
Standard Technical Specifications General Electric Plants, BWR/6

Bases (Sections 3.4–3.10)

**Issued by the
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PREFACE

This NUREG contains the improved Standard Technical Specifications (STS) for General Electric (GE) BWR/6 plants. Revision 1 incorporates the cumulative changes to Revision 0, which was published in September 1992. The changes reflected in Revision 1 resulted from the experience gained from license amendment applications to convert to these improved STS or to adopt partial improvements to existing technical specifications. This NUREG is the result of extensive public technical meetings and discussions between the Nuclear Regulatory Commission (NRC) staff and various nuclear power plant licensees, Nuclear Steam Supply System (NSSS) Owners Groups, specifically the GE Owners Group, NSSS vendors, and the Nuclear Energy Institute (NEI). The improved STS were developed based on the criteria in the Final Commission Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors, dated July 22, 1993 (58 FR 39132). Licensees are encouraged to upgrade their technical specifications consistent with those criteria and conforming, to the extent practical and consistent with the licensing basis for the facility, to Revision 1 to the improved STS. The Commission continues to place the highest priority on requests for complete conversions to the improved STS. Licensees adopting portions of the improved STS to existing technical specifications should adopt all related requirements, as applicable, to achieve a high degree of standardization and consistency.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Coolant Recirculation System is designed to provide a 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 Coolant 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 a two speed motor driven recirculation pump, a flow control valve, 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.

(continued)

BASES

BACKGROUND
(continued)

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

Each recirculation loop is manually started from the control room. The recirculation flow control valves provide regulation of individual recirculation loop drive flows. The flow in each loop can be manually or automatically controlled.

APPLICABLE
SAFETY ANALYSES

The operation of the Reactor Coolant 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.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the FSAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Ref. 3).

The transient analyses of Chapter 15 of the FSAR 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 average power range monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR setpoints for single loop operation are specified in the COLR. The APRM flow biased simulated thermal power setpoint is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement.

LCO

Two recirculation loops are required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. With the limits specified in SR 3.4.1.1 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)"), and APRM Flow Biased Simulated Thermal Power—High setpoint (LCO 3.3.1.1) may be

(continued)

BASES

LCO
(continued) applied to allow continued operation consistent with the assumptions of Reference 3.

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

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

ACTIONS

A.1

With the requirements of the LCO not met, 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 setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

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

(continued)

BASES

ACTIONS

A.1 (continued)

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 flow control valve position to re-establish forward flow or by tripping the pump.

B.1

With no recirculation loops in operation, or the Required Action and associated Completion Time of Condition A not met, the unit is required to 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 recirculation loop flows 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, the loop with the lower flow is considered inoperable. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.1.1 (continued)

performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the 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. FSAR, Section [6.3.3.4].
 2. FSAR, Section [5.5.1.4].
 - [3. Plant specific analysis for single loop operation.]
-
-

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Flow Control Valves (FCVs)

BASES

BACKGROUND

The Reactor Coolant 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 this affects the design basis transient and accident analyses. The jet pumps and the FCVs are part of the Reactor Coolant Recirculation System. The jet pumps are described in the Bases for LCO 3.4.3, "Jet Pumps."

The Recirculation Flow Control System consists of the electronic and hydraulic components necessary for the positioning of the two hydraulically actuated FCVs. The recirculation loop flow rate can be rapidly changed within the expected flow range, in response to rapid changes in system demand. Limits on the system response are required to minimize the impact on core flow response during certain accidents and transients. Solid state control logic will generate an FCV "motion inhibit" signal in response to any one of several hydraulic power unit or analog control circuit failure signals. The "motion inhibit" signal causes hydraulic power unit shutdown and hydraulic isolation such that the FCVs fail "as is."

APPLICABLE SAFETY ANALYSES

The FCV stroke rate is limited to $\leq 11\%$ per second in the opening and closing directions on a control signal failure of maximum demand. This stroke rate is an assumption of the analysis of the recirculation flow control failures on decreasing and increasing flow (Refs. 1 and 2). The closure of a recirculation FCV concurrent with a loss of coolant accident (LOCA) has been analyzed and found to be acceptable for a maximum closure rate of 11% of strokes per second (Ref. 3).

Flow control valves satisfy Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO An FCV in each operating recirculation loop must be OPERABLE to ensure that the assumptions of the design basis transient and accident analyses are satisfied.

APPLICABILITY In MODES 1 and 2, the FCVs are required to be OPERABLE, since during these conditions there is considerable energy in the reactor core, and the limiting design basis transients and accidents are assumed to occur. In MODES 3, 4, and 5, the consequences of a transient or accident are reduced and OPERABILITY of the flow control valves is not important.

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

A.1

With one or two required FCVs inoperable, the assumptions of the design basis transient and accident analyses may not be met and the inoperable FCV must be returned to OPERABLE status or hydraulically locked within 4 hours.

Opening an FCV faster than the limit could result in a more severe flow runout transient, resulting in violation of the Safety Limit MCPR. Closing an FCV faster than the limit assumed in the LOCA analysis (Refs. 1 and 2) could affect the recirculation flow coastdown, resulting in higher peak clad temperatures. Therefore, if an FCV is inoperable due to stroke times faster than the limits, deactivating the valve will essentially lock the valve in position, which

(continued)

BASES

ACTIONS

A.1 (continued)

will prohibit the FCV from adversely affecting the DBA and transient analyses. Continued operation is allowed in this Condition.

The 4 hour Completion Time is a reasonable time period to complete the Required Action, while limiting the time of operation with an inoperable FCV.

B.1

If the FCVs are not deactivated ("locked up") within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours. This brings the unit to a condition where the flow coastdown characteristics of the recirculation loop are not important. 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 unit systems.

SURVEILLANCE
REQUIREMENTS

SR 3.4.2.1

Hydraulic power unit pilot operated isolation valves located between the servo valves and the common "open" and "close" lines are required to close in the event of a loss of hydraulic pressure. When closed, these valves inhibit FCV motion by blocking hydraulic pressure from the servo valve to the common open and close lines as well as to the alternate subloop. This Surveillance verifies FCV lockup on a loss of hydraulic pressure.

The [18] 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 SR when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.2.2

This SR ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits.

The [18] 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 SR when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [15.3.2].
 2. FSAR, Section [15.4.5].
 3. [Plant specific Safety Evaluation Report.]
-
-

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Jet Pumps

BASES

BACKGROUND

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

Each reactor coolant recirculation loop contains 12 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 explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

Jet pumps satisfy Criterion 2 of the NRC Policy Statement.

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 Coolant 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 Coolant Recirculation System (LCO 3.4.1).

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

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding 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 allowed Completion Time of

(continued)

BASES

ACTIONS

A.1 (continued)

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 3.4.3.1

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

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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.3.1 (continued)

Total core flow can be determined from measurements of the recirculation loop drive flows. Once this relationship has been established, increased or reduced total core flow for the same recirculation loop drive flow may be an indication of failures in one or several jet pumps.

