B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC 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) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level such that an initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

The RCIC System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low (Level 2). The variable is monitored by four transmitters that are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic arrangement. Once initiated, the RCIC logic seals in and can be reset by the operator only when the reactor vessel water level signals have cleared.

The normally closed RCIC test line isolation valve is closed on a RCIC initiation signal to allow full system flow.

The RCIC System also monitors the water level in each condensate storage tank (CST) since this is the initial source of water for RCIC operation. Reactor grade water in the CSTs is the normal source. The CST suction source consists of two CSTs connected in parallel to the RCIC pump suction. Upon receipt of a RCIC initiation signal, the CSTs suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction from the suppression pool valves are open. If the water level in both CSTs fall below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in each CST. A level switch associated with each CST must actuate to cause the suppression pool suction valves to open and the CSTs suction valve to close. The channels are arranged in a one-out-of-two taken twice logic. To prevent losing suction to the pump when automatically transferring suction from the

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BASES

BACKGROUND (continued)	CSTs to the suppression pool on low CST level, the suction valves are interlocked so that the suppression pool suction path must be open before the CST suction path automatically closes. The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (two-out-of-two logic), at which time the RCIC steam inlet valve closes. The RCIC System restarts if vessel level again drops to the low level initiation point (Level 2).
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safeguard System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 1). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion. The OPERABILITY of the RCIC System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.2-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each RCIC System instrumentation 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 or

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

other appropriate documents. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

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

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 (Level 2)

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level – Low Low (Level 2) signals are initiated from four level 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.

The Reactor Vessel Water Level – Low Low (Level 2) Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow with high pressure coolant injection assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Level 1. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level - Low Low (Level 2) (continued)

Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 2).

The HPCI, RCIC and ATWS-RPT initiation functions (as described in Table 3.3.5.1-1, Function 3.a; Table 3.3.5.2-1, Function 1; and LCO 3.3.4.1.a including SR 3.3.4.1.4, respectively) describe the reactor vessel water level initiation function as "Low Low (Level 2)." The Allowable Values associated with the HPCI and RCIC initiation function is different from the Allowable Value associated with the ATWS-RPT initiation function as the ATWS function has a separate analog trip unit. Nevertheless, consistent with the nomenclature typically used in design documents, the "Low Low (Level 2)" is retained in describing each of these three initiation functions.

Four channels of Reactor Vessel Water Level - Low Low (Level 2) Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2. Reactor Vessel Water Level - High (Level 8)

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam inlet valve to prevent overflow into the main steam lines (MSLs).

Reactor Vessel Water Level - High (Level 8) signals for RCIC are initiated from two level transmitters from the narrow range water level measurement instrumentation, which 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. Both Level 8 signals are required in order to close the RCIC steam inlet valve.

The Reactor Vessel Water Level - High (Level 8) Allowable Value is high enough to preclude isolating the steam inlet valve during normal operation, yet low enough to prevent water overflowing into the MSLs. The Allowable Value is

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Reactor Vessel Water Level - High (Level 8) (continued)

referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 2).

Two channels of Reactor Vessel Water Level - High (Level 8) Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3. Condensate Storage Tank (CST) Level - Low

Low level in the CSTs indicates the unavailability of an adequate supply of makeup water from this normal source. Normally, the suction valve between the RCIC pump and the CSTs is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CSTs. However, if the water level in both CSTs falls below a preselected level, first the suppression pool suction valves automatically open, and then the CSTs suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CSTs suction valve automatically closes.

Two level switches are used to detect low water level in each CST. The Condensate Storage Tank Level - Low Function Allowable Value is set high enough (15,600 gallons of water is available in each CST) to ensure adequate pump suction head while water is being taken from the CST.

Four channels of Condensate Storage Tank Level - Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC automatic suction source alignment to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

4. Manual Initiation

The Manual Initiation push button switch introduces a signal into the RCIC System initiation logic that is redundant to the automatic protective instrumentation and provides manual initiation capability. There is one push button for the RCIC System.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Manual Initiation (continued)

The Manual Initiation Function is not assumed in any accident or transient analyses in the UFSAR. However, the Function is retained for overall redundancy and diversity of the RCIC function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button. One channel of Manual Initiation is required to be OPERABLE when RCIC is required to be OPERABLE.

ACTIONS

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

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.2-1. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

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 automatic initiation capability for the RCIC System. In

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

this case, automatic initiation capability is lost if two Function 1 channels in the same trip system are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC 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 B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level – Low Low (Level 2) channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC 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. 3) 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 B.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 E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 3) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out

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BASES

ACTIONS

C.1 (continued)

of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level - High (Level 8) Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability due to closure of the RCIC steam inlet valve. As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this case, automatic initiation capability (automatic suction source alignment) is lost if two Function 3 channels associated with the same CST are inoperable and untripped. In this situation (loss of automatic suction source alignment), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

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 D.1, the Completion Time only begins upon discovery that the RCIC System suction source cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The

(continued)

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

1 hour Completion Time from discovery of loss of initiation capability (automatic suction source alignment) is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC 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. 3) 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 D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

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

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.2-1.

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 as follows: (a) for up to 6 hours for Functions 2 and 4; and (b) for up to 6 hours for Functions 1 and 3, provided the associated Function maintains trip capability. Upon completion of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 (Ref. 3) 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 RCIC will initiate when necessary.

SR 3.3.5.2.1

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 parameter on other similar 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.

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

SR 3.3.5.2.2

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.2 (continued)

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 analysis of Reference 3.

SR 3.3.5.2.3 and SR 3.3.5.2.5

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 Frequency of SR 3.3.5.2.3 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 3.3.5.2.5 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.4

The 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 3.3.5.2-1. If the trip setting is discovered to be less conservative than the setting 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 accounted for in the appropriate setpoint methodology.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.4 (continued)

The Frequency of 184 days is based on the reliability, accuracy, and low failure rates of the associated solid-state electronic Analog Transmitter/Trip System components.

SR 3.3.5.2.6

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. 10 CFR 50.36(c)(2)(ii).
2. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).
3. 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.

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, logic circuits, 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) main steam line (MSL) pressure, (c) MSL flow, (d) condenser vacuum, (e) main steam tunnel area temperatures, (f) main steam line radiation, (g) drywell pressure, (h) containment radiation, (i) high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam line flow, (j) HPCI and RCIC steam line pressure, (k) HPCI and RCIC turbine exhaust diaphragm pressure, (l) HPCI and RCIC area temperatures, (m) reactor water cleanup (RWCU) area temperature, (n) Standby Liquid Control (SLC) System initiation, and (o) reactor 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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BASES

BACKGROUND (continued)

1. Main Steam Line Isolation

Most MSL Isolation Functions receive inputs from four channels. The outputs from these channels are combined in a one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate all MSL drain valves. The MSL drain line has two isolation valves with one two-out-of-two logic system associated with each valve.

The exceptions to this arrangement are the Main Steam Line Flow – High, Main Steam Tunnel Temperature – High and the Main Steam Line Radiation – High Functions. 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 channels. Two trip channels make up each trip system and both trip systems must trip to cause an MSL isolation. Each trip channel has four inputs (one per MSL), any one of which will trip the trip channel. The trip channels 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 of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one-out-of-four twice logic), with each trip system isolating one of the two MSL drain valves on the associated steam line. The Main Steam Tunnel Temperature – High Function receives input from 16 channels. The logic is arranged similar to the Main Steam Line Flow – High Function. The Main Steam Line Radiation – High Function receives inputs from four channels. The outputs from the channels are arranged into two two-out-of-two logic trip systems and isolates the MSL drain valves. This Function does not provide an MSIV isolation signal. Each trip system is associated with one MSL drain valve with a two-out-of-two logic.

2. Primary Containment Isolation

The Reactor Vessel Water Level – Low (Level 3) and Drywell Pressure – High Primary Containment Isolation Functions (Functions 2.a and 2.b) receive inputs from four channels. Normally the outputs from these channels are arranged into two two-out-of-two logic trip systems. One trip system initiates isolation of all inboard primary containment isolation valves, while the other trip system initiates isolation of all outboard primary containment isolation valves. Each logic closes one of the two valves on each

(continued)

BASES

BACKGROUND

2. Primary Containment Isolation (continued)

penetration, so that operation of either logic isolates the penetration. The exception to this arrangement for the Reactor Vessel Water Level – Low (Level 3) and Drywell Pressure – High Functions (Functions 2.d and 2.g) are with certain penetration flow paths (i.e., hydrogen/oxygen sample supply and return valves, and gaseous/particulate sample supply and return valves). For these penetration flow paths only one logic trip system closes two valves in each flow path as noted by footnote (c) to Table 3.3.6.1-1. The design is acceptable since it helps ensure post-accident sampling capability is maintained. The remainder of the penetration flow paths isolated by the Reactor Vessel Water Level – Low (Level 3) and Drywell Pressure – High Functions (Functions 2.a and 2.b) are extensive and are identified in Reference 1.

The Containment Radiation – High Function (Function 2.c) includes two channels, whose outputs are arranged in two one-out-of-one logic trip systems. Each trip system isolates one valve per associated penetration, so that operation of either logic isolates the penetration. The penetration flow paths isolated by this Function include the drywell and suppression chamber vent and purge valves.

The Reactor Vessel Water Level – Low Low Low (Level 1) and the Main Steam Line Radiation – High Functions (Functions 2.e and 2.f) both have four channels, whose outputs are arranged into two two-out-of-two logic trip systems for each Function. One trip system initiates isolation of the associated inboard isolation valves, while the other trip system initiates the isolation of the associated outboard valves. The penetration flow path isolated by these Functions is the recirculation loop sample valves.

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation

Most Functions that isolate HPCI and RCIC receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each trip system for HPCI and RCIC closes the associated steam supply valves. Each HPCI trip system closes the associated pump suction isolation valve. One HPCI trip system and both RCIC trip systems will also initiate a turbine trip which in turn closes the main pump minimum flow isolation valve and pump discharge to reactor isolation valve.

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BASES

BACKGROUND

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation (continued)

The exceptions are the HPCI and RCIC Turbine Exhaust Diaphragm Pressure – High, Steam Supply Line Pressure – Low, and the Equipment Area Temperature – High Functions (Functions 3.b through 3.j and 4.b through 4.f). These Functions receive inputs from four channels. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two two-out-of-two trip systems. The output of each equipment area temperature channel is connected to one trip system so that any channel will trip its associated trip system. This arrangement is consistent with all other area temperature Functions, in that any channel will trip its associated trip system.

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level – Low (Level 3) and Drywell Pressure – High Isolation Functions (Functions 5.e and 5.f) receive input from four channels. The outputs from these channels are connected into two two-out-of-two trip systems for each function. The SLC System Initiation Function (Function 5.d) receives input from two channels, with both channels providing input to one trip system. Any channel will initiate the trip logic. The Function is initiated by placing the SLC System initiation switch in any position other than stop (start system A or start system B). Therefore, a channel is defined as the circuitry required to trip the trip logic when the switch is in position start system A or start system B. The Area Temperature – High Functions (Functions 5.a, 5.b and 5.c) receive input from eight temperature monitors, four to each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on the RWCU suction penetration and only one trip system is connected to the RWCU return penetration outboard valve. The trip system associated with the SLC System Initiation Function is connected to the outboard RWCU suction valve and the outboard RWCU return penetration valve.

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BASES

BACKGROUND (continued)

6. Shutdown Cooling System Isolation

The Reactor Vessel Water Level – Low (Level 3) Function (Function 6.b) receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two two-out-of-two trip systems. Each of the two trip systems is connected to one of the two valves on the RHR shutdown cooling pump suction penetration and on one of the two inboard LPCI injection valves if in shutdown cooling mode. The Reactor Pressure – High Function (Function 6.a) receives input from two channels, with each channel providing input into each trip system using a one-out-of-two logic. However, only one channel input is required to be OPERABLE for a trip system to be considered OPERABLE. Each of the two trip systems is connected to one of the two valves on the shutdown cooling pump suction penetration.

7. Traversing Incore Probe System Isolation

The Reactor Vessel Water Level – Low (Level 3) Isolation Function receives input from two reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into one two-out-of-two logic trip system. The Drywell Pressure – High Isolation function receives input from two drywell pressure channels. The outputs from the drywell pressure channels are connected into one two-out-of-two logic trip system.

When either Isolation Function actuates, the TIP drive mechanisms will withdraw the TIPs, if inserted, and close the inboard TIP system isolation ball valves when the TIPs are fully withdrawn. The outboard TIP system isolation valves are manual shear valves.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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 50.36(c)(2)(ii) (Ref. 4). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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. 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. 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. 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 or other appropriate documents. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

Certain Emergency Core Cooling Systems (ECCS) and RCIC valves (e.g., minimum flow) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS and RCIC. The instrumentation requirements and ACTIONS

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

associated with these signals are addressed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation," and LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System 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 (Level 1)

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 Low (Level 1) Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level - Low Low Low (Level 1) Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 2). The isolation of the MSLs on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level 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 Low Low (Level 1) 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 Low (Level 1) Allowable Value is chosen to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits. In addition, the setting is low enough to allow the removal of heat from the reactor for a predetermined time following a

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

scram, prevent isolation on a partial loss of feedwater and to reduce challenges to the safety/relief valves (S/RVs). The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates the MSIVs and MSL drain 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 at a rate greater 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. 2). 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 transmitters that are connected to the MSL pressure averaging manifold. The transmitters are arranged such that, even though physically separated from each other, each transmitter 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.

The Allowable Value was selected to be high enough to detect a pressure regulator malfunction and prevent excessive RPV depressurization. In addition, the setting is low enough to prevent spurious isolations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

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

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. 2). The Function is automatically bypassed when the reactor mode switch is not in the run position.

This Function isolates the MSIVs and MSL drain valves.

1.c. 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 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. 3). 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 transmitters that are connected to the four MSLs. The transmitters 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 unisolated 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. In addition, the setting is high enough to permit the isolation of one main steam line at reduced power without causing an automatic isolation of the steam lines yet low enough to permit early detection of a gross steam line break.

This Function isolates the MSIVs and MSL drain valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.d. Condenser Vacuum - Low

The Condenser Vacuum - Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Vacuum - Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum - Low 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 prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be OPERABLE in MODES 2 and 3 when all turbine stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. The Function is automatically bypassed when the reactor mode switch is not in the run position and when all TSVs are closed.

This Function isolates the MSIVs and MSL drain valves.

1.e. Main Steam Tunnel Area Temperature - High

Main Steam Tunnel Area temperature is provided to detect a break in a main steam line and provides diversity to the high flow instrumentation. High temperature in the main steam tunnel outside the primary containment could indicate a break in a main steam line. The automatic closure of the MSIVs and MSL drains, prevents excessive loss of reactor coolant and the release of significant amounts of radioactive material from the reactor coolant pressure boundary. The isolation occurs when a very small leak has occurred. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Main Steam Tunnel Area temperature signals are initiated from resistance temperature detectors (RTDs) located in the area being monitored. Sixteen channels of Main Steam Tunnel Temperature-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 chosen high enough above the temperature expected during power operations to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

This Function isolates the MSIVs and MSL drain valves.

