

B 3.3 INSTRUMENTATION

B 3.3.5.2 Isolation Condenser (IC) System Instrumentation

BASES

BACKGROUND	<p>The purpose of the IC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser). A more complete discussion of IC System operation is provided in the Bases of LCO 3.5.3, "IC System."</p> <p>The IC System may be initiated by either automatic or manual means. Automatic initiation occurs for sustained (about 17 seconds) conditions of reactor vessel pressure high. The variable is monitored by four pressure switches that are connected to four time delay relays. The outputs of the time delay relays are connected in a one-out-of-two logic to a trip relay. The output of the trip relays are connected in a two-out-of-two logic arrangement. Once initiated, the IC logic can be overridden by the operator.</p>
APPLICABLE SAFETY ANALYSES	<p>The function of the IC System to provide core cooling to the reactor is used to respond to a main steam line isolation event. Although the IC System is an Engineered Safety Feature System, no credit is taken in the accident analyses for IC System operation. Based on its contribution to the reduction of overall plant risk, however, the IC System, and therefore its instrumentation, satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).</p>
LCO	<p>The OPERABILITY of the IC System instrumentation is dependent upon the OPERABILITY of the four channels of the Reactor Vessel Pressure-High Function. Each channel must have its setpoint within the Allowable Value specified in SR 3.3.5.2.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.</p> <p>The Allowable Value for the IC System instrumentation Function is specified in the SR. 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</p>

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LCO
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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., reactor vessel 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 (or design limits) are derived from the limiting values of the process parameters obtained from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

The Reactor Vessel Pressure-High Allowable Value is set high enough to ensure that a potential event is in process. The time delay is determined by engineering judgement to avoid spurious unnecessary activations of the IC by allowing time for the pressure spike, caused by a main steam isolation valve or stop valve closure, to decay.

Four channels of Reactor Vessel Pressure-High Function are available and are required to be OPERABLE when IC is required to be OPERABLE to ensure that no single instrument failure can preclude IC initiation.

APPLICABILITY The Function is required to be OPERABLE in MODE 1, and in MODES 2 and 3 with reactor steam dome pressure > 150 psig since this is when IC is required to be OPERABLE. (Refer to LCO 3.5.3 for Applicability Bases for the IC System.)

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BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to IC System 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 IC System 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 IC System instrumentation channel.

A.1 and A.2

Required Action A.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels result in a complete loss of automatic initiation capability for the IC System. In this case, automatic initiation capability is lost if two channels associated with the same trip relay are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of required Action A.2 is not appropriate, and the IC System must be declared inoperable within 1 hour after discovery of loss of IC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action A.1, the Completion Time only begins upon discovery that the IC System cannot be automatically initiated due to two or more inoperable, untripped Reactor Vessel Pressure-High channels. The 1 hour Completion Time for discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

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ACTIONS

A.1 and A.2 (continued)

Because of the redundancy of sensors available to provide initiation signals and the fact that the IC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. 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.2. Placing the inoperable channel 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 in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition B must be entered and its Required Action taken.

B.1

With any Required Action and associated Completion Time of Condition A not met, the IC System may be incapable of performing the intended function, and the IC System must be declared inoperable immediately.

SURVEILLANCE
REQUIREMENTS

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 Reactor Vessel Pressure-High Function maintains initiation 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.

SR 3.3.5.2.1

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

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SURVEILLANCE
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SR 3.3.5.2.1 (continued)

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 31 days is based on plant operating experience with regard to channel OPERABILITY and drift that demonstrates that failure of more than one channel in any 31 day interval is rare.

SR 3.3.5.2.2 and SR 3.3.5.2.3

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. A Note to SR 3.3.5.2.2 states that this SR is not required for the time delay portion of these channels. This allowance is consistent with the plant specific setpoint methodology. This portion of the channels must be calibrated in accordance with SR 3.3.5.2.3.

The Frequency of SR 3.3.5.2.2 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

The Frequency of SR 3.3.5.2.3 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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SR 3.3.5.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety 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 that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.
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B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND The primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most 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 a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logics are (a) reactor vessel water level, (b) area ambient temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) main steam line pressure, (f) high pressure coolant injection (HPCI) and isolation condenser steam line flow, (g) drywell radiation and pressure, (h) HPCI steam line pressure, (i) isolation condenser return flow, (j) recirculation line water temperature, and (k) reactor vessel pressure. Redundant sensor input signals from each parameter are provided for initiation of isolation. The only exception is SLC System initiation.

Primary containment isolation instrumentation has inputs to the trip logic of the isolation functions listed below.

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BACKGROUND
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1. Main Steam Line Isolation

The Reactor Vessel Water Level—Low Low, Main Steam Line Pressure—Low, and Main Steam Line Pressure—Timer Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of all main steam isolation valves (MSIVs), MSL drain valves, and recirculation loop sample isolation valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation.

The Main Steam Line Flow—High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of the four trip strings. Two trip strings make up each trip system and both trip systems must trip to cause an isolation of all MSIVs, MSL drain valves, and recirculation sample isolation valves. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings are arranged in a one-out-of-two taken twice logic. This is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation.

The Main Steam Line Tunnel Temperature—High Function receives input from 16 channels, four for each of the four tunnel areas. The logic is arranged similar to the Main Steam Line Flow—High Function. One channel from each steam tunnel area inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation.

MSL Isolation Functions isolate the Group 1 valves.

2. Primary Containment Isolation

The Reactor Vessel Water Level—Low and Drywell Pressure—High Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the PCIVs identified in Reference 1. Any channel will trip the

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2. Primary Containment Isolation (continued)

associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation.

The Drywell Radiation-High Function receives input from two radiation detector assemblies each connected to a switch. Each switch actuates two contacts. Each contact inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the PCIVs identified in Reference 1. The two contacts associated with the same switch provide input to both trip strings in the same trip system. Any contact will trip the associated trip string. The trip strings are arranged in a one-out-of-two taken twice logic. For the purpose of this Specification, a channel is considered to include a radiation detector assembly, a switch, and one of two contacts.

Primary Containment Isolation Functions isolate the Group 2 valves.

3, 4. High Pressure Coolant Injection System Isolation and Isolation Condenser System Isolation

The HPCI Steam Flow-High and HPCI Steam Flow Timer Functions each receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems is connected to both valves on the HPCI steam supply penetration. The Isolation Condenser Steam Flow-High and Return Flow-High Functions each receive input from one channel with its associated flow switch. The steam flow switch and the condensate flow switch are connected in a one-out-of-two logic in each of two trip strings. Each of the two trip strings provides input into two trip systems in a one-out-of-two logic and each trip system isolates either the inboard or outboard Isolation Condenser steam and condensate isolation valves. For the purpose of this Specification, an Isolation Condenser Steam Flow-High Function channel and the associated Return Flow-High channel must be OPERABLE (one separate channel for each trip system).

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3. 4. High Pressure Coolant Injection System Isolation and Isolation Condenser System Isolation (continued)

The HPCI Steam Supply Line Pressure—Low Function receives input from four steam supply pressure channels. The outputs from the HPCI steam supply pressure channels are connected in a one-out-of-two-twice arrangement which provides input to two trip systems. Either trip system isolates both valves in the HPCI steam supply penetration.

The HPCI Turbine Area Temperature—High Function receives input from 16 temperature switches. Four channels, each with an associated temperature switch, provide inputs to a one-out-of-two-twice logic arrangement in each of two AC and two DC trip strings. Each of the trip strings provides input into both an AC and DC trip system and only one trip string must trip to trip the associated trip system. However for OPERABILITY, only one DC trip string is required to provide input into the DC trip system and only one AC trip string is required to provide input into the AC trip system. Either trip system isolates both valves in the HPCI steam supply penetration.

HPCI and Isolation Condenser Functions isolate the Group 4 and 5 valves, as appropriate.

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level—Low Isolation Function receives input from four reactor vessel water level channels. Each channel inputs into one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the reactor water cleanup (RWCU) valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation. The SLC System Initiation Function receives input from the SLC initiation switch. The switch provides trip signal inputs to both trip systems in any position other than "OFF". The other switch positions are SYS 1, SYS 2, SYS 1+2 and SYS 2+1. For the purpose of this Specification, the SLC

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5. Reactor Water Cleanup System Isolation (continued)

initiation switch is considered to provide 1 channel input into each trip system. Each of the two trip systems is connected to one of the two RWCU valves.

RWCU Functions isolate the Group 3 valves.

6. Shutdown Cooling (SDC) System Isolation

The Reactor Vessel Water Level—Low Function receives input from four reactor vessel water level channels. Each channel inputs into one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the SDC suction isolation valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation. The Recirculation Line Water Temperature—High Function receives input from two channels, both of which provide input to both trip systems. Any channel will trip both trip systems. This is a one-out-of-two logic for each trip system. Each of the two trip systems is connected to one of the two valves on the SDC suction penetration. Only one of the trip systems isolates the SDC return penetration.

Shutdown Cooling System Isolation Functions isolate some Group 3 valves (SDC isolation valves).

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The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 2 and 3 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.35(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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The OPERABILITY of the primary containment instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. 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. Each channel must also respond within its assumed response time, where appropriate.

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., reactor vessel water level), 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 from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

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Certain Emergency Core Cooling Systems (ECCS) valves (e.g., containment spray isolation valves) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS. Some instrumentation requirements and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation," and are not included in this LCO.

In general, the individual Functions are required to be OPERABLE in MODES 1, 2, and 3 consistent with the Applicability for LCO 3.6.1.1, "Primary Containment." Functions that have different Applicabilities are discussed below in the individual Functions discussion.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

Main Steam Line Isolation

1.a. Reactor Vessel Water Level—Low Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level—Low Low Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level—Low Low Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 4). The isolation of the MSLs supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water

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1.a. Reactor Vessel Water Level—Low Low (continued)

(reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Low Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level—Low Low Allowable Value (LCO 3.3.5.1) to ensure that the MSIs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits.

This Function isolates the Group 1 valves.

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 5). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

The MSL low pressure signals are initiated from four pressure switches that are connected to the MSL header directly downstream of the main steam equalizing header. The switches are arranged such that, even though physically separated from each other, each switch is able to detect low MSL pressure. Four channels of Main Steam Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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1.b. Main Steam Line Pressure—Low (continued)

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 5).

This Function isolates the Group 1 valves.

1.c. Main Steam Line Pressure—Timer

The Main Steam Line Pressure—Timer is provided to prevent false isolations on low MSL pressure as a result of pressure transients, however, the timer must function in a limited time period to support the OPERABILITY of the Main Stem Line Pressure—Low Function by enabling the associated channels after a certain time delay. The Main Steam Line Pressure—Timer is directly assumed in the analysis of the pressure regulator failure (Ref. 5). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded.

The MSL low pressure timer signals are initiated when the associated MSL low pressure switch actuates. Four channels of Main Steam Line Pressure—Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to be long enough to prevent false isolations due to pressure transient but short enough to prevent excessive RPV depressurizations.

This Function isolates the Group 1 valves.

1.d. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If

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1.d. Main Steam Line Flow-High (continued)

the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow-High Function is directly assumed in the analysis of the main steam line break (MSLB) (Ref. 6). The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

The MSL flow signals are initiated from 16 differential pressure switches that are connected to the four MSLs (the differential pressure switches sense differential pressure across a flow restrictor). The differential pressure switches are arranged such that, even though physically separated from each other, all four connected to one MSL would be able to detect the high flow. Four channels of Main Steam Line Flow-High Function for each MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

This Function isolates the Group 1 valves.

1.e. Main Steam Line Tunnel Temperature-High

Main steam line tunnel temperature is provided to detect a leak in the RCPB in the steam tunnel and provides diversity to the high flow instrumentation. Temperature is sensed in four different areas of the steam tunnel above each main steam line. The isolation occurs when a very small leak has occurred in any one of the four areas. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the UFSAR, since bounding analyses are performed for large breaks, such as MSLBs.

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1.e. Main Steam Line Tunnel Temperature-High (continued)

Main steam line tunnel temperature signals are initiated from temperature switches located in the four areas being monitored. Even though physically separated from each other, any temperature switch in any of the four areas is able to detect a leak. Therefore, sixteen channels of Main Steam Line Tunnel Temperature-High Function are available, but only eight channels (two channels in each of the four trip strings) are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Main Steam Line Tunnel Temperature-High Allowable Value is chosen to detect a leak of less than 1% rated steam flow.

These Functions isolate the Group 1 valves.

Primary Containment Isolation

2.a. Reactor Vessel Water Level-Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on low RPV water level supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level-Low Function associated with isolation is implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level-Low signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level-Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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2.a. Reactor Vessel Water Level—Low (continued)

The Reactor Vessel Water Level—Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 2 and 3 valves.

2.b. Drywell Pressure—High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure—High Function, associated with isolation of the primary containment, is implicitly assumed in the UFSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell Pressure—High per Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure—High (LCO 3.3.5.1) and RPS Drywell Pressure—High (LCO 3.3.1.1) Allowable Values, since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 2 valves.

2.c. Drywell Radiation—High

High drywell radiation indicates possible gross failure of the fuel cladding. Therefore, when Drywell Radiation—High is detected, an isolation is initiated to limit the release of fission products. However, this Function is not assumed in any accident or transient analysis in the UFSAR because other leakage paths (e.g., MSIVs) are more limiting.

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2.c. Drywell Radiation-High (continued)

The drywell radiation signals are initiated from radiation detectors that are located in capped drywell penetrations. Two channels of Drywell Radiation-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is low enough to promptly detect gross failures in the fuel cladding.

This Function isolates the Group 2 valves.

High Pressure Coolant Injection System Isolation

3.a. HPCI Steam Line Flow-High

The HPCI Steam Line Flow-High Function is provided to detect a break of the HPCI steam lines and initiate closure of the HPCI steam line isolation valves. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and the core can uncover. Therefore, the isolations are initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for these Functions is not assumed in any UFSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the HPCI steam line breaks from becoming bounding.

The HPCI Steam Line Flow-High signals are initiated from two differential pressure transmitters that are connected to the system steam lines. Two channels of the HPCI Steam Line Flow-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

This Function isolates the Group 4 valves.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

3.b. HPCI Steam Line Flow - Timer

The HPCI Steam Line Flow - Timer is provided to prevent false isolations on HPCI Steam Line Flow - High during system startup transients and therefore improves system reliability. This Function is not assumed in any UFSAR transient or accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments support prevention of HPCI steam line breaks from becoming bounding.

The HPCI Steam Line Flow-Timer Function delays the HPCI Steam Line Flow-High signal by use of time delay relays. When a HPCI Steam Line Flow-High signal is generated, the time delay relays delay the tripping of the associated HPCI isolation trip system for a short time. Two channels of HPCI Steam Line Flow-Timer Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculation.

This Function, in conjunction with the HPCI Steam Line Flow-High Function, isolates the Group 4 valves.

3.c. HPCI Steam Supply Line Pressure - Low

Low HPCI steam supply line pressure indicates that the pressure of the steam in the HPCI turbine may be too low to continue operation of the turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI initiations. Therefore, they meet Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The HPCI Steam Supply Line Pressure-Low signals are initiated from four pressure transmitters that are connected to the system steam line. Four channels of HPCI Steam

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
LCO, and
APPLICABILITY

3.c. HPCI Steam Supply Line Pressure—Low (continued)

Supply Line Pressure—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are selected to be high enough to prevent damage to the system turbine.

These Functions isolate the Group 4 valves.

3.d. HPCI Turbine Area Temperature—High

HPCI turbine area temperatures are provided to detect a leak from the HPCI system steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

HPCI Turbine Area Temperature—High signals are initiated from temperature switches that are appropriately located to detect a leak from the system piping that is being monitored. Four instruments monitor each area. Sixteen instruments monitor the HPCI Turbine Area. Sixteen channels for HPCI Turbine Area Temperature—High are available, however only eight channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (a) to Table 3.3.6.1-1) each trip system associated with this Function requires all four channels to be associated with a single trip string (four channels within the same AC trip string for the AC trip system and four channels within the same DC trip string for the DC trip system).

The Allowable Value is set well above the expected ambient condition but low enough to detect steam line leakage.

These Functions isolate the Group 4 valves.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

Isolation Condenser System Isolation

4.a, 4.b. Isolation Condenser Steam Flow-High and Return
Flow-High

The Isolation Condenser Flow-High Functions are provided to detect a break of the isolation condenser lines and initiate closure of the inboard and outboard steam line and condensate return line isolation valves and vent line isolation valves. If steam or condensate is allowed to continue flowing out of the break, the reactor may depressurize and the core can uncover. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for these Functions is not assumed in any UFSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the Isolation Condenser steam flow or return flow breaks from becoming bounding.

The Isolation Condenser Flow-High signals are initiated from four differential pressure switches (two in the steam line and two in the condensate return line). Two channels of both Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLLB event as the bounding event.

These Functions isolate the Group 5 valves.

Reactor Water Cleanup System Isolation

5.a. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 7). SLC System initiation signals are initiated from the SLC initiation switch.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

5.a. SLC System Initiation (continued)

Two channels of the SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7).

There is no Allowable Value associated with this Function since the channels are mechanically actuated based solely on the position of the SLC System initiation switch.

This Function isolates the reactor water cleanup inboard and outboard valves.

