 hours. Other concrete walls have at least a 3- or 2-hour rating. Non-concrete walls in the facility generally have at least a 2-hour fire rating. All openings through walls have door ratings which are consistent with required wall ratings. Piping and cable tray penetrations are provided with fire stops to preserve the fire rating of the walls that are penetrated.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment in accordance with GDC 3 and 5 (Ref. 3 and 4). The fire protection program consists of fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel. The Fire Rated Assemblies are an integral part of the FPP.

The concept of defense-in-depth is used in safety-related systems to achieve a high degree of plant nuclear safety. This concept is also applicable to fire safety. With respect to the FPP, the defense-in-depth principle is aimed at achieving an adequate balance in:

1. preventing fires from starting;
2. detecting fires quickly, suppressing and extinguishing those fires that occur, and limiting their damage; and
3. designing plant safety systems so that a fire that starts and burns for a considerable time in spite of fire protection activities will not prevent essential plant safety functions from being performed.

The objective of the FPP is to minimize both the probability and the consequences of postulated fires. In spite of steps taken to reduce the probability of a fire, fires are expected to occur. Therefore, the Fire Rated Assemblies provide a means to contain and prevent the spread of fires in plant areas containing safety-related systems to ensure sufficient equipment remains functional to achieve and maintain safe plant shutdown conditions.

Nuclear Electric Insurance Limited (NEIL) Property Loss Standards and References 5 and 8 require that fire barriers separating redundant safety-related equipment or separating safety and non-safety-related equipment be rated for at least 3 hours. However, the functions of the plant do not always make it possible to enclose separate fire zones by minimum 3-hour fire barriers. Some features which compromise the 3-hour barriers are open stairways and openings in the slabs for equipment operation or removal. In these instances the fire loading was examined, and it was determined that, due to the low fire loadings, propagation would not occur.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

National Fire Protection Association (NFPA) Standard 803 requires that where electrical and mechanical equipment (except ventilation ducts) penetrate a fire barrier, the penetration must be sealed (fire stopped) with a material or device having a fire resistance rating equivalent to the fire resistance rating of the barrier. Fire barrier penetrations by conduit and piping are sealed with silicone foam sealant, grout or ceramic fiber. Fire barrier penetrations by electrical cable risers and cable trays are sealed with CT Gypsum or another suitable fire barrier penetration sealant. These penetration seal fire stops are qualified in accordance with NFPA Standard 251. Penetrations through fire barriers for the ventilation system are equipped with fire dampers. Fire dampers are not provided in the ducts penetrating through 3-hour rated wall separating the reactor and auxiliary buildings since malfunction of the fire damper would disrupt the entire reactor building ventilation. These ducts, however, are provided with isolation dampers in series, whose construction (3/8 inch thick steel plate) is more sturdy than 3-hour rated fire dampers. Fire dampers are not provided in the turbine building air riser shaft since its openings are provided with isolation dampers whose construction is sturdier than 1-½ hour fire dampers.

Reference 10 requires that fire doors have a fire resistance rating equivalent to the fire resistance rating of the barrier and be provided with either self closing mechanisms or automatic hold-open and release mechanisms or be maintained locked closed. Fire rated doors which also serve as security doors are electrically supervised by the controlled access system. An alarm will sound in the Central Alarm Station (CAS) if the door does not close within a specified time period.

The adequacy of fire protection for any particular plant safety system or area is determined by an analysis of the effects of the postulated fire relative to maintaining the ability to safely shutdown the plant and minimize radioactive releases to the environment in the event of a fire.

The Fire Rated Assemblies are designed to meet the requirements of GDC 3 and NFPA Standards with any deviations documented and justified (Ref. 9). Additionally, the Fire Rated Assemblies are not assumed in any accident or transient analyses of the UFSAR.

(continued)

BASES

TLCO	All fire rated assemblies, including walls, floors/ceilings, cable tray enclosures and other barriers separating safety-related fire areas or separating portions of redundant systems important to safe shutdown within a fire area shall be OPERABLE. In addition, all sealing devices in fire rated assembly penetrations (fire doors, fire windows, fire dampers, cable and piping penetration seals and ventilation seals) shall be OPERABLE. The OPERABILITY of these devices ensures that damage due to a plant fire is minimized by containing and preventing the spread of the fire into other fire areas.
APPLICABILITY	The potential for a fire exists at all times. For example, a fire could occur while moving irradiated fuel in the secondary containment with the core fully offloaded. Therefore, this TLCO is applicable even when fuel is not loaded in the core.
ACTIONS	A Note has been provided to modify the ACTIONS related to Fire Rated Assemblies. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable fire rated assemblies and sealing devices provide appropriate compensatory measures for separate, inoperable assemblies. As such, a Note has been provided that allows separate Condition entry for each inoperable fire rated assembly or sealing device.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2.1, A.1.2.2, A.2.1, and A.2.2

With a fire rated assembly or sealing device inoperable, the ability to contain the spread of fire between fire areas is degraded. Under these conditions, compensatory measures must be put into place to ensure that any fire in the affected area will be quickly detected and responded to (i.e., extinguished). Establishing a continuous fire watch on at least one side of the affected fire barrier (Required Action A.1.1) provides assurance that a fire in the area, or fire spreading from the other side of the barrier, will be immediately detected and reported such that the site Fire Brigade can quickly respond. Alternatively, per Required Actions A.1.2.1 and A.1.2.2, the OPERABILITY of fire detectors on at least one side of the affected barrier can be verified and an hourly fire watch patrol of the affected area established. The acceptable methods for performing a fire watch patrol (e.g., use of cameras, extent of inspection area, maximum inspection interval, etc.) are delineated in the applicable station implementing procedure. These actions are also effective in ensuring early detection of a fire in the affected area since the OPERABLE fire detectors provide continuous monitoring capability. The Completion Time for establishing one of these compensatory measures is 1 hour. Verification of the OPERABILITY of the fire detectors may be performed by an administrative check, by examining logs or other information, to determine if the fire detectors are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the fire detectors. However, if the OPERABILITY of the fire detectors cannot be verified within 1 hour, Required Action A.1.1 must be complied with.

NRC Regulatory Issues Summary (RIS) 2005-07, “Compensatory Measures to Satisfy the Fire Protection Program Requirements,” informs licensees that alternate compensatory measures may be used for a degraded or inoperable fire protection feature under certain circumstances. For plants that have adopted the standard fire protection license condition given in Generic Letter (GL) 86-10, “Implementation of Fire Protection Requirements”, and removed fire protection from the Technical Specifications in accordance with GL 88-12, “Removal of Fire Protection Requirements from Technical Specification”, the guidance in NRC RIS 2005-07 apply.

LaSalle has adopted the standard fire protection license condition contained in GL 86-10 and has removed fire protection from the Technical Specifications and relocated them to this Technical Requirements Manual. Such alternative compensatory measures may

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2.1, A.1.2.2, A.2.1, and A.2.2 (continued)

consist of administrative controls, operator briefings, temporary procedures, manual actions, temporary detection or a combination of such actions.

A technical evaluation must demonstrate that the alternative compensatory measures would not adversely impact the ability to achieve and maintain safe shutdown in the event of fire. This means that the new compensatory action must screen out in the 10 CFR 50.59 process. One example would be an evaluation using the guidance of NRC GL 91-18, “Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions” Revision 1 to incorporate a temporary operator action to compensate for a degraded/nonconforming condition. It is anticipated that a fire watch may be relieved once the evaluation is approved. A site Fire Protection Engineer must prepare or review the evaluation and the evaluation must be maintained as a plant record subject to subsequent inspection.

The technical evaluation should be performed consistent with the requirements of references 11 and 12.

As a result of the above information, a Note has been added provided to modify the Required Action A.1.2.2 to allow alternate compensatory measures based on a technical evaluation.

The inoperable fire rated assembly or device must be restored to OPERABLE status within 7 days (Required Action A.2.1). Alternately, a report can be prepared in accordance with the station’s Corrective Action Program (CAP) within 7 days of the discovery of the inoperability of the barrier per Required Action A.2.2. The CAP report should describe the cause of the inoperability and the plan for restoring the barrier to an OPERABLE status.

The Completion Times of one hour and 7 days are based on the original licensing basis for fire rated assemblies and devices.