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or 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. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

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

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

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

Note 2 allows this SR not to be performed when THERMAL POWER is $\leq 25\%$ RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section [6.3].
 2. GE Service Information Letter No. 330, June 9, 1990.
 3. NUREG/CR-3052, November 1984.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (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 safety/relief valves (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. In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston or cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Six of the S/RVs providing the relief function also provide the low-low set relief function specified in LCO 3.6.1.6, "Low-Low Set (LLS) Valves." Eight of the S/RVs that provide the relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS—Operating." The instrumentation associated with the relief valve function and low-low set relief function is discussed in the Bases for LCO 3.3.6.5, "Relief and Low-Low Set (LLS) Instrumentation," and instrumentation for the ADS function is discussed in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation."

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 2). For the purpose of the analyses, [six] of the S/RVs are assumed to operate in the relief mode, and seven in the safety mode. The analysis results demonstrate that the design S/RV capacity is 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 is met during the design basis event.

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 3 discusses additional events that are expected to actuate the S/RVs.

S/RVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The safety function of seven S/RVs is required to be OPERABLE in the safety mode, and an additional seven S/RVs (other than the seven S/RVs that satisfy the safety function) must be OPERABLE in the relief mode. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of seven S/RVs in the safety mode and six S/RVs in the relief mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

The S/RV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 are based on these setpoints, but also include the additional uncertainties of $\pm 1\%$ of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

(continued)

BASES

LCO (continued)

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

APPLICABILITY

In MODES 1, 2, and 3, the specified number of S/RVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. 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 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

With the safety function of one [required] S/RV inoperable, the remaining OPERABLE S/RVs are capable of providing the necessary overpressure protection. Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with two S/RVs inoperable. However, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE S/RVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

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

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. [If the inoperable required S/RV cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1] or if [two] or more [required] S/RVs 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 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 3.4.4.1

This Surveillance demonstrates that the [required] S/RVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the S/RV safety function lift settings must be performed during shutdown, since this is a bench test[, and 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 \pm [3]% for OPERABILITY; however, the valves are reset to \pm 1% during the Surveillance to allow for drift.

The [18 month] Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.

SR 3.4.4.2

The [required] relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.4.2 (continued)

The [18 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 SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.4.4.3

A manual actuation of each [required] S/RV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or 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 950 psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr]. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If the valve fails to actuate due only to the failure of the solenoid but

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.4.3 (continued)

is capable of opening on overpressure, the safety function of the S/RV is considered OPERABLE.

The [18] month on a STAGGERED TEST BASIS Frequency ensures that each solenoid for each S/RV is alternately tested. The 18 month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 1). Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
 2. FSAR, Section [5.2.5.5.3].
 3. FSAR, Section [15].
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Operational LEAKAGE

BASES

BACKGROUND

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

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE.

This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks 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 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 drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

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

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

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

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

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

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

RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

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

(continued)

BASES

LCO
(continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell air monitoring, drywell sump level monitoring, and drywell air cooler condensate flow rate monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

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

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 4 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

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

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

(continued)

BASES (continued)

ACTIONS

A.1

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

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 4 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 [4] hours" limit; either by isolating the source or other possible methods) is to evaluate RCS 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 needed to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down.

C.1 and C.2

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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

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 3.4.7, "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 7. In conjunction with alarms and other administrative controls, an 8 hour Frequency for this Surveillance is appropriate for identifying changes in LEAKAGE and for tracking required trends (Ref. 8).

REFERENCES

1. 10 CFR 50.2.
 2. 10 CFR 50.55a(c).
 3. 10 CFR 50, Appendix A, GDC 55.
 4. GEAP-5620, April 1968.
 5. NUREG-76/067, October 1975.
 6. FSAR, Section [5.2.5.5.3].
 7. Regulatory Guide 1.45.
 8. Generic Letter 88-01, Supplement 1.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

RCS PIVs are defined as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB). The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. The PIV leakage limit applies to each individual valve. Leakage through these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE."

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following typically connected systems:

- a. Residual Heat Removal (RHR) System;
- b. Low Pressure Core Spray System;

(continued)

BASES

BACKGROUND (continued)

- c. High Pressure Core Spray System; and
- d. Reactor Core Isolation Cooling System.

The PIVs are listed in Reference 6.

APPLICABLE SAFETY ANALYSES

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment. RCS PIV leakage satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm (Ref. 4).

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential). The observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one-half power.

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR flowpath are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR shutdown cooling mode of operation.

In MODES 4 and 5, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. 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 the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate affected RCS PIV flow paths. As such, a Note has been provided that allows separate Condition entry for each affected RCS PIV flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system OPERABILITY, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

A.1 and A.2

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

manual, deactivated, automatic, or check valve within 4 hours. Required Action A.1 and Required Action A.2 are modified by a Note stating that the valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB [or the high pressure portion of the system.]

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseal the leaking PIVs are taken. The 4 hours allows time for these actions and restricts the time of operation with leaking valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing another valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Required Action, the low probability of a second valve failing during this time period, and the low probability of a pressure boundary rupture of the low pressure ECCS piping when overpressurized to reactor pressure (Ref. 7).

B.1 and B.2

If leakage cannot be reduced or the system isolated, 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. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times 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

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.6.1 (continued)

per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The 18 month Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this Surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is not required to be performed in MODE 3. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

REFERENCES

1. 10 CFR 50.2.
 2. 10 CFR 50.55a(c).
 3. 10 CFR 50, Appendix A, GDC 55.
 4. ASME, Boiler and Pressure Vessel Code, Section XI.
 5. NUREG-0677, May 1980.
 6. FSAR, Section [].
 7. NEDC-31339, November 1986.
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. The Bases for LCO 3.4.5, "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 or three independently monitored variables, such as sump level changes 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 Closed 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 transmitters that supply level indications in the main control room.

The floor drain sump level indicators have switches that start and stop the sump pumps when required. A timer starts each time the sump is pumped down to the low level setpoint.

(continued)

BASES

BACKGROUND (continued)

If the sump fills to the high level setpoint before the timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit. A second timer starts when the sump pumps start on high level. Should this timer run out before the sump level reaches the low level setpoint, an alarm is sounded in the control room indicating a LEAKAGE rate into the sump in excess of a preset limit. A flow indicator in the discharge line of the drywell floor drain sump pumps provides flow indication in the control room.

The drywell air monitoring systems continuously monitor 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 systems are not capable of quantifying leakage rates, but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour. Larger changes in LEAKAGE rates are detected in proportionally shorter times (Ref. 3).

Condensate from four of the six drywell coolers is routed to the drywell floor drain sump and is monitored by a flow transmitter that provides indication and alarms in the control room. This drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS unidentified LEAKAGE.

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. 4 and 5). 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 of excess LEAKAGE in the control room.

A control room alarm 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 (Ref. 6).

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

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, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE. The other 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 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

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 atmospheric activity monitor [and the drywell air cooler condensate flow rate monitor] will provide indications of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 8 hours (SR 3.4.5.1), 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 LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the drywell floor drain sump monitoring system

(continued)

BASES

ACTIONS

A.1 (continued)

is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

B.1 and B.2

With both gaseous and particulate drywell atmospheric monitoring channels inoperable, grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed every 12 hours, the plant may be operated for up to 30 days to allow restoration of at least one of the required monitors.] [Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation since at least one other form of drywell leakage detection (i.e., air cooler condensate flow rate monitor) is available.]