5.b. Reactor Vessel Water Level—Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on low RPV water level supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level—Low Function associated with RWCU isolation is not directly assumed in the UFSAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

Reactor Vessel Water Level—Low signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level—Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level—Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level—Low Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 3 valves.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

Shutdown Cooling (SDC) System Isolation

6.a. Recirculation Line Water Temperature-High

The Recirculation Line Water Temperature-High Function is provided to isolate the Shutdown Cooling System. This interlock is provided for equipment protection to prevent exceeding the system design temperature, and credit for the interlock is not assumed in the accident or transient analysis in the UFSAR.

The Recirculation Line Water Temperature-High signals are initiated from the high recirculation loop temperature alarm circuit. Two channels (both providing input into two trip systems) of Recirculation Line Water Temperature-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor coolant temperature exceeds the system design temperature and equipment protection is needed. The Allowable Value was chosen to be low enough to protect the system equipment from exceeding its design temperature.

This Function isolates the Group 3 shutdown cooling valves.

6.b. Reactor Vessel Water Level-Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level-Low Function associated with Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the Shutdown Cooling System is bounded by breaks of the recirculation and MSL. The Shutdown Cooling System isolation on low RPV water level supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the Shutdown Cooling System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<u>6.b. Reactor Vessel Water Level-Low</u> (continued) Reactor Vessel Water Level-Low signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level-Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (b) to Table 3.3.6.1-1), only one channel per trip system (with an isolation signal available to one shutdown cooling pump suction isolation valve) of the Reactor Vessel Water Level-Low Function is required to be OPERABLE in MODES 4 and 5, provided the Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.
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The Reactor Vessel Water Level-Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level-Low Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level-Low Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel. In MODES 1 and 2, another isolation (i.e., Recirculation Line Water Temperature-High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates the Group 3 shutdown cooling valves.

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
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(continued)

BASES

ACTIONS
(continued) 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 diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 8 and 9) 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). 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 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). The MSL and Primary Containment Isolation Functions and portions of other system Isolation Functions are considered to be maintaining isolation

(continued)

BASES

ACTIONS

B.1 (continued)

capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. For Functions 1.a, 1.b, 1.c, 2.a, 2.b, 2.c, 5.b, 6.a, and 6.b, this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.d, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. Function 1.e, consists of channels that monitor several locations within a given area (e.g., different locations within the main steam tunnel area). However, any channel in any of the four areas is able to detect a leak. Therefore, this would require both trip systems to have one channel OPERABLE or in trip. The HPCI and portions of other system Isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 3.a, 3.b, 3.c, 4.a, 4.b, and 5.a, this would require one trip system to have one channel OPERABLE or in trip. For Function 3.d, this would require one trip system to have two or more channels OPERABLE or in trip (e.g., contacts 2370 or 2371 and 2372 or 2373).

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.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 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

(continued)

BASES

ACTIONS

C.1 (continued)

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.

D.1, D.2.1, and D.2.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with an MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. This Required Action will generally only be used if a Function 1.d channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow-High Function channel(s) are inoperable. Alternately, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). The 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 systems.

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 8 hours. The allowed Completion Time of 8 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS
(continued)

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channel. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1 and G.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, or any Required Action of Condition F is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated SLC subsystem(s) is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the associated SLC subsystems inoperable or isolating the RWCU System.

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

I.1 and I.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 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 Shutdown Cooling System is isolated.

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

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 isolation 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 reliability analysis (Refs. 8 and 9) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.6.1.1

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 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 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 LCO.

SR 3.3.6.1.2 and SR 3.3.6.1.5

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

SR 3.3.6.1.2 and SR 3.3.6.1.5 (continued)

The 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analyses described in References 8 and 9. The 24 month Frequency of SR 3.3.6.1.5 is based on engineering judgement and the reliability of the components.

SR 3.3.6.1.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than that accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analyses of References 9 and 10.

SR 3.3.6.1.4 and SR 3.3.6.1.6

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.

The Frequency of SR 3.3.6.1.4 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.6.1.6 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.6.1.7

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety 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.

REFERENCES

1. Technical Requirements Manual.
 2. UFSAR, Section 6.2.
 3. UFSAR, Chapter 15.
 4. UFSAR, Section 15.6.5.
 5. UFSAR, Section 15.1.3.
 6. UFSAR, Section 15.6.4.
 7. UFSAR, Section 9.3.5.
 8. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
 9. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
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B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs) and starts the Standby Gas Treatment (SGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation and establishment of vacuum with the SGT System ensures that fission products that leak from primary containment following a DBA, or are released outside primary containment, or are released during certain operations when primary containment is not required to be OPERABLE are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most 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 a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (1) reactor vessel water level, (2) drywell pressure, (3) reactor building exhaust high radiation, and (4) refueling floor high radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation.

For both the Reactor Vessel Water Level—Low and Drywell Pressure—High Function, the secondary containment isolation logic receives input from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to initiate the secondary containment isolation function. Any channel will trip the associated trip string. Any trip string will trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate the secondary containment

(continued)

BASES

BACKGROUND (continued)	isolation function. For both Reactor Building Exhaust Radiation-High and Refueling Floor Radiation-High Functions, the secondary containment isolation trip system logic receives input from four channels. Two channels of Reactor Building Exhaust Radiation-High are located in each of the unit reactor building exhaust ducts and two channels of Refueling Floor Radiation-High are located where they can monitor the environment of each of the unit spent fuel pools. The output of the channels associated with Unit 2 are provided to one trip system while the output of the channels associated with Unit 3 are provided to the other trip system. The output from these channels are arranged in two one-out-of-two trip system logics for each Function to initiate the secondary containment isolation function. Any Reactor Building Exhaust Radiation-High or Refueling Floor Radiation-High channel will initiate the secondary containment isolation function. Initiating the secondary containment isolation function provides an input to both secondary containment Train A and Train B logic. Either train initiates isolation of all secondary containment isolation valves and provides a start signal to the associated SGT subsystem.
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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<p>The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 2 and 3 to initiate closure of the SCIVs and start the SGT System to limit offsite doses.</p> <p>Refer to LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," Applicable Safety Analyses Bases for more detail of the safety analyses.</p> <p>The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.</p> <p>The OPERABILITY of the secondary containment isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function</p>
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(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.6.2-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each 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., reactor vessel water level), 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 from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions when SCIVs and the SGT System are required.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Vessel Water Level - Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level - Low Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation of systems on Reactor Vessel Water Level - Low support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 2).

Reactor Vessel Water Level - Low signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low Allowable Value was chosen to be the same as the Reactor Protection System (RPS) Reactor Vessel Water Level - Low Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), since this could indicate that the capability to cool the fuel is being threatened.

The Reactor Vessel Water Level - Low Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, this Function is not required. In addition, the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

1. Reactor Vessel Water Level—Low (continued)

Function is also required to be OPERABLE during operations with a potential for draining the reactor vessel (OPDRVs) to ensure that offsite dose limits are not exceeded if core damage occurs.

2. Drywell Pressure—High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The isolation and initiating of the systems on Drywell Pressure—High supports actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 2).

High drywell pressure signals are initiated from pressure switches that sense the pressure in the drywell. Four channels of Drywell Pressure—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude performance of the isolation function.

The Allowable Value was chosen to be the same as the RPS Drywell Pressure—High Function Allowable Value (LCO 3.3.1.1) since this is indicative of a loss of coolant accident (LOCA).

The Drywell Pressure—High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

3, 4. Reactor Building Exhaust Radiation-High and
Refueling Floor Radiation-High

High reactor building exhaust radiation or refuel floor radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Reactor Building Exhaust Radiation-High or Refueling Floor Radiation-High is detected, secondary containment isolation and actuation of the SGT System are initiated to support actions to limit the release of fission products as assumed in the UFSAR safety analyses (Refs. 2 and 3).

The Reactor Building Exhaust Radiation-High signals are initiated from radiation detectors that are located on the ventilation exhaust duct coming from the associated reactor building. Therefore, the channels must be declared inoperable if the associated reactor building ventilation exhaust duct is isolated. Refueling Floor Radiation-High signals are initiated from radiation detectors that are located on the refueling floor around the spent fuel storage pool. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Four channels of Reactor Building Exhaust Radiation-High Function and four channels of Refueling Floor Radiation-High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

The Reactor Building Exhaust Radiation-High and Refueling Floor Radiation-High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are also required to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<u>3, 4. Reactor Building Exhaust Radiation-High and Refueling Floor Radiation-High</u> (continued) be OPERABLE during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment, because the capability of detecting radiation releases due to fuel failures (due to fuel uncover or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.
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ACTIONS A Note has been provided to modify the ACTIONS related to secondary 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 secondary 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 secondary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 4 and 5) 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). If the inoperable channel cannot be restored to OPERABLE status

(continued)

BASES

ACTIONS

A.1 (continued)

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 capability to accommodate a single failure, and allow operation to continue. 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 Actions 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 a complete loss of isolation capability for the associated penetration flow path(s) or a complete loss of initiation capability for the SGT System. A Function is considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that a trip signal will be generated from the given Function on a valid signal. This ensures that the two SCIVs in the associated penetration flow path and the SGT System can be initiated on an isolation signal from the given Function. For the Functions with two one-out-of-two logic trip systems (Functions 1 and 2), this would require one trip system to have one channel OPERABLE or in trip. For Functions 3 and 4, this would require each 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 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to

(continued)

BASES

ACTIONS

C.1.1, C.1.2, C.2.1, and C.2.2 (continued)

maintain the secondary containment function. Isolating the associated penetration flow path(s) and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operation to continue. The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem.

Alternately, declaring the associated SCIVs or SGT subsystem(s) inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without unnecessarily challenging plant systems.

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

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 isolation 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 reliability analysis (Refs. 4 and 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated the 6 hour testing allowance does not significantly reduce the probability that the SCIVs will isolate the associated penetration flow paths and that the SGT System will initiate when necessary.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.6.2.1

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 channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.6.2.2

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 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

SR 3.3.6.2.2 (continued)

The Frequency of 92 days is based on the reliability analysis of References 4 and 5.

SR 3.3.6.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 4 and 5.

SR 3.3.6.2.4 and SR 3.3.6.2.5

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.

The Frequencies of SR 3.3.6.2.4 and SR 3.3.6.2.5 are based on the assumption of a 92 day and a 24 month calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.6.2.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety 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 that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 6.2.3.
 2. UFSAR, Section 15.6.5.
 3. UFSAR, Section 15.7.3.
 4. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
 5. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
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B 3.3 INSTRUMENTATION

B 3.3.6.3 Relief Valve Instrumentation

BASES

BACKGROUND

The low set portion of relief valve instrumentation is designed to mitigate the effects of postulated thrust loads on the relief valve discharge lines by preventing subsequent actuations with an elevated water leg in the discharge line. It also mitigates the effects of postulated pressure loads on the torus shell or suppression pool by preventing multiple actuations in rapid succession of the relief valve subsequent to their initial actuation. The low set function of relief valve instrumentation is contained within the control logic of the two relief valves that are set to initiate first on an overpressure event. The relief valve instrumentation, as a whole, is designed to mitigate the effects of overpressurization transients via the relief mode of five relief valves.

The relief valve instrumentation logic consists of separate channels for each of the five relief valves with each channel controlling one associated relief valve. Each channel contains a high pressure (PS_H) switch and a low pressure (PS_L) switch. The pressure switches sense reactor pressure from the upstream side of the relief valve to open the associated relief valve on a sensed high reactor pressure and close the valve following a reduction in reactor pressure. Actuation of the associated relief valve is accomplished via closure of the PS_H on a sensed high reactor pressure, which energizes the relief valve solenoid to open the valve. The PS_L closes to seal in the actuation signal and opens when reactor pressure has decreased below the low pressure setpoint of the switch to de-energize the solenoid and allow the relief valve to close.

The relief valve high pressure setpoints are set such that two of the five relief valves (i.e., the Low Set Relief Valves) will actuate at a pressure that is approximately twenty pounds lower than the remaining three relief valves (i.e., the Relief Valves). The lower pressure settings are intended to reduce the frequency of multiple relief discharges.

(continued)

BASES

BACKGROUND (continued)	Two Low Set Relief Valve Reactuation Time Delay channels are included in the associated control logic for the two relief valves designated to open at the lower reactor pressure (i.e., the Low Set Relief Valves). Each channel consists of a time delay dropout relay and its associated contacts. The channels are arranged in a two-out-of-two logic arrangement for each low set relief valve. The Low Set Relief Valve Reactuation Time Delay Function ensures a time delay of approximately 10 seconds occurs between the closure of the associated relief valve and any subsequent opening of the valve by preventing the reopening of the valve. In this fashion, the low set portion of relief valve instrumentation increases the time between (or prevents) subsequent actuations to allow the high water leg created from the initial relief valve opening to return to (or fall below) its normal water level; thus, reducing thrust loads from subsequent actuations to within their design limits.
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APPLICABLE SAFETY ANALYSES	<p>The relief valve instrumentation and low set function ensures that the containment loads remain within the primary containment design basis (Refs. 1 and 2). The opening setpoints of the relief valves also ensure that the transient analyses of Reference 3 can be met.</p> <p>The relief valve instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).</p>
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LCO	<p>The LCO requires OPERABILITY of sufficient relief valve instrumentation channels to ensure successfully accomplishing the relief valve function assuming any single instrumentation channel failure. Therefore, the OPERABILITY of the relief valve instrumentation is dependent on the OPERABILITY of the instrumentation channel Function specified in Table 3.3.6.3-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Value. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.</p> <p>Allowable Values are specified for each relief valve actuation Function in Table 3.3.6.3-1. Nominal trip</p> <p>(continued)</p>
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BASES

LCO
(continued)

setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure 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. 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., reactor vessel 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 from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

The Low Set Relief Valve Reactuation Time Delay is based on preventing unacceptable thrust loads on relief valve discharge piping due to relief valve openings with elevated water leg conditions. The time delay setpoint was chosen to ensure the two low set relief valves will remain closed following their initial opening, until normal water level in the discharge line is restored and is based on the calculated worst case elevated water leg duration.

The relief valve setpoint Allowable Values are based on the safety analysis performed in References 1, 2, and 3.

APPLICABILITY The relief valve instrumentation is required to be OPERABLE in MODES 1, 2, and 3 since considerable energy is in the

(continued)

BASES

APPLICABILITY (continued) nuclear system and the relief valves may be needed to provide pressure relief. If the relief valves are needed, then the relief valve function is required to ensure that the primary containment design basis is maintained. In MODES 4 and 5, the reactor pressure is low enough that the overpressure limit cannot be approached by assumed operational transients or accidents. Thus, relief valve instrumentation and associated pressure relief is not required.

ACTIONS

A.1

The failure of any relief valve instrument channel to provide the pressure setpoint or low set time delay for an individual relief valve does not affect the ability of the other relief valves to perform their relief or low set function. A relief valve is OPERABLE if the associated logic, has one Function 1.a or 2.a channel, as applicable, and, for low set relief valves, two Function 1.b channels OPERABLE. Therefore, 14 days is provided to restore the inoperable channel(s) to OPERABLE status (Required Action A.1). If the inoperable channel(s) cannot be restored to OPERABLE status within the allowable out of service time, Condition B must be entered and its Required Action taken. The 14 day Completion Time is considered appropriate because of the redundancy in the design (five relief valves are provided and any four relief valves can perform the relief function, two low set relief valves are provided and one low set relief valve can perform the low set function) and the very low probability of multiple relief instrumentation channel failures, which render the remaining relief valves inoperable, occurring together with an event requiring the relief or low set function during the 14 day Completion Time. The 14 day Completion Time to restore inoperable channels to OPERABLE status is based on the relief capability of the remaining relief valves, the low probability of an event requiring relief valve actuation and a reasonable time to complete the Required Action.

(continued)

BASES

ACTIONS
(continued)

B.1

If the Required Action and associated Completion Time of Condition A is not met, or two or more relief valves are inoperable due to inoperable channels, the relief valves may be incapable of performing their intended relief or low set function. Therefore, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 with 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LLS instrumentation Function are located in the SRs column of Table 3.3.6.3-1.

SR 3.3.6.3.1 and SR 3.3.6.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop and 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 of every 92 days for SR 3.3.6.3.1 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of once every 24 months for SR 3.3.6.3.2 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

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.6.3.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specified channel. The system functional testing performed in LCO 3.4.3, "Safety and Relief Valves" and LCO 3.6.1.6, "Low Set Relief Valves," overlaps this test to provide complete testing of the assumed safety function.

The Frequency of once every 24 months for SR 3.3.6.3.3 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.

REFERENCES

1. UFSAR, Section 5.2.2.
 2. UFSAR, Section 6.2.1.3.4.
 3. UFSAR, Chapter 15.
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B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Ventilation (CREV) System Instrumentation

BASES

BACKGROUND

The CREV System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. The CREV System is capable of fulfilling the stated safety function. The CREV System instrumentation provides control room alarms so that manual action can be taken to start the CREV System and pressurize control room emergency zone to minimize the consequences of radioactive material in the control room environment.

In the event of a Reactor Building Ventilation System-High High Radiation alarm signal, operator action is required to switch the CREV System to the isolation/pressurization mode of operation and close required dampers to maintain the control room emergency zone slightly pressurized with respect to the adjacent zones. A description of the CREV System is provided in the Bases for LCO 3.7.4, "Control Room Emergency Ventilation (CREV) System."