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.7.o.1, TSR 3.7.o.2, and TSR 3.7.o.3

Doorways are one of the largest penetrations through a fire rated assembly and are also the most frequently breached (e.g., through normal daily ingress and egress into areas and rooms). Therefore, in order to ensure that fire rated assemblies will be able to perform their function, it is important to periodically verify that plant fire doors are OPERABLE. These Surveillances ensure that; normally accessed doors are closed except for normal ingress and egress, normally open fire doors are free from obstructions or degradation that would prevent their automatic closure, and infrequently accessed fire doors are locked closed. These inspections are consistent with the requirements of NFPA Standard 80 (Ref. 6).

The Frequency of 24 hours and 7 days is based on the original licensing basis for fire doors and meets the recommendations of Reference 10.

TSR 3.7.o.4

For fire doors which also serve a security-related function, the performance of a CHANNEL FUNCTIONAL TEST ensures that a fire door which fails to close will be detected by providing an alarm at the CAS. These doors and the associated security monitoring devices comprise the Fire Door Supervision System. The Frequency of 31 days is based on the original licensing basis for the fire door supervisory system.

TSR 3.7.o.5

Fire doors are designed to automatically close either upon detection of a fire or following passage through the fire door. The mechanisms which accomplish this automatic function must be periodically inspected to ensure that they remain in good working order and are able to perform their specified function. Inspection of the fire door automatic hold-open mechanism, latches, and release and closing mechanisms ensures that any latch or mechanism degradation will be identified and corrected.

The 184 day Frequency is based on the original licensing basis for fire doors and meets the recommendations of Reference 10.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.o.6 and TSR 3.7.o.7

A visual inspection of each fire window, fire damper (including associated hardware), exposed surface of fire rated assemblies, and 10% of each type of sealed penetration shall be conducted to identify any apparent changes in appearance or abnormal degradation. The presence of an abnormal appearance or degradation does not necessarily represent a failure of this TSR, provided an evaluation determines that the degradation does not affect the OPERABILITY of the fire rated assembly or device (i.e., ability to perform its design function). Regardless of the outcome of this evaluation, if changes in appearance or abnormal degradation are discovered in penetration sealing devices, the sample population for the affected type of penetration seal must be expanded per TSR 3.7.o.7. An additional 10% sample of penetration seals of the degraded type on the affected Unit must be visually inspected. Inspections shall continue until either a sample contains no evidence of changes in appearance or abnormal degradation or all penetration seals of the affected type on the associated Unit have been tested. Testing of penetration seals is performed on a rotating basis such that each device is tested at least every 240 months.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month (i.e., 240 months for penetration seals based on the rotating test sample) Frequency.

BASES

REFERENCES

1. UFSAR Section 9.5.1.
2. 10 CFR 50.48.
3. 10 CFR 50, Appendix A, GDC 3.
4. 10 CFR 50, Appendix A, GDC 5.
5. Branch Technical Position ASB 9.5-1.
6. NFPA 80 – 1975.
7. NFPA 251 – 1972.
8. NFPA 803 – 1978.
9. NUREG–0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.
10. NUREG-0800, Standard Review Plan, Section 9.5.1.
11. CC-AA-309-101, Engineering Technical Evaluations.
12. CC-AA-211-1001, Generic Letter 86-10 Evaluations.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.a AC Circuits Inside Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. The isolation devices for penetrations in the primary containment boundary are part of the primary containment leak tight barrier. To maintain this barrier, the sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, O-rings, etc.) must be maintained leak tight (i.e., leakage within limits of Technical Specification SR 3.6.1.1.1).

Regulatory Guide 1.63 (Ref. 6) describes acceptable methods for compliance with Appendix B and General Design Criterion 50 of Appendix A to 10 CFR 50 requirements for the design, construction, and installation of electrical penetrations through the primary containment barrier. Additionally, the Institute of Electrical and Electronics Engineers (IEEE) Standard 317-1972 prescribes design, construction, installation, and testing requirements for these electrical penetration assemblies. The design of the station’s electrical penetrations is either a pressurized sealed canister type or a nonsealed type with an external pressurization source.

If an electrical fault were to occur in an electrical circuit penetrating primary containment, the fault current could result in an energy release high enough to cause weakening or failure of penetration seals. In order to protect the leak tight integrity of the primary containment electrical penetrations, circuits are either provided with overcurrent protection or maintained de-energized.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES	The LaSalle County Station primary containment electrical penetrations are designed and applied to withstand without loss of mechanical integrity, the maximum possible fault current versus time conditions within the two leads of any single phase circuit or the three leads of any one three phase circuit. The penetrations are designed with oversized conductors through the penetration seals such that they can withstand any conceivable fault current versus time condition not interrupted by the circuit's protective device (e.g., fuse or breaker). Should the protective device fail to clear the fault, the ratio of conductor size within the seals to the conductor size of the external circuit is such that failure of the electrical circuit external to the penetration seals is calculated to occur prior to failure of the penetration conductors. This capability was confirmed by testing. Nevertheless, AC circuits penetrating the primary containment which are not required for power operations are maintained de-energized to eliminate the possibility of conductor or penetration seal failure due to an electrical fault. These circuits are primarily for lighting, utility outlets and convenience power to be used for containment walkdowns, maintenance, and in-situ tests or observations. For normally energized circuits, refer to TLCO 3.8.b, "Primary Containment Penetration Conductor Overcurrent Protective Devices." The failure of an electrical penetration due to a circuit failure is not considered in any Design Basis Accident (DBA) or transient. The design of the penetrations meets the requirements of References 4, 5, and 6.
TLCO	Drywell lighting, drywell hoists and cranes, and welding grid systems inside the primary containment are not required for normal plant operations. Therefore, their electrical circuits are maintained de-energized. Compliance with this TLCO helps ensure that the primary containment electrical penetrations are maintained structurally sound and will limit leakage to those leakage rates assumed in the safety analyses. Normally energized circuits penetrating primary containment are addressed in TLCO 3.8.b.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. Therefore, the circuits specified in this TLCO must be de-energized, except as allowed by the relaxation during entry into the drywell addressed below, to eliminate the possibility of an electrical fault affecting the penetration integrity. During MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations of these MODES and circuits of this TLCO are not required to be de-energized. This Applicability is also consistent with the Applicability of LCO 3.6.1.1, “Primary Containment.” Having the drywell lighting de-energized is an operational problem during entry into the drywell because it prevents safe containment access without the use of portable lighting. Therefore, the drywell lighting circuits (or the other circuits specified in this TLCO, if needed) may be energized in MODES 1, 2, or 3, during evolutions which require entry into the drywell. The probability of a circuit overcurrent event which damages the integrity of the electrical penetration with a concurrent DBA is low enough that these “windows,” when the circuits are energized is justified.
ACTIONS	A Note has been provided to modify the ACTIONS related to AC circuits inside primary containment. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for energized AC circuits inside primary containment provide appropriate compensatory measures for separate energized circuits. As such, a Note has been provided that allows separate Condition entry for each energized circuit.

(continued)

BASES

ACTIONS (continued)

A.1

If it is discovered that one or more of the circuits specified in the TLCO are energized, the associated circuit breaker(s) must be placed in a tripped condition within one hour. The one hour Completion Time is commensurate with the ease of performing the Required Action. This time period also ensures that the probability of an accident (with a concurrent circuit fault) occurring during periods when the circuits are energized is minimal.

As stated in the Applicable Design Bases, the oversizing of the penetration assembly is such that fault current will not cause overheating of the electrical penetration before fault current is interrupted. Therefore, discovery of an energized circuit does not affect the OPERABILITY of the penetration as required by LCO 3.6.1.1. Furthermore, the evaluation summarized in Reference 8 determined the loss of this protection (i.e., circuit de-energization) to be a non-significant risk contributor to core damage frequency and offsite release.

SURVEILLANCE REQUIREMENTS

TSR 3.8.a.1

Verifying that each circuit breaker associated with the circuits specified in the TLCO is in the tripped position provides assurance that electrical penetration degradation due to a circuit fault will not occur. This TSR does not apply to breakers that are locked, sealed or otherwise secured in the tripped position since these breakers were verified to be in the correct position prior to locking, sealing, or securing. This TSR does not require any testing or breaker manipulation; rather, it involves verification that those breakers potentially capable of being mispositioned are in the correct position.

The 24 hour Frequency is based on the original licensing basis for AC circuits inside primary containment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.a.2

This TSR is only applicable to circuit breakers associated with circuits specified in the TLCO that are locked, sealed or otherwise secured in the tripped position. Acceptable methods of securing these breakers are locking/securing the disconnect or breaker handle in such a manner that movement of the handle can only be accomplished by removing the securing device, or by locking/securing access to the breaker (e.g., locking the access panel door) such that the breaker cannot be repositioned without unlocking/unsecuring the access device.