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 primary containment atmospheric monitoring channels are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

C.1

With the required drywell air cooler condensate flow rate monitoring system inoperable, SR 3.4.7.1 is performed every 8 hours to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.4.7.1. 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 the required drywell atmospheric monitoring system is inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.

(continued)

BASES

ACTIONS
(continued)

D.1 and D.2

With both the gaseous and particulate drywell atmospheric monitor channels and the drywell air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the drywell floor drain sump monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. 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 primary containment atmospheric monitoring channels and air cooler condensate flow rate are inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

E.1 and E.2

If any Required Action of Condition A, B, [C, or D] cannot be met 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 in an orderly manner and without challenging plant systems.

F.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

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.7.1 (continued)

properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.7.2

This SR requires 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 the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.7.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell. The Frequency of [18] months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
 2. Regulatory Guide 1.45, May 1973.
 3. FSAR, Section [5.2.5.2].
 4. GEAP-5620, April 1968.
 5. NUREG-75/067, October 1975.
 6. FSAR, Section [5.2.5.5.3].
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the 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, in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 100 (Ref. 1).

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

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the FSAR (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 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 100.

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 the NRC Policy Statement.

LCO

The specific iodine activity is limited to $\leq [0.2] \mu\text{Ci/gm}$ DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 100 limits.

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

(continued)

BASES

ACTIONS
(continued) restore transient specific activity excursions while the
plant remains at, or proceeds to power operation.

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is $\leq 4.0 \mu\text{Ci/gm}$, 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.

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

If the DOSE EQUIVALENT I-131 cannot be restored to $\leq [0.2] \mu\text{Ci/gm}$ within 48 hours, or if at any time it is $> [4.0] \mu\text{Ci/gm}$, it must be determined at least 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 during a postulated MSLB accident.

Alternately, the plant can be brought to MODE 3 within 12 hours and to 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 bringing the plant to MODES 3 and 4 are reasonable, based on

(continued)

BASES

ACTIONS

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

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

SURVEILLANCE
REQUIREMENTS

SR 3.4.8.1

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

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

REFERENCES

1. 10 CFR 100.11, 1973.
 2. FSAR, Section [15.1.40].
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 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 $\leq 200^{\circ}\text{F}$. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via separate feedwater lines or to the reactor via the LPCI injection path. The RHR heat exchangers transfer heat to the Standby Service Water System (LCO 3.7.1, "[Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)]").

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR Shutdown Cooling System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, two heat exchangers in series, and the

(continued)

BASES

LCO (continued)

associated piping and valves. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one 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.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for 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 System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and 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 interlock resets) the RHR Shutdown Cooling System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor 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,

(continued)

BASES

APPLICABILITY (continued)

"ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "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 LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single

(continued)

BASES

ACTIONS

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

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 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 Spent Fuel Pool Cooling System or the Reactor Water Cleanup System.

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

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable

(continued)

BASES

ACTIONS

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

separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

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

SURVEILLANCE
REQUIREMENTS

SR 3.4.9.1

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

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

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 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 at $\leq 200^{\circ}\text{F}$. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via separate feedwater lines or to the reactor via the LPCI injection path. The RHR heat exchangers transfer heat to the Standby Service Water System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR Shutdown Cooling System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, two heat exchangers in series, and the associated piping and valves. Each shutdown cooling

(continued)

BASES

LCO
(continued)

subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one 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 and 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.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for 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 System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 4, the RHR System may be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 200°F. Otherwise, a recirculation pump is required to be in operation.

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 MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "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 provided 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 LCO Note 2, 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.

(continued)

BASES

ACTIONS

A.1 (continued)

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 Spent Fuel Pool Cooling System or the Reactor Water Cleanup System.

B.1 and B.2

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

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

SURVEILLANCE
REQUIREMENTS

SR 3.4.10.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.10.1 (continued)

sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

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

The PTLR contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic testing, and data for the maximum rate of change of reactor coolant temperature. The heatup curve provides limits for both heatup and criticality.

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

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

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

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

(continued)

BASES

BACKGROUND (continued)

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

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

The 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.

The 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 leak 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. The 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. 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

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The elements of this LCO are:

- a. RCS pressure, temperature, and heatup or cooldown rate are within the limits specified in the PTLR, during RCS heatup, cooldown, and inservice leak and hydrostatic testing;
- b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within the limit of the PTLR during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;
- c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel meets the limit of the PTLR during recirculation pump startup, and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow;
- d. RCS pressure and temperature are within the criticality limits specified in the PTLR, prior to achieving criticality; and
- e. The reactor vessel flange and the head flange temperatures are within the limits of the PTLR when tensioning the reactor vessel head bolting studs.

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

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

(continued)

BASES

LCO (continued)

thermal gradients and also ensures the validity of the P/T limit curves.

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

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

ACTIONS

A.1 and A.2

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

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

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be brought to 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 possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by bringing the plant to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS
(continued)

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 > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

SURVEILLANCE
REQUIREMENTS

SR 3.4.11.1

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

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.

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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.4.11.2

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 3.4.11.3 and SR 3.4.11.4

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

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

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.11.3 has been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 [with reactor steam dome pressure \geq 25 psig]. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

SR 3.4.11.5, SR 3.4.11.6, and SR 3.4.11.7

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.5, SR 3.4.11.6, and SR 3.4.11.7 (continued)

during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature $\leq 80^{\circ}\text{F}$, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature $\leq 100^{\circ}\text{F}$, monitoring of the flange temperature is required every 12 hours to ensure the temperatures are within the limits specified in the PTLR.

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.

REFERENCES

1. 10 CFR 50, Appendix G.
 2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
 3. ASTM E 185-82, July 1982.
 4. 10 CFR 50, Appendix H.
 5. Regulatory Guide 1.99, Revision 2, May 1988.
 6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
 7. NEDO-21778-A, December 1978.
 8. FSAR, Section [15.1.26].
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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Reactor Steam Dome Pressure

BASES

BACKGROUND The reactor steam dome pressure is an assumed initial condition of Design Basis Accidents (DBAs) and transients and is also an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria.

APPLICABLE SAFETY ANALYSES The reactor steam dome pressure of $\leq [1045]$ psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of DBAs and transients used to determine the limits for fuel cladding integrity MCPR (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)").

Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Policy Statement.

LCO The specified reactor steam dome pressure limit of $\leq [1045]$ psig ensures the plant is operated within the assumptions of the transient analyses. Operation above the limit may result in a transient response more severe than analyzed.