The CREV System instrumentation has two trip systems, either of which provide sufficient information to ensure the CREV System is initiated and the dampers are closed when necessary. Each trip system receives input from one radiation monitor channel. Two detectors (one detector for each radiation monitor channel) are located in the reactor building ventilation exhaust duct. The output of each channel is provided to one trip system (i.e., one radiation monitor channel per trip system). The output from each channel is arranged in a one-out-of-one trip (alarm) system. A trip of any trip system will initiate a Reactor Building Ventilation System-High High Radiation Alarm in the control room. The 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 a signal to the alarm logic.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The ability of the CREV System to maintain the habitability of the control room emergency zone is explicitly assumed for certain accidents as discussed in the UFSAR safety analyses (Refs. 1, and 2). CREV System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A.
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CREV System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO	High reactor building ventilation exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When high reactor building ventilation exhaust radiation is alarmed in the control room, the CREV System is manually initiated in the isolation/pressurization mode and required dampers are closed since this condition could result in radiation exposure to control room personnel.
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The Reactor Building Ventilation System—High High Radiation Alarm Function signals are initiated from radiation detectors that are located in the ventilation exhaust ducting coming from the reactor building and refueling zones. The signals from each detector are input to individual monitors whose trip outputs are assigned to a control room alarm. Two channels of Reactor Building Ventilation System—High High Radiation Alarm Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the alarm function. The Allowable Value was selected to promptly detect gross failure of the fuel cladding and to ensure protection of control room personnel. Each channel must have its setpoint set within the specified Allowable Value in SR 3.3.7.1.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. 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 successive CHANNEL

(continued)

BASES

LCO
(continued) 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., reactor building ventilation exhaust radiation), 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 from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

APPLICABILITY The Reactor Building Ventilation System—High High Radiation Alarm Function is required to be OPERABLE in MODES 1, 2, and 3 and during movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and operations with a potential for draining the reactor vessel (OPDRVs), to ensure that control room personnel can be protected during a LOCA, fuel handling event, or vessel draindown event. During MODES 4 and 5, when these specified conditions are not in progress (e.g., CORE ALTERATIONS), the probability of a LOCA or fuel damage is low; thus, the Functions is not required.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to CREV System 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 CREV System 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 CREV System instrumentation channel.

A.1 and A.2

Because of the redundancy of sensors available to provide alarm signals, an allowable out of service time of 6 hours is provided to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the Function is still maintaining CREV System alarm capability. A Function is considered to be maintaining CREV System alarm capability when sufficient channels are OPERABLE such that both trip systems will generate an alarm signal on a valid signal. This would require one trip system per unit each with one channel OPERABLE. For a loss of CREV System alarm capability, the 6 hour allowance of Required Action A.2 is not appropriate. If the Function is not maintaining CREV System Instrumentation alarm capability, the CREV System must be declared inoperable within 1 hour of discovery of the loss of CREV System Instrumentation alarm capability in both trip systems (Required Action A.1). This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action A.1, the Completion Time only begins upon discovery that the CREV System Instrumentation alarm capability is lost in both trip systems. The 1 hour Completion Time (A.1) is acceptable because it minimizes risk while allowing time for restoring channels. If the inoperable channel

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

cannot be restored to OPERABLE status within the allowable out of service time, Condition B must be entered and its Required Action taken.

The 6 hour Completion Time is based on the consideration that this Function provides the primary signal to the control room so that manual action can be initiated to start the CREV System and close the required dampers; thus, ensuring that the design basis of the CREV System is met.

B.1 and B.2

With the Required Action and associated Completion Time not met, the CREV System must be placed in the isolation/pressurization mode of operation per Required Action B.1 to ensure that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the CREV System in operation must provide for automatically re-initiating the system upon restoration of power following a loss of power to the CREV System. Alternately, if it is not desired to start the CREV System, the CREV System must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CREV System in the isolation/pressurization mode of operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of channels, for placing the associated CREV System in operation, or for entering the applicable Conditions and Required Actions for the inoperable CREV System.

SURVEILLANCE
REQUIREMENTS

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 CREV System Instrumentation alarm capability. Upon completion of

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

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 reliability analysis (Refs. 3, and 4) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the CREV System Instrumentation alarm will initiate when necessary.

SR 3.3.7.1.1

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 upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.7.1.2

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 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 based on the reliability analyses of References 3 and 4.

SR 3.3.7.1.3

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.

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.

REFERENCES

1. UFSAR, Section 6.4.
 2. UFSAR, Section 15.6.5.
 3. 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.
 4. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
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B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4160 V Essential Service System (ESS) buses. Offsite power is the preferred source of power for the 4160 V ESS buses. If the monitors determine that insufficient voltage is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4160 V ESS bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different undervoltage Functions: Loss of Voltage and Degraded Voltage.

Each Division 1 and 2 4160 V ESS Bus Loss of Voltage and Degraded Voltage Function is monitored by two undervoltage relays for each ESS bus, whose outputs are arranged in a two-out-of-two logic configuration (Ref. 1). When, on decreasing voltage, the 4160 V ESS Bus Undervoltage (Loss of Voltage) Function setpoint has been exceeded on both relay channels, the Loss of Voltage Function sends a LOP signal to the respective bus load shedding scheme and starts the associated DG. For the Degraded Voltage Function, one Bus Undervoltage/Time Delay Function (two channels) and one Time Delay Function (one channel) are included. The Time Delay Function associated with the Bus Undervoltage relay is inherent to the Bus Undervoltage - Degraded Voltage relay and is nominally adjusted to seven seconds to prevent circuit initiation caused by grid disturbances and motor starting transients. The Bus Undervoltage/Time Delay Function provides input to the Time Delay Function. The Time Delay Function relay is nominally adjusted to five minutes to allow time for the operator to attempt to restore normal bus voltage. When a Bus Undervoltage/Time Delay Function setpoint has been exceeded and persists for seven

(continued)

BASES

BACKGROUND
(continued)

seconds on both relay channels, a control room annunciator alerts the operator of the degraded voltage condition and the five minute Time Delay Function timer is initiated. If the degraded voltage condition does not clear within five minutes, the five minute Time Delay Function relay sends a LOP signal to the respective bus load shedding scheme and starts the associated DG. If a degraded voltage condition exists coincident with an ECCS actuation signal, the five minute Time Delay Function is bypassed such that load shedding and the associated DG start will be initiated following the seven second time delay (Bus Undervoltage/Time Delay Function).

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 2, 3, and 4 analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of the DGs based on the loss of offsite power coincident with a loss of coolant accident (LOCA). The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4160 V ESS bus, with their setpoints within the specified Allowable Values. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

The Allowable Values are specified for each Function 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 the 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., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. 4160 V ESS Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4160 V ESS bus indicates that offsite power may be completely lost to the respective 4160 V ESS bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power prior to the voltage on the bus dropping below the

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

1. 4160 V ESS Bus Undervoltage (Loss of Voltage)
(continued)

minimum Loss of Voltage Function Allowable Value but after the voltage drops below the maximum Loss of Voltage Function Allowable Value. This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment.

Two channels of 4160 V ESS Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the bus undervoltage function. Refer to LCO 3.8.1, "AC Sources—Operating," and 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

2. 4160 V ESS Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4160 V ESS bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Value, however the transfer does not occur until after the inherent and No LOCA time delays have elapsed, as applicable. If a LOCA condition exists coincident with a loss of power to the bus, the Time Delay (No LOCA) Function is bypassed. This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover or

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY 2. 4160 V ESS Bus Undervoltage (Degraded Voltage)
(continued)

allow restoration to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Two channels of 4160 V ESS Bus Undervoltage/Time Delay (Degraded Voltage) Function and one channel of Degraded Voltage-Time Delay Function per associated bus are required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the degraded voltage and time delay function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS A Note has been provided to modify the ACTIONS related to LOP 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 LOP 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 LOP instrumentation channel.

A.1

With one or more channels of a Function inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. 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

(continued)

BASES

ACTIONS

A.1 (continued)

for the inoperability, restore capability to accommodate a single failure (within the LOP instrumentation), and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

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.

B.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

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 2 hours provided the associated Function maintains LOP initiation capability. LOP initiation capability is maintained provided the bus load shedding scheme and the associated DG can be initiated by the Loss of Voltage or Degraded Voltage Functions for one of the two 4160 V ESS buses. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.8.1.1 and SR 3.3.8.1.3

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 Frequencies of 18 months and 24 months are based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 18 month or 24 month interval, as applicable, is a rare event.

SR 3.3.8.1.2 and SR 3.3.8.1.4

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.

The Frequency is based upon the assumption of an 18 month or 24 month calibration interval, as applicable, in the determination of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.8.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

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.

REFERENCES

1. UFSAR, Section 8.3.1.7.
 2. UFSAR, Section 5.2.
 3. UFSAR, Section 6.3.
 4. UFSAR, Chapter 15.
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B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic and scram pilot valve solenoids.

The RPS electric power monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both in-series electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram pilot valve solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram pilot valve solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram pilot valve solenoids may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these

(continued)

BASES

BACKGROUND
(continued)

circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the inservice MG set or alternate power supply exceeds predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil (undervoltage release coil) within the circuit breaker driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE
SAFETY ANALYSES

The RPS Electric Power Monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the RPS equipment powered from the RPS buses can perform its intended function. RPS Electric Power Monitoring provides protection to the RPS components, by acting to disconnect the RPS bus from the power supply under specified conditions that could damage the RPS equipment.

RPS Electric Power Monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent on the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS bus powered components. Each of the inservice electric power monitoring assembly trip logic setpoints is required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint

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BASES

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(continued)

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., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip coil) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. 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 as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

The Allowable Values for the instrument settings are based on RPS component testing with the RPS providing 56 Hz \pm 1%, 126.5 V \pm 2.5%, and 108.0 V \pm 2.5%. The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS bus powered components from the inservice MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying

(continued)

BASES

APPLICABILITY (continued)	power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1 and 2; and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.
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ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable assembly to OPERABLE status. If the inoperable assembly cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly and the low probability of an event requiring RPS electric power monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternately, if it is not desired to remove the power supply from service (e.g., as in the case where removing the power supply(s) from service would result in a scram), Condition C or D, as applicable, must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS
(continued)

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable or both power monitoring assemblies in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1 or 2, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS
(continued)

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action D.1 results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

SURVEILLANCE
REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency 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.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance.

The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that 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.

SR 3.3.8.2.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly. The system functional test shall include actuation of the protective relays, tripping logic, and output circuit breakers. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

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.

REFERENCES

1. UFSAR, Section 7.2.3.
 2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System."
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes heat at a faster rate from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The Reactor Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable speed motor driven recirculation pump, a motor generator (MG) set to control pump speed and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section and result in partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core. The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred

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BASES

BACKGROUND
(continued)

to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 55 to 100% of RTP) without having to move control rods and disturb desirable flux patterns.

Each recirculation loop is manually started from the control room. The MG set provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled.

APPLICABLE
SAFETY ANALYSES

The operation of the Reactor Recirculation System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement. The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the UFSAR.

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Ref. 1).

The transient analyses in Chapter 15 of the UFSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System (RPS) average power range monitor (APRM) and the Rod Block Monitor Allowable Values is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR limits for single loop operation are specified in the COLR. The APRM Flow Biased Neutron Flux-High Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." The Rod Block Monitor-Upscale Allowable Value is in LCO 3.3.2.1, "Control Rod Block Instrumentation."

Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Two recirculation loops are normally required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternatively, with only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), APRM Flow Biased Neutron Flux-High Allowable Value (LCO 3.3.1.1), and the Rod Block Monitor-Upscale Allowable Value (LCO 3.3.2.1) must be applied to allow continued operation consistent with the assumptions of Reference 1.

(continued)

BASES (continued)

APPLICABILITY In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

 In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS A.1 and A.2

 With no recirculation loops in operation, the probability of thermal-hydraulic oscillations is greatly increased. Therefore, action must be taken as soon as practicable to reduce power to assure stability concerns are addressed and place the unit in at least MODE 2 within 8 hours and to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and transients and minimal dependence on the recirculation loop coastdown characteristics. 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 systems.

B.1 and C.1

 With both recirculation loops operating but the flows not matched, the flows must be matched within 2 hours. If matched flows are not restored, the recirculation loop with the lower flow must be declared "not in operation," as required by Required Action B.1. This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing pump speeds to re-establish forward flow or by tripping the pump.

(continued)

BASES

ACTIONS

B.1 and C.1 (continued)

With the requirements of the LCO not met for reasons other than Condition A or B (e.g., one loop "not in operation"), the recirculation loops must be restored to operation with matched flows within 24 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits for greater than 2 hours (i.e., Required Action B.1 has been taken). Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to the APLHGR and MCPR operating limits and RPS and RBM Allowable Values, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 hour and 24 hour Completion Times are based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

D.1

With the Required Action and associated Completion Time of Condition C not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for mismatch. At low core flow (i.e., < 70% of rated core flow), the APLHGR and MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. The jet pump loop flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Surveillance Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

REFERENCES

1. UFSAR, Section 6.3.3.3.
 2. UFSAR, Chapter 15.
 3. UFSAR, Section 15.3.1.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND The Reactor Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the Reactor Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two-thirds core height, the vessel can be reflooded and coolant level maintained at two-thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor recirculation loop contains ten jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section and result in partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE Jet pump OPERABILITY is an explicit assumption in the design
SAFETY ANALYSES basis loss of coolant accident (LOCA) analysis evaluated in
Reference 1.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet pumps satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two-thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Recirculation System is not required to be in operation, and when not in operation, sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability to reflood during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns", engineering judgement of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship may indicate a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow pattern or relationship of one jet pump to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.2.1 (continued)

the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

REFERENCES

1. UFSAR, Section 6.3.
 2. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.
 3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety and Relief Valves

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety valves are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). Each unit is designed with nine safety valves, one of which also functions in the relief mode. This valve is a dual function Target Rock safety/relief valve (S/RV).

The safety valves and S/RV are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The safety valves actuate in the safety mode (or spring mode of operation). In this mode, the safety valve opens when the inlet steam pressure reaches the lift set pressure. At that point, the vertical upward force generated by the inlet pressure under the valve disc balances the downward force generated by the spring. Slight steam leakage develops across the valve disc-to-seat interface and is directed into the huddle chamber. Pressure builds up rapidly in the huddle chamber developing an additional vertical lifting force on the disc and disc holder. This additional force in conjunction with the expansive characteristic of steam causes the valve to "pop" open to almost full lift. This satisfies the Code requirement. The S/RV is a dual function Target Rock valve that can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the S/RV spring loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. In the relief mode (or power actuated mode of operation), automatic or manual switch actuation energizes a solenoid valve which pneumatically actuates a plunger located within the main valve body. Actuation of the plunger allows pressure to be vented from the top of the main valve piston. This allows reactor pressure to lift the main valve piston, which opens the main valve. The relief valves and S/RV discharge steam

(continued)

BASES

BACKGROUND
(continued)

through a discharge line to a point below the minimum water level in the suppression pool. The safety valves discharge directly to the drywell.

In addition to the safety valves and S/RV, each unit is designed with four relief valves which actuate in the relief mode to control RCS pressure during transient conditions to prevent the need for safety valve actuation (except S/RV) following such transients. The relief valves are also located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. These valves are sized by assuming a turbine trip, a coincident scram and a failure of the turbine bypass system. The relief valves are of the Electromatic type, which are opened by automatic or manual switch actuation of a solenoid. The switch energizes the solenoid to actuate a plunger, which contacts the pilot valve operating lever, thereby opening the pilot valve. When the pilot valve opens, pressure under the main valve disc is vented. This allows reactor pressure to overcome main valve spring pressure, which forces the main valve disc downward to open the main valve. Two of the five relief valves are the low set relief valves and all of the relief valves, including the S/RV, are Automatic Depressurization System (ADS) valves. The low set relief requirements are specified in LCO 3.6.1.6, "Low Set Relief Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

APPLICABLE
SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, eight safety valves are assumed to operate in the safety mode. The relief valves and S/RV are not credited to function during this event. The analysis results demonstrate that the design safety valve capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure ($110\% \times 1250 \text{ psig} = 1375 \text{ psig}$). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. For other pressurization events, such as a turbine trip or generator load rejection with Main Turbine Bypass System failure (Refs. 2 and 3, respectively), the relief valves as well as the S/RV are assumed to function. The opening of the relief valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MINIMUM CRITICAL POWER RATIO (MCPR) during these events. In these events, the operation of four of the five relief valves are required to mitigate the events. Reference 4 discusses additional events that are expected to actuate the safety and relief valves.

Safety and relief valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The safety function of eight safety valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 1). The safety valve requirements of this LCO are applicable to the capability of the safety valves to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

The safety valve setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the UFSAR are based on these setpoints, but also include the additional uncertainties of $\pm 1\%$ of the nominal setpoint drift to provide an added degree of conservatism.

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

(continued)

BASES

LCO (continued)	The relief valves, including the S/RV, are required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, so that MCPR is not exceeded.
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APPLICABILITY	In MODES 1, 2, and 3, eight safety valves (not including the S/RV) and five relief valves (including the S/RV) must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The safety and relief valves may be required to provide pressure relief to discharge energy from the core until such time that the Shutdown Cooling (SDC) System is capable of dissipating the core heat.
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In MODE 4, decay heat is low enough for the Shutdown Cooling System to provide adequate cooling, and reactor pressure is low enough that the overpressure and MCPR limits are unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The safety and relief functions are not needed during these conditions.

ACTIONS

A.1

With the relief function of one relief valve (or S/RV) inoperable, the remaining OPERABLE relief valves are capable of providing the necessary protection. However, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE relief valves could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

The 14 day Completion Time to restore the inoperable required relief valve to OPERABLE status is based on the relief capability of the remaining relief valves, the low probability of an event requiring relief valve actuation, and a reasonable time to complete the Required Action.