Verifying that these circuit breakers are in the tripped position provides assurance that electrical penetration degradation due to a circuit fault will not occur. This TSR does not require any testing or breaker manipulation; rather, it involves verification that these breakers are in the correct position and that their locking, securing or sealing devices are properly installed and secured.

The 31 day Frequency is based on the original licensing basis for AC circuits inside primary containment and is consistent with the frequency of periodic system alignment checks performed in other Specifications and Requirements.

REFERENCES

1. UFSAR Section 8.4.1.
2. FSAR Appendix B.
3. FSAR Question and Answer 040.106.
4. 10 CFR 50, Appendix A, GDC 50.
5. 10 CFR 50, Appendix B.
6. Regulatory Guide 1.63, “Electrical Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants.”

(continued)

BASES

REFERENCES (continued)

7. IEEE 317-1972, “IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations.”

8. NEDO-31466 (and Supplement 1), “Technical Specification Screening Criteria Application and Risk Assessment,” November 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.b Primary Containment Penetration Conductor Overcurrent Protective Devices

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. The isolation devices for penetrations in the primary containment boundary are part of the primary containment leak tight barrier. To maintain this barrier, the sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, O-rings, etc.) must be maintained leak tight (i.e., leakage within limits of Technical Specification SR 3.6.1.1.1).

Regulatory Guide 1.63 (Ref. 6) describes acceptable methods for compliance with Appendix B and General Design Criterion 50 of Appendix A to 10 CFR 50 requirements for the design, construction, and installation of electrical penetrations through the primary containment barrier. Additionally, the Institute of Electrical and Electronics Engineers (IEEE) Standard 317-1972 prescribes design, construction, installation, and testing requirements for these electrical penetration assemblies. The design of the station's electrical penetrations is either a pressurized sealed canister type or a nonsealed type with an external pressurization source.

If an electrical fault were to occur in an electrical circuit penetrating primary containment, the fault current could result in an energy release high enough to cause weakening or failure of penetration seals. In order to protect the leak tight integrity of the primary containment electrical penetrations, circuits are either provided with overcurrent protection or maintained de-energized. Both instantaneous and thermal (long time) overcurrent protective devices are used on the penetration circuits.

(continued)

BASES (continued)

APPLICABLE DESIGN BASES

The LaSalle County Station (LSCS) primary containment electrical penetrations are designed and applied to withstand without loss of mechanical integrity, the maximum possible fault current versus time conditions within the two leads of any single phase circuit or the three leads of any one three phase circuit. The LSCS design meets the recommendations of Reference 6 by having two breakers for interruption of fault current for normally energized 6.9 kV, 4.16 kV, and 480 volt penetrations. Additionally, The penetrations are designed with oversized conductors through the penetration seals such that they can withstand any conceivable fault current versus time condition not interrupted by the primary protective device. Should the backup protective device also fail to clear the fault, the ratio of conductor size within the seals to the conductor size of the external circuit is such that failure of the electrical circuit external to the penetration seals is calculated to occur prior to failure of the penetration conductors. This capability was confirmed by testing.

Protection is also provided to lower voltage penetrations such as valve control power. The control circuits to valve operators, including their limit switches (since their power comes from a dedicated transformer fed by the controller's power source), are protected with the same redundant circuit protection devices as the parent component. Also, control power is protected with fusing as the primary protection device. Instrumentation circuits are typically protected by use of a single fuse. This is acceptable because the circuits are of such low energy that potential short circuit energy levels would have no adverse affect on the penetration seals.

Although Regulatory Guide 1.63 was issued after the LSCS construction permit, the LSCS electrical penetration design meets the objectives of the positions stated in the Regulatory Guide. The design of the penetrations also meets the requirements of References 4, 5, and 7.

The failure of an electrical penetration due to a circuit failure is not considered in any Design Basis Accident (DBA) or transient. For normally de-energized circuits, refer to TLCO 3.8.a, "AC Circuits Inside Primary Containment."

(continued)

BASES (continued)

TLCO	The primary containment penetration conductor overcurrent primary and backup protective devices specified in Table T3.8.b-1 for Unit 1 (Table T3.8.b-2 for Unit 2) are required to be OPERABLE. Compliance with this TLCO helps ensure that the primary containment electrical penetrations are protected from potentially damaging overcurrent conditions so that they will be maintained structurally sound and will limit leakage to those leakage rates assumed in the safety analyses. Normally de-energized circuits penetrating primary containment are addressed in TLCO 3.8.a. OPERABILITY of the primary containment penetration conductor overcurrent primary and backup protective devices are not dependent upon breaker position.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. Therefore, the devices specified in this TLCO must be OPERABLE to reduce the probability of an electrical fault affecting the penetration integrity. During MODES 4 and 5, the probability and consequences of a DBA are lessened due to the pressure and temperature limitations of these MODES and the devices of this TLCO are not required to be OPERABLE. This Applicability is also consistent with the Applicability of LCO 3.6.1.1, “Primary Containment.”
ACTIONS	A Note has been provided to modify the ACTIONS related to primary containment penetration conductor overcurrent protective devices. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment penetration conductor overcurrent protective devices provide appropriate compensatory measures for separate inoperable devices. As such, a Note has been provided that allows separate Condition entry for each inoperable device.

(continued)

BASES

ACTIONS (continued)

A.1, A.2.1, A.2.2, A.3.1, and A.3.2

If it is discovered that one or more primary containment penetration conductor overcurrent protective devices are inoperable, the device(s) must be restored to an OPERABLE status within 72 hours (Required Action A.1). Alternately, the associated circuit must be de-energized by either tripping, or racking out and removing a circuit breaker in the affected circuit (Required Action A.2.1 or A.3.1). De-energizing the affected circuit in this manner performs the intended function of the device and allows operation to continue. The Completion Time of 72 hours is reasonable considering the reliability of the penetration seals and the relative importance of supporting primary containment integrity.

In the event that the affected circuit is de-energized in accordance with Required Action A.2.1 or A.3.1, the associated circuit breaker must be verified to be tripped, or racked out and removed, on a periodic basis. This is necessary to ensure that primary containment electrical penetrations will not be subjected to excessive fault currents. This verification does not require any testing or breaker manipulation. Rather, it involves verification that these devices, capable of potentially being mispositioned, are in the correct position. The Completion Time of once per 7 days is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Required Action A.2.2 and A.3.2 ensure that appropriate remedial actions are taken, if necessary, if the associated system or component is rendered inoperable by de-energizing the affected circuit in accordance with Required Action A.2.1 or A.3.1. For example, de-energizing the power to inboard isolation valve 1(2)E51-F063 would result in an inoperable Primary Containment Isolation Valve (PCIV) and applicable Conditions and Required Actions of LCO 3.6.1.3, “PCIVs,” would have to be entered. Therefore, a determination of the OPERABILITY status of the affected system or component must be made immediately following the initial performance of Required Action A.2.1 or A.3.1.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.3.1, and A.3.2 (continued)

As stated in the Applicable Design Bases, the oversizing of the penetration assembly is such that fault current will not cause overheating of the electrical penetration before fault current is interrupted. Therefore, discovery of an inoperable primary containment penetration conductor overcurrent protective device does not affect the OPERABILITY of the penetration as required by LCO 3.6.1.1. Furthermore, the evaluation summarized in Reference 8 determined the loss of this protection to be a non-significant risk contributor to core damage frequency and offsite release.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A cannot be met, the plant must be brought to a MODE in which the TLCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

TSR 3.8.b.1

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated relays, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall be performed on a representative sample of the 6.9 kV and 4.16 kV circuit breaker protective relays every 24 months. A representative sample consists of at least 10% of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.8.b.1 (continued)

the 6.9 kV and 4.16 kV breakers listed in Table T3.8.b-1 for Unit 1 (Table T3.8.b-2 for Unit 2). Testing is performed on a rotating basis such that each device is tested at least once every 240 months.

The Frequency and sample size is based on the assumption of a 240 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

TSR 3.8.b.2

The integrated system functional test demonstrates the OPERABILITY of the protective relays and circuit breakers to provide complete testing of the associated function. Therefore, if a breaker is incapable of operating, the associated protective relaying would also be inoperable. Simulated automatic actuation of the system is accomplished by performing the test with the breaker racked to a test position. Although the breaker is tripped under no-load conditions, this testing is adequate to demonstrate that the associated electrical penetration will be protected under actual fault conditions since other more frequent Technical Specifications and non-Technical Specifications tests verify the current interrupting capability of the breaker.