APPLICABILITY In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these

(continued)

BASES

APPLICABILITY
(continued)

MODES, the reactor may be generating significant steam, and the DBAs and transients are bounding.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal. If the operator is unable to restore the reactor steam dome pressure to below the limit, then the reactor should be brought to MODE 3 to be within the assumptions of the transient analyses.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.4.12.1

Verification that reactor steam dome pressure is $\leq [1045]$ psig ensures that the initial conditions of the DBAs and transients are met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

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BASES (continued)

REFERENCES

1. FSAR, Section [5.2.2.2.4].
 2. FSAR, Section [15].
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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 is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. The ECCS also consists of 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 tank (CST), it is capable of providing a source of water for the HPCS System.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously the system aligns, and the pumps inject water, taken either from the CST 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 HPCS pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the spray sparger above the core. If the break is small, HPCS will maintain coolant inventory, as well as vessel level, while the RCS is still pressurized. If HPCS fails, it is backed up by ADS in combination with LPCI and LPCS. In this event, the ADS timed sequence would be allowed to time out and open the selected safety/relief valves (S/RVs), depressurizing the RCS and allowing the LPCI and LPCS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly, and the LPCI and LPCS systems 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 Standby Service Water (SWS) System. Depending on the location and size of the break, portions of the ECCS may be ineffective;

(continued)

BASES

BACKGROUND (continued)

however, the overall design is effective in cooling the core regardless of the size or location of the piping break. Although no credit is taken in the safety analysis for the RCIC System, it performs a similar function as HPCS but has reduced makeup capability. Nevertheless, it will maintain inventory and cool the core, while the RCS is still pressurized, following a reactor pressure vessel (RPV) isolation.

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

The LPCS System (Ref. 1) consists of a motor driven pump, a spray sparger above the core, piping, and valves to transfer water from the suppression pool to the sparger. The LPCS System is designed to provide cooling to the reactor core when the reactor pressure is low. Upon receipt of an initiation signal, the LPCS pump is automatically started when AC power is available. When the RPV pressure drops sufficiently, LPCS flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the LPCS System without spraying water into the RPV.

LPCI is an independent operating mode of the RHR System. There are three LPCI subsystems. Each LPCI subsystem (Ref. 2) consists of a motor driven pump, piping, and valves to transfer water from the suppression pool to the core. Each LPCI subsystem has its own suction and discharge piping and separate vessel nozzle that connects with the core shroud through internal piping. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, each LPCI pump is automatically started (C pump immediately, when AC power is available, and A and B pumps approximately 5.25 seconds after AC power is available). When the RPV pressure drops sufficiently, LPCI flow to the RPV begins. RHR System 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 core. A discharge test line is provided to route water from and to the suppression pool to allow testing of each LPCI pump without injecting water into the RPV.

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BASES

BACKGROUND (continued)

The HPCS System (Ref. 3) consists of a single motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suction source to the sparger. Suction piping is provided from the CST and the suppression pool. Pump suction is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCS System. The HPCS System is designed to provide core cooling over a wide range of RPV pressures (0 psid to 1177 psid, vessel to suction source). Upon receipt of an initiation signal, the HPCS pump automatically starts (when AC power is available) and valves in the flow path begin to open. Since the HPCS System is designed to operate over the full range of expected RPV pressures, HPCS flow begins as soon as the necessary valves are open. A full flow test line is provided to route water from and to the CST to allow testing of the HPCS System during normal operation without spraying water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed or RPV pressure is greater than the LPCS or LPCI pump discharge pressures following system initiation. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the ECCS discharge line "keep fill" systems are designed to maintain all pump discharge lines filled with water.

The ADS (Ref. 4) consists of 8 of the 20 S/RVs. It is designed to provide depressurization of the primary system during a small break LOCA if HPCS 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 (LPCS and LPCI), so that these subsystems can provide core cooling. Each ADS valve is supplied with pneumatic power from an air storage system, which consists of air accumulators and air receivers located in the drywell.

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BASES (continued)

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 10 CFR 50 (Ref. 8), and the results of these analyses are described in Reference 9.

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

- a. Maximum fuel element cladding temperature is $\leq 2200^{\circ}\text{F}$;
- b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;
- c. Maximum hydrogen generation from zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;
- d. The core is maintained in a coolable geometry; and
- e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a large break LOCA, failure of ECCS subsystems in Division 1 (LPCS and LPCI-A) or Division 2 (LPCI-B and LPCI-C) due to failure of its associated diesel generator is, in general, the most severe failure. For a small break LOCA, HPCS System failure is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each ECCS injection/spray subsystem and eight ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The low pressure ECCS

(continued)

BASES

LCO
(continued)

injection/spray subsystems are defined as the LPCS System and the three LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 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. 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.

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, the ADS function is not required when pressure is ≤ 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV 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, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability by assuming that various components and subsystems were taken

(continued)

BASES

ACTIONS

A.1 (continued)

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 HPCS System is inoperable, and the RCIC System is verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS System must be restored to OPERABLE status within 14 days. In this Condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be verified and RCIC is required to be OPERABLE, Condition D 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 based on the results of a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis

(continued)

BASES

ACTIONS

C.1 (continued)

LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 12.

D.1 and D.2

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

E.1

The LCO requires eight ADS valves to be OPERABLE to provide the ADS function. Reference 13 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only seven ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 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 is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

basis LOCA could result in the minimum required ECCS equipment not being available. Since both a high pressure (ADS) and low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 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 E or F are not met or if two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times 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 HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.1 (continued)

31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

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 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 potentially capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency 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 alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

This SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the 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. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.5.1.3

Verification every 31 days that ADS air receiver pressure is \geq [150] psig assures adequate air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 14). 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 [150] psig is provided by the ADS Instrument Air Supply System. The 31 day Frequency takes into consideration administrative control over operation of the Instrument Air Supply System and alarms for low air pressure.

SR 3.5.1.4

The performance requirements of the 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 the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system head that is 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 LOCAs. These values may be established during pre-operational testing. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.5 (continued)

verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 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 SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

SR 3.5.1.6

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 3.5.1.7 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 3.5.1.6 (continued)

The 18 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 SR when performed at the 18 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. This prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each ADS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the S/RV discharge lines. This is demonstrated by the response of the turbine control or bypass valve, 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 ADS valves divert steam flow upon opening. Sufficient time is therefore allowed, after the required pressure and flow are achieved, to perform this test. Adequate pressure at which this test is to be performed is [950] psig (the pressure recommended by the valve manufacturer). Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr]. Reactor startup is allowed prior to performing this test 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. SR 3.5.1.6 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 3.5.1.7 (continued)

The Frequency of 18 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 this Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [6.3.2.2.3].
 2. FSAR, Section [6.3.2.2.4].
 3. FSAR, Section [6.3.2.2.1].
 4. FSAR, Section [6.3.2.2.2].
 5. FSAR, Section [15.2.8].
 6. FSAR, Section [15.6.4].
 7. FSAR, Section [15.6.5].
 8. 10 CFR 50, Appendix K.
 9. FSAR, Section [6.3.3].
 10. 10 CFR 50.46.
 11. FSAR, Section [6.3.3.3].
 12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
 13. FSAR, Section [6.3.3.7.8].
 14. FSAR, Section [7.3.1.1.1.4.2].
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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 High Pressure Core Spray (HPCS) System, Low Pressure Core Spray (LPCS) System, and 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 judgment, 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 ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO Two ECCS injection/spray subsystems are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the three LPCI subsystems, the LPCS System, and the HPCS System. The LPCS System and each LPCI subsystem consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV.

One LPCI subsystem (A or B) may be aligned for decay heat removal in MODE 4 or 5 and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Because

(continued)

BASES

LCO
(continued) 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 uncover.