(continued)

BASES

ACTIONS
(continued)

B.1 and B.2

With less than the minimum number of required safety valves OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the relief function of the inoperable relief valves cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1, or if the relief function of two or more relief valves are inoperable, or if the safety function of one or more safety valves is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the safety valves, including the S/RV, will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the safety valve and S/RV safety lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The safety valve and S/RV setpoints are $\pm 1\%$ for OPERABILITY.

SR 3.4.3.2

A manual actuation of each relief valve, including the S/RV, is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.3.2 (continued)

control reactor pressure when the relief valve or the S/RV diverts steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is 300 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by at least 2.0 turbine bypass valves open.

This SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. Unit startup is allowed prior to performing this test because valve OPERABILITY is verified, per ASME Code requirements (Ref. 5), prior to valve installation. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the S/RV fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the S/RV is considered OPERABLE.

The 24 month Frequency ensures that each solenoid for each relief valve is tested. The 24 month Frequency was developed based on the relief valve tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 5). 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 3.4.3.3

The relief valves, including the S/RV, are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the relief valve operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TESTs in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," and LCO 3.3.6.3, "Relief Valve Instrumentation," overlap this SR to provide complete testing of the safety function.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.3.3 (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 when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.4.3.2.

REFERENCES

1. UFSAR, Section 5.2.2.
 2. UFSAR, Section 15.2.3.1.
 3. UFSAR, Section 15.2.2.1.
 4. UFSAR, Chapter 15.
 5. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and UFSAR, Section 3.1.2.4.1 (Ref. 1).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the RCPB from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests that, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 2 and 3) shows that leakage rates of hundreds of gallons per minute will precede crack instability.

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material degradation. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

BASES

LCO
(continued)

b. Unidentified LEAKAGE

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell floor drain sump flow rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies, because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(continued)

BASES (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to verify the source of the unidentified leakage increase is not material susceptible to IGSCC.

The 4 hour Completion Time is reasonable to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, an alternate method which may be used to quantify LEAKAGE is calculating flow rates using sump pump run times. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 4).

REFERENCES

1. UFSAR, Section 3.1.2.4.1.
 2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
 3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.
 4. Generic Letter 88-01, Supplement 1, February 1992.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

UFSAR, Section 3.1.2.4.1 (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. The Bases for LCO 3.4.4, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of the two monitored variables, such as measuring flow from the drywell floor drain sump and primary containment atmospheric particulate radioactivity level. Although alternate methods of detecting RCS LEAKAGE are available, the sole means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Reactor Building Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. Leakage into the drywell floor drain sump is pumped through a piping header that penetrates the containment wall to the floor drain collector tank.

(continued)

BASES

BACKGROUND
(continued)

Two drywell floor drain sump pumps take suction from the drywell floor drain sump and discharge to the Liquid Radioactive Waste Management Systems. The pumps alternate as lead and backup on each successive start. When a high level is reached in the floor drain sump, a level switch actuates to start the lead floor drain sump pump when the pump discharge valves are open. In the event the level continues to rise, a second level switch actuates to start the backup floor drain sump pump and initiates an alarm in the control room. When the level decreases to a low level, both floor drain sump pumps are stopped. A flow transmitter in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room. In addition, a leak rate recorder is provided capable of identifying a 1 gpm change over an 8 hour period. The pumps can also be started from the control room.

The primary containment atmospheric particulate sampling system provides a means to monitor the primary containment atmosphere for airborne particulate radioactivity. An increase of radioactivity may be attributed to RCPB steam or reactor water LEAKAGE. The primary containment atmospheric particulate sampling system is not capable of quantifying LEAKAGE rates. The primary containment atmospheric particulate sampling system consists of a manifold rack that allows drywell atmospheric grab samples to be obtained for analysis and a continuous air monitor that contains particulate and charcoal filters for monitoring of the drywell atmosphere.

APPLICABLE
SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 3 and 4). The drywell floor drain sump monitoring system is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room. The primary containment atmospheric particulate sampling system provides a means to detect changes in LEAKAGE rates (Ref. 5).

A control room alarm provided by the drywell floor drain sump monitoring system allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

The drywell floor drain sump monitoring system satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii). The primary containment atmospheric particulate sampling system is maintained to be consistent with NUREG-1433.

LCO

The drywell floor drain sump monitoring system is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, the flow monitoring portion of the system must be OPERABLE. The primary containment atmospheric particulate sampling system is available to the operators so closer examination can be made to determine the extent of any corrective action that may be required. Only one sampling method (either the manifold rack or the continuous air monitor) is required to meet the OPERABILITY requirements. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, the leakage detection systems are required to be OPERABLE to support LCO 3.4.4. This Applicability is consistent with that for LCO 3.4.4.

ACTIONS

A.1

With the drywell floor drain sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, other monitoring systems are normally available that will provide indication of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.4.1), operation may continue for 24 hours. The 24 hour Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the alternative form of leakage detection that is normally available and the fact that the LEAKAGE is still being determined every 12 hours.

(continued)

BASES

ACTIONS
(continued)

B.1

With the primary containment atmospheric particulate sampling system inoperable, operation may continue for 24 hours. The 24 hour Completion Time of Required Action B.1 is acceptable, based on operating experience, considering the alternative form of leakage detection that is normally available and the fact that the LEAKAGE is still being determined every 12 hours (SR 3.4.4.1).

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.4.5.1

This SR requires performance of a primary containment atmospheric particulate sample every 12 hours. This is performed by either removing and analyzing the particulate and charcoal filters from the continuous air monitor or by analyzing a grab sample.

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the drywell floor drain sump monitoring system instrumentation. The test ensures that the system can perform its function in the desired manner. The test also verifies the relative accuracy of the instrument string. 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.5.2

non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of the drywell floor drain sump monitoring system instrumentation channel (i.e., drywell floor drain sump pump discharge flow integrator). The calibration verifies the accuracy of the instrument string. The Frequency of SR 3.4.5.3 is based on the assumption of a 12 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 3.1.2.4.1.
 2. Regulatory Guide 1.45, May 1973.
 3. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
 4. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.
 5. UFSAR, Section 5.2.5.2.
 6. UFSAR, Section 5.2.5.6.4.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the reactor coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the reactor coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 100 limit.

APPLICABLE Analytical methods and assumptions involving radioactive
SAFETY ANALYSES material in the primary coolant are presented in the UFSAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite and control room doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100. The limits on the specific activity of the primary coolant also ensure the thyroid dose to control room operators, resulting from a MSLB outside containment during steady state operation will not exceed the limits of GDC 19 of 10 CFR 50, Appendix A (Ref. 3).

The limit on specific activity is a value from a parametric evaluation of typical site locations. This limit is conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to ≤ 0.2 $\mu\text{Ci/gm}$ DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits and GDC 19 of 10 CFR 50, Appendix A (Ref. 3).

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 $\mu\text{Ci/gm}$, samples must be analyzed for DOSE EQUIVALENT I-131 at least once

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

A Note to the Required Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 0.2 $\mu\text{Ci/gm}$ within 48 hours, or if at any time it is > 4.0 $\mu\text{Ci/gm}$, it must be determined at least once every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 100 and GDC 19 of 10 CFR 50, Appendix A (Ref. 3) during a postulated MSLB accident.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without

(continued)

BASES

ACTIONS B.1, B.2.1, B.2.2.1, and B.2.2.2 (continued)

challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS SR 3.4.6.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES 1. 10 CFR 100.11.
 2. UFSAR, Section 15.6.4.
 3. 10 CFR 50, Appendix A, GDC 19.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Shutdown Cooling (SDC) System—Hot Shutdown

BASES

BACKGROUND Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to $\leq 212^{\circ}\text{F}$ in preparation for performing Refueling or Cold Shutdown maintenance operations, or the decay heat must be removed for maintaining the reactor in the Hot Shutdown condition.

The three redundant, manually controlled shutdown cooling subsystems (loops) of the SDC System provide decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Each loop has a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The SDC heat exchangers transfer heat to the Service Water System via the Reactor Building Closed Cooling Water (RBCCW) System.

APPLICABLE SAFETY ANALYSES Decay heat removal by operation of the SDC System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result.

The SDC System meets Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO Two SDC subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one SDC subsystem must be in operation. An OPERABLE SDC subsystem consists of one OPERABLE SDC pump, one heat exchanger, the associated piping and valves, and the necessary portions of the RBCCW System capable of providing cooling water to the heat exchanger and SDC pump seal cooler. The subsystems have a common suction source and common discharge piping. Thus, to meet the LCO, two loops must be OPERABLE. Since the piping is a passive component that is assumed not to fail, it is allowed to be

(continued)

BASES

LCO
(continued) common to both subsystems. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one SDC subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both required SDC subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 2 allows one required SDC subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected SDC System or on some other plant system or component that necessitates placing the SDC System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the SDC subsystems or other operations requiring SDC flow interruption and loss of redundancy.

APPLICABILITY In MODE 3 with reactor vessel coolant temperature below the SDC cut-in permissive temperature (i.e., the actual temperature at which the interlock resets) the SDC System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor vessel coolant temperature greater than or equal to the SDC cut-in permissive temperature, this LCO is not applicable. Operation of the SDC System in the shutdown cooling mode is not allowed above this temperature because the RCS temperature may exceed the design temperature of the shutdown cooling piping. Decay heat removal at reactor temperatures greater than or equal to the SDC cut-in permissive temperature is typically accomplished by condensing the steam in the main condenser.

(continued)

BASES

APPLICABILITY (continued)	The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.8, "Shutdown Cooling (SDC) System—Cold Shutdown"; LCO 3.9.8, "Shutdown Cooling (SDC)—High Water Level"; and LCO 3.9.9, "Shutdown Cooling (SDC)—Low Water Level."
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ACTIONS	<p>A Note to the ACTIONS excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the redundancy of the OPERABLE subsystems, the low pressure at which the plant is operating, the low probability of an event occurring during operation in this condition, and the availability of alternate methods of decay heat removal capability.</p> <p>A second Note has been provided to modify the ACTIONS related to SDC 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 shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable SDC subsystem.</p>
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A.1, A.2, and A.3

With one required SDC subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced SDC capability. Therefore, an alternate method of decay heat removal must be provided.

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BASES

ACTIONS

A.1, A.2, and A.3 (continued)

With both required SDC subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial SDC subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam Systems and the Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate/Feed System).

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

B.1, B.2, and B.3

With no required SDC subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, reactor coolant circulation by the SDC subsystem or recirculation pump must be restored without delay.

Until SDC or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

(continued)

BASES

ACTIONS B.1, B.2, and B.3 (continued)

During the period when the reactor coolant is being circulated by an alternate method (other than by the required SDC subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE
REQUIREMENTS SR 3.4.7.1

This Surveillance verifies that one SDC subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the SDC subsystem in the control room.

This Surveillance is modified by a Note allowing sufficient time to align the SDC System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Shutdown Cooling (SDC) System—Cold Shutdown

BASES

BACKGROUND Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant $\leq 212^{\circ}\text{F}$ in preparation for performing Refueling or maintenance operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition.

The three redundant, manually controlled shutdown cooling subsystems (loops) of the SDC System provide decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Each loop has a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the low pressure coolant injection path and associated recirculation loop. The SDC heat exchangers transfer heat to the Service Water System, via the Reactor Building Closed Cooling Water (RBCCW) System.

APPLICABLE Decay heat removal by operation of the SDC System in the
SAFETY ANALYSES shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result.

The SDC System meets Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO Two SDC subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one SDC subsystem must be in operation. An OPERABLE SDC subsystem consists of one OPERABLE SDC pump, one heat exchanger, the associated piping and valves, and the necessary portions of the RBCCW System capable of providing cooling water to the heat exchanger and SDC pump seal cooler. The subsystems have a common suction source and common discharge piping. Thus, to meet the LCO, two loops must be OPERABLE. Since the piping is a passive

(continued)

BASES

LCO
(continued)

component that is assumed not to fail, it is allowed to be common to both subsystems. Additionally, each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one SDC subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 allows both required SDC subsystems to not be in operation during hydrostatic testing. This allowance is acceptable because adequate reactor coolant circulation will be maintained by operation of a reactor recirculation pump to ensure adequate core flow and since systems are available to control reactor coolant temperature. Note 2 permits both SDC subsystems and recirculation pumps to not be in operation for a period of 2 hours in an 8 hour period. Note 3 allows one required SDC subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected SDC System or on some other plant system or component that necessitates placing the SDC System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the SDC subsystems or other operations requiring SDC flow interruption and loss of redundancy.

APPLICABILITY

In MODE 4, the SDC System must be OPERABLE and one SDC subsystem shall be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 212°F. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor vessel coolant temperature greater than or equal to the SDC cut-in permissive temperature, this LCO is not applicable. Operation of the SDC System in the shutdown cooling mode is not allowed above this temperature because the RCS temperature may exceed the design temperature of the

(continued)

BASES

APPLICABILITY
(continued)

shutdown cooling piping. Decay heat removal at reactor temperatures greater than or equal to the SDC cut-in permissive temperature is typically accomplished by condensing the steam in the main condenser.

The requirements for decay heat removal in MODE 3 below the cut-in permissive temperature and in MODE 5 are discussed in LCO 3.4.7, "Shutdown Cooling (SDC) System—Hot Shutdown"; LCO 3.9.8, "Shutdown Cooling (SDC)—High Water Level"; and LCO 3.9.9, "Shutdown Cooling (SDC)—Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to SDC 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 shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable SDC subsystem.

A.1

With one of the two required SDC subsystems inoperable, except as permitted by LCO Note 3, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both required SDC subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial SDC subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the

(continued)

BASES

ACTIONS

A.1 (continued)

functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam System and the Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate/Feed System).

B.1 and B.2

With no required SDC subsystem and no recirculation pump in operation, except as permitted by LCO Notes 1 and 2, and until SDC or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required SDC System or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.8.1

This Surveillance verifies that one SDC subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the SDC subsystem in the control room.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Specification contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic testing, and criticality, and also limits the maximum rate of change of reactor coolant temperature. The P/T limit curves are applicable for 32 effective full power years.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted,

(continued)

BASES

BACKGROUND
(continued)

as necessary, based on the evaluation findings and the recommendations of Reference 5.

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The non-nuclear heatup and cooldown curve applies during heatups with non-nuclear heat (e.g., recirculation pump heat) and during cooldowns when the reactor is not critical (e.g., following a scram). The curve provides the minimum reactor vessel metal temperatures based on the most limiting vessel stress.

The P/T criticality limits include the Reference 1 requirement that they be at least 40°F above the non-critical heatup curve or the non-critical cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing. Reference 1 also allows boiling water reactors to operate with the core critical below the minimum permissible temperature allowed for the inservice hydrostatic pressure test (i.e., inservice leak and hydrostatic testing) when the water level is within the normal range for power operation and the pressure is less than 20% of the preservice system hydrostatic test pressure (for Dresden 2 and 3, this pressure is 312 psig). Under these conditions, the minimum temperature is 60°F above the RT_{NDT} of the closure flange regions which are stressed by the bolt preload (for Dresden 2 and 3, this temperature is 83°F).

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the

(continued)

BASES

BACKGROUND (continued)	RCPB components. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.
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APPLICABLE SAFETY ANALYSES	<p>The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Reference 7 approved the curves and limits required by this Specification. Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.</p> <p>RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ij).</p>
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- | | |
|-----|---|
| LCO | <p>The elements of this LCO are:</p> <ul style="list-style-type: none">a. RCS pressure and temperature are within the limits specified in Figures 3.4.9-1, 3.4.9-2, and 3.4.9-3, heatup and cooldown rates are $\leq 100^{\circ}\text{F}$ in any 1 hour period during RCS heatup, cooldown, and inservice leak and hydrostatic testing, and the RCS temperature change during inservice leak and hydrostatic testing is $\leq 20^{\circ}\text{F}$ in any 1 hour period when the RCS temperature and pressure are being maintained with the limits of Figure 3.4.9-1;b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is $\leq 145^{\circ}\text{F}$ during recirculation pump startup in MODES 1, 2, 3, and 4;c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is $\leq 50^{\circ}\text{F}$ during recirculation pump startup in MODES 1, 2, 3, and 4; |
|-----|---|

(continued)

BASES

LCO
(continued)

- d. RCS pressure and temperature are within the criticality limits specified in Figure 3.4.9-3, prior to achieving criticality; and
- e. The reactor vessel flange and the head flange temperatures are $\geq 83^{\circ}\text{F}$ when tensioning the reactor vessel head bolting studs and when the reactor head is tensioned.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leak and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

- a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;
- b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and
- c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an engineering evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 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 limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by placing the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an engineering evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to $> 212^{\circ}\text{F}$. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

Condition C is modified by a Note requiring Required Action C.2 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 limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.9.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits a reasonable time for assessment and correction of minor deviations.

Surveillance for heatup, cooldown, or inservice leak and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leak and hydrostatic testing.

SR 3.4.9.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.9.3 and SR 3.4.9.4

Differential temperatures within the applicable limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 8) are satisfied.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.9.3 and SR 3.4.9.4 (continued)

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3 and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. The Notes also state the SRs are only required to be met during a recirculation pump startup since this is when the stresses occur.