The integrated system functional test shall be performed on a representative sample of the 6.9 kV and 4.16 kV circuit breaker protective relays every 24 months. A representative sample consists of at least 10% of the 6.9 kV and 4.16 kV breakers listed in Table T3.8.b-1 for Unit 1 (Table T3.8.b-2 for Unit 2). If, during testing, a circuit breaker (or associated protective relay) is found to be inoperable, an additional 10% of all circuit breakers of the inoperable type on the affected Unit must be functionally tested. Testing shall continue until either a sample contains no failures or all breakers of the inoperable type on the affected Unit have been tested. Testing is performed on a rotating basis such that each device is tested at least once every 240 months.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.8.b.2 (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month (i.e., 240 months based on the rotating test sample) Frequency.

TSR 3.8.b.3

This TSR, applicable to 480 volt circuit breakers, provides assurance of breaker reliability by functionally testing at least one representative sample of each manufacturer's brand of circuit breaker. Each manufacturer's molded case and metal case circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of molded case circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for Surveillance purposes.

Functional testing of these circuit breakers consists of injecting a current in excess of 120% of the breaker's nominal setpoint and measuring the response time. The measured response time is compared to the manufacturer's data to ensure that it is $\leq$ 120% of the value specified for test current by the manufacturer.

The functional test shall be performed on a representative sample from each type of 480 volt circuit breaker every 24 months. A representative sample consists of at least 10% of each type of 480 volt breaker for the breakers listed in Table T3.8.b-1 for Unit 1 (Table T3.8.b-2 for Unit 2). If, during testing, a circuit breaker is found to be inoperable, an additional 10% of all circuit breakers of the inoperable type on the affected Unit must be functionally tested. Testing shall continue until either a sample contains no failures or all breakers of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.8.b.3 (continued)

inoperable type on the affected Unit have been tested. Testing is performed on a rotating basis such that each device is tested at least once every 240 months.

The TSR is modified by a Note which requires that each circuit breaker found inoperable during this test be restored to OPERABLE or replaced with an OPERABLE breaker prior to returning the affected circuit to operation. This ensures that an electrical penetration circuit is not re-energized unless it has OPERABLE overcurrent protection.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 24 month (i.e., 240 months based on the rotating test sample) Frequency.

TSR 3.8.b.4

Inspections and preventative maintenance are performed on each required circuit breaker to determine overall breaker degradation due to age and usage. These inspections and preventative maintenance activities are performed in accordance with the breaker manufacturer's recommendations and may include; cleaning and inspecting breaker cubicle components, exercising breakers, relays, and overloads to demonstrate proper operation, and inspecting bus bar connections and other equipment in the breaker enclosure.

The 60 month Frequency is based on the original licensing basis of these breaker inspections.

REFERENCES

1. UFSAR Section 8.4.1.

2. FSAR Appendix B.

3. FSAR Question and Answer 040.106.

(continued)

BASES

REFERENCES (continued)

4. 10 CFR 50, Appendix A, GDC 50.

5. 10 CFR 50, Appendix B.

6. Regulatory Guide 1.63, “Electrical Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants.”

7. IEEE 317-1972, “IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations.”

8. NEDO-31466 (and Supplement 1), “Technical Specification Screening Criteria Application and Risk Assessment,” November 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.c Motor Operated Valves Thermal Overload Protection Devices

BASES

BACKGROUND

Motor-operated valves are used in the residual heat removal, high pressure core spray (HPCS), and low pressure core spray (LPCS) emergency core cooling systems; they are also used in the reactor core isolation cooling (RCIC), feedwater, reactor water cleanup, standby gas treatment, standby liquid control, main steam, and hydrogen recombiner systems. In addition, motor-operated valves are installed on various primary and secondary containment isolation lines.

Valve motor operators in these safety systems are provided with thermal overload protection devices. To ensure that the thermal overloads will not prevent the motor-operated valves from performing their safety-related functions under emergency conditions, the thermal overload protection devices are either bypassed during an accident or have sufficiently high trip setpoints to prevent inadvertent trips during valve operation per Regulatory Guide 1.106 (Ref. 3). Thermal overload bypass circuits are normally installed on safety-related motor-operated valves that are required to operate during or immediately following an accident such as the primary containment automatic isolation, emergency core cooling, and RCIC system valves. Thermal overload bypass circuits are not installed on the hydrogen recombiner valves since these valves are not required to be operated until several hours after the accident has occurred. In addition, these valves are normally closed and are provided with only a remote manual control system.

For the valves equipped with thermal overload bypass circuits, the thermal overload protection is either; (1) normally in the circuit but automatically bypassed whenever any safety-related use of the valve is initiated, or (2) continuously bypassed and temporarily placed in the circuit via a test switch when the motors are undergoing periodic surveillance or maintenance testing. These devices are integral to the motor starter circuit.

(continued)

BASES

BACKGROUND (continued)	To prevent the valve motors from being damaged during normal operation or surveillance testing when the thermal overloads are not bypassed, the thermal overloads are set to trip the valve motor operators during locked rotor conditions.
APPLICABLE DESIGN BASES	Motor-operated valves (MOVs) with thermal overload protection devices are used in safety systems and in their auxiliary supporting systems. Operating experience has shown that indiscriminate application of thermal overload protection devices to these valve motors could result in a needless hindrance to successful completion of safety functions. Thermal overload relays are designed primarily to protect continuous-duty motors while they are running rather than during starting. Use of these overload devices to protect intermittent-duty motors may therefore result in undesired actuation of the devices if the cumulative effect of heating caused by successive starts at short intervals is not taken into account in determining the overload trip setting. It is generally very difficult for any thermally sensitive device to adequately approximate the varying thermal characteristics of an intermittent-duty motor over its full range of starting and loading conditions. This is mainly caused by the wide variations in motor heating curves for various sizes and designs and also by the difficulty in obtaining motor heating data to an acceptable accuracy. Since the trip function in a thermal overload device is dependent on temperature, the degree of overload protection provided is affected by changes in ambient temperature at the motor or starter location. This aspect becomes more complex in safety system applications where, in some cases, the motor to be protected is inside the containment and the overload protection devices are outside the containment. In such a situation, the temperature difference between the motor and the overload device could be as high as 200°F under design basis conditions. Thus, the selection of an appropriate trip setpoint for such a valve motor must take into consideration operation of the valve under various

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

temperatures for both normal and postulated accident conditions, including loss-of-coolant accidents.

The accuracy obtainable with the thermal overload relay trip generally varies from -5% to 0% of trip setpoint. Since the primary concern in the application of overload devices is to protect the motor windings against excessive heating, the above negative tolerance in trip characteristics of the protection device is considered in the safe direction for motor protection. However, this conservative design feature built into these overload devices for motor protection could interfere in the successful functioning of a safety-related system (i.e., the thermal overload device could open to remove power from a motor before the safety function has been completed or even initiated). In safety system applications, the criterion for establishing an overload trip setpoint should be to complete the safety function (e.g., drive the valve to its proper position to mitigate the effects of an accident) rather than merely to protect the motor from destructive heating. Where setpoint conflicts exist between motor protection and completion of the safety function, the thermal overload devices are automatically bypassed during accident conditions. An alternate method for resolving this conflict is to maintain the thermal overload devices continuously bypassed during normal plant operation and to place them temporarily in force when the valve motors are operated for normal plant evolutions or during periodic testing.

For the hydrogen recombiner motor-operated valves, the thermal overloads are always in the circuit. However, setting calculations based on Reference 2 demonstrate that the thermal overloads for these valves will not inadvertently trip during required valve operation. The trip setpoints of these thermal overloads have been verified to account for the uncertainties due to the ambient temperature at the location of the overload device following an accident and the inaccuracies in the device trip characteristics.

The Motor Operated Valves Thermal Overload Protection Devices meet Regulatory Position C.1 or C.2 of Reference 3, as applicable. The operation of thermal overload bypass circuitry is explicitly assumed in the UFSAR to ensure that safety-related MOVs are capable of performing their specified safety function.

(continued)

BASES (continued)

TLCO

The thermal overload protection devices for valves without bypass devices and the thermal overload protection bypass devices for valves with bypass devices must be OPERABLE to ensure that valve motor thermal overload protection will not prevent safety-related valves from performing their specified safety function.