APPLICABILITY OPERABILITY of the 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 upper containment pool gate removed, and the water level maintained at ≥ 22 ft 8 inches above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncover in case of an inadvertent draindown.

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

ACTIONS

A.1 and B.1

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

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must be initiated immediately 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

If both of the required ECCS injection/spray subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must be initiated immediately to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours.

If at least one 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 (i.e., one isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each secondary containment penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed by an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

(continued)

BASES

ACTIONS

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

The 4 hour Completion Time to restore at least one 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.

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of [12.67 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 ECCS 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 the suppression pool level is < [12.67 ft], the HPCS System is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is \geq [12.67 ft] or the HPCS System is aligned to take suction from the CST and the CST contains \geq [170,000] gallons of water, equivalent to 18 ft, ensures that the HPCS System can supply makeup water to the RPV.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications 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 3.5.1.4, and SR 3.5.1.5 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

(continued)

BASES

**SURVEILLANCE
REQUIREMENTS**
(continued)

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 operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, RHR valves that are required for LPCI subsystem operation may be aligned for decay heat removal. Therefore, this SR is modified by a Note that allows one LPCI subsystem of the RHR System to be considered OPERABLE for the ECCS function if all the required valves in the LPCI flow path can be manually realigned (remote or local) to allow injection into the RPV and the system is not otherwise inoperable. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.

REFERENCES

1. FSAR, Section [6.3.3.4].
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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 RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

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. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or the suppression pool level is high, 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 main steam line A, upstream of the inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, [165] psig to [1155] 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 from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)

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 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 line "keep fill" system is designed to maintain the pump discharge line filled with water.

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 Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system is included in the Technical Specifications as required by the NRC Policy Statement.

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.

APPLICABILITY

The RCIC System is required to be OPERABLE in 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 \leq 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODES 2 or 3 with reactor steam dome pressure > 150 psig, and the

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

HPCS 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 RPV pressure since the HPCS System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of the HPCS is therefore verified within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if the HPCS is out of service for maintenance or other reasons. Verification does not require performing the Surveillances needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of the HPCS System cannot be verified, however, Condition B must be immediately entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCS) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming that 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 the similar functions of the HPCS and RCIC, the AOTs (i.e., Completion Times) determined for the HPCS 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 HPCS 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. 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 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 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.

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BASES

**SURVEILLANCE
REQUIREMENTS
(continued)**

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 capability to provide rated flow is tested both at the higher and lower operating ranges of the system. 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. Reactor steam pressure must be \geq [920] psig to perform SR 3.5.3.3 and \geq [150] psig to perform SR 3.5.3.4. Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time 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 test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, 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.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 18 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply just prior to or during startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 18 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 to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.3.5 (continued)

the system to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance test also ensures that 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) trip 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 safety function.

The 18 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 SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
 2. FSAR, Section [5.4.6.2].
 3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary 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. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";
- c. All equipment hatches are closed; and
- d. The pressurized sealing mechanism associated with a penetration is OPERABLE, except as provided in LCO 3.6.1.[].

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BASES

BACKGROUND (continued)

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.

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 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 [0.437]% by weight of the containment and drywell air per 24 hours at the maximum peak containment pressure (P_a) of ([11.5] psig) (Ref. 4).

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

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 10 CFR 50, Appendix J, leakage test. At this time, the combined Type B and C leakage must be $< 0.6 L_a$, and the overall Type A leakage must be $< 0.75 L_a$. Compliance with this LCO will ensure a primary containment

(continued)

BASES

LCO
(continued) configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2.

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

ACTIONS

A.1

In the event that 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 that is 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 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.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. Failure to meet air lock leakage testing (SR 3.6.1.2.1 and SR 3.6.1.2.4), [secondary containment bypass leakage (SR 3.6.1.3.9),] resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.6), or main steam isolation valve leakage (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 10 CFR 50, Appendix J, as modified by approved exemptions (Ref. 3). As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, 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 $\leq 1.0 L_a$. At $\leq 1.0 L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.1.2

The structural integrity of the primary containment is ensured by the successful completion of the Primary Containment Tendon Surveillance Program and by associated visual inspections of the steel liner and penetrations for evidence of deterioration or breach of integrity. This ensures that the structural integrity of the primary containment will be maintained in accordance with the provisions of the Primary Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 5).

REFERENCES

1. FSAR, Section [6.2].
2. FSAR, Section [15.6.5].

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BASES

REFERENCES
(continued)

3. 10 CFR 50, Appendix J.
 4. FSAR, Section [].
 5. Regulatory Guide 1.35, Revision [1].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double door primary containment air locks have been built into the primary containment to provide personnel access to the primary containment 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 lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors has inflatable seals that are maintained > [60] psig by the seal air flask and pneumatic system, which is maintained at a pressure \geq [90] psig. Each door has two seals to ensure they are single failure proof in maintaining the leak tight boundary of primary containment.

Each air lock is nominally a right circular cylinder, 10 ft 2 inches in diameter, 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 air lock that provide control room indication of door position. [Additionally, control room indication is provided to alert the operator whenever an air lock interlock mechanism is defeated.] 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 door 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 primary containment leakage rate to within limits in the event of a

(continued)

BASES

BACKGROUND
(continued)

DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

APPLICABLE
SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of [0.437]% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of [11.5] psig. 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.

Primary containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

As part of the primary containment, 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 each 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 open 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

(continued)

BASES

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

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

ACTIONS The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed 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, then 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 door). The ability 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.

(continued)

BASES

ACTIONS
(continued)

The ACTIONS are modified by a third Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment is exceeding its leakage limit. 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 must be verified closed (Required Action A.1) in each affected air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the 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 with an inoperable door 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 in view of 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 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.

(continued)

BASES

ACTIONS

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

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

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside primary containment that are required by TS or activities on equipment 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. 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 one air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated

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BASES

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

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 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 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. 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.

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BASES

ACTIONS
(continued)

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 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established [during initial air lock and primary containment OPERABILITY testing]. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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 of SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the overall primary containment leakage rate.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.2.2

The seal air flask pressure is verified to be at \geq [90] psig every 7 days to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable through operating experience and is considered adequate in view of the other indications available to operations personnel that the seal air flask pressure is low.

SR 3.6.1.2.3

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. 3), 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 only challenged when the primary containment air lock door is opened, this test is only required to be performed upon entering or exiting a primary containment air lock, but is not required more frequently than once per 184 days. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls [such as indications of interlock mechanism status available to operations personnel].

SR 3.6.1.2.4

A seal pneumatic system test to ensure that pressure does not decay at a rate equivalent to $>$ [2] psig for a period of [48] hours from an initial pressure of [90] psig is an effective leakage rate test to verify system performance. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.2.4 (continued)

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 [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [3.8].
 2. 10 CFR 50, Appendix J.
 3. FSAR, Table [6.2-13].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs 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 the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

The [6] and [20] inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions. The [6] and [20] inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness. The purge valves must be closed when not being used for pressure control, ALARA, or air quality considerations to ensure that the primary containment boundary assumed in the safety analysis will be maintained.