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits within 30 minutes before and every 30 minutes thereafter while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature $\leq 93^{\circ}\text{F}$, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature $\leq 113^{\circ}\text{F}$, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within the specified limits.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7 (continued)

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature $\leq 93^{\circ}\text{F}$ in MODE 4. SR 3.4.9.7 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature $\leq 113^{\circ}\text{F}$ in MODE 4. The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.
 2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
 3. ASTM E 185-82, July 1982.
 4. 10 CFR 50, Appendix H.
 5. Regulatory Guide 1.99, Revision 2, May 1988.
 6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
 7. Letter from Robert Pulsifer (NRC) to ComEd, "Issuance of Amendments 153 and 148 for Dresden 2 and 3," dated February 28, 1997.
 8. UFSAR, Section 15.4.4.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of design basis accidents and transients.
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APPLICABLE SAFETY ANALYSES	<p>The reactor steam dome pressure of ≤ 1005 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analyses are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analyses of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoint"). The nominal reactor operating pressure is approximately 1005 psig. Transient analyses typically use the nominal or a design dome pressure as input to the analysis. Small deviations (5 to 10 psi) from the nominal pressure are not expected to change most of the transient analyses results. However, sensitivity studies for fast pressurization events (main turbine generator load rejection without bypass, turbine trip without bypass, and feedwater controller failure) indicate that the delta-CPR may increase for lower initial pressures. Therefore, the fast pressurization events have considered a bounding initial pressure based on a typical operating range to assure a conservative delta-CPR and operating limit.</p>
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Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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BASES (continued)

LCO	The specified reactor steam dome pressure limit of ≤ 1005 psig ensures the plant is operated within the assumptions of the reactor overpressure analysis. Operation above the limit may result in a transient response more severe than analyzed.
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APPLICABILITY	<p>In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam and events that may challenge the overpressure limits are possible.</p> <p>In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.</p>
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ACTIONS	<p><u>A.1</u></p> <p>With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized.</p>
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	<p><u>B.1</u></p> <p>If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.</p>
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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1005 psig ensures that the initial condition of the vessel overpressure protection analysis is met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

REFERENCES

1. UFSAR, Section 5.2.2.1.
 2. UFSAR, Chapter 15.
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND ISOLATION CONDENSER (IC) SYSTEM

B 3.5.1 ECCS - Operating

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 consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the Low Pressure Coolant Injection (LPCI) System, and the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the contaminated condensate storage tank (CCST), it is capable of providing a source of water for the HPCI, LPCI and CS systems.

On receipt of an initiation signal, ECCS pumps automatically start; the system aligns and the pumps inject water, taken either from the CCST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, the ADS timed sequence would be allowed to time out and open the relief valves and safety/relief valve (S/RV) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly and the LPCI and CS cool the core.

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the Containment Cooling Service Water System. Depending on the

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BASES

BACKGROUND
(continued)

location and size of the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break.

The combined operation of all ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started immediately when normal AC power is available and approximately 14 seconds after emergency power is available. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

The LPCI System is composed of two LPCI subsystems (loops) (Ref. 2). Each subsystem consists of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the selected recirculation loop. The two LPCI subsystems are interconnected via the two, normally open, LPCI System cross-tie valves. The LPCI System is equipped with a loop select logic that determines which, if any, of the recirculation loops has been broken and selects the non-broken loop for injection. If neither loop is determined to be broken, then "B" recirculation loop is selected for injection. The LPCI System cross-tie valves must be open to support OPERABILITY of both LPCI subsystems. Similarly, the LPCI swing bus is required to be energized to support both LPCI subsystems. Therefore, with the LPCI cross-tie valves not full open, or the LPCI swing bus not energized, both LPCI subsystems must be considered inoperable. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically

(continued)

BASES

BACKGROUND (continued)

started (simultaneously and immediately when normal AC power is available, and sequentially, with A and C pumps after approximately 4 seconds and B and D pumps after approximately 9 seconds, when emergency AC power is available). LPCI System valves are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the selected recirculation loop. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the selected recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for each LPCI subsystem to route water from and to the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "Suppression Pool Cooling."

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CCST and the suppression pool. Pump suction for HPCI is normally aligned to the CCST source to minimize injection of suppression pool water into the RPV. However, if the CCST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from the reactor vessel.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1120 psig). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine steam supply valve open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine control valves are automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CCST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open or remain open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS System discharge lines are kept full of water using a "keep fill" system (jockey pump system). The HPCI System is normally aligned to the CCST. The height of water in the CCST is sufficient to maintain the piping full of water up to the first isolation valve. When the HPCI System is aligned to the suppression pool the "keep fill" system must be aligned to the HPCI discharge line.

The ADS (Ref. 4) consists of 5 valves (4 relief valves and one S/RV). It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup. The S/RV used for automatic depressurization is equipped with one air accumulator and associated inlet check valve. The accumulator provides the pneumatic power to actuate the valve. However, the S/RV is not credited in the safety analysis since qualification of the accumulator for this valve to perform the ADS function has not been demonstrated (Ref. 5).

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 6 and 7. The required analyses and assumptions are defined in Reference 8. The results of these analyses are also described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

- a. Maximum fuel element cladding temperature is $\leq 2200^{\circ}\text{F}$;

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

- b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;
- c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;
- d. The core is maintained in a coolable geometry; and
- e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 8. For a large discharge pipe break LOCA, failure of the LPCI valve on the unbroken recirculation loop is considered the most severe failure. For a small break LOCA, HPCI failure is the most severe failure. In the analysis of events requiring ADS operation, it is assumed that only three of the five ADS valves operate. Therefore, four ADS valves are required to be OPERABLE to meet single failure criteria. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each ECCS injection/spray subsystem and four electromechanical ADS valves are required to be OPERABLE. The S/RV can not be used to satisfy the ADS requirement. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low pressure ECCS injection/spray subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

(continued)

BASES (continued)

APPLICABILITY	All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS-Shutdown."
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ACTIONS	<p><u>A.1</u></p> <p>If any one LPCI pump is inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE pumps provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE LPCI subsystems, concurrent with a LOCA, may result in the LPCI subsystems not being able to perform their intended safety function. The 30 day Completion Time is based on a reliability study cited in Reference 11 that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowable repair times (i.e., Completion Times).</p>
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B.1

If a LPCI subsystem is inoperable for reasons other than Condition A or a CS subsystem is inoperable, the inoperable low pressure ECCS injection/spray subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and

(continued)

BASES

ACTIONS

B.1 (continued)

subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

C.1

If one LPCI pump in each subsystem is inoperable, one LPCI pump must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE ECCS subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE ECCS subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

D.1

If two LPCI subsystems are inoperable for reasons other than Condition C, one inoperable subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CS subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining CS subsystems, concurrent with a LOCA, may result in ECCS not being able to perform its intended safety function. The 72 hour Completion Time is based on a reliability study cited in Reference 11 that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowable repair times (i.e., Completion Times).

(continued)

BASES

ACTIONS
(continued)

E.1 and E.2

If any Required Action and associated Completion Time of Condition A, B, C, or D is not met, the plant must be brought to a MODE in which the LCO 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 systems.

F.1 and F.2

If the HPCI System is inoperable and the IC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this Condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the IC System will automatically provide core cooling at most reactor operating pressures. Verification of IC OPERABILITY is therefore required immediately when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if IC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the IC System. If the OPERABILITY of the IC System cannot be verified, however, Condition I must be immediately entered. In the event of component failures concurrent with a design basis LOCA, there is a potential, depending on the specific failures, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

G.1 and G.2

If any one low pressure ECCS injection/spray subsystem, or one LPCI pump in both LPCI subsystems, is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem(s) or the HPCI System must be restored to OPERABLE status within 72 hours.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

In this Condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem(s) are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem(s) to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

H.1

The LCO requires four ADS valves to be OPERABLE in order to provide the ADS function. Reference 12 contains the results of an analysis that evaluated the effect of two ADS valves being out of service. Per this analysis, operation of only three ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced, because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study cited in Reference 10 and has been found to be acceptable through operating experience.

I.1 and I.2

If any Required Action and associated Completion Time of Condition F, G, or H is not met, or if two or more required ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times

(continued)

BASES

ACTIONS

I.1 and I.2 (continued)

are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

J.1

When multiple ECCS subsystems are inoperable, as stated in Condition J, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCI System, CS System, and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points. The 31 day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.2 (continued)

those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.1.3

Verification every 31 days of the correct breaker alignment to the LPCI swing bus demonstrates that the AC electrical power is available to ensure proper operation of the associated LPCI injection valves and the recirculation pump discharge valves. The 31 day Frequency has been found acceptable based on engineering judgment and operating experience.

SR 3.5.1.4

Cycling the recirculation pump discharge valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will close when required.

Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to be closed to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for the LPCI subsystem. Acceptable methods of de-energizing the valve include de-energizing breaker control power, racking out the breaker or removing the breaker.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.4 (continued)

The Frequency of this SR is in accordance with the Inservice Testing Program. If any recirculation pump discharge valve is inoperable and in the open position, both LPCI subsystems must be declared inoperable.

SR 3.5.1.5, SR 3.5.1.6, and SR 3.5.1.7

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8) and are bounded by the requirements of SR 3.5.1.5. This periodic Surveillance is performed (in accordance with the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a test line pressure or system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values have been established analytically.

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested at both the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Reactor steam pressure must be ≥ 920 psig to perform SR 3.5.1.6 and ≥ 150 psig to perform SR 3.5.1.7. Adequate steam flow is represented by at least 2 turbine bypass

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.5, SR 3.5.1.6, and SR 3.5.1.7 (continued)

valves open, or total steam flow $\geq 10^6$ lb/hr. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.6 and SR 3.5.1.7 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for performing the flow test after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SRs.

The Frequency for SR 3.5.1.5 and SR 3.5.1.6 is in accordance with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.1.7 is based on the need to perform the Surveillance under the conditions that apply during a startup from a plant outage. Operating experience has shown that these components usually pass the SR 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.

SR 3.5.1.8

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This SR also ensures that the HPCI System will automatically restart on an RPV low-low water level signal

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.8 (continued)

received subsequent to an RPV high water level trip and that the HPCI suction is automatically transferred from the CCST to the suppression pool on high suppression pool water level or low CCST water level. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform the 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 SR 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.

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.9

The ADS designated valves are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.10 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform the Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.9 (continued)

Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR 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.

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.5.1.10.

SR 3.5.1.10

A manual actuation of each ADS valve is performed to verify that the valve and solenoid are functioning properly and that no blockage exists in the valve discharge lines. This is demonstrated by the response of the turbine control or bypass valve or by a change in the measured flow or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this SR. Adequate pressure at which this SR is to be performed is 300 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by at least 2 turbine bypass valves open. Reactor startup is allowed prior to performing this SR because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance. SR 3.5.1.9 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.10 (continued)

The Frequency of 24 months is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR 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.

SR 3.5.1.11

The LPCI System injection valves and recirculation pump discharge valves are powered from the LPCI swing bus, which must be energized after a single failure, including loss of power from the normal source to the swing bus. Therefore, the automatic transfer capability from the normal power source to the backup power source must be verified to ensure the automatic capability to detect loss of normal power and initiate an automatic transfer to the swing bus backup power source. Verification of this capability every 24 months ensures that AC electrical power is available for proper operation of the associated LPCI injection valves and recirculation pump valves. The swing bus automatic transfer scheme must be OPERABLE for both LPCI subsystems to be OPERABLE. The Frequency of 24 months is based on the need to perform the Surveillance under the conditions that apply during a startup from a plant outage. Operating experience has shown that the components usually pass the SR 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 6.3.2.1.
2. UFSAR, Section 6.3.2.2.
3. UFSAR, Section 6.3.2.3.
4. UFSAR, Section 6.3.2.4.

(continued)

BASES

REFERENCES
(continued)

5. Letter from J.A. Zwolinski (NRC) to D.L. Farrar (Commonwealth Edison Company), "Resolution of NUREG-0737 Item II.K.3.28, Verify Qualification of Accumulators on Automatic Depressurization Valves," dated June 16, 1986.
 6. UFSAR, Section 15.6.4.
 7. UFSAR, Section 15.6.5.
 8. 10 CFR 50, Appendix K.
 9. UFSAR, Section 6.3.3.
 10. 10 CFR 50.46.
 11. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
 12. EMF-97-025(P) Revision 1, LOCA Break Spectrum for Dresden Unit 2 and 3, dated May 30, 1997.
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND ISOLATION CONDENSER (IC) SYSTEM

B 3.5.2 ECCS - Shutdown

BASES

BACKGROUND	A description of the Core Spray (CS) System and the Low Pressure Coolant Injection (LPCI) System is provided in the Bases for LCO 3.5.1, "ECCS-Operating."
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APPLICABLE SAFETY ANALYSES	The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one low pressure ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two low pressure ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.
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The low pressure ECCS subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO	Two low pressure ECCS injection/spray subsystems are required to be OPERABLE. The low pressure ECCS injection/spray subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or contaminated condensate storage tanks (CCSTs) to the reactor pressure vessel (RPV). Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or the CCSTs to the RPV. A single LPCI pump is required per subsystem because of the similar injection capacity in relation to a CS subsystem. In addition, in MODES 4 and 5, the LPCI System cross-tie valves are not required to be open.
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BASES (continued)

APPLICABILITY OPERABILITY of the low pressure ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 23 ft above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncover in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is ≤ 150 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

(continued)

BASES

ACTIONS A.1 and B.1 (continued)

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

C.1, C.2, D.1, D.2, and D.3

With both of the required ECCS injection/spray subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One required ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours. The 4 hour Completion Time to restore at least one low pressure ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

If at least one required low pressure ECCS injection/spray subsystem is not restored to OPERABLE status within the 4 hour Completion Time, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. The administrative controls may consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way the penetration can be rapidly isolated when a need for

(continued)

BASES

ACTIONS

C.1, C.2, D.1, D.2, and D.3 (continued)

secondary containment is indicated). OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.1

The minimum water level of 10 ft 4 inches above the bottom of the suppression chamber required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS System and LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to OPERABLE CCSTs.

When suppression pool level is < 10 ft 4 inches, the CS and LPCI subsystems are considered OPERABLE only if they can take suction from the CCSTs, and the CCSTs water volume is sufficient to provide the required NPSH and vortex prevention for the CS pump and LPCI pump. Therefore, a verification that either the suppression pool water level is \geq 10 ft 4 inches or that required low pressure ECCS injection/spray subsystems are aligned to take suction from the CCSTs and the CCSTs contain \geq 140,000 available gallons of water, equivalent to 23 ft in both CCSTs with the CCSTs crosstied, ensures that the required low pressure ECCS injection/spray subsystems can supply at least 140,000 gallons of makeup water to the RPV. The CS and LPCI suctions are uncovered at the 90,000 gallon level. However, as noted, only one required low pressure ECCS injection/spray subsystem may take credit for the CCST option during OPDRVs. During OPDRVs, the volume in the CCSTs may not provide adequate makeup if the RPV were

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

completely drained. Therefore, only one low pressure ECCS injection/spray subsystem is allowed to use the CCSTs. This ensures the other required ECCS subsystem has adequate makeup volume.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool water level and CCST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool or CCST water level condition.

SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5

The Bases provided for SR 3.5.1.1, SR 3.5.1.5, and SR 3.5.1.8 are applicable to SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5, respectively.

SR 3.5.2.3

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR 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 that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

REFERENCES

1. UFSAR, Section 6.3.3.4.1.
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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND ISOLATION CONDENSER (IC) SYSTEM

B 3.5.3 IC System

BASES

BACKGROUND

The IC System is not part of the ECCS; however, the IC System is included with the ECCS section because of their similar functions.

The IC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation to provide adequate core cooling. Under these conditions, the High Pressure Coolant Injection (HPCI) and IC systems perform similar functions.

The IC System (Ref.1) is a passive high pressure system comprised of one natural circulation heat exchanger, two AC motor-operated isolation valves, two D.C. motor-operated isolation valves, and two tube side high point vent isolation valves to main steam line "A". The IC System functions as a heat sink for decay heat removal from the reactor vessel following reactor scram and isolation from the main condenser. This function prevents overheating of the reactor fuel, controls reactor pressure, and limits the loss of reactor coolant through the relief valves. The IC System is automatically initiated by sustained reactor vessel high pressure and, once activated, remains in operation until manually removed from service.

The isolation condenser shell contains two tube bundles. When the IC System is in operation, both tube bundles are in service.

The IC System is designed to provide core cooling for reactor pressure ≥ 150 psig. The shell side of the condenser has a minimum water level of 6 feet which provides an inventory of $\geq 18,700$ gallons. This minimum level provides $\geq 11,300$ gallons (approximately 3 feet) of water above the top of the tube bundles. The shell side water temperature must be $\leq 210^\circ\text{F}$. During normal plant operations, when the system is in standby, makeup is from the clean demineralized water storage tank. Makeup during IC System operation can be provided from the Condensate

(continued)

BASES

BACKGROUND (continued)	Transfer System. Since during operation of the IC System, water in the shell will boil, the condenser is vented to the atmosphere via one line.
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APPLICABLE SAFETY ANALYSES	The function of the IC System is to respond to main steam line isolation events by providing core cooling to the reactor. Although the IC System is an Engineered Safety Feature System, no credit is taken in the accident analyses for IC System operation. Based on its contribution to the reduction of overall plant risk, the system satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
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LCO	The OPERABILITY of the IC System provides adequate core cooling such that actuation of any of the low pressure ECCS subsystems is not required in the event of RPV isolation. The IC System reduces the loss of RPV inventory during an isolation event.
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APPLICABILITY	The IC System is required to be OPERABLE during MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig, since IC is the primary non-ECCS source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure \leq 150 psig, and in MODES 4 and 5, IC is not required to be OPERABLE since the low pressure ECCS injection/spray subsystems can provide sufficient core cooling.
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ACTIONS	<u>A.1 and A.2</u> If the IC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is immediately verified to be OPERABLE, the IC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the IC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified immediately when the IC System is inoperable. This may be performed as an administrative check, by examining logs or
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(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be immediately verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, IC (as opposed to HPCI) is an acceptable source of core cooling which also limits the loss of the RPV water level. Therefore, a limited time is allowed to restore the inoperable IC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 2) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and IC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to IC.