1.f. Main Steam Line Radiation-High

The Main Steam Line Radiation-High isolation signal has been removed from the MSIV isolation logic circuitry (Ref. 1); however, this isolation Function has been retained for the MSL drains valves (and other valves discussed under Function 2.f) to ensure that the assumptions utilized to determine that acceptable offsite doses resulting from a control rod drop accident (CRDA) are maintained.

Main Steam Line Radiation-High signals are generated from four radiation elements and associated monitors, which are located near the main steam lines in the steam tunnel. Four instrumentation channels of the Main Steam Line Radiation-High Function are available and required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be low enough that a high radiation trip results from the fission products released in the CRDA. In addition, the setting is adjusted high enough above the background radiation level in the vicinity of the main steam lines so that spurious trips are avoided at rated power.

This Function isolates the MSL drain valves.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Primary Containment Isolation

2.a, 2.g. Reactor Vessel Water Level - Low (Level 3)

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 Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level - Low (Level 3) 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 (Level 3) signals are initiated from level 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. For Function 2.a, four channels of Reactor Vessel Water Level - Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. For Function 2.g, two channels of Reactor Vessel Water Level - Low (Level 3) are required to be OPERABLE for each hydrogen/oxygen and gaseous/particulate sample supply and return penetration to ensure these penetrations can be isolated.

The Reactor Vessel Water Level - Low (Level 3) Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates the valves listed in Reference 1.

2.b, 2.d. 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

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b, 2.d. Drywell Pressure - High (continued)

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 transmitters that sense the pressure in the drywell. For Function 2.b, four channels of Drywell Pressure - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. For Function 2.d, two channels of Drywell Pressure - High are required to be OPERABLE for each hydrogen/oxygen and gaseous/particulate sample supply and return penetration to ensure these penetrations can be isolated.

The Allowable Value was selected to be as low as possible without inducing spurious trips. The Allowable Value is chosen to be the same as the RPS Drywell Pressure - High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

These Functions isolate the valves listed in Reference 1.

2.c. Containment Radiation - High

High containment radiation indicates possible gross failure of the fuel cladding. Therefore, when Containment 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.

The containment radiation signals are initiated from radiation detectors that are located in the drywell. Two channels of Containment 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. However, the setting is high enough to avoid spurious isolation.

This Function isolates the containment vent and purge valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.e. Reactor Vessel Water Level - Low Low Low (Level 1)

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 recirculation loop sample valves occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level - Low Low Low (Level 1) Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level - Low Low Low (Level 1) Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 3). The isolation of the recirculation loop sample valves on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level 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 Low Low (Level 1) 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 Low (Level 1) Allowable Value is chosen to ensure that the recirculation loop sample valves close on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 100 limits. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates the recirculation loop sample valves.

2.f. Main Steam Line Radiation - High

The Main Steam Line Radiation-High isolation signal has been removed from the MSIV isolation logic circuitry (Ref. 1); however, this isolation Function has been retained for the recirculation loop sample valves to ensure that the assumptions utilized to determine that acceptable offsite doses resulting from a CRDA are maintained.

Main Steam Line Radiation - High signals are generated from four radiation elements and associated monitors, which are

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Main Steam Line Radiation-High (continued)

located near the main steam lines in the steam tunnel. Four Instrumentation channels of the Main Steam Line Radiation-High Function are available and required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be low enough that a high radiation trip results from the fission products released in the Design Basis CRDA. In addition, the setting is adjusted high enough above the background radiation level in the vicinity of the main steam lines so that spurious trips are avoided at rated power.

This Function isolates the recirculation loop sample valves.

High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Isolation

3.a, 4.a. HPCI and RCIC Steam Line Flow-High

Steam Line Flow-High Functions are provided to detect a break of the RCIC or HPCI steam lines and initiate closure of the steam line isolation valves of the appropriate system. 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 RCIC or HPCI steam line breaks from becoming bounding.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a, 4.a. HPCI and RCIC Steam Line Flow - High (continued)

The Allowable Values are chosen to be low enough to ensure a timely detection of a turbine steam line break so that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event. The setting is adjusted high enough to avoid spurious isolations during HPCI and RCIC startups.

These Functions isolate the valves, as appropriate, as listed in Reference 1.

3.b, 4.b. HPCI and RCIC Steam Supply Line Pressure - Low

Low steam pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system's 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 and RCIC initiations (Ref. 5).

The HPCI and RCIC Steam Supply Line Pressure - Low signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure - Low 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 selected to be high enough to prevent damage to the system's turbine and low enough to ensure HPCI and RCIC Systems remain OPERABLE.

These Functions isolate the valves, as appropriate, as listed in Reference 1.

3.c, 4.c. HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High

High turbine exhaust diaphragm pressure could indicate that the turbine rotor is not turning, or there is a broken turbine blading or shrouding, thus allowing reactor pressure to act on the turbine exhaust line. The system is isolated

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.c, 4.c. HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High (continued)

to prevent overpressurization of the turbine exhaust line. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations (Ref. 5).

The HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High signals are initiated from switches (four for HPCI and four for RCIC) that are connected to the area between the rupture diaphragms on each system's turbine exhaust line. Four channels of both HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High 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 high enough to prevent damage to low pressure components in the turbine exhaust pathway. The settings are adjusted low enough to avoid isolation of the system's turbine.

These Functions isolate the valves, as appropriate, as listed in Reference 1.

3.d, 3.e, 3.f, 3.g, 3.h, 3.i, 3.j, 4.d, 4.e, 4.f. HPCI and RCIC Area Temperature - High

HPCI and RCIC Area temperatures are provided to detect a leak from the associated 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.

Area Temperature - High signals are initiated from resistance temperature detectors (RTDs) that are appropriately located to protect the system that is being monitored. Two instruments monitor each area for a total of 16 channels for HPCI and 8 channels for RCIC. All channels for each HPCI and RCIC Area Temperature - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d, 3.e, 3.f, 3.g, 3.h, 3.i, 3.j, 4.d, 4.e, 4.f. HPCI and RCIC Area Temperature - High (continued)

The Allowable Values are set high enough above normal operating levels to avoid spurious operation but low enough to provide timely detection of a steam leak.

These Functions isolate the valves, as appropriate, as listed in Reference 1.

Reactor Water Cleanup (RWCU) System Isolation

5.a, 5.b, 5.c. RWCU Area Temperatures - High

RWCU area temperatures are provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred. If the small leak continues without isolation, offsite dose limits may be reached. 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 recirculation or MSL breaks.

Area temperature signals are initiated from temperature elements that are located in the area that is being monitored. Eight thermocouples provide input to the Area Temperature - High Functions (two per area or room). Eight channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Area Temperature - High Allowable Values are set high enough to avoid spurious isolation yet low enough to provide timely detection and isolation of a break in the RWCU System.

These Functions isolates both RWCU suction valves and the return valve.

5.d. 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. 6). The RWCU isolation signal is initiated when the control room SLC initiation switch is in any position other than stop.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.d. SLC System Initiation (continued)

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.

Two channels (start system A or start system B) 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).

As noted (footnote (d) to Table 3.3.6.1-1), this Function is only required to close one of the RWCU suction isolation valves and one return isolation valve since the signals only provide input into one of the two trip systems.

5.e. Reactor Vessel Water Level - Low (Level 3)

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 Level 3 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 (Level 3) 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 (Level 3) signals are initiated from four level 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 (Level 3) 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 (Level 3) Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low (Level 3) Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened. The Allowable Value is referenced from a level of water

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.e. Reactor Vessel Water Level - Low (Level 3) (continued)

352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates both RWCU suction valves and the RWCU return valve.

5.f. 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 transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable value was selected to be as low as possible without inducing spurious trips. The Allowable Value is chosen to be the same as the RPS Drywell Pressure - High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates both RWCU suction valves and one RWCU return valve.

6.a. Reactor Pressure - High

The Reactor Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This interlock Function is provided only for equipment protection to prevent an intersystem LOCA scenario, and credit for the interlock is not assumed in the accident or transient analysis in the UFSAR.

The Reactor Pressure - High signals are initiated from two pressure switches that are connected to different taps on

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.a. Reactor Pressure - High (continued)

reactor recirculation pump B suction line. Each switch provides input to each trip system. However, only one channel input is required to be OPERABLE for a trip system to be considered OPERABLE. Two channels of Reactor Pressure - 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 can be pressurized; thus, equipment protection is needed.

The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates both RHR shutdown cooling pump suction valves.

6.b. Reactor Vessel Water Level - Low (Level 3)

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 (Level 3) Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the reactor water recirculation system and MSL. The RHR Shutdown Cooling System isolation on Level 3 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 RHR Shutdown Cooling System.

Reactor Vessel Water Level - Low (Level 3) signals are initiated from four level 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 (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (e) to Table 3.3.6.1-1), only one trip system of the Reactor Vessel Water Level - Low (Level 3) Function are required to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.b. Reactor Vessel Water Level - Low (Level 3) (continued)

be OPERABLE in MODES 4 and 5, provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance or other activity is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level - Low (Level 3) Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low (Level 3) Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

The Reactor Vessel Water Level - Low (Level 3) 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., Reactor Pressure - High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates both RHR shutdown cooling pump suction valves and the inboard LPCI injection valves.

Traversing Incore Probe System Isolation

7.a. Reactor Vessel Water Level- Low (Level 3)

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 Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level- Low (Level 3) 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 (Level 3) signals are initiated from level 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. Two channels of Reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7.a. Reactor Vessel Water Level-Low (Level 3) (continued)

Vessel Water Level - Low (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The isolation function is ensured by the manual shear valve in each penetration.

The Reactor Vessel Water Level - Low (Level 3) Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 13).

This Function isolates the TIP System isolation ball valves.

7.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 transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The isolation function is ensured by the manual shear valve in each penetration.

The Allowable Value is chosen to be the same as the RPS Drywell Pressure - High Allowable Value (LCO 3.3.1.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the TIP System isolation ball valves.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of

(continued)

BASES

ACTIONS (continued)

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. Note 2 has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.b, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b (which have components common to RPS) and 24 hours for Functions other than Functions 2.a, 2.b, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b has been shown to be acceptable (Refs. 6 and 7) 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.

(continued)

BASES

ACTIONS (continued)

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 isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions (associated with MSIV isolation) are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip (or the associated trip system in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. The other 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 at least one of the PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, and 1.d (associated with MSIV isolation), this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c (associated with MSIV isolation), this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. For Function 1.e, four areas are monitored by four channels (e.g., different locations within the main steam tunnel area). Therefore, this would require both trip systems to have one channel per location OPERABLE or in trip (associated with MSIV isolation). For Functions 1.a, 1.b, 1.d, and 1.f (associated with MSL drain isolation) this would require one trip system to have two channels, each OPERABLE or in trip. For Function 1.c (associated with MSL drain isolation) this will require one trip system to have two channels, associated with each MSL, each OPERABLE or in trip. For Function 1.e this would require one trip system to have two channels, associated with each main steam tunnel area, each to be OPERABLE or in trip. For Functions 2.d and 2.g, as noted by footnote (c) to Table 3.3.6.1-1, there is only one trip system provided for each associated penetration. For these penetrations (i.e., hydrogen/oxygen sample and return, and gaseous/particulate sample supply and return), this will require both channels to be OPERABLE or in trip in order to close at least one valve. For Functions 2.a, 2.b, 2.e, 2.f, 3.b, 3.c, 4.b, 4.c, 5.e, 5.f, and 6.b, this would require one trip system to have two channels, each OPERABLE or in trip. For Functions 2.c, 3.a, 3.d, 3.e, 3.f, 3.g, 3.h, 3.i, 4.a, 4.d, 4.e, 5.a, 5.c, and 6.a, this would require one trip system to have one channel OPERABLE or in trip. For Functions 3.j, 4.f, and 5.b each Function consists of

(continued)

BASES

ACTIONS

B.1 (continued)

channels that monitor two different locations. Therefore, this would require one channel per location to be OPERABLE or in trip (the channels are not required to be in the same trip system). For Function 5.d, this would require that with the SLC initiation switch in start system A or B the associated valve will close. For Function 7.a and 7.b the logic is arranged in one trip system, therefore this would require both channels to be OPERABLE or in trip, or the manual shear valves to be OPERABLE.

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 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 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). Alternately, the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with one MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. 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.

(continued)

BASES

ACTIONS (continued)

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 6 hours.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

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 channels. 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

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 channels. The 24 hour Completion Time is acceptable due to the fact the penetrations associated with these Functions (TIP System penetration) are a small bore (approx 1/2 inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation.

(continued)

BASES

ACTIONS (continued)

H.1 and H.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 or G 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.

I.1 and I.2

If the channel is not restored to OPERABLE status within the allowed Completion Time, the associated SLC subsystem 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.

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

J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated). Actions must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

SURVEILLANCE REQUIREMENTS

As noted (Note 1) 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillances are modified by Note 2 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 as follows: (a) for Functions 2.d, 2.g, 7.a, and 7.b; and (b) for Functions other than 2.d, 2.g, 7.a, and 7.b provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 7 and 8) 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. For Functions 2.d and 2.g, this allowance is permitted since the associated penetration flow path(s) involve sample lines which form a closed system with the primary containment atmosphere. For Functions 7.a and 7.b, this is permitted since the associated penetrations can be manually isolated if needed.

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.

Channel 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.1 (continued)

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

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire 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 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analysis described in References 7 and 8.

SR 3.3.6.1.3, SR 3.3.6.1.5, 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.

SR 3.3.6.1.6 however is only a calibration of the radiation detectors using a standard radiation source. As noted for SR 3.3.6.1.3, the main steam tunnel radiation detectors are excluded from CHANNEL CALIBRATION due to ALARA reasons (when the plant is operating, the radiation detectors are generally in a high radiation area; the steam tunnel). This exclusion is acceptable because the radiation detectors are passive devices, with minimal drift. The radiation

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.3, SR 3.3.6.1.5, and SR 3.3.6.1.6 (continued)

detectors are calibrated in accordance with SR 3.3.6.1.6 on a 24 month Frequency. The CHANNEL CALIBRATION of the remaining portions of the channel (SR 3.3.6.1.3) are performed using a standard current source.

Reactor Vessel Water Level - Low Low Low (Level 1), Main Steam Line Pressure - Low and Main Steam Line Flow - High Function sensors (Functions 1.a, 1.b, and 1.c, respectively) are excluded from ISOLATION INSTRUMENTATION RESPONSE TIME testing (Ref. 11). However, during the CHANNEL CALIBRATION of these sensors, a response check must be performed to ensure adequate response. This testing is required by Reference 11. Personnel involved in this testing must have been trained in response to Reference 12 to ensure that they are aware of the consequences of instrument response time degradation. This response check must be performed by placing a fast ramp or a step change into the input of each required sensor. The personnel must monitor the input and output of the associated sensor so that simultaneous monitoring and verification may be accomplished.

The Frequency of SR 3.3.6.1.3 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 Frequencies of SR 3.3.6.1.5 and SR 3.3.6.1.6 are based on the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.4

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 184 days is based on operating experience that demonstrates this equipment to be reliable.

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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. While this Surveillance can be performed with the reactor at power for some 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. Therefore, the Frequency was found to be acceptable from a reliability standpoint.

SR 3.3.6.1.8

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the emergency diesel generator (EDG) start time. For channels assumed to respond within the EDG start time, sufficient margin exists in the 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test.