Two types of thermal overload bypass devices integral with the motor starter are provided, “Continuous” and under “Accident Conditions”. “Continuous” bypass devices are OPERABLE provided they are maintained in the bypass position (i.e., thermal overload protection devices are not placed in force). “Accident Conditions” thermal overload protection bypass devices are OPERABLE if they are capable of automatically bypassing the associated thermal overload protection device upon receipt of the applicable safety system initiation signal(s).

The MOVs applicable to this Requirement, including the type of bypass devices provided, are listed in Table T3.8.c-1 and Table T3.8.c-2 for Unit 1 and Unit 2 respectively.

APPLICABILITY

Motor Operated Valves required to be OPERABLE by Technical Specifications (TS) or the Technical Requirements Manual (TRM) need to be protected from premature actuation of the motor thermal overload devices in order to assure that they will be able to perform their specified safety functions. Therefore, thermal overload protection devices or thermal overload protection bypass devices, as applicable, must be OPERABLE whenever the associated MOV is required to be OPERABLE. If an MOV is not required to be OPERABLE by the TS or TRM (e.g., due to its Applicability in certain MODES), then the equipment is not necessary to assure safe operation of the plant and the associated protection device or bypass device is not required.

ACTIONS

The ACTIONS are modified by a Note to provide clarification that, for the purpose of this TLCO, separate Condition entry is allowed for each thermal overload protection or bypass device. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable

(continued)

BASES

ACTIONS (continued)

device. Complying with the Required Actions may allow for continued operation, and subsequent inoperable devices are governed by subsequent Condition entry and application of associated Required Actions.

A second Note has been added to ensure appropriate remedial actions are taken, as necessary, if the affected system(s) are rendered inoperable by an inoperable thermal overload protection or bypass device (e.g., HPCS rendered inoperable due to an inoperable bypass device on the injection valve). For inoperable bypass devices, the OPERABILITY of the associated MOV is dependent on the type of bypass device (continuous or accident) and whether the MOV is automatically or manually actuated to perform its specified safety function.

<u>For MOVs with “Continuous” bypass devices</u>: Automatically actuated valves which are already in their accident position and valves which are manually actuated to perform their specified safety function remain OPERABLE when the associated thermal overload protection devices are placed in force.

<u>For MOVs with “Accident condition” bypass devices</u>: Valves which are already in their accident position remain OPERABLE when the associated bypass device is inoperable. If a valve is manually actuated to perform its function and is not in its accident position, the valve would remain OPERABLE if an evaluation is performed concluding that it is still capable of performing its specified safety function. The evaluation must consider the ability of personnel to bypass the thermal overload protection device within the times assumed in the UFSAR for the affected function and must take into account the projected environmental conditions at the location where the bypassing operation is to be performed.

Some MOVs in Table T3.8.c-1 and Table T3.8.c-2 have multiple safety functions or dual safety positions (e.g., closed for containment isolation and open for emergency core cooling). Careful consideration must be given to each function and required position when determining the effect of inoperable bypass devices on the OPERABILITY of supported systems.

(continued)

BASES

ACTIONS (continued)

An exception is provided in Note 2 which allows the Conditions and Required Actions of a system made inoperable by an inoperable thermal overload bypass device to not be entered. If an “Accident Conditions” bypass device is made inoperable due to an inoperable initiation instrument channel(s) that has an LCO specified in TS, then the allowances of LCO 3.0.6 concerning Condition and Required Action entry may be utilized for the TS LCOs of MOV(s) that are in turn made inoperable by the inoperable bypass device. This exception only applies if the bypass device is inoperable solely due to a TS support system LCO not being met. (Refer to the Bases of LCO 3.0.6).

A.1 and A.2

With a continuous thermal overload protection bypass device of an MOV not in continuous bypass (i.e., placed in force) or an accident condition bypass device inoperable, action may be taken to either bypass the associated thermal overload protection device or declare the affected valve inoperable within 8 hours. Bypassing the thermal overload of the affected MOV ensures that the valve will be able to perform its function when required. The allowed 8 hour Completion Time is reasonable considering the time needed to perform periodic maintenance and testing of the valves and the low probability of an event occurring during the time the thermal overloads are not bypassed or the bypass device is inoperable. The Completion Time is based on the original licensing basis for thermal overload bypass devices.

As Noted, this Condition is only applicable to valves designated as having “Continuous” or “Accident Conditions” bypass devices in Tables T3.8.c-1 and T3.8.c-2.

B.1 and B.2

With a thermal overload protection device of an MOV inoperable, action may be taken to either bypass the thermal overload protection device or declare the affected valve inoperable. Continuously bypassing the thermal

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

overload of the affected MOV ensures that the valve will be able to perform its function when required. The Completion Time is based on the original licensing basis for thermal overload protection devices.

As Noted, this Condition is only applicable to valves designated as having no (None) bypass devices in Tables T3.8.c-1 and T3.8.c-2.

SURVEILLANCE REQUIREMENTS

TSR 3.8.c.1

Periodically verifying that thermal overload protection is continuously bypassed for thermal overloads that are temporarily placed in force for valve motor maintenance or testing helps ensure that the switches and contacts used for bypassing the thermal overloads are OPERABLE. For valves whose thermal overloads are in force during normal plant operations and are bypassed automatically under accident conditions, the performance of a CHANNEL FUNCTIONAL TEST ensures that the bypass devices will actuate when required.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

An additional Frequency is provided to ensure that thermal overload bypass devices are OPERABLE prior to restoring the associated valve to an OPERABLE status whenever maintenance has been performed on the motor starting circuitry. This requirement is in addition to the requirements of TSR 3.0.a and SR 3.0.1 for the affected valves since MOVs can be considered OPERABLE (depending on their function and position) without an OPERABLE thermal overload bypass device. The Frequency ensures that all functions of the MOV are OPERABLE following motor starter maintenance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.8.c.1 (continued)

As Noted, this TSR is only applicable to valves designated as having "Continuous" or "Accident Conditions" bypass devices in Tables T3.8.c-1 and T3.8.c-2.

TSR 3.8.c.2

Thermal overload protection devices on some MOVs are temporarily placed in force during maintenance activities or testing in which the valve must be stroked. This ensures that motor damage protection is provided during these non-accident valve manipulation activities. This TSR ensures that compliance with the TLCO is restored upon completion of maintenance or testing activities. This surveillance is performed by verifying that the thermal overload bypass switch associated with the valve is in the normal (i.e., thermal overload continuously bypassed) position.

As Noted, this TSR is only applicable to valves designated as having "Continuous" bypass devices in Tables T3.8.c-1 and T3.8.c-2.

TSR 3.8.c.3

A CHANNEL CALIBRATION is a complete check of the instrument loop, including associated trip unit, and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. A representative sample shall consist of $\geq$ 25% of all thermal overload protection devices such that, at least once every 8 years, each device is calibrated and the associated valve cycled through at least one complete cycle of travel with the motor operator following calibration.

The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. An

(continued)

BASES

SURVEILLANCE REQUIREMENTS

TSR 3.8.c.3 (continued)

additional Frequency is provided to ensure that thermal overload protection devices are OPERABLE prior to restoring the associated valve to an OPERABLE status whenever maintenance has been performed on the motor starting circuitry. This requirement is in addition to the requirements of TSR 3.0.a and SR 3.0.1 for the affected valves since MOVs can be considered OPERABLE (if the thermal overload protection is continuously bypassed per Required Action B.2) without an OPERABLE thermal overload protection device. The Frequency ensures that all functions of the MOV are OPERABLE following motor starter maintenance.

As Noted, this TSR is only applicable to valves designated as having no (None) bypass devices in Tables T3.8.c-1 and T3.8.c-2.

REFERENCES

1. UFSAR Section 6.3.2.2.13.

2. IEEE Standard 741 - 1990.

3. Regulatory Guide 1.106, Revision 1, “Thermal Overload Protection for Electric Motors on Motor-Operated Valves.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.d Battery Monitoring and Maintenance

BASES

BACKGROUND

This TLCO delineates the requirements for maintaining the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for Technical Specification (TS) LCO 3.8.4, "DC Sources – Operating," and LCO 3.8.5, "DC Sources – Shutdown." The Battery Monitoring and Maintenance Program described in 5.0.c implements the program specified in TS 5.5.14 (Ref. 2) for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications" (Ref. 4).