B.1 and B.2

If the IC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.5.3.1

This SR verifies the water volume and temperature in the shell side of the IC to be sufficient for proper operation. Based on a scram from 2552.3 MWt (101% RTP), a minimum water level of 6 feet at a temperature of $\leq 210^{\circ}\text{F}$ in the condenser

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.3.1 (continued)

provides sufficient decay heat removal capability for 20 minutes of operation without makeup water, before beginning to uncover the tube bundles. The volume and temperature allow sufficient time for the operator to provide makeup to the condenser.

The 24 hour Frequency is based on operating experience related to the trending of the parameter variations during normal operation.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the IC flow path provides assurance that the proper flow path will exist for IC operation. This SR 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 that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the IC System. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.3

The IC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the IC System will cause the system to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.3.3 (continued)

operate as designed; that is, actuation of all automatic valves to their required positions. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

The 24 month Frequency is based on the need to perform the 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 SR 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.

SR 3.5.3.4

Verifying the proper flow path and heat exchange capacity for IC System operation ensures the capability of the IC System to remove the design heat load. This SR verifies the IC System capability to remove heat consistent with the design requirements of 252.5×10^6 Btu/hr. The IC System capacity is equivalent to the decay heat rate 5 minutes after a reactor scram.

The 60 month Frequency is based on engineering judgement, and has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Section 5.4.6.
 2. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 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. The primary containment consists of a drywell, which is a steel pressure vessel, enclosed in reinforced concrete, and a suppression chamber, which is a steel torus-shaped pressure vessel, connected by vent pipes. The primary containment 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 the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

- a. All penetrations required to be closed during accident conditions are either:
 1. capable of being closed by an OPERABLE automatic containment isolation system, or
 2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";
- b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Lock";
- c. All equipment hatches are closed and sealed; and
- d. The sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

(continued)

BASES

BACKGROUND (continued)	This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.
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APPLICABLE SAFETY ANALYSES	<p>The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.</p> <p>The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.</p> <p>Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.</p> <p>The maximum allowable leakage rate for the primary containment (L_a) is 1.6% by weight of the containment air per 24 hours at the design basis LOCA peak calculated containment pressure (P_a) of 48 psig.</p> <p>Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).</p>
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LCO	Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0 L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to
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(continued)

BASES

LCO
(continued) ensure the primary containment pressure and temperature does not exceed design limits. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

In the event primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage limit (SR 3.6.1.2.1) or main steam isolation valve leakage limit (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program.

As left leakage prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test is required to be $< 0.6 L_a$ for combined Type B and C leakage, and $\leq 0.75 L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0 L_a$. At $\leq 1.0 L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

Maintaining the pressure suppression function of the primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell-to-suppression chamber differential pressure during a 7.5 minute period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure (≥ 1.0 psid) between the drywell and the suppression chamber and verifying that the measured bypass leakage is $\leq 2\%$ of the acceptable A/\sqrt{K} design value of 0.18 ft^2 (Ref. 4). The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.1.2 (continued)

view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation, in this event, the Note indicates, increasing the Frequency to once every 12 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. UFSAR, Section 6.2.1.
 2. UFSAR, Section 15.6.5.
 3. 10 CFR 50, Appendix J, Option B.
 4. Dresden Station Special Report No. 23, "Information Concerning Dresden Units 2 and 3 Drywell to Torus Vacuum Breakers," April 1973.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

One double door primary containment air lock has been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. The air lock is designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in primary containment internal pressure results in increased sealing force on each door).

Each air lock is nominally a right circular cylinder, 10 ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. The air lock is provided with gear driven position indicators on both doors that provide local indication of door position. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions as allowed by this LCO, the primary containment may be accessed through the air lock, when the interlock mechanism has failed, by manually performing the interlock function.

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary

(continued)

BASES

BACKGROUND
(continued)

containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analysis.

APPLICABLE
SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.6% by weight of the containment air mass per 24 hours at the design basis LOCA peak calculated containment pressure (P_a) of 48 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment.

The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

As part of the primary containment pressure boundary, the air lock safety function is related to control of containment leakage following a DBA. Thus, the air lock structural integrity and leak tightness are essential to the successful mitigation of such an event.

The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in the air lock is

(continued)

BASES

LCO
(continued) sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the OPERABLE outer door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial measures are taken when necessary, if air lock leakage results in exceeding overall containment leakage rate acceptance criteria. Pursuant to LCO 3.0.6, actions are not required, even if primary containment leakage is exceeding L_a . Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

(continued)

BASES

ACTIONS
(continued)

A.1, A.2, and A.3

With one primary containment air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1) in the air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

Required Action A.3 ensures that the air lock penetration has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate given the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls.

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BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

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BASES

ACTIONS
(continued)

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if the overall air lock leakage is not within limits. In many instances, primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours (Required Action C.3). The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria which are applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Types B and C primary containment leakage rate.

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the primary containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.2.2 (continued)

Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY 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. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the air lock.

REFERENCES

1. UFSAR, Section 6.2.1.3.
 2. UFSAR, Section 15.6.5.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment function assumed in the safety analyses will be maintained. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges (which include plugs and caps as listed in Reference 1), and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration, except for penetrations isolated by excess flow check valves, so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

The reactor building-to-suppression chamber vacuum breakers serve a dual function, one of which is primary containment isolation. However, since the other safety function of the vacuum breakers would not be available if the normal PCIV actions were taken, the PCIV OPERABILITY requirements are not applicable to the reactor building-to-suppression chamber vacuum breakers valves. Similar surveillance

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BASES

BACKGROUND
(continued)

requirements in the LCO for reactor building-to-suppression chamber vacuum breakers provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The primary containment purge valves are 18 inches in diameter; vent valves are 2, 6, and 18 inches in diameter. The 18 inch primary containment vent and purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained except for torus purge valve 1601-56. This valve is normally open for pressure control. This is acceptable since this valve and other vent and purge valves are designed to automatically close on LOCA conditions. The isolation valves on the 18 inch vent lines from the suppression chamber and drywell have 2 inch bypass lines around them for use during normal reactor operation. Use of the 2 inch vent valves will reduce oxygen content during operation and prevent high pressure from reaching the Standby Gas Treatment System filter trains and the Reactor Building Ventilation System in the unlikely event of a loss of coolant accident (LOCA) during venting.

APPLICABLE
SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a LOCA and a main steam line break (MSLB). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in References 2 and 3, the LOCA is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

3 second closure time is assumed in the MSIV closure (the most severe overpressurization transient) analysis (Ref. 4) and the LOCA analysis (Ref. 2), and the 5 second closure time provides added margin to the 10 seconds assumed in the MSLB analysis (Ref. 3). Likewise, it is assumed that the primary containment isolates such that release of fission products to the environment is controlled.

The DBA analysis assumes that isolation of the primary containment is complete and leakage is terminated, except for the maximum allowable leakage rate, L_a , prior to fuel damage.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment vent and purge valves. Two valves in series on each vent and purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

PCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.7, "Reactor Building-to-Suppression Chamber Vacuum Breakers." The valves covered by this LCO are listed with their associated stroke times in the Technical Requirements Manual (Ref. 1).

The normally closed manual PCIVs are considered OPERABLE when the valves are closed and blind flanges are in place, or open under administrative controls. Normally closed automatic PCIVs which are required by design (e.g., to meet

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BASES

LCO
(continued)

10 CFR 50 Appendix R requirements) to be de-activated and closed, are considered OPERABLE when the valves are de-activated and closed. These passive isolation valves and devices are those listed in Reference 1.

MSIVs must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE in MODES 4 and 5. Certain valves, however, are required to be OPERABLE to prevent inadvertent reactor vessel draindown. These valves are those whose associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS
(continued)

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures that appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these actions are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable, except for MSIV leakage rate not within limit, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside primary containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and the existence of other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two or more PCIVs inoperable, except for MSIV leakage rate not within limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must

(continued)

BASES

ACTIONS

B.1 (continued)

be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, except for MSIV leakage rate not within limit, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The Completion Time of 4 hours for valves other than EFCVs and in penetrations with a closed system is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 72 hours for penetrations with a closed system is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Reference 5. The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two or more PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

(continued)

BASES

ACTIONS
(continued)

D.1

With the MSIV leakage rate (SR 3.6.1.3.10) not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The Completion Time of 8 hours allows a period of time to restore MSIV leakage rate to within limit given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO 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 systems.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the unit must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending an OPDRV would result in closing the shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

valve(s) to OPERABLE status. This allows shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the 18 inch primary containment vent and purge valves are closed as required or, if open, opened for an allowable reason. If a vent or purge valve is opened in violation of this SR, the valve is considered inoperable. The torus purge valve, 1601-56, is normally open for pressure control, therefore this valve is excluded from this SR. However, this is acceptable since this valve is designed to automatically close on LOCA conditions. The SR is modified by a Note stating that the SR is not required to be met when the vent or purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open, provided the drywell vent and purge valves and their associated suppression chamber vent and purge valves are not open simultaneously. The 18 inch vent and purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other PCIV requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits.

This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.2 (continued)

PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.3 (continued)

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that each valve will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.3.6

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. 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.

SR 3.6.1.3.8

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This test is performed by blowing down the instrument line during an inservice leak or hydrostatic test and verifying a distinctive "click" when the poppet valve seats or a quick reduction in flow. This SR provides assurance that the instrumentation line EFCVs will perform as designed. 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.8 (continued)

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.

SR 3.6.1.3.9

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4). Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges must be followed.

SR 3.6.1.3.10

The analyses in References 2 and 3 are based on leakage that is less than the specified leakage rate. The leakage rate of each main steam isolation valve path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves). If both isolation valves in the penetration are closed the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying leakage is only to be used for this SR (i.e., Appendix J maximum pathway leakage limits are to be quantified in accordance with the Primary Containment Leakage Rate Testing Program). The combined leakage through all MSIV leakage paths must be ≤ 46 scfh when tested at ≥ 25 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

MSIV leakage is considered part of L_a .

(continued)

BASES (continued)

- REFERENCES
1. Technical Requirements Manual.
 2. UFSAR, Section 15.6.5.
 3. UFSAR, Section 15.6.4.
 4. UFSAR, Section 15.2.4.
 5. UFSAR, Section 6.2.4.1.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The drywell pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).
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APPLICABLE SAFETY ANALYSES	<p>Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial drywell pressure of 1.5 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the maximum allowable of 62 psig.</p> <p>The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is 48 psig (Ref. 1).</p> <p>Drywell pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).</p>
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LCO	In the event of a DBA, with an initial drywell pressure ≤ 1.5 psig, the resultant peak drywell accident pressure will be maintained below the drywell design pressure.
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APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.
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(continued)

BASES (continued)

ACTIONS

A.1

With drywell pressure not within the limit of the LCO, drywell pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell pressure cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell pressure is within the limit ensures that unit operation remains within the limit assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.

REFERENCES

1. Dresden Nuclear Power Station Units 2 and 3 Plant Unique Analysis Report, COM-02-041, May 1983.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 1 safety analyses.
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APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 1). Analyses assume an initial average drywell air temperature of 150°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 281°F (Ref. 2). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident.
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Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO	In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the drywell design temperature. As a result, the ability of primary containment to perform its design function is ensured.
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(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.
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ACTIONS	<p><u>A.1</u></p> <p>With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems.</p>
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B.1 and B.2

If the drywell average air temperature cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. Drywell air temperature is monitored in various quadrants and at various elevations (referenced to mean sea level) selected to provide a representative sample of the overall drywell atmosphere. Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

(continued)

BASES

SURVEILLANCE
REQUIREMENT

SR 3.6.1.5.1 (continued)

The 24 hour Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.

REFERENCES

1. UFSAR, Section 6.2.1.3.
 2. UFSAR, Section 6.2.1.1.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low Set Relief Valves

BASES

BACKGROUND

The relief valves can actuate in either the relief mode, the Automatic Depressurization System mode, or the low set relief mode. In addition, one relief valve is designed to open in the safety mode. (However, for the purposes of this LCO, only the low set relief mode of the relief valves is required.) In the low set relief mode (or power actuated mode of operation), a switch energizes the solenoid to actuate a plunger, which contacts the pilot valve operating lever, thereby, opening the pilot valve. When the pilot valve opens, pressure under the main valve disc is vented. This allows reactor pressure to overcome main valve spring pressure, which forces the main valve disc downward to open the main valve. The main valve can stay open with valve inlet steam pressure as low as 50 psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the main valve.

Two of the relief valves are equipped to provide the low set relief function. The low set relief setpoints cause the low set relief valves to be opened at a lower pressure than the other relief valves and stay open longer, so that reopening more than two relief valves is prevented on subsequent actuations. Therefore, the low set relief function prevents excessive short duration relief valve cycles with valve actuation at the low set relief setpoint.

Each relief valve discharges steam through a discharge line and quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load. A time delay in the low set relief valve logic prevents actuation concurrent with an elevated water level in the discharge line.

APPLICABLE SAFETY ANALYSES

The low set relief mode functions to ensure that the containment design basis of no more than two relief valve operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of relief valves (following the initial opening), and the corresponding

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

higher loads, are avoided. The safety analysis demonstrates that the low set relief functions to avoid the induced thrust loads on the relief valve discharge line resulting from "subsequent actuations" of the relief valve during Design Basis Accidents (DBAs). Even though two low set relief valves are specified, only one low set relief valve is required to operate in any DBA analysis.

Low set relief valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two low set relief valves are required to be OPERABLE to satisfy the assumptions of the safety analyses (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical capability of the low set relief valves to function for controlling the opening and closing of the low set relief valves.

APPLICABILITY

In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of relief valves. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the low set relief valves OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one low set relief valve inoperable, the remaining OPERABLE low set relief valve is adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining low set relief valve and the low probability of an event occurring during this period in which the remaining low set relief valve capability would be required.

B.1 and B.2

If two low set relief valves are inoperable or if the inoperable low set relief valve cannot be restored to OPERABLE status within the required Completion Time, the

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each low set relief valve is performed to verify that the valve and solenoids are functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the low set relief valves divert steam flow upon opening. Sufficient time is therefore allowed, after the required pressure and flow are achieved, to perform this test. Adequate pressure at which this test is to be performed is ≥ 300 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by at least 2 turbine bypass valves open.

The 24 month Frequency was based on the relief valve tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 2). The Frequency of 24 months ensures that each solenoid for each low set relief valve is tested. 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.

This SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. Unit startup is allowed prior to performing the test because valve OPERABILITY is verified by Reference 2 prior to valve installation. The 12 hours allowed for manual actuation

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.6.1 (continued)

after the required pressure and flow is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR.

SR 3.6.1.6.2

The low set relief designated relief valves are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the low set relief function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.3, "Low Set Relief Valve Instrumentation," overlaps this SR to provide complete testing of the safety 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.

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

REFERENCES

1. UFSAR, Section 6.2.1.3.5.3.
 2. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a mechanical vacuum breaker and an air operated butterfly valve), located in series in each of two parallel 20 inch lines connected to a common 20 inch inlet line from the reactor building. The two parallel 20 inch vacuum breaker lines connect to a common 20 inch line, which, in turn, connects to the suppression chamber airspace. The butterfly valve is actuated by a differential pressure switch. The mechanical vacuum breaker is self actuating (similar to a check valve) and can be locally operated for testing purposes. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the

(continued)

BASES

BACKGROUND (continued)	maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensable gases are assumed for conservatism.
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APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the reactor building-to-suppression chamber vacuum breakers are presented in Reference 1 as part of the accident response of the containment systems. Internal (suppression-chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.
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The safety analyses assume the external vacuum breakers to be closed initially, with the mechanical vacuum breakers counter balanced to open at 0.5 psid and to be fully open in 5 seconds. The air operated butterfly valve vacuum breakers are assumed to open concurrent with the mechanical vacuum breakers and be full open in 30 seconds (Ref. 1). Since only one of the two parallel 20 inch vacuum breaker lines is required to protect the suppression chamber from excessive negative differential pressure, the single active failure criterion is satisfied. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and that at least one vacuum breaker in each line remains closed and leak tight with positive primary containment pressure.

Three cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

- a. Inadvertent actuation of one drywell spray loop during normal operation;
- b. Inadvertent actuation of one drywell spray loop during normal operation with the suppression chamber free air volume completely filled with saturated steam; and

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

- c. Inadvertent actuation of one drywell spray loop during normal operation with the suppression chamber free air volume filled with an air/steam mixture.

The results of these three cases show that the external vacuum breakers, with an opening setpoint of 0.5 psid, are capable of maintaining the differential pressure within design limits.

The reactor building-to-suppression chamber vacuum breakers satisfy 10 CFR 50.36(c)(2)(ii).