ISOLATION INSTRUMENTATION RESPONSE TIME acceptance criteria are included in Reference 9. ISOLATION SYSTEM RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements. However, the sensors for Functions 1.a, 1.b, and 1.c are excluded from specific ISOLATION SYSTEM RESPONSE TIME measurement since the conditions of Reference 10 are satisfied. For Functions 1.a, 1.b, and 1.c, sensor response time may be allocated based on either assumed design sensor response time or the manufacturer's stated design response time.

ISOLATION INSTRUMENTATION RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. A Note requires STAGGERED TEST BASIS Frequency to be determined based on 2 channels. This will ensure that all required channels are tested during two Surveillance Frequency intervals. For Functions 1.a and 1.b, two channels must be tested during

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.8 (continued)

each test, while for Function 1.c, eight channels must be tested. The 24 month Frequency is consistent with the refueling cycle and is based upon plant operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. UFSAR, Table 7.3-1.
2. UFSAR, Section 14.5.
3. UFSAR, Section 14.6.
4. 10 CFR 50.36(c)(2)(ii).
5. NEDO-31466, Technical Specification Screening Criteria Application and Risk Assessment, November 1987.
6. UFSAR, Section 3.9.3.
7. NEDC-31677P-A, Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation, July 1990.
8. NEDC-30851P-A, Supplement 2, Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation, March 1989.
9. UFSAR, Table 7.3-12.
10. NEDO-32291-A, System Analyses For the Elimination of Selected Response Time Testing Requirements, October 1995.
11. NRC letter dated October 28, 1996, Issuance of Amendment 235 to Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.
12. NRC Bulletin 90-01, Supplement 1, Loss of Fill-Oil in Transmitters Manufactured by Rosemount, December 1992.
13. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).

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), trips the refuel floor exhaust fans, trips the tank and equipment drain sump exhaust fan, and places the reactor building ventilation system in the recirculation mode of operation 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 within the required time limits 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, logic circuits, 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 ventilation exhaust radiation, and (4) refueling floor ventilation exhaust radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation.

The outputs of the logic channels for reactor water level and drywell pressure are arranged into two two-out-of-two trip system logics. The outputs of the logic channels for reactor building ventilation exhaust and refueling ventilation exhaust radiation are arranged into two one-out-of-one trip system logics. One trip system initiates isolation of one automatic isolation valve (damper) and starts one SGT subsystem while the other trip system initiates isolation of the other automatic isolation valve in the penetration and starts the other SGT subsystem. Each

(continued)

BASES

BACKGROUND (continued)	logic closes one of the two valves on each penetration and starts one SGT subsystem, so that operation of either logic isolates the secondary containment and provides for the necessary filtration of fission products.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the secondary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves and start the SGT System to limit offsite and control room doses.

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.

The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

The OPERABILITY of the secondary containment isolation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function 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. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

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.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

parameters obtained from the safety analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

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.

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

1. Reactor Vessel Water Level - Low (Level 3)

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 for release of radioactive material and of the resulting offsite and control room dose. The Reactor Vessel Water Level - Low (Level 3) Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation systems on Reactor Vessel Water Level - Low (Level 3) support actions to ensure that any offsite releases are within the limits calculated in the safety analysis (Ref. 4).

Reactor Vessel Water Level - Low (Level 3) signals are initiated from level 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 (Level 3) Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Reactor Vessel Water Level - Low (Level 3) (continued)

The Reactor Vessel Water Level - Low (Level 3) Allowable Value was chosen to be the same as the RPS level scram Allowable Value (LCO 3.3.1.1, "Reactor Protection System Instrumentation"), since this could indicate that the capability to cool the fuel is being threatened. The Allowable Value is referenced from a level of water 352.56 inches above the lowest point in the inside bottom of the RPV and also corresponds to the top of a 144 inch fuel column (Ref. 8).

The Reactor Vessel Water Level - Low (Level 3) 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 Function is also required to be OPERABLE during operations with a potential for draining the reactor vessel (OPDRVs) because the capability of isolating potential sources of leakage must be provided to ensure that offsite and control room 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 and control room release. The Drywell Pressure - High Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiating signals. The isolation and initiation systems on high drywell pressure supports actions to ensure that any offsite and control room releases are within the limits calculated in the safety analysis (Ref. 4).

High drywell pressure signals are initiated from pressure transmitters 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure - High (continued)

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.

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

High secondary containment 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 refueling accident. When Exhaust Radiation - High is detected, secondary containment isolation and actuation of the SGT System are initiated to limit the release of fission products as assumed in the UFSAR safety analyses (Refs. 4 and 5).

The Exhaust Radiation - High signals are initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building and the refueling floor zones. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Ventilation Exhaust Radiation - High Function and two channels of Refueling Floor Ventilation Exhaust 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 and are set in accordance with the ODCM.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3, 4. Reactor Building and Refueling Floor Ventilation Exhaust Radiation - High (continued)

The Reactor Building and Refueling Floor Ventilation Exhaust Radiation - High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable RCS energy exists; 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 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 uncovery or dropped fuel assemblies) must be provided to ensure that offsite and control room dose limits are not exceeded.

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 for Functions 1 and 2 (which have components common to RPS), and 24 hours for Functions 3 and 4, has been shown to be acceptable (Refs. 6 and 7) 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

(continued)

BASES

ACTIONS

A.1 (continued)

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. 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 loss of isolation capability for the associated penetration flow path(s) or a loss of initiation capability for the SGT System. A Function is considered to be maintaining secondary containment 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 SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For the Functions with two two-out-of-two logic trip systems (Functions 1 and 2), this would require one trip system to have both channels OPERABLE or in trip. For Functions 3 and 4, this would require one trip system to have one OPERABLE or tripped channel.

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 of Condition A or B 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

(continued)

BASES

ACTIONS

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

ensure the ability to maintain the secondary containment function. Isolating the associated secondary containment penetration flow path(s) (closing the ventilation supply and exhaust automatic isolation dampers) 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.

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 secondary containment 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. 6 and 7) 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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.1 (continued)

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.

Channel 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 entire 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 analysis of References 6 and 7.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.3 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 3.3.6.2.3 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.

SR 3.3.6.2.4

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 184 days is based on the reliability, accuracy and lower failure rates of the solid-state electronic Analog Transmitters/Trip System components.

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.

While this Surveillance can be performed with the reactor at power for some 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.2.6 (continued)

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 5.3.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).
4. UFSAR, Section 14.6.1.3.
5. UFSAR, Section 14.6.1.4.
6. NEDC-31677P-A, Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation, July 1990.
7. NEDC-30851P-A, Supplement 2, Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation, March 1989.
8. Drawing 11825-5.01-15D, Rev. D, Reactor Assembly Nuclear Boiler, (GE Drawing 919D690BD).

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Ventilation Air Supply (CREVAS) System Instrumentation

BASES

BACKGROUND

The CREVAS 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. Two independent CREVAS subsystems are each capable of fulfilling the stated safety function. The instrumentation for the CREVAS System provides an alarm so that manual action can be taken to place the CREVAS System in the isolate mode of operation to pressurize the control room to minimize the infiltration of radioactive material into the control room environment.

In the event of a Control Room Air Inlet Radiation - High signal, the CREVAS System is manually started in the isolate mode. Air is then drawn in from the air intake source and passes through one of two special filter trains each consisting of a prefilter, a high efficiency (HEPA) filter, two charcoal filters and a second HEPA filter. This air is then combined with recirculated air and directed to one of two control room ventilation fans and directed to the control room to maintain the control room slightly pressurized with respect to the adjacent areas.

The CREVAS System instrumentation consists of a single trip system with one Control Room Air Inlet Radiation - High channel. The channel includes electronic equipment (e.g., detector, monitor and trip relay) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs to an alarm in the control room.

APPLICABLE SAFETY ANALYSES

The ability of the CREVAS System to maintain the habitability of the control room is explicitly assumed for certain accidents as discussed in the UFSAR safety analyses (Refs. 1, 2, 3, and 4) and further discussed in Reference 5. CREVAS 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

CREVAS System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 6).

LCO

The OPERABILITY of the CREVAS System instrumentation is dependent upon the OPERABILITY of the Control Room Air Inlet Radiation—High Function. This Function must have one OPERABLE channel, with its setpoint within the specified Allowable Value. The 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.

An Allowable Value is specified for the Control Room Air Inlet Radiation—High Function in SR 3.3.7.1.2. A nominal trip setpoint is specified in the setpoint calculation. The nominal setpoint is selected to ensure that the setpoint does not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. 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., control room air inlet radiation), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., output relay) changes state. The analytic limit is derived from the limiting value of the process parameters obtained from the safety analysis. The trip setpoint is derived from the analytical limit and accounts for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoint derived in this manner provides adequate protection because all expected uncertainties are accounted for. The Allowable Value is then derived from the trip setpoint by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties). The Allowable Value was selected to ensure protection of the control room personnel.

The control room air inlet radiation monitor measures radiation levels in the inlet ducting of the control room. A high radiation level may pose a threat to control room

(continued)

BASES

LCO (continued)	personnel; thus, an alarm is provided in the control room so that the CREVAS System can be placed in the isolate mode of operation.
APPLICABILITY	The Control Room Air Inlet Radiation-High Function is required to be OPERABLE in MODES 1, 2, and 3 and during CORE ALTERATIONS, OPDRVs, and movement of irradiated fuel assemblies in the secondary containment, to ensure that control room personnel are 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 Function is not required.
ACTIONS	A.1 and A.2 With the Control Room Air Inlet Radiation-High Function inoperable one CREVAS subsystem must be placed in the isolate mode of operation per Required Action A.1 to ensure that control room personnel will be protected in the event of a Design Basis Accident. Alternately, if it is not desired to start a CREVAS subsystem, the CREVAS System must be declared inoperable within 1 hour. The 1 hour Completion Time is intended to allow the operator time to place the CREVAS subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of the channel, for placing one CREVAS subsystem in operation, or for entering the applicable Conditions and Required Actions for two inoperable CREVAS subsystems.
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. 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 low probability of an event requiring this Function during this time period and since many other alarms are available to indicate whether a design basis event has occurred.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel 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.

SR 3.3.7.1.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific 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 14.6.1.2.
2. UFSAR, Section 14.6.1.3.
3. UFSAR, Section 14.6.1.4.
4. UFSAR, Section 14.6.1.5.
5. UFSAR, Section 14.8.2.
6. 10 CFR 50.36(c)(2)(ii).

B 3.3 INSTRUMENTATION

B 3.3.7.2 Condenser Air Removal Pump Isolation Instrumentation

BASES

BACKGROUND

The condenser air removal pump isolation instrumentation initiates an isolation of the suction and discharge valves of the condenser air removal pumps following events in which main steam line radiation exceeds predetermined values. Isolating the condenser air removal pump limits the offsite doses in the event of a control rod drop accident (CRDA).

The condenser air removal pump isolation instrumentation (Ref. 1) includes sensors, logic circuits, relays and switches that are necessary to cause initiation of the condenser air removal pumps isolation. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the condenser air removal pump isolation logic.

The isolation logic consists of two trip systems, with two channels of Main Steam Line Radiation—High in each trip system. Each trip system is a one-out-of-two logic for this Function. Thus, either channel of Main Steam Line Radiation—High in each trip system are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that both trip systems must trip to result in an isolation signal.

There are two isolation valves associated with this function.

APPLICABLE SAFETY ANALYSES

The condenser air removal pump isolation is assumed in the safety analysis for the CRDA. The condenser air removal pump isolation instrumentation initiates an isolation of the condenser air removal pump to limit offsite doses resulting from fuel cladding failure in a CRDA (Ref. 2).

The condenser air removal pump isolation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

The OPERABILITY of the condenser air removal pump isolation is dependent on the OPERABILITY of the individual Main Steam Line Radiation—High instrumentation channels, which must have a required number of OPERABLE channels in each trip

(continued)

BASES

LCO (continued)

system, with their setpoints within the specified Allowable Value of SR 3.3.7.2.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated isolation valve.

An Allowable Value is specified for the Main Steam Line Radiation—High isolation Function in SR 3.3.7.2.2. A nominal trip setpoint is specified in the setpoint calculations. The nominal setpoint is 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. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (i.e., Main Steam Line Radiation—High), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limit is derived from the limiting values of the process parameters obtained from the safety analysis. The trip setpoint is derived from the analytical limit and accounts for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoint derived in this manner provides adequate protection because all expected uncertainties are accounted for. The Allowable Value is then derived from the trip setpoint by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties). The Allowable Value was selected to be low enough that a high radiation trip results from the fission products released in the CRDA. In addition, the setting is adjusted high enough above the background radiation level in the vicinity of the main steam lines so that spurious trips are avoided at rated power.

APPLICABILITY

The condenser air removal pump isolation is required to be OPERABLE in MODES 1 and 2 when any condenser air removal pump is not isolated and any main steam line not isolated to mitigate the consequences of a postulated CRDA. In this condition fission products released during a CRDA could be discharged directly to the environment. Therefore,

(continued)

BASES

APPLICABILITY (continued)

condenser air removal pump isolation is necessary to assure conformance with the radiological evaluation of the CRDA. In MODE 3, 4 or 5 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. When the condenser air removal pumps or main steam lines are isolated in MODE 1 or 2, fission product releases via this pathway would not occur.

ACTIONS

A Note has been provided to modify the ACTIONS related to condenser air removal pump 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 condenser air removal pump 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 condenser air removal pump isolation instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with condenser air removal pump isolation capability maintained (refer to Required Action B.1 Bases), the condenser air removal pump isolation instrumentation is capable of performing the intended function. However, the reliability and redundancy of the condenser air removal pump isolation instrumentation is reduced, such that a single failure in one of the remaining channels could result in the inability of the condenser air removal pump isolation instrumentation to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities affecting multiple channels, and the low probability of an event requiring the initiation of condenser air removal pump isolation, 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

(Required Action A.1). Alternately, the inoperable channel, or associated trip system, may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable isolation valve, since this may not adequately compensate for the inoperable valve (e.g., the valve may be inoperable such that it will not isolate). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in loss of condenser vacuum), or if the inoperable channel is the result of an inoperable valve, Condition B 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 result in the Function not maintaining condenser air removal pump isolation capability. The Function is considered to be maintaining condenser air removal pump isolation capability when sufficient channels are OPERABLE or in trip such that the condenser air removal pump isolation instruments will generate a trip signal from a valid Main Steam Line Radiation—High signal, and at least one isolation valve will close. This requires one channel of the Function in each trip system to be OPERABLE or in trip, and one condenser air removal pump isolation valve to be OPERABLE.

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, C.2, and C.3

With any Required Action and associated Completion Time of Condition A or B not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to

(continued)

BASES

ACTIONS

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

at least MODE 3 within 12 hours (Required Action C.3). Alternately, the condenser air removal pumps may be isolated since this performs the intended function of the instrumentation (Required Action C.1). An additional option is provided to isolate the main steam lines (Required Action C.2), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, or to remove the condenser air removal pump from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

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 the associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains condenser air removal pump isolation trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 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 condenser air removal pumps will isolate when necessary.

SR 3.3.7.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2.1 (continued)

gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Channel 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 channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.7.2.2 and SR 3.3.7.2.3

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. SR 3.3.7.2.3, however, is only a calibration of the radiation detectors using a standard radiation source.