(continued)

BASES (continued)

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 loss of coolant accident (LOCA), a main steam line break (MSLB), and a fuel handling accident inside primary containment (Refs. 1 and 2). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in Reference 1, the MSLB is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 5 second closure time is assumed in the analysis. The safety analyses assume that the purge valves are closed at event initiation. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that within 60 seconds after the accident, isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a . The primary containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times.

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

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

[The purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3. In this case, the single failure criterion remains applicable to the primary containment purge valve due to failure in the control circuit associated with each valve. Again, the primary containment purge valve design precludes a single failure from compromising the primary containment boundary as long as the system is operated in accordance with this LCO.]

PCIVs satisfy Criterion 3 of the NRC Policy Statement.

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. Primary containment purge valves that are not qualified to close under accident conditions must be sealed closed [or blocked to prevent full opening] to be OPERABLE. The valves covered by this LCO are listed with their associated stroke times in the FSAR (Ref. 3).

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 flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 3. Purge valves with resilient seals, secondary bypass valves, MSIVs, and hydrostatically tested 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.

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be sealed closed in MODES 4 and 5. Certain valves are required to be OPERABLE, however, to prevent inadvertent reactor vessel draindown and release of radioactive material during a postulated fuel handling accident. These valves are those whose associated instrumentation is required to be OPERABLE according to 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) [except for the [] inch primary containment purge valve flow path(s)] to be unisolated intermittently under administrative controls. [The primary containment purge valve exception applies to primary containment purge valves that are not qualified to close under accident conditions.] 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. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust directly from the primary containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls. A single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by the exception to SR 3.6.1.3.1 and Note 2 to SR 3.6.1.3.2.

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

(continued)

BASES

ACTIONS
(continued)

subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures 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 are taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable [except for purge valve or secondary containment bypass leakage not within limits], the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period 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 must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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

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

Required Action A.2 is modified by a Note that 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. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable, 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 single active failure.

(continued)

BASES

ACTIONS

B.1 (continued)

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 PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within [4] hours. The [4] hour Completion Time 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. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path 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. The Completion Time of once per 31 days for verifying that 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 this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written

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BASES

ACTIONS

C.1 and C.2 (continued)

specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by a Note that 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. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1

With the secondary containment bypass leakage rate, not within limit, the assumptions of the safety analysis are not met. Therefore, the leakage must be restored to within limit within 4 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 isolation 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 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function.

E.1, E.2, and E.3

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by 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

(continued)

BASES

ACTIONS

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

de-activated automatic valve, closed manual valve, and blind flange]. If a purge valve with resilient seals is utilized to satisfy Required Action E.1 it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are 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 valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from 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 isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the containment purge valve with resilient seal that is isolated in accordance with Required Action E.1, SR 3.6.1.3.6 must be performed at least once every [] days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per [] days was chosen and has been shown acceptable based on operating experience.

(continued)

BASES

ACTIONS
(continued)

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, H.1, I.1, and I.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Also, if applicable, action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending the OPDRVs 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 valves to OPERABLE status. This allows RHR to remain in service while actions are being taken to restore the valve.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.1

Each [] inch primary containment purge valve is required to be verified sealed closed at 31 day intervals. This SR is intended to apply to primary containment purge valves that are not fully qualified to open under accident conditions. This SR is designed to ensure that a gross breach of primary containment is not caused by an inadvertent or spurious opening of a primary containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.1 (continued)

limit offsite doses. Primary containment purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The 31 day Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 5), related to primary containment purge valve use during unit operations.

This SR allows a valve that is open under administrative controls to not meet the SR during the time the valve is open. Opening a purge valve under administrative controls is restricted to one valve in a penetration flow path at a given time (refer to discussion for Note 1 of the ACTIONS) in order to effect repairs to that valve. This allows one purge valve to be opened without resulting in a failure of the Surveillance and resultant entry into the ACTIONS for this purge valve, provided the stated restrictions are met. Condition E must be entered during this allowance, and the valve opened only as necessary for effecting repairs. Each purge valve in the penetration flow path may be alternately opened, provided one remains sealed closed, if necessary, to complete repairs on the penetration.

The SR is modified by a Note stating that primary containment purge valves are only required to be sealed closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves or the release of radioactive material will exceed limits prior to the closing of the purge valves. At other times when the purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization concerns are not present and the purge valves are allowed to be open.

SR 3.6.1.3.2

This SR verifies that the [20] inch primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.2 (continued)

this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits.

The SR is also modified by a Note (Note 1) stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves, or the release of radioactive material will exceed limits prior to the purge valves closing. At other times when the purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies) pressurization concerns are not present and the purge valves are allowed to be open.

The SR is modified by a Note (Note 2) stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided the drywell [purge supply and exhaust] lines are isolated. These primary containment purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other primary containment purge valve requirements discussed in SR 3.6.1.3.1.

SR 3.6.1.3.3

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment, drywell, and steam tunnel, and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.3 (continued)

containment, and capable of being mispositioned, are in the correct position. Since verification of valve position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open.

SR 3.6.1.3.4

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment, drywell, or steam tunnel, and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, drywell, or steam tunnel the Frequency of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low.

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.4 (continued)

under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.5

Verifying the isolation time of each power operated and each 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 analysis. The isolation time and Frequency of this SR are [in accordance with the Inservice Testing Program or 92 days].

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 4), is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining this penetration leak tight (due to the direct path between primary containment and the environment), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

The SR is modified by a Note stating that the primary containment purge valves are only required to meet leakage rate testing requirements in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, purge valve leakage must be minimized to ensure offsite radiological release is within limits. At other times when the purge valves are required to be capable of closing

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.6 (continued)

(e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. The Frequency of this SR is [in accordance with the Inservice Testing Program or 18 months].

SR 3.6.1.3.8

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 SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.9

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 6 are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.9 (continued)

the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J maximum pathway leakage limits are to be quantified in accordance with Appendix J). The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions (and therefore, the Frequency extensions of SR 3.0.2 may not be applied), since the testing is an Appendix J, Type C test. This SR simply imposes additional acceptance criteria.

Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

[Bypass leakage is considered part of L_a . [Reviewer's Note: Unless specifically exempted].]

SR 3.6.1.3.10

The analyses in References 2 and 3 are based on leakage that is less than the specified leakage rate. Leakage through all four MSIVs must be \leq [100] scfh when tested at P_t ([11.5] psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference 4, as modified by approved exemptions. Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 4), as modified by approved

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.10 (continued)

exemptions; thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of References 2 and 3 are met. The combined leakage rates must be demonstrated to be in accordance with the leakage test frequency of Reference 4, as modified by approved exemptions; thus SR 3.0.2 (which allows Frequency extensions) does not apply.

[This SR is modified by a Note that states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.]

SR 3.6.1.3.12

Reviewer's Note: This SR is only required for those plants with purge valves with resilient seals allowed to be open during [MODE 1, 2, or 3] and having blocking devices on the valves that are not permanently installed.

Verifying that each [] inch primary containment purge valve is blocked to restrict opening to \leq [50%] is required to ensure that the valves can close under DBA conditions within the time limits assumed in the analyses of References 2 and 3.