LCO

All reactor building-to-suppression chamber vacuum breakers are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that the two vacuum breakers (mechanical vacuum breaker and air operated butterfly valve) in each of the two lines from the reactor building to the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, the requirement ensures both vacuum breakers in each line will open to relieve a negative pressure in the suppression chamber.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell, which, after the suppression chamber-to-drywell vacuum breakers open (due to excessive differential pressure between the suppression chamber and drywell), would result in depressurization of the suppression chamber. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside primary containment could occur due to inadvertent initiation of drywell sprays.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining reactor building-to-suppression chamber vacuum breakers OPERABLE is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each reactor building-to-suppression chamber vacuum breaker line.

A.1

With one or more lines with one vacuum breaker not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable vacuum breakers must be restored to OPERABLE status or the open vacuum breaker closed within 7 days. The 7 day Completion Time takes into account the redundancy afforded by the remaining breakers, the fact that the OPERABLE breaker in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breakers to be OPERABLE during this period.

B.1

With one or more lines with two vacuum breakers not closed, primary containment integrity is not maintained. Therefore, one open vacuum breaker must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

C.1

With one line with one or more vacuum breakers inoperable for opening, the leak tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened, however, if both vacuum breakers in at least one vacuum breaker penetration are not OPERABLE. Therefore, the inoperable vacuum breaker must be restored to OPERABLE status within 7 days. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

(continued)

BASES

ACTIONS
(continued)

D.1

With two lines with one or more vacuum breakers inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breakers is lost. Therefore, all vacuum breakers in one line must be restored to OPERABLE status within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

E.1 and E.2

If any Required Action and associated Completion time can not be met, the plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker 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.

Two Notes are added to this SR. The first Note allows reactor-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The 92 day Frequency of this SR was developed based upon Inservice Testing Program requirements to perform valve testing at least once every 92 days.

SR 3.6.1.7.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of ≤ 0.5 psid is valid. 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. For this plant, the 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. UFSAR, Section 6.2.1.2.4.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 12 internal vacuum breakers installed in 6 parallel lines connecting the suppression chamber to the vent headers of the vent system between the drywell and the suppression chamber. The vacuum breakers 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 suppression chamber-drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be locally operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

(continued)

BASES

BACKGROUND
(continued)

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the waterleg in the vent system during normal operation.

APPLICABLE
SAFETY ANALYSES

Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Internal (suppression chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary.

The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 0.5 psid (Ref. 2). Additionally, 3 of the 12 internal vacuum breakers are assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that 9 of 12 vacuum breakers be OPERABLE are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The vacuum breakers are sized on the basis of the Bodega pressure suppression system tests. These tests were conducted by simulating a small break LOCA, which tend to cause vent system waterleg height variations. The vacuum breaker capacity selected is more than adequate to limit the pressure differential between the suppression chamber and drywell post LOCA with the valves set to operate at 0.5 psid differential pressure. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight until the suppression chamber is at a positive pressure relative to the drywell.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
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LCO	Only 9 of the 12 vacuum breakers must be OPERABLE for opening to provide assurance that the vacuum breakers will open so that drywell-to-suppression chamber negative differential pressure remains below the design value. This LCO also ensures that all suppression chamber-to-drywell vacuum breakers are closed (except during testing or when the vacuum breakers are performing their intended design function). The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.
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APPLICABILITY	<p>In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell, which, after the suppression chamber-to-drywell vacuum breakers open (due to excessive differential pressure between the suppression chamber and drywell), would result in depressurization of the suppression chamber. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of drywell sprays.</p>
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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 breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one of the required vacuum breakers inoperable for opening (e.g., a vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it

(continued)

BASES

ACTIONS

A.1 (continued)

would not function as designed during an event that depressurized the drywell), the remaining eight OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one of the nine required vacuum breakers inoperable, 72 hours is allowed to restore at least one of the inoperable vacuum breakers to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

B.1

With one 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 LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker due to the low probability of an event that would pressurize primary containment. The required 4 hour Completion Time is considered adequate to safely plan and complete the manual cycling necessary to close the vacuum breaker which may be located in a high radiation area.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO 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 systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.8.1

Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication. 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.

Two Notes are added to this SR. The first Note allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.8.2

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The 31 day Frequency of this SR was developed, based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. A 31 day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE. In addition, this functional test is required within 12 hours after a discharge of steam to the suppression chamber from the relief valves.

SR 3.6.1.8.3

Verification of the vacuum breaker opening setpoint from the closed position is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.5 psid is valid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.8.3 (continued)

the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. UFSAR, Section 6.2.1.2.4.2.
 2. UFSAR, Table 6.2-1.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from relief valve discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from steam exhaust lines in the turbine driven High Pressure Coolant Injection System. Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

- a. Complete steam condensation;
- b. Primary containment peak pressure and temperature;
- c. Condensation oscillation loads; and
- d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the pool temperature analyses required by Reference 3). An initial pool temperature of 95°F is assumed for the Reference 1, 2, and 4 analyses. Reactor shutdown at a pool temperature of

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

110°F and vessel depressurization at a pool temperature of 120°F are assumed for the Reference 2 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are:

- a. Average temperature $\leq 95^{\circ}\text{F}$ with THERMAL POWER $> 1\%$ RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.
- b. Average temperature $\leq 105^{\circ}\text{F}$ with THERMAL POWER $> 1\%$ RTP and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to $\leq 95^{\circ}\text{F}$ within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is $> 95^{\circ}\text{F}$ is short enough not to cause a significant increase in unit risk.
- c. Average temperature $\leq 110^{\circ}\text{F}$ with THERMAL POWER $\leq 1\%$ RTP. This requirement ensures that the unit will be shut down at $> 110^{\circ}\text{F}$. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

At 1% RTP, heat input is approximately equal to normal system heat losses.

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.
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ACTIONS	<u>A.1 and A.2</u>
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With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power limit, the initial conditions exceed the conditions assumed for the Reference 1, 2, and 4 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool average temperature to be restored below the limit. Additionally, when suppression pool temperature is $> 95^{\circ}\text{F}$, increased monitoring of the suppression pool temperature is required to ensure that it remains $\leq 110^{\circ}\text{F}$. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the power must be reduced to $\leq 1\%$ RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS
(continued)

C.1

Suppression pool average temperature is allowed to be $> 95^{\circ}\text{F}$ with THERMAL POWER $> 1\%$ RTP, and when testing that adds heat to the suppression pool is being performed. However, if temperature is $> 105^{\circ}\text{F}$, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature $> 110^{\circ}\text{F}$ requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 within 36 hours is required at normal cooldown rates (provided pool temperature remains $\leq 120^{\circ}\text{F}$). Additionally, when suppression pool temperature is $> 110^{\circ}\text{F}$, increased monitoring of pool temperature is required to ensure that it remains $\leq 120^{\circ}\text{F}$. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high suppression pool average temperature in this condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained at $\leq 120^{\circ}\text{F}$, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 150 psig within 12 hours, and the plant must be brought to at least 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 systems.

(continued)

BASES

ACTIONS E.1 and E.2 (continued)

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE
REQUIREMENTS SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. UFSAR, Section 6.2.
 2. NEDC-22170, Dresden 2 and 3 Nuclear Generating Plant Suppression Pool Temperature Response, July 1982.
 3. NUREG-0783.
 4. Dresden Nuclear Power Station Units 2 and 3 Plant Unique Analysis Report, COM-02-041, May 1983.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from relief valve discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the steam exhaust line in the turbine driven High Pressure Coolant Injection (HPCI) System and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 116,300 ft³ at the low water level limit of 14 ft 6.5 inches and 119,800 ft³ at the high water level limit of 14 ft 10.5 inches.

If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the relief valve quenchers, downcomer lines, or HPCI turbine exhaust line. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified.

If the suppression pool water level is too high, it could result in excessive clearing loads from relief valve discharges and excessive pool swell loads during a DBA LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to relief valve discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.
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Suppression pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO	A limit that suppression pool water level be ≥ 14 ft 6.5 inches and ≤ 14 ft 10.5 inches above the bottom of the suppression chamber is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation.
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APPLICABILITY	In MODES 1, 2, and 3, a DBA would cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS - Shutdown."
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ACTIONS	<p><u>A.1</u></p> <p>With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as the downcomers are covered, HPCI turbine exhaust is covered, and relief valve quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and the capability of the Suppression Pool Spray System. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.</p>
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(continued)

BASES

ACTIONS
(continued)

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.2.1

Verification of the suppression pool water level is to ensure 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 available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.

REFERENCES

1. UFSAR, Section 6.2.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each suppression pool cooling subsystem contains two pumps and one heat exchanger and is manually initiated and independently controlled. The two subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the containment cooling heat exchangers and returning it to the suppression pool. Containment cooling service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink.

The heat removal capability of one low pressure coolant injection (LPCI) pump in one subsystem is sufficient to meet the overall DBA pool cooling requirement for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or stuck open relief valve. Relief valve leakage and High Pressure Coolant Injection System testing increase suppression pool temperature more slowly. The Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the Suppression Pool Cooling System is adequate to maintain the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

The Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two suppression pool cooling subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A suppression pool cooling subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause both a release of radioactive material to primary containment and a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.

ACTIONS

A.1

With one suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS
(continued)

B.1

With two suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and the potential avoidance of a plant shutdown transient that could result in the need for the suppression pool cooling subsystems to operate.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual and power operated valves in the suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR 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 provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the suppression pool cooling mode is manually initiated. This SR 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 SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.3.1 (continued)

event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.3.2

Verifying that each required LPCI pump develops a flow rate ≥ 5000 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that the primary containment peak pressure and temperature can be maintained below the design limits during a DBA (Ref. 1). The flow is a normal test of centrifugal pump performance required by ASME Code, Section XI (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice tests confirm component OPERABILITY, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. UFSAR, Section 6.2.
 2. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Suppression Pool Spray

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the Suppression Pool Spray System removes heat from the suppression chamber airspace. The suppression pool is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel (RPV) through relief valves. The heat addition to the suppression pool results in increased steam in the suppression chamber, which increases primary containment pressure. Steam blowdown from a DBA can also bypass the suppression pool and end up in the suppression chamber airspace. Some means must be provided to remove heat from the suppression chamber so that the pressure and temperature inside primary containment remain within analyzed design limits. This function is provided by two redundant suppression pool spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two suppression pool spray subsystems contains two pumps and one heat exchanger, which are manually initiated and independently controlled. The two subsystems perform the suppression pool spray function by circulating water from the suppression pool through the containment cooling heat exchangers and returning it to the suppression pool spray sparger. The sparger only accommodates a small portion of the total low pressure coolant injection (LPCI) pump flow; the remainder of the flow returns to the suppression pool through the suppression pool cooling return line or minimum flow line. Thus, both suppression pool cooling and suppression pool spray functions may be performed when the Suppression Pool Spray System is initiated. Containment cooling service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink. Either suppression pool spray subsystem is sufficient to condense the steam from small bypass leaks from the drywell to the suppression chamber airspace during the postulated DBA.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break loss of coolant accidents. The intent of the analyses is to demonstrate that the pressure reduction capacity of the Suppression Pool Spray System is adequate to maintain the primary containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit.

The Suppression Pool Spray System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO In the event of a DBA, a minimum of one suppression pool spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two suppression pool spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A suppression pool spray subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS A.1

With one suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE suppression pool spray subsystem is adequate to perform the primary containment bypass leakage mitigation function.

(continued)

BASES

ACTIONS

A.1 (continued)

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass mitigation capability. The 7 day Completion Time was chosen in light of the redundant suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

With both suppression pool spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to reduce pressure in the primary containment are available.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and 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 systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual and power operated valves in the suppression pool spray mode flow path provides assurance that the proper flow path exists for system operation. This SR 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 provided it can be aligned to the accident position within the time assumed in the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.1 (continued)

accident analysis. This is acceptable since the suppression pool spray mode is manually initiated. This SR 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 SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.4.2

This Surveillance is performed every 10 years to verify that the spray nozzles are not obstructed and that spray flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Section 6.2.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.5 Drywell-to-Suppression Chamber Differential Pressure

BASES

BACKGROUND The toroidal shaped suppression chamber, which contains the suppression pool, is connected to the drywell (part of the primary containment) by eight main vent pipes. The main vent pipes exhaust into a continuous vent header, from which 96 downcomer pipes extend into the suppression pool. The pipe exit is 3.67 ft below the minimum suppression pool water level required by LCO 3.6.2.2, "Suppression Pool Water Level." During a loss of coolant accident (LOCA), the increasing drywell pressure will force the waterleg in the downcomer pipes into the suppression pool at substantial velocities as the "blowdown" phase of the event begins. The length of the waterleg has a significant effect on the resultant primary containment pressures and loads.

APPLICABLE SAFETY ANALYSES The purpose of maintaining the drywell at a slightly higher pressure with respect to the suppression chamber is to minimize the drywell pressure increase necessary to clear the downcomer pipes to commence condensation of steam in the suppression pool and to minimize the mass of the accelerated water leg. This reduces the hydrodynamic loads on the torus during the LOCA blowdown. The required differential pressure results in a downcomer waterleg of 3.21 to 3.54 ft.

Initial drywell-to-suppression chamber differential pressure affects both the dynamic pool loads on the suppression chamber and the peak drywell pressure during downcomer pipe clearing during a Design Basis Accident LOCA. Drywell-to-suppression chamber differential pressure must be maintained within the specified limits so that the safety analysis remains valid.

Drywell-to-suppression chamber differential pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO A drywell-to-suppression chamber differential pressure limit of 1.0 psid is required to ensure that the containment conditions assumed in the safety analyses are met. A

(continued)

BASES

LCO
(continued) drywell-to-suppression chamber differential pressure of < 1.0 psid corresponds to a downcomer water leg of > 3.54 ft. Failure to maintain the required differential pressure could result in excessive forces on the suppression chamber due to higher water clearing loads from downcomer vents and higher pressure buildup in the drywell.

A Note is provided to allow for periods of up to 4 hours when the LCO is not required to be met during the performance of required Surveillances that reduce the differential pressure. The 4 hour time is acceptable since the probability of a DBA LOCA occurring during this time is low.

APPLICABILITY Drywell-to-suppression chamber differential pressure must be controlled when the primary containment is inert. The primary containment must be inert in MODE 1, since this is the condition with the highest probability for an event that could produce hydrogen. It is also the condition with the highest probability of an event that could impose large loads on the primary containment.

Inerting primary containment is an operational problem because it prevents primary containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the unit startup and is de-inerted as soon as possible in the unit shutdown. As long as reactor power is < 15% RTP, the probability of an event that generates hydrogen or excessive loads on primary containment occurring within the first 24 hours following a startup or within the last 24 hours prior to a shutdown is low enough that these "windows," with the primary containment not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If drywell-to-suppression chamber differential pressure is not within the limit, the conditions assumed in the safety analyses are not met and the differential pressure must be restored to within the limit within 24 hours. The 24 hour Completion Time provides sufficient time to restore

(continued)

BASES

ACTIONS

A.1 (continued)

differential pressure to within limit and takes into account the low probability of an event that would create excessive suppression chamber loads occurring during this time period.

B.1

If the differential pressure cannot be restored to within limits within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. This is done by reducing power to $\leq 15\%$ RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.5.1

The drywell-to-suppression chamber differential pressure is regularly monitored to ensure that the required limits are satisfied. The 12 hour Frequency of this SR was developed based on operating experience relative to differential pressure variations and pressure instrument drift during applicable MODES and by assessing the proximity to the specified LCO differential pressure limit. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal pressure condition.

REFERENCES

None.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Oxygen Concentration

BASES

BACKGROUND

The primary containment is designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inerted, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o provides a method to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment. Radiolysis is the only significant reaction mechanism whereby oxygen, the limiting combustion reactant, is produced within the containment. The Technical Specification requirement to inert the primary containment and maintain oxygen < 4.0 v/o, in conjunction with the elimination of potential sources of air and oxygen (other than by radiolysis) from entering the primary containment provide assurance that the amount of oxygen that could be introduced into the containment will not cause the containment to become de-inerted within the first 30 days after an accident. This is consistent with the requirements of Generic Letter 84-09 (Ref. 1) for plants without recombiners. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.

APPLICABLE SAFETY ANALYSES

The Reference 2 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, will not result in the primary containment becoming de-inerted within the first 30 days following an accident.

Primary containment oxygen concentration satisfies 10 CFR 50.36(c)(2)(ii).

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen and oxygen does not result in a combustible mixture inside primary containment.

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen and oxygen.

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

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration

(continued)

BASES

ACTIONS

A.1 (continued)

must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the availability of other hydrogen and oxygen mitigating systems (e.g., post-accident nitrogen purge) and the low probability and long duration of an event that would generate significant amounts of hydrogen and oxygen occurring during this period.

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to $\leq 15\%$ RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.3.1.1

The primary containment must be determined to be inerted by verifying that oxygen concentration is < 4.0 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which could lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. Generic Letter 84-09, May 1984.
 2. UFSAR, Section 6.2.5.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment is a structure that completely encloses both primary containments and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSES

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a fuel handling accident (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

associated leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment.

Secondary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained, the hatches and blowout panels must be closed and sealed, the sealing mechanisms (e.g., welds, bellows, or O-rings) associated with each secondary containment penetration must be OPERABLE (such that secondary containment leak tightness can be maintained), and all inner or all outer doors in each secondary containment access opening must be closed.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

(continued)

BASES (continued)

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO 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 systems.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not

(continued)

BASES

ACTIONS C.1, C.2, and C.3 (continued)

specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE
REQUIREMENTS SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.4

Verifying that one secondary containment access door in each access opening is closed and each equipment hatch is closed and sealed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. In addition, for equipment hatches that are floor plugs, the "sealed" requirement is effectively met by gravity. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door. The intent is to not breach the secondary containment at any

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.4 (continued)

time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times, i.e., all inner doors closed or all outer doors closed. Thus each access opening has one door closed. However, all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. The 31 day Frequency for SR 3.6.4.1.2 has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door status that are available to the operator. The 24 month Frequency for SR 3.6.4.1.4 is considered adequate in view of the existing administrative controls on equipment hatches.