As noted for SR 3.3.7.2.2, the main steam line radiation detectors are excluded from CHANNEL CALIBRATION due to ALARA reasons (when the plant is operating, the radiation detectors are generally in a high radiation area; the steam tunnel). This exclusion is acceptable because the radiation detectors are passive devices, with minimal drift. The radiation detectors are calibrated in accordance with SR 3.3.7.2.3 on a 24 month Frequency. The CHANNEL CALIBRATION of the remaining portions of the channel (SR 3.3.6.1.2) are performed using a standard current source.

The Frequency of SR 3.3.7.2.2 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 3.3.7.2.3 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of detector drift in the setpoint analysis.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) 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 these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. UFSAR, Section 10.4.3.1.
2. UFSAR, Section 14.6.1.2.
3. 10 CFR 50.36(c)(2)(ii).
4. NEDC-31677P-A, Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation, July 1990.

B 3.3 INSTRUMENTATION

B 3.3.7.3 Emergency Service Water (ESW) System Instrumentation

BASES

BACKGROUND

The purpose of the ESW System instrumentation is to initiate appropriate responses from the system to ensure the ESW safe shutdown loads are cooled following a Design Basis Accident (DBA) or transient coincident with a loss of preferred power. The ESW safe shutdown loads are described in the Bases for LCO 3.7.2, "Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)".

The ESW System may be initiated by either automatic or manual means. Upon receipt of a loss of power signal as described in the Bases of LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," or an ECCS initiation signal as described in the Bases of LCO 3.3.5.1, "Emergency Core Cooling System Instrumentation," the Emergency Diesel Generators (EDGs) will start, which in turn starts the associated ESW pump. Each ESW pump will automatically pump lake water to the associated EDG cooler. The remaining ESW loads will be automatically cooled when the associated ESW supply header isolation valve opens and the associated ESW minimum flow valve closes. This occurs when the ESW instrumentation initiation logic (known as the ESW lockout matrix) actuates upon low reactor building closed loop cooling water (RBCLCW) pump discharge pressure. In addition, the ESW pumps will automatically start in response to the ESW instrumentation initiation logic.

ESW instrumentation are provided inputs by pressure switches that sense RBCLCW pump discharge pressure. Four channels of ESW instrumentation are provided as input to two one-out-of-two twice initiation logics. Each initiation logic system will open the associated ESW pump discharge header valve, close the minimum flow control valve to ensure cooling water is provided to supply the safe shutdown loads of the ESW System, start the associated ESW pump, and open the associated RBCLCW System discharge valves. However, the opening of the RBCLCW System discharge valves are not required. The opening of these RBCLCW System discharge valves are not necessary since RBCLCW does not cool any safe shutdown loads. Each channel consists of a pressure sensor and switch, that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel outputs a RBCLCW pump discharge initiation signal to both ESW initiation logic circuits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The actions of the ESW System are implicitly assumed in the safety analyses of References 1 and 2. The ESW System instrumentation is required to be OPERABLE to support the ESW System. Refer to LCO 3.7.2 for Applicable Safety Analyses Bases of ESW System.

The ESW System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

LCO

The LCO requires four ESW instrumentation channels, which monitor the RBCLCW pump discharge header pressure, to be OPERABLE. The four channels provide input to both logic systems to ensure that no single instrument failure will prevent ESW from supplying the safe shutdown loads. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.7.3.1. The Allowable Value is set high enough to ensure logic initiation during a complete loss of the RBCLCW System and low enough to avoid logic initiation during small RBCLCW System pressure transients. The actual setpoint is calibrated to be consistent with the 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 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 (i.e., RBCLCW pump discharge header pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., pressure switch) changes state. The analytic limit is derived from the limiting values of the process parameters obtained from the safety analysis or other appropriate documents. The trip setpoint is derived from the analytic limit and accounts for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Value is then derived from the trip setpoint by

(continued)

BASES

LCO (continued)

accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

APPLICABILITY

The ESW System instrumentation is required to be OPERABLE in MODES 1, 2, and 3 to support the ESW System. (Refer to LCO 3.7.2 for Applicability Bases of ESW System).

ACTIONS

A Note has been provided to modify the ACTIONS related to ESW pressure 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 ESW pressure channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ESW pressure channel.

A.1

Because of the redundancy of the actuation signals, an allowable out of service time of 24 hours is considered to be acceptable to permit restoration of any inoperable channel to OPERABLE status. This out of service time is consistent with the allowed out of service times for other similar Functions in the Technical Specifications. The ESW System instrumentation redundancy is consistent with redundancy of certain ECCS Functions as described in the Bases of LCO 3.5.1, "Emergency Core Cooling System—Operating".

This out of service time is only acceptable provided the ESW pressure channels are still maintaining actuation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the Completion 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

(continued)

BASES

ACTIONS

A.1 (continued)

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 ESW System initiation), 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 result in redundant automatic initiation capability being lost for both ESW initiation logic systems. The ESW initiation logic systems are considered to be maintaining initiation capability when sufficient channels are OPERABLE or in trip such that one logic system will generate an initiation signal from the given Function on a valid signal. This will ensure that at least one ESW System will receive an initiation signal.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The Completion Time is acceptable because it minimizes risk while allowing for restoration or tripping of channels.

C.1

If any Required Action and associated Completion Time of Condition A or B are not met, the associated ESW subsystem(s) must be declared inoperable immediately. This declaration also requires entry into applicable Conditions and Required Actions for inoperable ESW subsystem(s) in LCO 3.7.2.

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 ESW 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. This Note is based on a reliability analysis assumption that 6 hours is the average

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ESW initiation will occur when necessary.

SR 3.3.7.3.1

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.

SR 3.3.7.3.2

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional test performed in LCO 3.7.2 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. UFSAR, Chapter 5.
2. UFSAR, Chapter 14.
3. 10 CFR 50.36(c)(2)(ii).

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 4.16 kV emergency buses. The Main Generator (normal), the 115 kV transmission network (reserve), the 345 kV transmission network (backfeed) are the preferred sources of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from these power sources and connected to the onsite emergency diesel generator (EDG) power sources.

Each 4.16 kV emergency 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 types of undervoltage protection Functions: Loss of Voltage and Degraded Voltage (Ref. 1). Each 4.16 kV Emergency Bus Loss of Voltage Function and Degraded Voltage Function is monitored by two undervoltage relays for each emergency bus. These relay outputs are arranged in a two-out-of-two logic configuration for each 4.16 kV Emergency Bus Loss of Voltage and Degraded Voltage Function. The Emergency Bus Undervoltage and Degraded Voltage Function signals provide input to their respective Bus Undervoltage and Degraded Voltage-Time Delay Functions. Each 4.16 kV Emergency Bus has one Loss of Voltage-Time Delay relay. The Degraded Voltage Function utilizes two time delay relays, one time delay for a bus undervoltage (degraded voltage) in conjunction with a loss of coolant accident (LOCA) signal and the other for a bus undervoltage (degraded voltage) without a LOCA (non-LOCA). When a voltage Function setpoint has been exceeded and the respective time delay completed, the time delay relay will start the associated EDG subsystem, trip the associated breakers providing normal, backfeed, or reserve power, trip all associated 4.16 kV motor breakers (after EDG reaches 75% of rated voltage), initiate EDG breaker close permissive (in conjunction with 90% of rated voltage), and initiate sequential starting of the ECCS pumps if the LOCA signal is present. The sequential starting of the ECCS pumps is not considered part of the LOP Instrumentation and is tested in LCO 3.8.1, "AC Sources – Operating," and LCO 3.8.2, "AC Sources – Shutdown."

(continued)

BASES

BACKGROUND (continued)	The channels include electronic equipment (e.g., internal relay contacts, coils) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The LOP instrumentation is required for Engineered Safeguards to function in any accident with a loss of the preferred power sources. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the EDGs, provide plant protection in the event of any of the Reference 2 and 3 analyzed accidents in which a loss of all the preferred power sources are assumed. The initiation of the EDGs on loss of all the preferred power sources, 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 EDGs based on the loss of the preferred power sources during a loss of coolant accident. The emergency diesel starting and loading times have been included in the delay time associated with each safety system component requiring EDG supplied power following a loss of the preferred power sources.

The LOP instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

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 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. 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.

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. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

process parameter (e.g., emergency bus voltage via secondary windings), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., internal relay contacts) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the design and safety analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

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

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that preferred power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. The Loss of Voltage Function is monitored via the secondary windings of two transformers associated with each emergency bus. Therefore, the power supply to the bus is transferred from the preferred power source to EDG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Allowable Value is low enough to prevent spurious power supply transfer, but high enough to ensure that power is available to the required equipment. The Allowable Value corresponds to approximately 71.5% of nominal emergency bus voltage. The Time Delay Allowable Values are long enough to provide time for the preferred power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) (continued)

Two channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function and one channel of Loss of Voltage-Time Delay per associated emergency bus are required to be OPERABLE when the associated EDG is required to be OPERABLE to ensure that no single instrument failure can preclude the EDG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the EDGs.

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while preferred 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. The Degraded Voltage Function is monitored via the secondary windings of two transformers associated with each emergency bus. Therefore, power supply to the bus is transferred from the preferred power source to onsite EDG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The 4.16 kV Bus Undervoltage (Degraded Voltage) Allowable Value is low enough to prevent spurious power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Allowable Value corresponds to approximately 93% of nominal emergency bus voltage. The Time Delay Allowable Values are long enough to provide time for the preferred power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function, one channel of Degraded Voltage-Time Delay (LOCA), and one channel of Degraded Voltage-Time Delay (non-LOCA) per associated bus are required to be OPERABLE when the associated EDG is required to be OPERABLE to ensure that no single instrument failure can preclude the EDG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the EDGs.

(continued)

BASES (continued)

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 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 an EDG 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 EDG(s) is declared inoperable immediately. This requires

(continued)

BASES

ACTIONS

B.1 (continued)

entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable EDG(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.

SR 3.3.8.1.1

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.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.8.1.2

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.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 8.6.5.

2. UFSAR, Section 6.4.

3. UFSAR, Section 14.6.

4. 10 CFR 50.36(c)(2)(ii).

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, scram pilot valve solenoids, and various valve isolation logic.

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. (Safety functions powered by the RPS buses deenergize to actuate.)

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 circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing

(continued)

BASES

BACKGROUND (continued)	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 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 equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by acting to disconnect the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment. RPS electric power monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
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 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 and SR 3.3.8.2.3). 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

(continued)

BASES

LCO (continued)

process parameter (e.g., overvoltage), 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 design and safety analysis. The trip setpoints are derived from the analytical limits and account for all worst case instrumentation uncertainties as appropriate (e.g., drift, process effects, calibration uncertainties, and severe environmental errors (for channels that must function in harsh environments as defined by 10 CFR 50.49)). The trip setpoints derived in this manner provide adequate protection because all expected uncertainties are accounted for. The Allowable Values are then derived from the trip setpoints by accounting for normal effects that would be seen during periodic surveillance or calibration. These effects are instrumentation uncertainties observed during normal operation (e.g., drift and calibration uncertainties).

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 10 V (to scram pilot valve solenoids). 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 components from the inservice MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a non-class 1E source supplying 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 MODES 3, 4, and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

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

(continued)

BASES

ACTIONS

A.1 (continued)

inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus 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 or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

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.

(continued)

BASES

ACTIONS

B.1 (continued)

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 or isolation), 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 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

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 3, 4, or 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. All actions must continue until the applicable Required Actions are completed.

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 entire 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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1 (continued)

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. 3).

SR 3.3.8.2.2 and SR 3.3.8.2.3

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 3.3.8.2.4

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 electric power monitoring assembly. The system functional test shall include actuation of the protective relays, tripping logic, and output circuit breakers. Only one signal per electric power monitoring

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.4 (continued)

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 8.9.5.

2. 10 CFR 50.36(c)(2)(ii).

3. NRC Generic Letter 91-09, Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System, June 1991.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Water Recirculation System is designed to provide forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes more heat 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 Water 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, driven by 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. 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 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

(continued)

BASES

BACKGROUND (continued)

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 void negative reactivity 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., 65% to 100% of RTP) without having to move control rods and disturb desirable flux patterns. The recirculation flow also provides sufficient core flow to ensure thermal-hydraulic stability of the core is maintained.

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 Water 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 14 of the UFSAR.

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

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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. 3).

The transient analyses of Chapter 14 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 control rod block instrumentation Allowable Values are 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 Neutron Flux – High (Flow Biased) Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." The Rod Block Monitor – Upscale Allowable Value is specified in LCO 3.3.2.1, "Control Rod Block Instrumentation."

Operation of the Reactor Water Recirculation System also ensures adequate core flow at higher power levels such that conditions conducive to the onset of thermal hydraulic instability are avoided. The UFSAR Section 16.6 (Ref. 4) requires protection of fuel thermal safety limits from conditions caused by thermal hydraulic instability. Thermal hydraulic instabilities can result in power oscillations which could result in exceeding the MCPR Safety Limit. The MCPR Safety Limit is set such that 99.9% of the fuel rods avoid boiling transition if the limit is not violated (refer to the Bases for SL 2.1.1.2). Implementation of operability requirements for avoidance of, and protection from thermal-hydraulic instability, consistent with the BWR Owners' Group Long-Term Stability Solution Option I-D (Refs. 5 and 6) provides assurance that power oscillations are either prevented or can be readily detected and suppressed without exceeding the specified acceptable fuel design limits. To minimize the likelihood of thermal- hydraulic instability which results in power oscillations, a power-to-flow "Exclusion Region" is calculated using the approved methodology specified in Specification 5.6.5. The resulting "Exclusion Region" may change each fuel cycle and is therefore specified in the COLR. Entries into the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

"Exclusion Region" may occur as a result of an abnormal event, such as a single recirculation pump trip, loss of feedwater heating, or be required to prevent equipment damage.

The core-wide mode of oscillation in the neutron flux is more readily detected (and suppressed) than the regional mode of oscillation due to the spatial averaging of the Average Power Range Monitor (APRM). The Option I-D analysis for JAFNPP (Ref. 7) demonstrates that this protection is provided at a high statistical confidence level for regional mode oscillations. Reference 7 also demonstrates that the core-wide mode of oscillation is more likely to occur rather than regional oscillations due to the large single-phase pressure drop associated with the small fuel inlet orifice diameters.

Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 8).

LCO

Two recirculation loops are required to be in operation with their flows matched within the limits specified in SR 3.4.1.2 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. With the limits specified in SR 3.4.1.2 not met, the recirculation loop with the lower flow must be considered not in operation. 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 Neutron Flux—High (Flow Biased) 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 3. In addition, during two-loop and single-loop operation, the combination of core flow and THERMAL POWER must be outside the Exclusion Region of the power-to-flow map specified in the COLR to ensure core thermal-hydraulic instability does not occur.