The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.12 (continued)

concerns are not present, thus the purge valves can be fully open. The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

REFERENCES

1. FSAR, Chapter [15].
 2. FSAR, Section [6.2].
 3. FSAR, [Table 6.2-44].
 4. 10 CFR 50, Appendix J.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Primary Containment Pressure

BASES

BACKGROUND

The primary containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

The limits on primary containment [to secondary containment differential] pressure have been developed based on operating experience. The auxiliary building, which is part of the secondary containment, completely surrounds the lower portion of the primary containment. Therefore, the primary containment design external differential pressure, and consequently the Specification limit, are established relative to the auxiliary building pressure. The auxiliary building pressure is kept slightly negative relative to the atmospheric pressure to prevent leakage to the atmosphere.

Transient events, which include inadvertent containment spray initiation, can reduce the primary containment pressure (Ref. 1). Without an appropriate limit on the negative containment pressure, the design limit for negative internal pressure of [-3.0] psid could be exceeded. Therefore, the Specification pressure limits of [-0.1 and 1.0 psid] were established (Ref. 2).

The limitation on the primary [to secondary containment differential] pressure provides added assurance that the peak LOCA primary containment pressure does not exceed the design value of 15 psig (Ref. 1).

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 3). Among the inputs to the design basis analysis is the initial primary containment internal pressure. The primary containment [to secondary containment differential] pressure can affect the initial containment internal pressure. The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 15 psig and that peak negative pressure for an inadvertent

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

containment spray event does not exceed the design value of [-3.0] psid.

Primary containment pressure satisfies Criterion 2 of the NRC Policy Statement.

LCO

A limitation on the primary [to secondary containment differential] pressure of [≥ -0.1 and ≤ 1.0 psid] is required to ensure that primary containment initial conditions are consistent with the initial safety analyses assumptions so that containment pressures remain within design values during a LOCA and the design value of containment negative pressure is not exceeded during an inadvertent operation of containment sprays.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in 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 primary containment pressure within limits is not required in MODE 4 or 5.

ACTIONS

A.1

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

B.1 and B.2

If primary [to secondary containment differential] pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 primary containment [to secondary containment differential] pressure is within limits ensures that operation remains within the limits assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending primary containment 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 primary containment pressure condition.

REFERENCES

1. FSAR, Section [6.2.1.].
 2. FSAR, Section [6.2.1.1.4.2].
 3. FSAR, Section [6.2].
-
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Primary Containment Air Temperature

BASES

BACKGROUND

Heat loads from the drywell, as well as piping and equipment in the primary containment, add energy to the primary containment airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature inside primary containment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This primary containment air temperature limit is an initial condition input for the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial primary containment average air temperature. Analyses assume an initial average primary containment air (and suppression pool) temperature of [95]°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA primary containment temperature does not exceed the maximum allowable temperature of 185°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident.

Primary containment air temperature satisfies Criterion 2 of the NRC Policy Statement.

LCO

With an initial primary containment average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the primary containment design temperature. As a result, the ability of

(continued)

BASES

LCO
(continued) 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 reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining primary containment average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

When primary containment average air temperature is not within the limit of the LCO, it must be restored within 8 hours. This 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 primary containment average air temperature 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 3.6.1.5.1

Verifying that the primary containment average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.5.1 (continued)

containment analyses. In order to determine the primary containment average air temperature, an arithmetic average is calculated, using measurements taken at locations within the primary containment selected to provide a representative sample of the overall primary containment atmosphere.

The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within primary containment as a result of environmental heat sources (due to large volume of the primary containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal primary containment air temperature condition.

REFERENCES

1. FSAR, Section [6.2].
-
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low-Low Set (LLS) Valves

BASES

BACKGROUND

The safety/relief valves (S/RVs) can actuate either in the relief mode, the safety mode, the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcome the spring force and open the pilot valve. As in the safety mode, opening the pilot valve allows a differential pressure to develop across the main valve piston and thus opens the main valve. The main valve can stay open with valve inlet steam pressure as low as [0] psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.

[Six] of the S/RVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and stay open longer, such that reopening of more than one S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short duration S/RV cycles with valve actuation at the relief setpoint.

Each S/RV discharges steam through a discharge line and quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load.

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of one S/RV operating on "subsequent actuations" is met (Ref. 1). In other words, multiple simultaneous openings of S/RVs (following the initial opening) and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis Accidents (DBAs). Furthermore, the LLS function justifies the primary containment analysis assumption that multiple simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though [six]

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

LLS S/RVs are specified, all [six] LLS S/RVs do not operate in any DBA analysis.

LLS valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

[Six] LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 2). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.

APPLICABILITY

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

ACTIONS

A.1

With one LLS valve inoperable, the remaining OPERABLE LLS valves are adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS S/RVs and the low probability of an event in which the remaining LLS S/RV capability would be inadequate.

B.1 and B.2

If two or more LLS valves are inoperable or if the inoperable LLS valve 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Adequate pressure at which this test is to be performed is $\geq [950]$ psig (the pressure recommended by the valve manufacturer). 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. Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow $\geq 10^6$ lb/hr]. The [18] month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 3). The Frequency of [18] months on a STAGGERED TEST BASIS ensures that each solenoid for each S/RV is alternately tested. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Since steam pressure is required in order to perform the Surveillance, however, and steam may not be available during a unit outage, the Surveillance may be performed during the shutdown prior to or the startup following a unit outage. Unit startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 3 prior to valve installation. After adequate reactor steam dome pressure and flow are reached, 12 hours are allowed to prepare for and perform the test.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.6.2

The LLS designed S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.5.4 overlaps this SR to provide complete testing of the safety function.

The 18 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 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

REFERENCES

- [1. GESSAR-II, Appendix 3BA.8.]
 2. FSAR, Section [5.5.17].
 3. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage and low energy line breaks.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, a heat exchanger, and three spray spargers inside the primary containment (outside of the drywell) above the refueling floor. Dispersion of the spray water is accomplished by 350 nozzles in each subsystem.

The RHR containment spray mode will be automatically initiated, if required, following a LOCA, or it may be manually initiated according to emergency procedures.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be $[0.9] \text{ ft}^2$. The analysis demonstrates that

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

with containment spray operation the primary containment pressure remains within design limits.

The RHR Containment Spray System satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a Design Basis Accident (DBA), a minimum of one RHR containment spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below design limits. To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

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

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR containment spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1 and C.2

If the inoperable RHR containment spray subsystem 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 3.6.1.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system 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. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR is justified because the valves are operated under procedural control and because improper valve position would affect only a single subsystem. This Frequency has been shown to be acceptable based on operating experience.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.7.1 (continued)

A Note has been added to this SR that allows RHR containment spray subsystems to be considered OPERABLE during alignment to and operation in the RHR shutdown cooling mode when below [the RHR cut in permissive pressure in MODE 3], if capable of being manually realigned and not otherwise inoperable. At these low pressures and decay heat levels (the reactor is shut down in MODE 3), a reduced complement of subsystems can provide the required containment pressure mitigation function thereby allowing operation of an RHR shutdown cooling loop when necessary.