SR 3.6.4.1.3

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to maintain the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 4000 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.3 verifies that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can be maintained. When the SGT System is operating as designed, the maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.3 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 4000 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of the SR is to ensure secondary containment boundary integrity. The secondary purpose of the SR is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of ensuring OPERABILITY of the SGT System. This SR need not be performed with each SGT subsystem. The SGT subsystem used for this Surveillance is staggered to ensure that in

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.1.3 (continued)

addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of this Surveillance relative to secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. UFSAR, Section 15.6.5.
 2. UFSAR, Section 15.7.3.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs (i.e., dampers) close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations required to be closed during accident conditions are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIVs is required to ensure that

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic, isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in the Technical Requirements Manual (Ref. 3).

The normally closed manual SCIVs are considered OPERABLE when the valves are closed and blind flanges are in place, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

The second Note provides clarification, that for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

(continued)

BASES

ACTIONS

B.1 (continued)

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO 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 systems.

D.1, D.2, and D.3

If any Required Action and associated Completion Time are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment manual isolation valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.4.2.2

Verifying that the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance 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 15.6.5.
 2. UFSAR, Section 15.7.3.
 3. Technical Requirements Manual.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by UFSAR, Section 3.1.2.4.12 (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of two fully redundant subsystems that are shared between Unit 2 and Unit 3, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

- a. A demister;
- b. An electric heater;
- c. A rough prefilter;
- d. A high efficiency particulate air (HEPA) filter;
- e. A charcoal adsorber;
- f. A second HEPA afterfilter; and
- g. A centrifugal fan.

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. Each SGT subsystem is capable of processing the secondary containment volume, which includes both Unit 2 and Unit 3. The internal pressure of the secondary containment is maintained at a negative pressure of ≥ 0.25 inches water gauge when the SGT System is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building, even at wind speeds of 100 mph.

(continued)

BASES

BACKGROUND
(continued)

The demister is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than 70% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, the primary charcoal filter train inlet damper opens, the cooling damper closes, the associated fan starts, and the fan discharge damper opens. When sufficient flow develops, the heater turns on and the flow control damper begins modulating to control system flow and maintain a negative pressure in the secondary containment. If either a low flow or heater off condition exists for the primary subsystem after 20 seconds, the primary subsystem is tripped and the standby SGT subsystem starts.

APPLICABLE
SAFETY ANALYSES

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Ref. 3 and 4). For these analyzed events, the SGT System is assumed to be manually initiated after 10 minutes to reduce, via filtration and adsorption, the radioactive material released to the environment.

The SGT System satisfies 10 CFR 50.36(c)(2)(ii).

LCO

Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES.

(continued)

BASES

APPLICABILITY (continued)	In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System in OPERABLE status is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.
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ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status in 7 days. In this condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT System and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO 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 systems.

C.1, C.2.1, C.2.2, and C.2.3

During movement of irradiated fuel assemblies, in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should immediately be placed in operation. This action

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the plant in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must immediately be suspended. Suspension of these activities must not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGTS subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, one SGT subsystem must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of supporting the required radioactivity release control function in MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring the SGT System) occurring during periods where the required radioactivity release control function may not be maintained is minimal.

(continued)

BASES

ACTIONS
(continued)

E.1 and E.2

If one SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO 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 systems.

F.1, F.2, and F.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action F.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.3.1

Operating (from the control room using the manual initiation switch) each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR verifies that each SGT subsystem starts on receipt of an actual or simulated initiation signal. While this Surveillance can be performed with the reactor at power, operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

- REFERENCES
1. UFSAR, Section 3.1.2.4.12.
 2. UFSAR, Section 6.5.3.2.
 3. UFSAR, Section 15.6.5.
 4. UFSAR, Section 15.7.3.
 5. Regulatory Guide 1.52, Rev. 2.
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B 3.7 PLANT SYSTEMS

B 3.7.1 Containment Cooling Service Water (CCSW) System

BASES

BACKGROUND

The CCSW System is designed to provide cooling water for the containment cooling heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The CCSW System is operated whenever the containment cooling heat exchangers are required to operate in the suppression pool cooling or containment spray mode of the LPCI System.

The CCSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, two 3500 gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with two pumps operating to maintain safe shutdown conditions. Also, when available, both subsystems with one pump operating in each subsystem are capable of providing the required cooling capacity to maintain safe shutdown conditions. The two subsystems are separated from each other (and cannot be cross connected), so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. The CCSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The CCSW System is described in the UFSAR, Section 9.2.1, Reference 1.

Cooling water is pumped by the CCSW pumps from the associated crib house suction bay through the tube side of the containment cooling heat exchangers, and discharges to the Service Water (SW) 48-inch discharge header and subsequently to the cooling lake or Illinois River. The normal and ultimate heat sink (UHS) cooling water sources for the CCSW System are described in UFSAR, Section 9.2.5 (Ref. 2). The SW System and the discharge flow paths to the cooling lake and Illinois River are described in UFSAR, Sections 9.2.2 and 2.4.8 (Refs. 3 and 4), respectively.

The system is initiated manually from the control room. If operating and a loss of coolant accident (LOCA) occurs, the

(continued)

BASES

BACKGROUND (continued)	system is automatically tripped to allow the diesel generators to automatically power only that equipment necessary to reflood the core. The system can be manually started any time the LOCA signal is manually overridden or clears and adequate electrical power is available.
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APPLICABLE SAFETY ANALYSES	<p>The CCSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the CCSW System to support long term cooling of the primary containment is discussed in UFSAR, Section 6.2.2 (Ref. 5). This analysis explicitly assumes that the CCSW System will provide adequate cooling support to the equipment required for safe shutdown. This analysis includes the evaluation of the long term primary containment response after a design basis LOCA.</p> <p>Analyses for long term cooling were performed for one LPCI pump, two CCSW pumps, and one containment cooling heat exchanger (this assumes a single failure of an emergency diesel generator) using different pump flow rates and heat exchanger performance values which were also evaluated for the various flows. As discussed in the UFSAR, Section 6.2.1.3.2 (Ref. 6) for these analyses, manual initiation of the OPERABLE CCSW subsystem and containment cooling are assumed to occur 10 minutes after a DBA. The CCSW flow assumed in the analyses is 2500 gpm per pump with two pumps operating in one loop. In this case, the maximum suppression chamber water temperature and pressure are 178.6°F and 9.8 psig, respectively, well below the design temperature of 281°F and maximum allowable pressure of 62 psig.</p> <p>The CCSW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).</p>
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LCO	Two CCSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.
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(continued)

BASES

LCO
(continued)

A CCSW subsystem is considered OPERABLE when:

- a. Two pumps are OPERABLE; and
- b. An OPERABLE flow path is capable of taking suction from the UHS and transferring the water to the containment cooling heat exchanger and separately to the associated safety related equipment at the assumed flow rate.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head and maximum suction source temperature are covered by the requirements specified in LCO 3.7.3, "Ultimate Heat Sink (UHS)."

APPLICABILITY

In MODES 1, 2, and 3, the CCSW System is required to be OPERABLE to support the OPERABILITY of primary containment cooling (LCO 3.6.2.3, "Suppression Pool Cooling," and LCO 3.6.2.4, "Suppression Pool Spray"). The Applicability is therefore consistent with the requirements of these systems.

The CCSW System is not required to be OPERABLE in MODES 4 and 5 as it does not support or otherwise affect Shutdown Cooling (SDC) System operation. The Unit 2 CCSW System is required to be OPERABLE during the movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, and during operations with a potential for draining the reactor vessel (OPDRVs). At least one Unit 2 CCSW pump, the Ultimate Heat Sink, and a flow path are required during these conditions to provide backup cooling to the condensing unit of the Control Room Emergency Ventilation Air Conditioning (AC) System (LCO 3.7.4, "Control Room Emergency Ventilation Air Conditioning (AC) System").

ACTIONS

A.1

With one CCSW pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE CCSW pumps are adequate to perform the CCSW heat removal function. However, the overall reliability is reduced because a single

(continued)

BASES

ACTIONS

A.1 (continued)

failure in the OPERABLE subsystem could result in reduced CCSW capability. The 30 day Completion Time is based on the remaining CCSW heat removal capability and the low probability of a DBA with concurrent worst case single failure.

B.1

With one CCSW pump inoperable in each subsystem, if no additional failures occur in the CCSW System, then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity for long term containment cooling to maintain safe shutdown conditions. One inoperable pump is required to be restored to OPERABLE status within 7 days. The 7 day Completion Time for restoring one inoperable CCSW pump to OPERABLE status is based on engineering judgment, considering the level of redundancy provided and the low probability of an event occurring requiring CCSW during this period.

C.1

Required Action C.1 is intended to handle the inoperability of one CCSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the CCSW subsystem to OPERABLE status. With the unit in this condition, the remaining OPERABLE CCSW subsystem is adequate to perform the CCSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE CCSW subsystem could result in loss of CCSW function. The Completion Time is based on the redundant CCSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring CCSW during this period.

D.1

With both CCSW subsystems inoperable (e.g., both subsystems with inoperable pumps(s) or flow paths, or one subsystem with an inoperable pump and one subsystem with an inoperable

(continued)

BASES

ACTIONS

D.1 (continued)

flow path), the CCSW System is not capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time for restoring one CCSW subsystem to OPERABLE status, is based on the Completion Times provided for the suppression pool cooling and spray functions.

E.1 and E.2

If any Required Action and associated Completion Time of Conditions A, B, C, or D are not met, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit 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 and without challenging unit systems.

SURVEILLANCE
REQUIREMENTS

SR 3.7.1.1

Verifying the correct alignment for each manual and power operated valve in each CCSW subsystem flow path provides assurance that the proper flow paths will exist for CCSW operation. This SR 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 the nonaccident position, and yet considered in the correct position, provided it can be realigned to its accident position. This is acceptable because the CCSW System is a manually initiated system.

This SR 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 SR 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.

(continued)

BASES (continued)

- REFERENCES
1. UFSAR, Section 9.2.1.
 2. UFSAR, Section 9.2.5.
 3. UFSAR, Section 9.2.2.
 4. UFSAR, Section 2.4.8.
 5. UFSAR, Section 6.2.2.
 6. UFSAR, Section 6.2.1.3.2.
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B 3.7 PLANT SYSTEMS

B 3.7.2 Diesel Generator Cooling Water (DGCW) System

BASES

BACKGROUND

The DGCW System is designed to provide cooling water for the removal of heat from the two diesel generator (DG) heat exchangers. Each DGCW subsystem provides cooling water to its associated DG. The DGCW System can also be used as an alternate water supply for containment cooling service water (CCSW) keep fill and can be aligned to provide cooling water to the Emergency Core Cooling System (ECCS) room coolers. However, the sole safety related function of the DGCW System is to provide cooling water to the DG heat exchangers.

The DGCW pump autostarts upon receipt of a DG start signal when power is available to the pump's electrical bus. Cooling water is pumped from the crib house circulating water bays by the DGCW pump to the associated DG heat exchangers. After removing heat from the heat exchangers, the water is discharged to a service water (SW) discharge header. A cross tie header allows the DGCW pumps to take suction from alternate circulating water bays when a bay is unavailable. Also, the capability exists to align the DGCW subsystem associated with either DG2 or DG3 to provide cooling water to the DG 2/3 heat exchangers. However, the DGCW pump associated with DG2 or DG3 would not auto-start on a DG 2/3 start signal. Furthermore, the DGCW pumps can only provide sufficient cooling for its associated (two) heat exchangers. A complete description of the DGCW System is presented in the UFSAR, Section 9.5.5 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the DGCW System to provide adequate cooling to the DG heat exchangers is an implicit assumption for the safety analyses presented in the UFSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). The ability to provide onsite emergency AC power is dependent on the ability of the DGCW System to cool the DGs.

The DGCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO	<p>The OPERABILITY of the DGCW System is required to provide a coolant source to ensure effective operation of the DGs in the event of an accident or transient. The OPERABILITY of the DGCW System is based on having an OPERABLE pump and an OPERABLE flow path capable of taking suction from the ultimate heat sink and transferring water to the associated DG heat exchangers. The OPERABILITY of the opposite unit's DGCW subsystem is required to provide adequate cooling to ensure effective operation of the required opposite unit's DG heat exchangers in the event of an accident in order to support operation of the shared systems such as the Standby Gas Treatment System and Control Room Emergency Ventilation System.</p> <p>An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the DGCW pump and the maximum suction source temperature are covered by the requirements specified in LCO 3.7.3, "Ultimate Heat Sink (UHS)."</p>
APPLICABILITY	<p>In MODES 1, 2, and 3, the DGCW subsystems are required to be OPERABLE to support the OPERABILITY of equipment serviced by the DGCW subsystems and required to be OPERABLE in these MODES.</p> <p>In MODES 4 and 5, the OPERABILITY requirements of the DGCW subsystems are determined by the systems they support; therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. Thus, the LCOs of the systems supported by the DGCW subsystems will govern DGCW System OPERABILITY requirements in MODES 4 and 5.</p>
ACTIONS	<p>The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DGCW subsystem. This is acceptable, since the Required Actions for the Condition provide appropriate compensatory actions for each inoperable DGCW subsystem. Complying with the Required Actions for one inoperable DGCW subsystem may allow for continued operation, and subsequent inoperable DGCW subsystem(s) are governed by separate Condition entry and application of associated Required Actions.</p>

(continued)

BASES

ACTIONS
(continued)

A.1

If one or more DGCW subsystems are inoperable, the associated DG(s) cannot perform their intended function and must be immediately declared inoperable. In accordance with LCO 3.0.6, this also requires entering into the Applicable Conditions and Required Actions for LCO 3.8.1, "AC Sources - Operating."

SURVEILLANCE
REQUIREMENTS

SR 3.7.2.1

Verifying the correct alignment for manual valves in the DGCW subsystem flow paths provides assurance that the proper flow paths will exist for DGCW subsystem operation. This SR 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. This SR 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 SR 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.

SR 3.7.2.2

This SR ensures that each DGCW subsystem pump will automatically start to provide required cooling to the associated DG heat exchangers when the DG starts. These starts may be performed using actual or simulated initiation signals.

Operating experience has shown that these components usually pass the SR 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.

(continued)

BASES (continued)

- REFERENCES
1. UFSAR, Section 9.5.5.
 2. UFSAR, Chapter 6.
 3. UFSAR, Chapter 15.
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B 3.7 PLANT SYSTEMS

B 3.7.3 Ultimate Heat Sink (UHS)

BASES

BACKGROUND The Containment Cooling Service Water (CCSW) and the Diesel Generator Cooling Water (DGCW) Systems are designed to provide cooling water to components required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The CCSW System is described in UFSAR, Section 9.2.1 (Ref. 1) while the DGCW System is described in UFSAR, Section 9.5.5 (Ref. 2). These systems are also described in the Bases for LCO 3.7.1, "Containment Cooling Service Water (CCSW) System," and LCO 3.7.2, "Diesel Generator Cooling Water (DGCW) System." The UHS provides a suction source and discharge pathway for the cooling water associated with these systems. The UHS is described in UFSAR, Section 9.2.5 (Ref. 3).

The UHS consists of water sources from either the Kankakee River (normal), or the cooling lake (alternate) and can be aligned as either a closed cycle operating system utilizing the cooling lake and canals, or an open cycle operating system with the discharge returning to the Illinois River. The UHS provides cooling water to plant systems (Main Condenser Circulating Water System (primary user), the CCSW System, the Service Water System, the Fire Protection System, and the DGCW System) for both normal and emergency plant operations.

APPLICABLE SAFETY ANALYSES Sufficient water inventory is available for the CCSW and the DGCW Systems post LOCA cooling requirements. This water source is provided by the UHS. The ability of the UHS to support longterm cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the UFSAR, Section 6.2 (Ref. 4). These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The ability of the UHS to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in Reference 4. The ability to provide onsite emergency AC power is dependent on the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

ability of the UHS to cool the DGs. The long term cooling capability of the CCSW pumps and DGCW pumps is also dependent on the cooling provided by the UHS System.

The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the UHS is based on having a minimum water level in the CCSW and DGCW pump suction bays of 501.5 ft mean sea level and a maximum water temperature of 95°F.

APPLICABILITY

In MODES 1, 2, and 3, the UHS is required to be OPERABLE to support OPERABILITY of the equipment serviced by the CCSW and DGCW Systems. Therefore, the UHS is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the UHS is determined by the systems it supports.

ACTIONS

A.1 and A.2

If the UHS is determined inoperable the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit 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 and without challenging unit systems.

SURVEILLANCE
REQUIREMENTS

SR 3.7.3.1

This SR verifies the water level in the CCSW and DGCW pump suction bays to be sufficient for the proper operation of the CCSW and DGCW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.7.3.2

Verification of the UHS temperature ensures that the heat removal capabilities of the CCSW and DGCW Systems are within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

REFERENCES

1. UFSAR, Section 9.2.1.
 2. UFSAR, Section 9.5.5.
 3. UFSAR, Section 9.2.5.
 4. UFSAR, Section 6.2.
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