APPLICABILITY

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

(continued)

BASES

APPLICABILITY (continued)

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

With the reactor operating at core flow and THERMAL POWER conditions within the Exclusion Region of the power-to-flow map it is in a condition where thermal-hydraulic instabilities are conservatively predicted to occur, and must be brought to an operating state where such instabilities are not predicted to occur. To achieve this status, action must be taken immediately to exit the Exclusion Region. This is accomplished by inserting control rods or increasing core flow such that the combination of THERMAL POWER and core flow move to a point outside the Exclusion Region. The action is considered sufficient to preclude core thermal-hydraulic instabilities which could challenge the MCPR safety limit. The starting of a recirculation pump is not used as a means to exit the Exclusion Region of the power-to-flow map. Starting an idle recirculation pump could result in a reduction in inlet core enthalpy and enhance conditions necessary for thermal-hydraulic instabilities.

B.1

With the requirements of the LCO not met for reasons other than Condition A, 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. The loop with the lower flow must be considered not in operation. 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 operating limits and RPS and control rod block Allowable Values, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

(continued)

BASES

ACTIONS

B.1 (continued)

The 24 hour Completion Time is 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.

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.

C.1

With any Required Action and associated Completion Time of Condition A or B not met, or no recirculation loop is in operation, 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the combination of core flow and THERMAL POWER are within appropriate limits to prevent uncontrolled thermal-hydraulic oscillations. At low recirculation flows and high reactor power, the reactor exhibits increased susceptibility to thermal-hydraulic instability. The power-to-flow map specified in the COLR is based on guidance provided in Reference 7. The 12 hour Frequency is based on operating experience and the operator's knowledge of the reactor status, including significant changes in THERMAL POWER and core flow.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 (continued)

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the APRM Neutron Flux—High (Startup) Function in LCO 3.3.1.1 will prevent operation in the Exclusion Region while in MODE 2.

SR 3.4.1.2

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 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 recirculation loop jet pump 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, Condition B must be entered, and the loop with the lower flow must be declared "not in operation". (However, for the purpose of performing SR 3.4.1.1, the flow rate of both loops shall be used.) The SR is not required when only one loop is 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 14.6.

2. UFSAR, Section 14.5.

3. NEDO-24281, FitzPatrick Nuclear Power Plant Single-Loop Operation, August 1980.

4. UFSAR, Section 16.6.

5. NEDO-31960-A, BWR Owners' Group Long Term Stability Solutions Licensing Methodology, June 1991.

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BASES

REFERENCES (continued)

6. NEDO-31960-A, Supplement 1, BWR Owners' Group Long-Term Stability Solutions Licensing Methodology, March 1992.

7. GENE-637-044-0295, Application Of The "Regional Exclusion With Flow-Biased APRM Neutron Flux Scram" Stability Solution (Option I-D) To The James A. FitzPatrick Nuclear Power Plant, February 1995.

8. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Water 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 vessel internals, and in conjunction with the Reactor Water Recirculation System 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 a recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor coolant recirculation loop contains 10 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. 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 SAFETY ANALYSES

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

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

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BASES

APPLICABLE SAFETY ANALYSES (continued)	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 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
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 Water 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 Water Recirculation System (LCO 3.4.1). In MODES 3, 4, and 5, the Reactor Water 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	<u>A.1</u> 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.

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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. 3). 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. 3 and 4). 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, recirculation loop jet pump flow, and recirculation pump flow, these relationships may need to be re-established each cycle. Jet Pump OPERABILITY is considered acceptable prior to startup of the plant following a refueling outage due to acceptable results obtained during the previous operating cycle, or by visual inspection of the jet pumps. 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.

An inoperable jet pump may, in the event of a design basis accident, increase the blowdown area and reduce the capability to reflood the core. Thus, the requirement for shutdown of the plant exists with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance for degradation on a prescribed schedule. During single loop operation (SLO), the jet pump OPERABILITY surveillance is only performed for the jet pumps in the operating recirculation loop, as the loads on the jet pumps in the inactive loop have been demonstrated through operating experience at other BWRs to be very low due to the low flow in the reverse direction through them. The jet pumps in the non-operating recirculation loop during SLO are considered OPERABLE based on this low expected loading,

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

acceptable surveillance results obtained during two recirculation loop operation prior to entering SLO, or by visual inspection of the jet pumps during outages. Upon startup of an idle recirculation loop when THERMAL POWER is greater than 25% of RATED THERMAL POWER, the specified jet pump surveillances are required to be performed for the previously idle loop within 4 hours, as specified in the SR.

The recirculation pump speed operating characteristics (recirculation pump flow and recirculation loop jet 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 recirculation pump flow and recirculation loop jet 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 jet pump diffuser to lower plenum differential pressure pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 3). Normal flow ranges and established jet pump differential pressure patterns are established by plotting historical data as discussed in Reference 3.

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.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.2.1 (continued) Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% of 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 14.6. 2. 10 CFR 50.36(c)(2)(ii). 3. GE Service Information Letter No. 330, including Supplement 1, Jet Pump Beam Cracks, June 9, 1980. 4. NUREG/CR-3052, Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure, November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code (Ref. 1) 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 S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. However, for the purposes of this LCO, only the safety mode is required. In the safety mode (or spring mode of operation), the 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. This satisfies the Code requirement.

Each S/RV can be opened manually in the relief mode from the control room by its associated two-position switch. If one of these switches is placed in the open position the logic output will energize the associated S/RV solenoid control valve directing the pneumatic supply to open the valve. Seven of these S/RV solenoid control valves can also be energized by the relay logic associated with the Automatic Depressurization System (ADS). ADS requirements are specified in LCO 3.5.1, "ECCS—Operating." In addition each S/RV can be manually operated from another control switch located at the ADS auxiliary panel located outside the control room. These switches will energize a different S/RV solenoid control valve. The details of S/RVs pneumatic supply and mechanical operation in the relief mode are described in Reference 2.

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

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BASES

APPLICABLE SAFETY ANALYSES (continued)

scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Refs. 3 and 4). For the purpose of the analyses (Ref. 4), nine S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that nine S/RVs are capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig (at the vessel bottom) is met during the most severe pressurization transient.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 5 discusses additional events that are expected to actuate the S/RVs.

S/RVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 6).

LCO

The safety function of nine S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 3 and 4). The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

The single nominal S/RV setpoint is established (Ref. 2) 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 single nominal S/RV setpoint is set below the RPV design pressure (1250 psig) in accordance with ASME Code requirements. The transient evaluations in Reference 5 are based on this single setpoint, but also include the additional uncertainties of ± 3% of the nominal setpoint to provide an added degree of conservatism.

Operation with fewer valves OPERABLE than specified, or with setpoints outside the analysis 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.

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BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, nine S/RVs 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 S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is 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 S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of the inoperable required S/RVs cannot be restored to OPERABLE status, 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 required S/RVs open at the pressures assumed in the safety analysis of References 3 and 4. The demonstration of the S/RV safety function 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 S/RV setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.3.2

A manual actuation of each required S/RV is performed while bypassing main steam flow to the condenser and observing ≥ 10% closure of the turbine bypass valves to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can also be demonstrated by the response of the turbine control 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 control reactor pressure when the S/RVs 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 970 psig (the pressure consistent with vendor recommendations). Adequate steam flow is represented by two or more turbine bypass valves open, or total steam flow ≥ 10^6 lb/hr. These conditions will require the plant to be in MODE 1, which has been shown to be an acceptable condition to perform this test. This test causes a small neutron flux transient which may cause a scram in MODE 2 while operating close to the Average Power Range Monitors Neutron Flux - High (Startup) Allowable Value. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code 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 steam pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If a valve 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 on a STAGGERED TEST BASIS Frequency ensures that each solenoid for each S/RV is alternately tested. The 24 month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

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BASES (continued)

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. UFSAR, Section 4.4.
3. UFSAR, Section 14.5.1.2.
4. UFSAR, Section 16.9.3.2.3.
5. UFSAR, Section 14.5.2.
6. 10 CFR 50.36(c)(2)(ii).
7. ASME, Boiler and Pressure Vessel Code, Section XI.

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. Some joints in ≤ 1 inch piping are also threaded.

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 16.6 (Refs. 1, 2, and 3).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell 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 the drywell 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.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 shows that leakage rates much greater than 5 gpm will precede crack instability (Refs. 4, 5, and 6).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism that produces relatively tight cracks in piping and components. Intergranular stress corrosion cracking (IGSCC) would be typical of tight cracks on stainless steel piping and components susceptible to IGSCC (Refs. 8 and 9). Inspection programs (Refs. 10 and 11) are in place to detect cracking of piping and components.

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) (Ref. 7).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, because it is 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.

b. Unidentified LEAKAGE

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

(continued)

BASES

LCO (continued)

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 which may be detected by the drywell equipment drain sump monitoring system). 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.

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 unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

(continued)

BASES

ACTIONS (continued)

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 evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type of piping is very 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, 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, any method may be used to quantify LEAKAGE within the guidelines of Reference 8. In

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.4.1 (continued) conjunction with alarms and other administrative controls, a 4 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 9).

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. UFSAR, Section 16.6.
4. UFSAR, Section 4.10.
5. UFSAR, Section 16.3.
6. DRF-E31-00029-3(E), Summary of the Design of the Leak Detection System (LDS) for New York Power Authority, James A. FitzPatrick Nuclear Power Plant, November 1997.
7. 10 CFR 50.36(c)(2)(ii).
8. UFSAR, Section 4.10.3.4.
9. Generic Letter 88-01, NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping, US Nuclear Regulatory Commission, January 1988.
10. UFSAR, Section 16.4.
11. UFSAR, Section 16.5.14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

The JAFNPP design basis (Ref. 1) requires means for detecting and, to the extent practical identifying the location of the source of RCS LEAKAGE. Reliable means are provided to detect leakage from the reactor coolant pressure boundary (RCPB) before predetermined limits are exceeded (Refs. 2 and 3).

Limits are established on abnormal leakage so that corrective action can be taken before unacceptable results occur (Ref. 4). 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 two independently monitored variables, such as sump pump flow and drywell gaseous and particulate radioactivity levels. The primary 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 Loop Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump. The drywell floor drain sump has instrumentation that supply level indicators in the control room.

The floor drain sump level instrumentation include switches that start and stop the sump pumps where required. A timer starts each time the sump is pumped down to the low level setpoint. If the sump fills to the high level setpoint before the timer ends, an alarm sounds in the control room, indicting a LEAKAGE rate into the sump in excess of a preset limit. In addition, the pump-out time is monitored and

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BASES

BACKGROUND (continued)	whenever the pump-out time exceeds a preset interval (indicating an increase in leak rate) an alarm annunciates in the control room. As the water which has been collected in the drywell floor drain sump is pumped out, the discharge flow is measured and total flow indicated by a flow integrator. The unidentified LEAKAGE and unidentified LEAKAGE increase are periodically calculated from this flow integrator. A flow recorder continually plots time versus discharge flow rate: an increase in leakage rate is also detectable by an increase in sump discharge flow time and an increased frequency in discharge flow cycles. The drywell continuous atmospheric monitoring system continuously monitors the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell atmosphere particulate and gaseous radioactivity monitoring system is not capable of quantifying LEAKAGE rates. The sensitivity and response time of the system are a function of: location of the leak; amount of fission or corrosion product remaining in the atmosphere where they may be measured; plateout of these products in the sampling lines; effectiveness of the drywell coolers in reducing airborne concentrations; and the power level at the time of leakage occurrence (Ref. 3). The drywell continuous atmospheric particulate monitoring system is sufficiently sensitive to detect a reactor coolant leak of 1 gpm within 4 hours. The drywell continuous atmospheric gaseous monitoring system, however, will not alarm for reactor coolant leaks (since there is no retention factor for noble gases in the reactor coolant). The drywell continuous atmospheric gaseous monitoring system will respond only if the leak is in the steam portion of the RCPB. Larger changes in LEAKAGE rates can be detected in proportionally shorter times (Ref. 5).
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. 6 and 7). Each of the leakage detection systems inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm or indication of excess LEAKAGE in the control room.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

A control room alarm or indication allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Refs. 6 and 7). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii) (Ref. 8).

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 since this portion is capable of quantifying unidentified LEAKAGE from the RCS. The other monitoring systems (one channel each of the drywell continuous atmospheric particulate and drywell continuous atmospheric gaseous monitoring systems) provide early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.

APPLICABILITY

In MODES 1, 2, and 3, 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, the drywell continuous atmospheric monitors 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 4 hours (SR 3.4.4.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available. Required Action A.1 is modified by a Note that states that the provisions of

(continued)

BASES

ACTIONS

A.1 (continued)

LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the drywell floor drain sump monitoring system is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

B.1

With one required drywell continuous atmospheric monitoring channel inoperable, SR 3.4.5.1 must be performed every 8 hours for the remaining OPERABLE drywell continuous atmospheric monitoring channel to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.4.5.1. The 8 hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leakage detection are available. However, this Required Action is modified by a Note that allows this action to be not applicable if both drywell continuous atmospheric monitoring systems are inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.

C.1 and C.2

With both required gaseous and particulate drywell continuous atmospheric monitoring channels inoperable, grab samples of the drywell atmosphere must be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the two monitors.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE. The 30 day Completion Time for restoration recognizes that at least one other form of leakage detection is available.

The Required Actions are modified by a Note that states that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when both the gaseous and particulate drywell continuous atmospheric monitoring systems are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If any 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.

E.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

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 other required instrumentation (the drywell floor drain sump monitoring system or drywell continuous atmospheric monitoring channel, as applicable) is OPERABLE. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring RCS leakage.

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required drywell continuous atmospheric monitoring channels. The check gives reasonable confidence that the channels are operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument channel. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. 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 required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument channel. The Frequency is 92 days and operating experience has proven this Frequency is acceptable.

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 4.10.
3. UFSAR, Section 4.10.3.4.
4. UFSAR, Section 4.10.2.3.
5. JAF-CALC-PRM-03345, Rev. 0, March 2000.
6. UFSAR, Section 4.10.3.2.
7. UFSAR, Section 16.3.2.2.
8. 10 CFR 50.36(c)(2)(ii).

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 100.11 (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 SAFETY ANALYSES

Analytical methods and assumptions involving radioactive 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 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 the control room operators, resulting from an MSLB outside containment during steady state operation will not exceed the limits specified in GDC 19 of 10 CFR 50, Appendix A (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are 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) (Ref. 4).

LCO

The specific iodine activity is limited to ≤ 0.2 μCi/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.

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 ≤ 2.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 μCi/gm within 48 hours, or if at any time it is > 2.0 μCi/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 100.11 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 challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the plant 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.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 100.11.
2. UFSAR, Section 14.8.
3. 10 CFR 50, Appendix A, GDC 19.
4. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling 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 ≤ 212°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 two redundant, manually controlled shutdown cooling subsystems (loops) of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same reactor water recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated reactor water recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").
APPLICABLE SAFETY ANALYSES	Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses (Ref. 1). Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The RHR shutdown cooling subsystem meets Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
LCO	Two RHR shutdown cooling subsystems are required to be OPERABLE. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both RHR pumps (and two RHR service water pumps) in one loop or one RHR pump (and one RHR service water pump) in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (from the control

(continued)

BASES

LCO (continued)

room or locally) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling 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. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

The Note allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR shutdown cooling subsystem 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 RHR shutdown cooling subsystems or other operations requiring loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR cut-in permissive pressure (i.e., the actual pressure at which the shutdown cooling suction valve isolation logic interlock resets (Function 6.a of LCO 3.3.6.1, "Primary Containment Isolation Instrumentation")) the RHR System is required to be OPERABLE so that it may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is normally in operation to circulate coolant to provide for temperature monitoring.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut-in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS - Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

(continued)

BASES

APPLICABILITY (continued)

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System – Cold Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR) – High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR) – Low Water Level."