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for a 58 cell battery and 240 V for a 116 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage $\geq$ 2.065 Vpc, the battery will maintain its capacity for 30 days without further charging per manufacturers instructions. Optimal long term performance however, is obtained by maintaining a float voltage of 2.17 to 2.25 Vpc for Division 1 and Division and 2.20 to 2.25 Vpc for Division 3. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.23 Vpc corresponds to a total float voltage output of 129.3 V for a 58 cell battery and 258.7 V for a 116 cell battery as discussed in the UFSAR, Section 8.3.2 (Ref. 3).

APPLICABLE DESIGN BASES

The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The batteries are provided as a source of power for vital loads in case of emergencies such as loss of AC power.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	The 250-volt battery is adequately sized to supply its loads until AC power sources to redundant loads are restored. Each 125-volt battery is sized to supply control power requirements of the switchgear and logic circuitry of one of the three engineered safety feature divisions. The ampere-hour capacity of each battery is adequate to supply expected essential loads following station trip and loss of all AC power without battery terminal voltage falling below 210 VDC / 105 Vdc.
TLCO	Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Section 5.0.c, Technical Specification (TS) Program and Manuals as required by TS 5.5.14 (Ref. 2). The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each DC battery to monitor and restore cell parameters to Category A and B. Complying with the Required Actions for one DC battery allow for continued operation, and subsequent inoperable DC electrical power subsystem(s) are governed by separate Condition entry and application of TS 3.8.4 and TS 3.8.5 (Ref. 1).
APPLICABILITY	The battery parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, battery parameter limits are only required when the associated DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussion in the Bases for TS LCO 3.8.4 and LCO 3.8.5.

(continued)

BASES

ACTIONS

A.1, A.2, A.3, A.4, and A.5

With one or more battery cell parameters not within Table T3.8.d-1, Category A or B limits, the battery remains operable but action is required to monitor and restore the cell parameters. Within one hour, verification that the affected pilot cell electrolyte level is above the top of the plates and not overflowing and float voltage > 2.07 V. Within 24 hours and every 7 days thereafter, verification of all of the affected battery cell parameters meet the Category C limits. Within 31 days, battery cell parameters are to be restored to meet Category A and B limits. Within in 31 days, if electrolyte level is less than the limit, conduct an equalizing charge and any IEEE-450 recommended testing of the affected battery cell(s).

B.1

If any of the Required Action and associated Completion Time of Condition A is not met, or if one or more batteries with one or more Surveillance acceptance criteria are not met for reasons other than Condition A, a CAP document must be prepared immediately. The document should discuss the reason for exceeding the Completion Time of the Required Action, identify proposed restorative actions, and provide a schedule for restoring the normal battery cell(s) parameters to Category A and B.

SURVEILLANCE REQUIREMENTS

TSR 3.8.d.1

The TSR verifies that Table T3.8.d-1 Category A battery cell parameters are consistent with IEEE-450 (Ref. 4), which recommends regular battery inspection (at least one per month) including voltage, specific gravity, and electrolyte level of pilot cells.

TSR 3.8.d.2

The quarterly inspection of specific gravity, voltage, and electrolyte level for each connected cell is consistent with IEEE-450 (Ref. 4). In addition, within 7 days of a battery discharge < 110 V for a 125 V battery and < 220 V for the 250 V battery or a battery overcharge

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.d.2 (continued)

> 150 V for a 125 V battery and > 300 V for the 250 V battery, the battery must be demonstrated to meet Table 3.8.6-1 Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 110 V or 220 V, as applicable, do not constitute a battery discharge provided the battery terminal voltage and float return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 4), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge. The 7 day requirement is based on engineering judgment.

TSR 3.8.d.3

This TSR verification that the average temperature of representative cells is ≥ 60°F for the 125 V batteries and ≥ 65°F for the 250V battery is consistent with a recommendation of IEEE-450-1995 (Ref 4) which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. For this TSR, a check of 10 connected cells is considered representative for the 125V batteries, and a check of 20 connected cells is considered representative for the 250V battery.

Lower than normal temperatures act to inhibit or reduce battery capacity. This TSR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer's recommendations and the battery sizing calculations.

TSR 3.8.d.4

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. Note that though multiple individual battery connections can approach the 1.5E-4 ohm limit without affecting the ability of the battery to meet its design function, the total battery connection resistance must remain within the values specified by Reference 5 or equivalent.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.d.4 (continued)

The connection resistance limits established for this TSR are within the values established by industry practice. The connection resistance limits of this TSR are related to the resistance of individual bolted connections, and do not include the resistance of conductive components (e.g., cables or conductors located between cells, racks, or tiers).

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

TSR 3.8.d.5

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The presence of physical damage or deterioration does not necessarily represent a failure of this TSR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The 24-month Frequency for the Surveillance is based on engineering judgment. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

TSR 3.8.4.6 and TSR 3.8.4.7

Visual inspection and resistance measurements of inter-cell and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.4.6 and TSR 3.8.4.7 (continued)

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this TSR, provided visible corrosion is removed during performance of this Surveillance.

The connection resistance limits for this TSR are within the values established by industry practice. The connection resistance limits of this TSR are related to the resistance of individual bolted connections, and do not include the resistance of conductive components (e.g., cables or conductors located between cells, racks, or tiers). Note that though multiple individual battery connections can approach the 1.5E-4 ohm limit without affecting the ability of the battery to meet its design function, the total battery connection resistance must remain within the values specified by Reference 5 or equivalent.

The 24-month Frequency for the Surveillance is based on engineering judgment. Operating experience has shown that these components usually pass the TSR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. TS 3.8.4 and TS 3.8.5.
2. TS 5.5.14.
3. UFSAR Chapter 8.
4. IEEE 450, 1995.
5. LaSalle Calculation D36, 125VDC and 250 VDC Battery Inter-cell Connector Resistance

B 3.9 REFUELING OPERATIONS

B 3.9.a Decay Time

BASES

BACKGROUND	A fuel handling accident in the fuel handling and storage facility resulting in damage to fuel cladding and subsequent release of radioactive material is one of the postulated accidents used to evaluate the adequacy of structures, systems, and components with respect to the public health and safety. A fuel handling accident during refueling operations could release a fraction of the fission product inventory in a nuclear power plant to the environment. An illustrative accident sequence consists of the dropping of a fuel assembly resulting in breaching of the fuel rod cladding, release of a portion of the volatile fission gases from the damaged fuel rods, absorption of water soluble gases in and transport of soluble and insoluble gases through the water, air filtration prior to release into the environment, and dispersion of the released fission products into the atmosphere. The number and exposure histories of fuel assemblies assumed to be damaged determine the total amount of radioactive material available for immediate release into the water during a fuel handling accident. A conservative approach to determining the quantity of a radioactive material available for release from a fuel assembly is to assume that the assembly with the peak inventory is damaged. The inventory for the peak assembly represents an upper limit value and is not expected to be exceeded. The inventory is calculated assuming maximum full power operation immediately preceding shutdown. Radioactive decay of the fission product inventory during the interval between shutdown and commencement of fuel handling operations is also taken into consideration.
APPLICABLE DESIGN BASES	During movement of irradiated fuel assemblies, the time that the reactor has been subcritical is an initial design parameter in the analysis of a fuel handling accident postulated by Regulatory Guide 1.25 (Ref. 4). Analysis of the fuel handling accident is described in UFSAR Section 15.7.4.

(continued)

BASES

APPLICABLE DESIGN BASES (continued)

The fuel handling accident is assumed to occur as a consequence of a failure of the fuel assembly lifting mechanism resulting in the dropping of a raised fuel assembly onto other fuel bundles in the core. The accident which produces the largest number of failed spent fuel rods is the drop of a spent fuel bundle onto the reactor core when the reactor vessel head is off.

The analytical methods and associated assumptions used to evaluate the consequences of this accident are considered to provide a realistic yet conservative assessment of the consequences. These methods and assumptions constitute the LaSalle UFSAR Design Basis for this event. The fuel assembly is dropped from the maximum height allowed by the fuel handling equipment, which is less than 30 feet. The fuel assembly is expected to impact on the reactor core at a small angle from the vertical, possibly inducing a bending mode of failure on the fuel rods of the dropped assembly. The kinetic energy acquired by the falling fuel assembly is dissipated in one or more impacts. Based on the fuel geometry in the reactor core, four fuel assemblies are struck by the impacting assembly. The fractional energy loss on the first impact is approximately 80%. The second impact is expected to be less direct. The broad side of the dropped assembly impacts approximately 24 more fuel assemblies, so that after the second impact only 136 ft-lb (approximately 1% of the original kinetic energy) is available for a third impact. Because a single fuel rod is capable of absorbing 250 ft-lb in compression before cladding failure, it is unlikely that any fuel rod will fail on a third impact. A total of 124 fuel rods within the 29 affected fuel assemblies are expected to fail as a result of the accident.