ACTIONS

A Note to the ACTIONS 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 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.

A second Note has been provided to modify the ACTIONS related to RHR shutdown cooling 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 RHR shutdown cooling subsystem.

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

With one required RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by the LCO Note, 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 RHR shutdown cooling capability. Therefore, an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown

(continued)

BASES

ACTIONS

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

cooling 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 and Main Steam Systems, Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate System), or a combination of an RHR pump and safety/relief valve(s).

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.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow path provides assurance that the proper flow paths will exist for RHR 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 can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. 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. This Frequency has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1 (continued)

This Surveillance is modified by a Note allowing sufficient time to verify RHR shutdown cooling subsystem OPERABILITY after clearing the pressure interlock that isolates the system. The Note takes exception to the requirements of the Surveillance being met (i.e., valves are aligned or can be aligned 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

1. UFSAR, Chapter 14.

2. 10 CFR 50.36(c)(2)(ii).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR) Shutdown Cooling 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 ≤ 212°F in preparation for performing refueling operations, or the decay heat must be removed for maintaining the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems (loops) of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same reactor water recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via a reactor water recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses (Ref. 1). Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System meets Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, one or two RHR service water pumps providing water to the heat exchanger, as required for temperature control, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both RHR pumps (and two RHR service water pumps) in one loop or one RHR pump (and one RHR service water pump) in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. In MODE 4, the RHR cross tie valves (10MOV-20 and 10RHR-09) may be opened to allow pumps in one loop to

(continued)

BASES

LCO (continued)

discharge through the opposite recirculation loop to make a complete subsystem. Additionally, each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (from the control room or locally) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling 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. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

The Note allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR shutdown cooling subsystems 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 RHR shutdown cooling subsystems or other operations requiring loss of redundancy.

APPLICABILITY

In MODE 4, the RHR System is required to be OPERABLE so that it may be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 212°F. Otherwise, a recirculation pump is normally in operation to circulate coolant to provide for temperature monitoring.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS – Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling

(continued)

BASES

APPLICABILITY (continued)

System — Hot Shutdown"; LCO 3.9.7, "Residual Heat Removal (RHR) — High Water Level"; and LCO 3.9.8, "Residual Heat Removal (RHR) — Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling 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 RHR shutdown cooling subsystem.

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by the LCO Note, 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 RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling 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 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)

(continued)

BASES

ACTIONS

A.1 (continued)

the Condensate and Main Steam Systems, Reactor Water Cleanup System (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate System), or a combination of an RHR pump and safety/relief valve(s).

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR shutdown cooling flow path provides assurance that the proper flow paths will exist for RHR 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 can be manually (from the control room or locally) aligned is allowed to be in a non-RHR shutdown cooling position provided the valve can be repositioned. 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. This Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Chapter 14.

2. 10 CFR 50.36(c)(2)(ii).

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.

This Specification contains P/T limit curves for heatup, cooldown, inservice leakage and hydrostatic testing, and criticality and also limits the maximum rate of change of reactor coolant temperature.

Each P/T limit curve defines an acceptable region for normal operation. The curves are used for operational guidance during heatup or cooldown maneuvering. Pressure and temperature are monitored and compared to the applicable curve to ensure 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, abnormal operational transients, and system inservice leakage and hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

The nil-ductility transition (NDT) temperature, RT_{NDT}, is defined as the temperature below which ferritic steel breaks in a brittle rather than ductile manner. The RT_{NDT} increases as a function of neutron exposure at integrated neutron exposures greater than approximately 10^{17} nvt with neutron energy in excess of 1 MeV.

The actual shift in the RT_{NDT} of the vessel material is determined periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance

(continued)

BASES

BACKGROUND (continued)

with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves are adjusted, 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 locations.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls. However, the P/T limit curves reflect the most restrictive of the heatup and cooldown curves.

The P/T criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leakage and hydrostatic testing.

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 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.

APPLICABLE SAFETY ANALYSES

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 establishes the methodology for determining the P/T limits. Reference 8

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 9).

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in Figure 3.4.9-1 or Figure 3.4.9-2, as applicable. In addition, RCS temperature change averaged over a one hour period is: ≤ 100°F when the RCS pressure and temperature are on or to the right of curve C of Figure 3.4.9-1 or Figure 3.4.9-2, as applicable, during inservice leak and hydrostatic testing; ≤ 20°F when the RCS pressure and temperature are to the left of curve C of Figure 3.4.9-1 or Figure 3.4.9-2, as applicable, during inservice leak and hydrostatic testing; and ≤ 100°F during other heatup and cooldown operations;

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ≤ 145°F during recirculation pump startup;

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is ≤ 50°F during recirculation pump startup;

d. RCS pressure and temperature are within the limits specified in Figure 3.4.9-1 or Figure 3.4.9-2, as applicable, prior to achieving criticality; and

e. The reactor vessel flange and the head flange temperatures are ≥ 90°F when tensioning the reactor vessel head bolting studs and when any stud 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.

(continued)

BASES

LCO (continued)

The limits on the rate of change of RCS temperature, influenced by RCS flow and RCS stratification, control the thermal gradient through the vessel wall. For this reason, both RCS temperature and RPV metal temperatures are used as inputs for calculating the heatup, cooldown, and inservice leakage 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.

P/T limit curves are provided for plant operations through 24 EFPY (Figure 3.4.9-1) and 32 EFPY (Figure 3.4.9-2). Curves A, A_{BH} (bottom head), and A_{NB} (non-beltline) establish the minimum temperature for hydrostatic and leak testing, Curves B and B_{BH} (bottom head) establish limits for plant heatup and cooldown when the reactor is not critical or during low power physics tests, and Curve C establishes the limits when the reactor is critical. In addition, ART is the adjusted reference temperature.

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 the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation can continue. This 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 engineering evaluation of a mild violation. A mild violation is one which is technically acceptable because it is bounded by an existing evaluation or one which reasonably can be expected to be found acceptable following evaluation. 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 sufficiently severe event caused entry into an unacceptable region. Either occurrence indicates a need for more careful examination of the event, best accomplished with the RCS at

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

reduced pressure and temperature. With the reduced pressure and temperature conditions, the likelihood 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 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°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 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within RCS pressure and temperature limits as well as within RCS temperature change limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

is accomplished by monitoring the bottom head drain, recirculation loop, and RPV metal temperatures. 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. The limits of Figures 3.4.9-1 and 3.4.9-2 are met when operation is on or to the right of the applicable curve.

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied. In general, if two consecutive temperature readings taken ≥ 30 minutes apart are within 5°F of each other the activity can be considered complete.

This SR is modified by a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing. Unlike steady-state operation, these intentional operational transients may be characterized by large pressure and temperature changes, and performance of this SR provides assurance that RCS pressure and temperature remain within acceptable regions of the P/T limit curves as well as within RCS temperature change limits.

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, SR 3.4.9.4, and SR 3.4.9.5

Differential temperatures within the specified limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.3, SR 3.4.9.4, and SR 3.4.9.5 (continued)

addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 10) are satisfied.

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.

Compliance with the temperature differential requirement in SR 3.4.9.3 is demonstrated by comparing the bottom head drain line temperature to the reactor vessel steam dome saturation temperature. SR 3.4.9.4 requires the verification that the active recirculation pump flow exceeds 40% of rated pump flow or the active recirculation pump has been operating below 40% rated flow for a period no longer than 30 minutes. As specified in Reference 11 and 12, the alternative verification of SR 3.4.9.4 will ensure the temperature differential of SR 3.4.9.3 is met.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.5 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3, SR 3.4.9.4, and SR 3.4.9.5 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during a recirculation pump startup since this is when the stresses occur. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. SR 3.4.9.3 is modified by a second Note, which clarifies that the SR does not have to be performed if SR 3.4.9.4 is satisfied. This is acceptable since References 11 and 12 demonstrate that SR 3.4.9.4 is an acceptable alternative. In addition, SR 3.4.9.4 is modified by a second Note, which clarifies that the SR does not have to be met if SR 3.4.9.3 is satisfied. This is acceptable since SR 3.4.9.3 directly verifies the stratification limit is met.

SR 3.4.9.6, SR 3.4.9.7, and SR 3.4.9.8

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 when any reactor vessel head bolting stud is tensioned with RCS

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.6, SR 3.4.9.7, and SR 3.4.9.8 (continued)

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 while tensioning the reactor vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When any reactor vessel head bolting stud is tensioned with RCS temperature ≤ 100°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When any reactor vessel head bolting stud is tensioned with RCS temperature ≤ 120°F, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within specified limits.

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 3.4.9.6 is modified by a Note which requires the SR to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.7 is modified by a Note which states that the SR is not required to be performed until 30 minutes after RCS temperature is ≤ 100°F in MODE 4. SR 3.4.9.8 is modified by a Note which states that the SR is not required to be performed until 12 hours after RCS temperature is ≤ 120°F in MODE 4. These Notes are necessary to specify when the reactor vessel flange and head flange temperatures are required to be within 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, Radiation Embrittlement of Reactor Vessel Materials, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

(continued)

BASES

REFERENCES (continued)

7. GE-NE-B1100732-01, Revision 1, Plant FitzPatrick RPV Surveillance Materials Testing and Analysis of 120° Capsule at 13.4 EFPY, February 1998, including Errata and Addenda Sheets dated June 17, 1999 and December 3, 1999.

8. Letter from Guy Vissing (NRC) to James Knubel (NYPA) Issuance of Amendment No. 258 to James A. FitzPatrick Nuclear Power Plant, November 29, 1999.

9. 10 CFR 50.36(c)(2)(ii).

10. UFSAR, Section 14.5.7.2.

11. GE-NE-208-04-1292, Evaluation of Idle Recirculation Loop Restart Without Vessel Bottom Temperature Indication for FitzPatrick Nuclear Power Plant, December 1992.

12. JAF-RPT-RWR-02076, Verification of Alternative Operating Conditions for Idle Recirculation Loop Restart Without Vessel Bottom Temperature Indication, June 25, 1995.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) 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) mode of the Residual Heat Removal (RHR) 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 condensate storage tanks (CSTs), they are capable of providing a source of water for the HPCI and CS systems.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously, the system aligns and the pumps inject water, taken either from the CSTs 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, if the ADS timed sequence is allowed to time out, the selected safety/relief valves (S/RVs) would open, 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 RHR Service Water System. Depending on the 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.

(continued)

BASES

BACKGROUND (continued)

All low pressure 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 if preferred power is available, the CS pumps in both subsystems will automatically start after a time delay of approximately 11 seconds. If a CS initiation signal is received when preferred power is not available, the CS pumps start approximately 11 seconds after the associated bus is energized by the emergency diesel generators (EDGs). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop. The two LPCI subsystems can be interconnected via the RHR System cross tie line; however, this line is maintained closed to prevent loss of both LPCI subsystems during a LOCA. The line is isolated by chain-locking the 10MOV-20 valve in the closed position with electric power disconnected from its motor operator, and maintaining the manually operated gate valve (10RHR-09) locked in the closed position. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal if preferred power is available, LPCI pumps A and D start in approximately one second. LPCI pumps B and C are started in approximately 6 seconds to limit the loading of the preferred power sources. With a loss of preferred power LPCI pumps A and D start in approximately one second after the associated bus is energized by the EDGs, and LPCI pumps B and C start approximately 6 seconds after the associated bus is energized by the EDGs to limit the loading of the EDGs. If one EDG should fail to force parallel, an associated LPCI pump will not start (LPCI pump B or C) to ensure the other EDG in the same EDG subsystem is not overloaded. RHR System

(continued)

BASES

BACKGROUND (continued)

valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the recirculation loops. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps. A full flow test line is provided for each LPCI subsystem to route water from 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, "RHR 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 both CSTs and the suppression pool. Pump suction for HPCI is normally aligned to both CSTs to minimize injection of suppression pool water into the RPV. However, if the water supply is low in both CSTs, 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 and ensures the containment loads do not exceed design values. The steam supply to the HPCI turbine is piped from the "C" main steam line upstream of the inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1195 psig). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is 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 to the CSTs to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valve in the HPCI line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. The minimum flow bypass valves for the LPCI and CS pumps are normally open for the same purpose. To ensure rapid delivery of water to the RPV and to minimize water hammer

(continued)

BASES

BACKGROUND (continued)

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 full" system (jockey pump system). The HPCI System is normally aligned to the CSTs. The height of water in the CSTs is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water. Therefore, HPCI does not require a "keep full" system.

The ADS (Ref. 4) consists of 7 of the 11 S/RVs. 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. Each of the S/RVs used for automatic depressurization is equipped with one air accumulator and associated inlet check valves. The accumulator provides the pneumatic power to actuate the valves. One of the ADS valves shares an accumulator with a non-ADS valve.

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 5, 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 ≤ 2200°F;

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;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 5. For a LOCA due to a large recirculation pump suction line pipe break, failure of the Division 2 125 VDC battery 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 five of the seven ADS valves operate. Since six ADS valves are required to be OPERABLE, the explicit assumption of the failure of an ADS valve is not considered in the analysis. 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) (Ref. 11).

LCO

Each ECCS injection/spray subsystem and six ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems (which includes both pumps per subsystem), 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 active component 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.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the system is being realigned from or to the RHR shutdown cooling mode. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

(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."

ACTIONS

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable or if one LPCI pump in both LPCI subsystems is inoperable, the inoperable subsystem(s) 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 active component 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 consistent with the recommendations provided in a reliability study (Ref. 12) 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).

B.1 and B.2

If the inoperable low pressure ECCS subsystem(s) 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.

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY immediately is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition G must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is consistent with the recommendations provided in a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

D.1 and D.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. 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 active component 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 low pressure subsystem 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 to OPERABLE status. This Completion Time is consistent with the recommendations provided in a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

E.1

The LCO requires six ADS valves to be OPERABLE in order to provide the ADS function. Reference 5 contains the results of an analysis that evaluated the effect of two of the seven ADS valves being out of service. This analysis shows that, assuming a failure of the HPCI System, operation of only five ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced, because a single active component failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation with five ADS valves is only allowed for a limited time. The 14 day Completion Time is consistent with the recommendations provided in a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem or one LPCI pump in both LPCI subsystems is inoperable in addition to one required ADS valve inoperable, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS injection/spray subsystem(s). However, overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure system (ADS) and low pressure subsystem(s) are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS subsystem(s) or the ADS valve to OPERABLE status. This Completion Time is consistent with the recommendations provided in a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

G.1 and G.2

If any Required Action and associated Completion Time of Condition C, D, E, or F 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

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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

When multiple ECCS subsystems are inoperable, as stated in Condition H, 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 and observe water flow through the vent. 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 those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

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.

In MODE 3 with reactor dome pressure less than the actual RHR cut in permissive pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the system is being realigned from or to the RHR shutdown cooling mode. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than the shutdown cooling permissive pressure, a reduced complement of low pressure ECCS subsystems should provide the required cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

SR 3.5.1.3

Verification every 31 days that ADS pneumatic supply header pressure is ≥ 95 psig ensures adequate pneumatic pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least one valve actuation can occur with the drywell at 70% of design pressure (Ref. 13). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥ 95 psig is provided by the ADS nitrogen

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.3 (continued)

supply. The 31 day Frequency takes into consideration administrative controls over operation of the pneumatic system and alarms for low pneumatic pressure.

SR 3.5.1.4

Verification every 31 days that the RHR System cross tie valves are closed and power to the motor operated valve is disconnected ensures that each LPCI subsystem remains independent and a failure of the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include de-energizing breaker control power or racking out or removing the breaker. If one or more of the RHR System cross tie valves are open or power has not been removed from the motor operated valve, both LPCI subsystems must be considered inoperable. In addition, plant procedures require the motor operated cross tie valve to be chain-locked closed and the manual cross tie valve to be locked closed. The 31 day Frequency has been found acceptable, considering that these valves are under strict administrative controls that will ensure the valves continue to remain closed with either control or motive power removed.

SR 3.5.1.5

Cycling open and closed each LPCI motor operated valve independent power supply battery charger AC input breaker and verification that each LPCI inverter output has a voltage of $\geq$ 576 V and $\leq$ 624 V while supplying its respective bus demonstrates the capability of the supply to become independent from emergency AC power and that the AC electrical power is available to ensure proper operation of the associated LPCI injection and heat exchanger bypass valves and the recirculation pump discharge valve. Each inverter and battery charger AC input breaker must be OPERABLE for the associated LPCI subsystem to be OPERABLE. The 31 day Frequency has been found acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.6

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 close 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.

The specified Frequency is once during reactor startup before THERMAL POWER is > 25% RTP. However, this SR is modified by a Note that states the Surveillance is only required to be performed if the last performance was more than 31 days ago. Verification during reactor startup prior to reaching > 25% RTP is an exception to the normal Inservice Testing Program generic valve cycling Frequency of 92 days, but is considered acceptable due to the demonstrated reliability of these valves. If the valve is inoperable and in the open position, the associated LPCI subsystem must be declared inoperable.

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8). 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 at least 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 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 may be established during preoperational testing.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9 (continued)

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. Adequate reactor steam pressure must be ≥ 970 psig to perform SR 3.5.1.8 and > 150 psig to perform SR 3.5.1.9. Adequate steam flow is represented by at least one turbine bypass valve open or main turbine generator load is greater than 100 MWe. 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 3.5.1.8 and SR 3.5.1.9 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 3.5.1.7 and SR 3.5.1.8 is in accordance with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.1.9 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.10

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. The HPCI System actual or simulated automatic actuation test must be performed with adequate steam pressure for verification of automatic pump startup. 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. Thus, sufficient time is allowed after adequate pressure and flow are achieved to perform this test associated with the HPCI System. Adequate reactor steam dome pressure is > 150 psig. Adequate steam flow is represented by at least one turbine bypass valve open. This SR also ensures that the HPCI System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip. In addition, this SR also ensures that the HPCI suction is automatically transferred from the CSTs to the suppression pool on high suppression pool water level or low CST 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.

For CS and LPCI, 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. For HPCI, the 24 month Frequency is based on the need to perform the surveillance under 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.

This SR is modified by two Notes. Note 1 states that for the HPCI System, the Surveillance is 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 actual or simulated automatic actuation for the HPCI System after the required pressure

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.10 (continued)

and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SR. Note 2 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 3.5.1.11

The ADS designated S/RVs 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 3.5.1.13 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 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 3.5.1.13. This prevents the possibility of an RPV pressure blowdown.

SR 3.5.1.12

A LPCI motor operated valve independent power supply subsystem inverter test is a test of the inverter's capability, as found, to satisfy the design requirements (inverter duty cycle). The discharge rate and test length correspond to the design duty cycle requirements.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.12 (continued)

The Frequency of 24 months is acceptable, given plant conditions required to perform the test and the other requirements existing to ensure adequate LPCI inverter performance during the 24 month interval. In addition, the Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.5.1.13

A manual actuation of each required ADS valve is performed while bypassing main steam flow to the condenser and observing ≥ 10% closure of the turbine bypass valves to verify that the valve and solenoid are functioning properly and that no blockage exists in the S/RV discharge lines. This can also be 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 ≥ 970 psig (the pressure consistent with vendor recommendations). Adequate steam flow is represented by at least two or more turbine bypass valves open or total steam flow ≥ 10^6 lb/hr. These conditions will require the plant to be in MODE 1, which has been shown to be an acceptable condition to perform this test. This test causes a small neutron flux transient which may cause a scram in MODE 2 while operating close to the Average Power Range Monitors Neutron Flux – High (Startup) Allowable Value. 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 and flow are reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance. SR 3.5.1.11 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.13 (continued)

The Frequency of 24 months on a STAGGERED TEST BASIS ensures that both solenoids for each ADS valve are alternately tested. The Frequency 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.

REFERENCES

1. UFSAR, Section 6.4.3.
2. UFSAR, Section 6.4.4.
3. UFSAR, Section 6.4.1.
4. UFSAR, Section 6.4.2.
5. NEDC-31317P, Revision 2, James A. FitzPatrick Nuclear Power Plant SAFER/GESTR-LOCA, Loss-of-Coolant Accident Analysis, April 1993.
6. UFSAR, Section 14.6.1.5.
7. UFSAR, Section 14.6.1.3.
8. 10 CFR 50, Appendix K.
9. UFSAR, Section 6.5.
10. 10 CFR 50.46.
11. 10 CFR 50.36(c)(2)(ii).
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), Recommended Interim Revisions to LCOs for ECCS Components, December 1, 1975.
13. UFSAR, Section 4.4.5.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 ECCS – Shutdown

BASES

BACKGROUND	A description of the Core Spray (CS) System and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS – Operating."
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. The low pressure ECCS subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).
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 from both condensate storage tanks (CSTs) to the reactor pressure vessel (RPV). The CST suction source consists of two CSTs connected in parallel. Each OPERABLE LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. Only a single LPCI pump is required per subsystem because of the larger injection capacity in relation to a CS subsystem. In MODES 4 and 5, the RHR System cross tie valves are not required to be closed. One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and

(continued)

BASES

LCO (continued)

operation for decay heat removal includes when the system is realigned from or to the RHR shutdown cooling mode. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery.

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 ≥ 22 feet 2 inches above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery 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 active component 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

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

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 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 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., at least one secondary containment isolation valve and associated instrumentation are OPERABLE or acceptable administrative controls assure isolation capability. These administrative 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

(continued)

BASES

ACTIONS

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

secondary containment isolation 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 and SR 3.5.2.2

The minimum water level of 10.33 ft 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 an OPERABLE CST.

When suppression pool level is < 10.33 ft, the CS System is considered OPERABLE only if it can take suction from both CSTs, and the CST water level is sufficient to provide the required NPSH for the CS pump. Therefore, a verification that either the suppression pool water level is ≥ 10.33 ft or that CS is aligned to take suction from both CSTs and the CSTs contain $\geq 354,000$ gallons (two tanks) of water, equivalent to 324 inches (27 ft), ensures that the CS System can supply at least 50,000 gallons of makeup water to the RPV. An excess amount of water remains as a supplementary volume and to ensure adequate CS pump NPSH. The CS suction is uncovered at approximately 258,000 gallons (two tanks). However, as noted, only one required CS subsystem may take credit for the CST option during OPDRVs. During OPDRVs, the volume in the CSTs may not provide adequate makeup if the RPV were completely drained. Therefore, only one CS subsystem is allowed to use the CSTs. 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 CST water level variations and instrument drift during

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2 (continued)

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 CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.7, and SR 3.5.1.10 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

SR 3.5.2.4

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.

In MODES 4 and 5, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows one LPCI subsystem to be considered OPERABLE during alignment and operation for shutdown cooling if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the system is being realigned from or to the RHR shutdown cooling mode. Because of the low pressure and low temperature conditions in MODE 4 and 5 sufficient time

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.5.2.4 (continued) will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. This will ensure adequate core cooling if an inadvertent RPV draindown should occur.
REFERENCES	1. UFSAR, Section 6.5.3. 2. 10 CFR 50.36(c)(2)(ii).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

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

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) 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 is provided from the condensate storage tanks (CSTs) and the suppression pool. Pump suction is normally aligned to the CSTs to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from the "B" main steam line upstream of the associated inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1195 psig). Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water to the CSTs to allow testing of the RCIC System during normal operation without injecting water into the RPV.

The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to

(continued)

BASES

BACKGROUND (continued)	overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge piping is kept full of water. The RCIC System is normally aligned to the CSTs. The height of water in the CSTs is sufficient to maintain the piping full of water up to the first isolation valve. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep full" system.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safeguard System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).
LCO	The OPERABILITY of the RCIC 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 accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event.
APPLICABILITY	The RCIC System is required to be OPERABLE during MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig, since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the RPV.
ACTIONS	<u>A.1 and A.2</u> If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified immediately when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or 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 verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is consistent with the recommendations in a reliability study (Ref. 4) 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 RCIC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

B.1 and B.2

If the RCIC 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.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

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

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC 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. For the RCIC 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 affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.3 and SR 3.5.3.4 (continued)

capability to provide rated flow against a system head corresponding to reactor pressure is tested both at 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 RCIC System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Adequate reactor steam pressure must be ≥ 970 psig to perform SR 3.5.3.3 and > 150 psig to perform SR 3.5.3.4. Adequate steam flow is represented by at least one turbine bypass valve open, or main turbine generator load is greater than 100 MWe. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure Surveillance has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable.

These SRs 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 SR.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform the Surveillance under 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 3.5.3.5

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) signal (Level 8 signal closes RCIC steam inlet valve, and subsequent Level 2 signal will re-open valve) and that the suction is automatically transferred from the CST to the suppression pool. 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 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.

This SR is modified by Note 1 that says the Surveillance is not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The time allowed for this test after required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. Adequate reactor pressure must be available to perform this test. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Thus, sufficient time is allowed after adequate pressure and flow are achieved to perform this test. Adequate reactor steam pressure is > 150 psig. Adequate steam flow is represented by at least one turbine bypass valve open. Reactor startup is allowed prior to performing this test because the reactor pressure is low and the time allowed to satisfactorily perform the test is short.

This SR is modified by Note 2 that excludes vessel injection 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.

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BASES (continued)

REFERENCES

1. UFSAR, Section 16.6.
2. UFSAR, Section 4.7.
3. 10 CFR 50.36(c)(2)(ii).
4. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), Recommended Interim Revisions to LCOs for ECCS Components, December 1, 1975.

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 the drywell (a steel pressure vessel in the shape of an inverted light bulb) and the suppression chamber (a steel pressure vessel in the shape of a torus) located below and encircling the drywell. The primary containment surrounds the Reactor Coolant 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 Locks"; and

c. All equipment hatches are closed.

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 specified in the Primary Containment Leakage Rate Testing Program which is in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

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.

The DBA that postulates the maximum release of radioactive material within primary containment is a Loss of Coolant Accident (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.

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.

The maximum allowable leakage rate for the primary containment (L_a) is 1.5% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 45 psig (Primary Containment Leakage Rate Testing Program).

Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

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 the applicable leakage limits must be met. 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 for the primary containment air locks are addressed in LCO 3.6.1.2 and specified in the Primary Containment Leakage Rate Testing Program.

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

(continued)

BASES

APPLICABILITY (continued)

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.

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 the air lock leakage limit (SR 3.6.1.2.1), or the 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. Failure to meet the Low Pressure Coolant Injection (LPCI) or Core Spray (CS)System injection line air operated testable check valve leakage limit (SR 3.6.1.3.11) does not result in failure of this SR since the LPCI and CS testable check valve leakage is not included in the Primary Containment Leakage Rate Testing Program limits (Ref. 5 and 6).

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

As left leakage, prior to 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 ≤ 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 ≤ 1.0 L_a. At ≤ 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 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 is a leak test that confirms that the bypass area between the drywell and suppression chamber is less than the equivalent of a one inch diameter plate orifice (Ref. 1). This ensures that the leakage paths that would bypass the suppression pool are within allowable limits (i.e., ≤ 71 scfm).

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber (≥ 1 psi)and verifying that the pressure in the suppression chamber does not increase by more than 0.25 inches of water per minute over a 10 minute period. The leakage test is performed every 24 months. The 24 month Frequency was developed considering 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, as 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 5.2.
2. UFSAR, Section 14.6.1.3.
3. 10 CFR 50, Appendix J, Option B.

(continued)

BASES

REFERENCES (continued)	4.	10 CFR 50.36(c)(2)(ii).
	5.	License Amendment 40, dated November 9, 1978.
	6.	License Amendment 234, dated October 4, 1996.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double door primary containment air locks (personnel access hatch and emergency escape hatch) have been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entry and exit. The air locks are 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 locks limit the release of radioactive material to the environment during normal plant 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 personnel access hatch 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, with doors at each end that are interlocked to prevent simultaneous opening. The air locks are provided with limit switches on both doors in each airlock that provide control room 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 locks form part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining the primary 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 plant safety analysis.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The postulated DBA that results in 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 maximum allowable leakage rate (L_a) for the primary containment is 1.5% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 45 psig (Primary Containment Leakage Rate Testing Program). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

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

LCO

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

The primary containment air locks are 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 each air lock is 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 into 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 locks are not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

(continued)

BASES (continued)

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 for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary 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. After each entry and exit, the OPERABLE door must be immediately closed .

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by a third 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.

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

With one primary containment air lock door inoperable in one or more primary containment air locks, the OPERABLE door in each affected air lock must be verified closed (Required Action A.1). 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.

(continued)

BASES

ACTIONS

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

In addition, the affected 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 the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 ensures that the affected 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 affected air lock for entry and exit for 7 days under administrative controls.

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

(continued)

BASES

ACTIONS

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

the OPERABLE door except during the 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 in one or both primary containment air locks, 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 same air lock are inoperable. With both doors in the same 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 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.

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

With one or more air locks 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 both doors in an air lock have

(continued)

BASES

ACTIONS

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

failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) 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 affected primary containment air locks must be verified closed. This Required 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 each affected 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks 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 regard to air lock leakage (Type B leakage tests). The acceptance criteria were approved in License Amendment 97 (Ref. 3). Subsequently, License Amendment 261 (Ref. 4) allowed an increased overall air lock leakage rate (i.e., Amendment 261 increased the value of L_a; therefore, the overall air lock

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

leakage rate limit value that corresponds to 0.05 L_a increased). 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 is applicable to SR 3.6.1.1.1 (Primary Containment Leakage Rate Testing Program). This ensures that air lock leakage is properly accounted for in determining the combined Type 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 (Ref. 1), 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 primary containment air lock 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 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 use of the air lock.

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BASES (continued)

REFERENCES

1. UFSAR, Section 5.2.
2. 10 CFR 50.36(c)(2)(ii).
3. NRC letter dated November 21, 1985, Issuance of Amendment 97 to the Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.
4. NRC letter dated April 21, 2000, Issuance of Amendment 261 to the Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant.

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 and closed systems are considered passive devices. Check valves, and other automatic valves designed to close without operator action following an accident, are considered active devices. One or more barriers are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. When two or more barriers are provided, 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 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.