Two separate analyses are provided for this event. The first is based on conservative design-basis assumptions known to be acceptable to the NRC for purposes of determining adequacy of the plant design to meet 10 CFR 100 criteria. The second analysis is based on what is believed to be more realistic assumptions. For both analyses, the fission product inventory in the fuel rods assumed to be damaged is based on 1000 days of continuous operation at 3489 MW(t). This assumption results in an equilibrium fission product concentration at the time the reactor is shut down. Longer operating histories do not

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	increase the concentration of fission products of concern. Additionally, a 24-hour period for decay from the above power condition is assumed because it is not expected that fuel handling can begin within 24 hours following initiation of reactor shutdown. The 24-hour decay time allows time to shut down the reactor, depressurize it, remove the reactor vessel head, and remove the reactor internals above the core. It is not expected that these operations could be accomplished in less than 24 hours, and they would normally require approximately 48 hours. Specific fuel handling accident analyses are also conducted for each specific type of fuel in the core. The assumptions made in these specific fuel type analyses account for differences in fuel construction/operation and are conservative with respect to the LaSalle UFSAR design basis assumptions. The fuel handling accident analyses and assumptions comply with the guidance set forth in Reference 4. In addition, although Decay Time satisfies Criterion 2 of the Technical Specification Selection Criteria in 10 CFR 50.36, the 24 hour decay time following subcriticality will always be met for a refueling outage because of the operations required prior to moving irradiated fuel in the reactor vessel. For this reason, the Requirement is not required to be in the Technical Specifications to provide adequate protection of the public health and safety and has been relocated to the TRM.
TLCO	The minimum requirement for subcriticality of $\geq$ 24 hours prior to the movement irradiated fuel in the reactor vessel ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.
APPLICABILITY	TLCO 3.9.a is applicable when moving irradiated fuel assemblies within the reactor pressure vessel (RPV). The TLCO minimizes the possibility of a fuel handling accident that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident.

(continued)

BASES (continued)

ACTIONS

A.1

If the reactor has been subcritical for < 24 hours, all operations involving movement of irradiated fuel assemblies within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of irradiated fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

TSR 3.9.a.1

Verification of the time that the reactor has been subcritical ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Allowing time for the short lived fission products to decay limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident (Ref. 1).

The Frequency of prior to initial movement of irradiated fuel in the reactor vessel is considered adequate since the requirement to be subcritical is time based and once verified to be $\geq$ 24 hours, cannot become less than 24 hours until the reactor is once again made critical following refueling operations.

REFERENCES

1. UFSAR Section 15.7.4.

2. 10 CFR 50.36.

3. 10 CFR 100.

4. Regulatory Guide 1.25, “Assumptions Used for Evaluating the Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors.”

5. Safety Evaluation related to Amendments 147 and 133 for LaSalle County Station Units 1 and 2, “Conversion to Improved Standard Technical Specifications.”

B 3.9 REFUELING OPERATIONS

B 3.9.b Communications

BASES

BACKGROUND	The purpose of the plant communications system is to provide reliable intra-plant and plant-to-offsite communications. The communications subsystems used for intra-plant communications are the public address (PA) system, the dial telephone system, the sound-powered telephone system, and the intra-plant radio system. The refueling platform is capable of communicating with the main control room by any of these intra-plant subsystems. A dedicated GAI-tronics PA system between the refueling platform and the control room serves as the primary means of communication during refueling operations. Dial telephone and sound-powered telephone jacks are also provided on the refueling platform and radio communications are made possible by the use of radio repeater antennas located around the periphery of the refueling floor.
APPLICABLE DESIGN BASES	The plant communications system is designed to provide effective intra-plant communications during normal plant operations and during transient, fire, and accident conditions under the maximum potential noise levels. During refueling operations, personnel in the main control room monitor core reactivity as well as safety system status and operation. Personnel performing core manipulations on the refueling platform have a limited amount of indication available to them. Therefore, having an open line of communication between personnel in the main control room and on the refueling platform is important in assuring that appropriate actions will be taken in the event of an unexpected core reactivity change or a problem with plant safety systems (e.g., a breach of secondary containment). The dedicated GAI-tronics PA system between the refueling platform and the main control room is the preferred means of maintaining this direct communications link during

(continued)

BASES

APPLICABLE DESIGN BASES (continued)	refueling operations. If necessary, the dial telephone, sound-powered telephone, or intra-plant radio system may be used to provide this direct communications link in the event of a GAI-tronics system malfunction. The plant communications system conforms to industry standards and meets the acceptance criteria of Reference 2.
TLCO	Maintaining direct communications between the control room and the refueling platform ensures that refueling platform personnel can be promptly informed of significant changes in the facility status or core reactivity. To qualify as "direct", the communication subsystem being used must have an open communications channel that does not rely on a signaling device to initiate communication. For example, the dial telephone system may be used provided that the phone line is maintained open (i.e., by speakerphone or headset) so that extension dialing and ringing is not necessary to initiate a communication.
APPLICABILITY	Direct communications between control room and refueling platform personnel is required during refueling platform activities which have the potential to affect core reactivity or which could result in a significant release of radioactive material. Therefore, this TLCO is applicable during all CORE ALTERATIONS except for the movement of control rods using the normal drive system. Although normal control rod movement within a fueled cell during MODE 5 is considered a CORE ALTERATION, it is acceptable to not establish communications between the control room and the refueling platform because the movement of the control rod is performed by control room personnel. Since control room personnel control the evolution, observe core reactivity response, and monitor safety system status, maintaining a communications link with the refueling platform is not necessary, therefore, the TLCO is not applicable for this specific CORE ALTERATION.

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BASES (continued)

ACTIONS	A.1 If direct communications between control room and refueling platform personnel is lost, CORE ALTERATIONS must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Once the communications problems have been resolved, CORE ALTERATIONS may continue following successful completion of TSR 3.9.b.1.
SURVEILLANCE REQUIREMENTS	TSR 3.9.b.1 Verifying communications capability between control room and refueling platform personnel ensures that vital information concerning core and equipment status can be quickly communicated from one location to the other. The 12 hour Frequency takes into account less formal, but more frequent, demonstrations of refueling platform to control room communications capability.
REFERENCES	1. UFSAR Section 9.5.2. 2. NUREG-0800, Standard Review Plan, Section 9.5.2. 3. NUREG–0519, Safety Evaluation Report related to the operation of LaSalle County Station Units 1 and 2.

B 3.9 REFUELING

B 3.9.c Crane and Hoist

BASES

BACKGROUND

The fuel handling system in conjunction with the fuel storage area provides a safe and effective means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after postirradiation cooling. The fuel handling system also provides for safe disassembly, handling, and reassembly of the reactor vessel head during refueling operations.

Regulatory Guide 1.13 and NUREG-0612 describe the design requirements for fuel handling systems to ensure that the fuel is protected from mechanical damage due to accidents during crane and hoist operations. The fuel handling system, consisting of the spent fuel cask, reactor building crane, and associated fuel servicing equipment was designed and constructed to comply with these requirements. The requirements for the control of heavy loads (defined as a load whose weight is greater than the combined weight of a single fuel assembly and its handling tool) handled by the fuel handling system are delineated in Reference 1. The requirements for the control of light loads by the fuel handling system are specified in this Requirement.

Transfer of fuel assemblies between the new fuel vault and the Unit 1 and Unit 2 Spent Fuel Pools (SFP), as well as within the SFPs, and the Unit 1 and Unit 2 Reactor Pressure Vessels is performed with the fuel handling system equipment and fuel servicing equipment. The fuel servicing equipment is located on the refueling platform and consists of the fuel hoist, the frame mounted hoist, and the trolley mounted hoist. The fuel hoist (also referred to as the main hoist) is contained within the NF500 mast. The frame mounted and trolley mounted hoists are considered auxiliary hoists. All the hoists have load sensing devices (load cells) and fail safe brakes. The fuel hoist is mounted on the main trolley of the refueling platform and is used to remove and install fuel from the Reactor Pressure Vessel (RPV) and to move fuel within the

(continued)

BASES

BACKGROUND (continued)	SFP. The frame hoist is also mounted on the main trolley and moves with the refueling platform operator's cab. The frame hoist contains air lines which may be attached to air operated grapples and tools. The tools are used to service the RPV (e.g., remove fuel support pieces, handle control rods, etc.). The mono hoist serves the same functions as the frame hoist. The difference between the two auxiliary hoists is that the mono hoist is mounted on its own trolley and can be moved independently of the refueling platform operator's cab. The fuel and auxiliary hoists have load limiting features designed to prevent damage to the fuel or fuel racks during fuel or RPV component transfer operations.
APPLICABLE DESIGN BASES	The fuel servicing equipment provides for handling of fuel assemblies, and other associated light loads such as control rods, fuel support pieces, and RPV service tools. The design objective of the fuel servicing equipment is to permit the safe and efficient transfer of nuclear fuel and other RPV components while avoiding criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. To meet this objective, the refueling platform fuel and auxiliary hoists are provided with a number of interlocks. The interlocks designed to prevent inadvertent criticality events during refueling operations are addressed in LCO 3.9.1, "Refueling Equipment Interlocks." In order to assure that the weight of loads being handled above irradiated fuel assemblies does not exceed that of one fuel assembly and its associated handling tool, the fuel and auxiliary hoists are provided with overload cutoffs that prevent further raising of the load when the weight exceeds a specified limit. An uptravel stop is provided to ensure the load cannot be raised any higher than 8 feet below the rails of the refueling platform. This weight limit and normal carrying height establishes what is considered the upper bound on the potential energy available to damage irradiated fuel if a load drop were to occur. These limits help ensure that the input assumptions of the accident analysis of Reference 2 remain valid. The overload cutoff also ensures core internals are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations. In addition, the uptravel stop ensures that personnel

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BASES

APPLICABLE DESIGN BASES (continued)	radiation exposures are maintained As Low as Reasonably Achievable (ALARA) by maintaining an adequate amount of water shielding between the irradiated component and refueling platform personnel. Three additional design interlocks are provided to help ensure that damage to irradiated fuel does not occur during refueling operations. The hoist loaded interlock ensures that a control rod, bridge, or hoist block is generated, as applicable, while a load is suspended from the hoist over the reactor core to prevent excessive reactivity insertion. The fuel hoist slack cable cutoff and downtravel stop interlocks help ensure that irradiated fuel is not damaged during loading into the RPV. The fuel servicing equipment, with the exception of the refuel platform frame and trolley structures due to seismic considerations, is not safety-related and does not perform any specified safety functions. The overload cutoff and uptravel stop interlocks only assist in ensuring the assumptions of the fuel handling accident analysis are maintained. Therefore, the inoperability of one of these interlocks does not cause the plant to be in an unanalyzed condition provided the assumptions of Reference 2 are maintained (e.g., a fuel bundle was not actually raised greater than 30 feet over the top of the fuel seated in the RPV). In addition, the hoist loaded interlock setpoints provided in this Requirement help ensure the OPERABILITY of interlocks required by SR 3.9.1.1. Refer to LCO 3.9.1, “Refueling Interlocks,” for the fuel loaded interlock Bases.
TLCO	To prevent mechanical damage to fuel assemblies within the RPV during refueling, the cranes and hoists used for handling fuel assemblies and control rods must be OPERABLE. To be OPERABLE, the crane or hoist must have sufficient capacity for handling these loads. In addition, the applicable interlocks specified in the Surveillance Requirements for the associated crane or hoist must also be OPERABLE. The cranes and hoists applicable to this Requirement are the fuel hoist (main hoist), the frame hoist, and the mono hoist located on the refueling platform.

(continued)

BASES (continued)

APPLICABILITY

In MODE 5, mechanical damage to irradiated fuel in the RPV could result in a release of radioactive material to the environment. The crane and hoist interlocks protect against events or accidents which could result in mechanical damage to fuel in the RPV during MODE 5. The refueling platform cranes and hoists, including their associated interlocks, are only required to be OPERABLE during in-vessel fuel or control rod movement since this is the only time a fuel handling accident in the RPV can occur.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no in-vessel fuel movement activities are possible. Therefore, the refueling platform cranes and hoists are not required to be OPERABLE in these MODES.

ACTIONS

A Note has been provided to modify the ACTIONS related to cranes and hoists. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable cranes and hoists provide appropriate compensatory measures for separate inoperable cranes or hoists. As such, a Note has been provided that allows separate Condition entry for each crane or hoist.

A.1

With one or more required cranes or hoists inoperable, in-vessel fuel or control rod movement with the affected equipment must be immediately suspended. This action ensure that operations are not performed with equipment that would potentially not be blocked from unacceptable operation (e.g., raising an irradiated fuel bundle to a height less than 8 feet below the refueling platform rails). Suspension of in-vessel movement shall not preclude completion of movement of a component to a safe position.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

TSR 3.9.c.1

Verifying the OPERABILITY of the overload cutoff of each crane and hoist ensures that core components are protected from excessive lifting forces and limits the maximum potential kinetic energy available in the event of a load drop accident. Each crane or hoist is tested to ensure that further raising of the load is prohibited when the load weight exceeds 1600 +100/-0 pounds for the NF500 mast (fuel hoist) and 1000 $\pm$50 pounds for the auxiliary hoists. This demonstration must be performed once within 7 days prior to the start of in-vessel fuel or control rod movement with the associated hoist. The Completion Time is acceptable due to the relatively short duration of in-vessel manipulations during an outage and takes into account less formal, but more frequent, checks of load weight during refueling operations.

TSR 3.9.c.2

Verifying the OPERABILITY of the loaded interlock of each crane and hoist ensures that the respective hoist loaded signal is functioning properly to provide an input to the Reactor Manual Control System (RMCS). The hoist loaded signal is used in conjunction with the refuel bridge proximity (over the core) switches to provide control rod blocks to RMCS, refuel bridge blocks, or hoisting blocks, as required, to prevent simultaneously loading fuel and manipulating control rods in the reactor. Each crane or hoist is tested to ensure that a hoist loaded signal is generated when the load weight exceeds 700 +50/-0 pounds for the NF500 mast (fuel hoist) and 400 $\pm$50 pounds for the auxiliary hoists. This demonstration must be performed once within 7 days prior to the start of in-vessel fuel or control rod movement with the associated hoist. The Completion Time is acceptable due to the relatively short duration of in-vessel manipulations during an outage and takes into account administrative controls on hoist operation.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.9.c.3

Verifying the OPERABILITY of the fuel hoist slack cable cutoff ensures that fuel assemblies are protected from mechanical damage due to excessive friction or inadvertent
engagement with other core components during fuel loading. The test verifies that further lowering of the load is prohibited when the load weight falls below a predetermined setpoint which is indicative of the hoist being in an unloaded condition. This demonstration must be performed once within 7 days prior to the start of in-vessel fuel or control rod movement with the fuel hoist. The Completion Time is acceptable due to the relatively short duration of in-vessel manipulations during an outage and takes into account less formal, but more frequent, verifications of slack cable cutoff actuation during refueling operations.

TSR 3.9.c.4

Verifying the OPERABILITY of the uptravel stop of each crane and hoist ensures that radiation exposure to personnel is maintained ALARA and limits the maximum potential kinetic energy available in the event of a load drop accident. Each crane or hoist is tested to ensure that further raising of the load is prohibited while the grapple is still at least 8 feet below the rails of the refueling platform. This demonstration must be performed once within 7 days prior to the start of in-vessel fuel or control rod movement with the associated hoist. The Completion Time is acceptable due to the relatively short duration of in-vessel manipulations during an outage and takes into account less formal, but more frequent, verifications of uptravel stop actuation during refueling operations.

TSR 3.9.c.5

The downtravel stop acts as a backup to the slack cable cutoff for the fuel hoist. The test verifies that further lowering of the load is prohibited prior to the grapple exceeding 54 feet below the refueling platform rails in the event the slack cable cutoff were to malfunction. This

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BASES

SURVEILLANCE REQUIREMENTS	TSR 3.9.c.5 (continued) demonstration must be performed once within 7 days prior to the start of in-vessel fuel or control rod movement with the fuel hoist. The Completion Time is acceptable due to the relatively short duration of in-vessel manipulations during an outage and takes into account administrative controls on fuel hoist operation.
REFERENCES	1. UFSAR Section 9.1.4. 2. UFSAR Section 15.7.4. 3. Regulatory Guide 1.13, "Fuel Storage Facility Design Basis." 4. NUREG-0612, "Control of Heavy Loads at Nuclear Plants." 5. NUREG-0800, Standard Review Plan, Section 9.1.2.