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BASES

BACKGROUND (continued)

The primary containment suppression chamber and drywell vent and purge lines are 20 and 24 inches in diameter respectively, and are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. The isolation valves on both the suppression chamber and drywell vent lines have 2 inch bypass lines around them for use during normal reactor operation or when it is not necessary to open the 20 and 24 inch valves. The only primary containment vent path provided, by design, is from the common 30 inch suppression chamber and drywell vent line through two parallel lines with valves (one 6 inches in diameter, the other 12 inches in diameter) to the 24 inch Standby Gas Treatment (SGT) System suction line. When in MODES 1, 2, and 3 only the low-flow 6 inch line (with valve 27MOV-121) is allowed to be open whenever the 20 or 24 inch vent and purge valves are open. The full-flow 12 inch line (with valve 27MOV-120) is required to be closed to prevent high pressure from reaching the SGT System filter trains in the unlikely event of a loss of coolant accident (LOCA) during venting. Closure of these valves will not prevent the SGT System from performing its design function (that is, to maintain a negative pressure in the secondary containment).

APPLICABLE SAFETY ANALYSES

The PCIV 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, control rod drop accident, 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 vent and purge valves) are minimized. Of the events analyzed in Reference 1 for which the consequences are mitigated by PCIVs, the MSLB is the most limiting event due to radiological consequences to control room personnel. 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, after signal generation, since the

(continued)

BASES

APPLICABLE

3 second closure time is assumed in the MSIV closure analysis (Ref. 2) and the 5 second closure time is consistent with or conservative to the times assumed in the MSLB analyses (Refs. 3 and 4). Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis does not assume a specific closure time for primary containment isolation valves (PCIVs). The analysis assumes that the leakage from the primary containment is 1.5 percent primary containment air weight per day (L_a) at pressure P_a throughout the accident. The bases for PCIV closure times, and the specified valve closure times, are specified in UFSAR Section 7.3.3.1 and UFSAR Table 7.3-1 (Refs. 5 and 6), respectively.

The single failure criterion required to be imposed in the conduct of plant 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) (Ref. 7).

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. The 20 and 24 inch vent and purge valves must be maintained closed or blocked to prevent full opening. 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 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers." The valves covered by this LCO are listed in Reference 8. The associated stroke time of each automatic PCIV is included in the Inservice Testing (IST) Program.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind

(continued)

BASES

LCO (continued)

flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 8.

MSIVs, Low Pressure Coolant Injection (LPCI) and Core Spray (CS) System air operated testable check valves 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 and the primary containment vent and purge valves are not required to be normally closed 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

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 inoperabilities due to MSIV leakage or LPCI or CS System air operated testable check valve leakage 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 occur. This Required Action does not require any testing or

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

device 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 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 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 the isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing of 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 inoperabilities due to MSIV leakage or LPCI or CS System air operated testable check valve leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must 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

(continued)

BASES

ACTIONS

B.1 (continued)

single active component 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 inoperabilities due to MSIV leakage or LPCI or CS System air operated testable check valve leakage not within limits, 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 component 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 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 9. 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 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 device manipulation. Rather, it involves verification, that those devices outside

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

containment and capable of potentially being mispositioned are in the correct position. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves 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.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges 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.

D.1

With any MSIV leakage rate 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 8 hour Completion Time is reasonable considering the time required to restore the

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BASES

ACTIONS

D.1 (continued)

leakage by isolating the penetration, the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown, and the relative importance of MSIV leakage to the overall containment function.

E.1

With the one or more penetration flow paths with LPCI System or CS System air operated testable check valve leakage rate not within limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 72 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, or closed manual valve. 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 72 hour Completion Time is reasonable considering the time required to restore the leakage and the importance to maintain these penetrations available to perform the required function during a design basis accident.

F.1 and F.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.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required to OPERABLE during MODE 4 or 5, the plant must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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 and valve(s) are restored to OPERABLE status. If suspending an OPDRV would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR 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 primary containment vent and purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that the SR is not required to be met when the vent and 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 full-flow 12 inch line (with valve 27MOV-120) to the SGT System is closed and one or more SGT System reactor building suction valves are open. This will ensure there is no damage to the filters if a LOCA were to occur with the vent and purge valves open since excessive differential pressure is not expected with the full-flow 12 inch line closed and one or more SGT System reactor building suction valves open. The 20 and 24 inch vent and purge valves are capable of closing against the dynamic effects of 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 ensures 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.2 (continued)

This SR does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of valve position for isolation devices outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the isolation devices are in the correct positions.

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 isolation devices, once they have been verified to be in the 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. 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.

SR 3.6.1.3.3

This SR ensures that each primary containment manual isolation valve and blind flange that is 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 isolation devices inside primary containment, the Frequency defined as "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 isolation devices 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

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 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 isolation devices, 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 the 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 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 plant 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 a simulated instrument line break. This SR provides assurance that the instrumentation line EFCVs will perform so that secondary containment will not be overpressurized during the postulated instrument line break (Ref. 10). The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.9

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).

SR 3.6.1.3.10

The analyses in Reference 11 are based on leakage that is more than the specified leakage rate. Leakage through each MSIV must be ≤ 11.5 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 in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.11

Surveillance of each air operated testable check valve associated with the LPCI and CS Systems vessel injection penetrations provides assurance that the resulting radiation dose rate that would result if the reactor coolant were released to the reactor building at the specified limit will be small (Ref. 12). The acceptance criteria for each air operated testable check valve associated with the LPCI and CS Systems vessel injection penetrations is < 10 gpm when hydrostatically tested at ≥ 1035 psig or < 10 scfm when pneumatically tested at ≥ 45 psig, at ambient temperature (Ref. 12). The leakage rates must be demonstrated in accordance with the leakage rate test Frequency required by the Primary Containment Leakage Rate Testing Program.

REFERENCES

1. UFSAR, Section 14.6.
2. UFSAR, Section 14.5.2.3.
3. UFSAR, Section 6.5.3.2.
4. UFSAR, Section 14.8.2.1.2.

(continued)

BASES

REFERENCES (continued)

5. UFSAR, Section 7.3.3.1.

6. UFSAR, Table 7.3-1.

7. 10 CFR 50.36(c)(2)(ii).

8. Technical Requirements Manual.

9. UFSAR, Section 5.2.3.5.

10. UFSAR, Section 16.3.2.5.

11. UFSAR, Section 14.8.2.1.1.

12. NRC Letter to NYPA, November 9, 1978 NRC Safety Evaluation Supporting Amendment 40 to the Facility Operating License No. DPR-59.

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).

APPLICABLE SAFETY ANALYSES

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 (Refs. 1, 2 and 3). Analyses assume an initial drywell pressure of 1.95 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 drywell design pressure of 56 psig.

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 41.2 psig (Ref. 4).

Drywell pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

In the event of a DBA, with an initial drywell pressure ≤ 1.95 psig, the resultant peak drywell accident pressure will be maintained below the maximum allowable drywell pressure.

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.

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

(continued)

BASES

ACTIONS

A.1 (continued)

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 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 limit ensures that plant 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. UFSAR, Section 14.6.1.3.3.
2. NEDO-24578, Revision 0, Mark I Containment Program Plant Unique Load Definition, James A. FitzPatrick Nuclear Power Plant, March 1979.
3. UFSAR, Section 16.9.3.5.
4. UFSAR, Section 16.9.3.5.1.3.
5. 10 CFR 50.36(c)(2)(ii).

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.
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 (Refs. 1 and 2). Analyses assume an initial average drywell air temperature of 135°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature and pressure do not exceed the drywell design pressure of 56 psig coincident with a design temperature of 309°F (Ref. 3). Exceeding these design limitations 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 spectrum of break sizes. Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).
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 and pressure are maintained within the drywell design limits and within the environmental qualification envelope of the equipment in the drywell. As a result, the ability of primary containment to perform its design function is ensured.
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

(continued)

BASES

APPLICABILITY (continued)	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.

ACTIONS

A.1

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.

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 areas and at various elevations (referenced to mean sea level). Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.1.5.1 (continued) indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.
REFERENCES	1. UFSAR, Section 14.6.1.3.3. 2. GE-NE-T23-00737-01, James A. FitzPatrick Nuclear Power Plant Higher RHR Service Water Temperature Analysis, August 1996. 3. UFSAR, 16.7.3.2.3. 4. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 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 reactor building-to-suppression chamber vacuum relief system consists of four vacuum breakers (two parallel sets of 100% capacity vacuum breaker pairs, each set consisting of a self-actuating vacuum breaker and an air operated vacuum breaker), located in two lines. The air operated vacuum breakers are actuated by differential pressure switches and can be remotely operated from the relay room. The self-actuating vacuum breakers function similar to a check valve. 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 ventilation equipment. Inadvertent spray actuation results in a more significant negative pressure transient.

The reactor building-to-suppression chamber vacuum breakers are sized to mitigate any depressurization transient and limit the 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 noncondensible gases are assumed for conservatism.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Suppression chamber-to-drywell and 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.

The safety analyses assume the reactor building-to-suppression chamber vacuum breakers to be closed initially (Ref. 1). Additionally, one or both reactor building-to-suppression chamber vacuum breakers in each line are assumed to fail in a closed position. Therefore, the single active failure criterion is met.

Several cases were considered in the safety analyses to determine the maximum negative pressure differential between the containment and reactor building assuming the reactor building-to-suppression chamber vacuum breakers remain closed (Ref. 1):

a. A small break loss of coolant accident followed by actuation of one Residual Heat Removal (RHR) containment spray loop;

b. Inadvertent actuation of one RHR containment spray loop during normal operation;

c. A large break loss of coolant accident followed by actuation of one RHR containment spray loop.

The results of these cases show that the reactor building-to-suppression chamber vacuum breakers are not required to mitigate the consequences of any DBA since the maximum resulting negative differential pressure is 1.92 psid (case a) which is below the design differential pressure limit of 2 psid. However, to ensure the resulting negative pressure is minimized, the reactor building-to-suppression chamber vacuum breakers are included in the design and set to ensure the valves start to open at ≤ 0.5 psid.

The reactor building-to-suppression chamber vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

All reactor building-to-suppression chamber vacuum breakers are required to be OPERABLE to ensure the primary containment design differential pressure limit is not challenged. This requirement ensures both vacuum breakers in each line (self-actuated vacuum breaker and air operated

(continued)

BASES

LCO (continued)	vacuum breaker) will open to relieve a negative pressure in the suppression chamber. This LCO also ensures that the two vacuum breakers 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).
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 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 also occur due to inadvertent initiation of the RHR Containment Spray System. 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.
ACTIONS	A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. <u>A.1</u> 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 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression-chamber-to-drywell vacuum breakers in LCO 3.6.1.7, "Suppression-Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining breakers, the fact

(continued)

BASES

ACTIONS

A.1 (continued)

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 the consequences of an event that causes a containment depressurization is threatened if one or more vacuum breakers in at least one vacuum breaker penetration are not OPERABLE. Therefore, the inoperable vacuum breaker must be restored to OPERABLE status within 72 hours. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

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 vacuum relief 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.

(continued)

BASES

ACTIONS (continued)

E.1 and E.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 3.6.1.6.1

Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance may be performed by observing local or remote indications of vacuum breaker position. Position indications of the air operated vacuum breakers are available in the control and relay rooms while position indications of the self actuating vacuum breakers are only available in the relay room. 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 building-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.

SR 3.6.1.6.2

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 Frequency of this SR is in accordance with the Inservice Testing Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.3

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 of SR 3.6.1.6.3 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.6.1.6.4

Demonstration of each self-actuating vacuum breaker opening setpoint is necessary to ensure that the design function regarding vacuum breaker opening differential pressure of ≤ 0.5 psid is valid. 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, which is based on the operating cycle. The 24 month Frequency is further justified because SR 3.6.1.6.2 is performed at a shorter Frequency that conveys the proper functioning status of each self-actuating vacuum breaker.

REFERENCES

1. Design Bases Document-016A, Section 5.2.10, Maximum Design Negative Pressure for Containment.

2. 10 CFR 50.36(c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 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 5 external vacuum breakers located on the external lines connecting the top of the suppression chamber with drywell vent pipes, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self-actuating valve, similar to a check valve, which can be manually operated locally 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, drywell spray actuation, and steam condensation from sprays or subcooled reflood water 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 ventilation equipment. Spray actuation or the spilling of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the suppression chamber-to-drywell 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, the gas mixture 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 out of a line break, or Residual Heat Removal (RHR) Containment Spray System actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark I Vent System downcomers are 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

(continued)

BASES

BACKGROUND (continued)	drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The suppression chamber-to-drywell vacuum breakers may limit the height of the waterleg in the vent system during time periods when drywell-to-suppression chamber differential pressure is not required or is not maintained within the limits specified in LCO 3.6.2.4, "Drywell-to-Suppression Chamber Differential Pressure."
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are used as part of the accident analyses of the primary containment systems. Suppression chamber-to-drywell and 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 suppression chamber-to-drywell vacuum breakers are closed initially and start to open at a differential pressure of 0.5 psid (Refs. 1 and 2). Additionally, 1 of the 5 vacuum breakers is assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design differential pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that all vacuum breakers be OPERABLE (the additional vacuum breaker is required to meet the single failure criterion) are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The cross sectional areas of the vacuum breakers are sized on the basis of the Bodega Bay pressure suppression system tests. The vacuum breaker capacity selected on this test basis is more than adequate to limit the pressure differential between the suppression chamber and drywell during post-accident drywell cooling operations to a value which is within the suppression system design values (Refs. 3 and 4). Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight, until the suppression pool is at a positive pressure relative to the drywell. The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

(continued)

BASES (continued)

LCO

All vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers are also required to be closed (except during testing or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

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 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. 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 also occur due to inadvertent actuation of the RHR Containment Spray System during normal operation.

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 vacuum breakers inoperable for opening (e.g., the vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining four OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single active failure in one of the remaining vacuum breakers could result in an excessive negative drywell-to-suppression chamber differential pressure during a DBA. Therefore, with one of the five vacuum breakers inoperable, 72 hours is allowed to restore the inoperable vacuum breaker to OPERABLE status so that plant conditions

(continued)

BASES

ACTIONS

A.1 (continued)

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 occurring that would require the remaining vacuum breaker capability.

B.1

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for primary containment overpressurization due to 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. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify the bypass leakage between the drywell and suppression chamber is within the limits of SR 3.6.1.1.2 or by local observation. The required 2 hour Completion Time is considered adequate to perform this test. If the leak test fails, not only must this ACTION be taken (close the open vacuum breaker within the required Completion Time), but also the appropriate Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," must be entered.

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 3.6.1.7.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

SR 3.6.1.1.2, the bypass leakage test. If the bypass test fails, not only must the vacuum breaker(s) be considered open and the appropriate Conditions and Required Actions of this LCO be entered, but also the appropriate Condition and Required Actions of LCO 3.6.1.1 must be entered. Each suppression chamber-to-drywell vacuum breaker disc will be seated as long as the arm movement is ≤ 1.0 degree. The vacuum breakers are considered closed if the associated position light indicates the closed position since it is set to actuate at ≤ 1.0 degree. 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 3.6.1.7.2

Each 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 Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.7.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker opening differential pressure of 0.5 psid is valid. The 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because SR 3.6.1.7.2 is performed at a shorter Frequency that conveys the proper functioning status of each vacuum breaker.

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