SR 3.6.1.7.2

Verifying each RHR pump develops a flow rate \geq [5650] gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. [The Frequency of this SR is in accordance with the Inservice Testing Program or 92 days.]

SR 3.6.1.7.3

This SR verifies that each RHR containment spray subsystem automatic valve actuates to its correct position upon receipt of an actual or simulated automatic actuation signal. Actual spray initiation is not required to meet this SR. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.6 overlaps this SR to provide complete testing of the safety function. The [18] 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.7.3 (continued)

the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.7.4

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

REFERENCES

1. FSAR, Section [6.2.1.1.5].
 2. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Penetration Valve Leakage Control System (PVLCS)

BASES

BACKGROUND

The PVLCS supplements the isolation function of primary containment isolation valves (PCIVs) in process lines that also penetrate the secondary containment. These penetrations are sealed by air from the PVLCS to prevent fission products leaking past the isolation valves and bypassing the secondary containment after a Design Basis Accident (DBA) loss of coolant accident (LOCA).

The PVLCS consists of [two] independent, manually initiated subsystems, either of which is capable of preventing fission product leakage from the containment post LOCA. Each subsystem is comprised of an air compressor, an accumulator, an injection valve, and three injection headers with separate isolation valves. This system has additional headers, which serve the Main Steam Isolation Valve Leakage Control System and safety/relief valve (S/RV) actuator air accumulators.

Each process line has two PCIVs and an additional manual isolation valve outside of the outboard PCIV. The two outboard valves are double disk gate valves. Each valve is provided sealing air from its electrically associated division of PVLCS to the area between the dual disk seats. The PVLCS is started manually.

APPLICABLE SAFETY ANALYSES

The analyses described in Reference 1 provide the evaluation of offsite dose consequences during accident conditions. During the first 25 minutes following an accident, the isolation valves on lines that penetrate primary containment and also penetrate secondary containment are assumed to leak fission products directly to the environment, without being processed by the Standby Gas Treatment System. The analyses take credit for manually initiating PVLCS after 25 minutes and do not assume any further secondary containment bypass leakage.

The PVLCS satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO [Two] PVLCS subsystems must be OPERABLE such that in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A PVLCS subsystem is OPERABLE when all necessary components are available to supply each associated dual seat isolation valve with sufficient air pressure to preclude containment leakage when the containment atmosphere is at the maximum peak containment pressure, P_a .

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 PVLCS is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

With one PVLCS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE PVLCS subsystem is adequate to perform the leakage control function. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA, the amount of time available after the event for operator action to prevent exceeding this limit, the low probability of failure of the OPERABLE PVLCS subsystem, and the availability of the PCIVs.

B.1

With [two] PVLCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA, the availability of 25 minutes for operator action, and the availability of the PCIVs.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable PVLCS subsystem 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 3.6.1.8.1

The minimum air supply necessary for PVLCS OPERABILITY varies with the system being supplied with compressed air from the PVLCS accumulators. Due to the support system function of PVLCS for S/RV actuator air, however, the specified minimum pressure of [101] psig is required, which provides sufficient air for [] S/RV actuations with the drywell pressure at 30 psig. This minimum air pressure alone is sufficient for PVLCS to support the OPERABILITY of these S/RV systems and is verified every 24 hours. The 24 hour Frequency is considered adequate in view of other indications available in the control room, such as alarms, to alert the operator to an abnormal PVLCS air pressure condition.

SR 3.6.1.8.2

A simulated system operation is performed every [18] months to ensure that the PVLCS will function throughout its operating sequence. This includes correct automatic positioning of valves once the system is initiated manually. Proper functioning of the compressor and valves is verified by this Surveillance. The [18] month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES 1. FSAR, Section [15.6.5].

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.9 Main Steam Isolation Valve (MSIV) Leakage Control System (LCS)

BASES

BACKGROUND

The MSIV LCS supplements the isolation function of the MSIVs by processing the fission products that could leak through the closed MSIVs after a Design Basis Accident (DBA) loss of coolant accident (LOCA).

The MSIV LCS consists of two independent subsystems: an inboard subsystem, which is connected between the inboard and outboard MSIVs; and an outboard subsystem, which is connected immediately downstream of the outboard MSIVs. Each subsystem is capable of processing leakage from MSIVs following a DBA LOCA. Each subsystem consists of blowers (four blowers for the inboard subsystem and two blowers for the outboard subsystem), valves, piping, and heaters (for the inboard subsystem only). The four electric heaters in the inboard subsystem are provided to boil off any condensate prior to the gas mixture passing through the flow limiter.

Each subsystem operates in two process modes: depressurization and bleedoff. The depressurization process reduces the steam line pressure to within the operating capability of equipment used for the bleedoff mode. During bleedoff (long term leakage control), the blowers maintain a negative pressure in the main steam lines (Ref. 1). This ensures that leakage through the closed MSIVs is collected by the MSIV LCS. In both process modes, the effluent is discharged to the auxiliary building, which encloses a volume served by the Standby Gas Treatment (SGT) System.

The MSIV LCS is manually initiated approximately 20 minutes following a DBA LOCA (Ref. 2).

APPLICABLE SAFETY ANALYSES

The MSIV LCS mitigates the consequences of a DBA LOCA by ensuring that fission products that may leak from the closed MSIVs are diverted to the auxiliary building and ultimately filtered by the SGT System. The analyses in Reference 3 provide the evaluation of offsite dose consequences. The operation of the MSIV LCS prevents a release of untreated leakage for this type of event.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

The MSIV LCS satisfies Criterion 3 of the NRC Policy Statement.

LCO

One MSIV LCS subsystem can provide the required processing of the MSIV leakage. To ensure that this capability is available, assuming worst case single failure, two MSIV LCS subsystems must be OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment. Therefore, MSIV LCS OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the MSIV LCS OPERABLE is not required in MODE 4 or 5 to ensure MSIV leakage is processed.

ACTIONS

A.1

With one MSIV LCS subsystem inoperable, the inoperable MSIV LCS subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE MSIV LCS subsystem is adequate to perform the required leakage control function. However, the overall reliability is reduced because a single failure in the remaining subsystem could result in a total loss of MSIV leakage control function. The 30 day Completion Time is based on the redundant capability afforded by the remaining OPERABLE MSIV LCS subsystem and the low probability of a DBA LOCA occurring during this period.

B.1

With two MSIV LCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA.

(continued)

BASES

ACTIONS
(continued)

C.1 and C.2

If the MSIV LCS subsystem 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 3.6.1.9.1

Each MSIV LCS blower is operated for \geq [15] minutes to verify OPERABILITY. The 31 day Frequency was developed considering the known reliability of the LCS blower and controls, the two subsystem redundancy, and the low probability of a significant degradation of the MSIV LCS subsystem occurring between surveillances and has been shown to be acceptable through operating experience.

SR 3.6.1.9.2

The electrical continuity of each inboard MSIV LCS subsystem heater is verified by a resistance check, by verifying the rate of temperature increase meets specifications, or by verifying the current or wattage draw meets specifications. The 31 day Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

SR 3.6.1.9.3

A system functional test is performed to ensure that the MSIV LCS will operate through its operating sequence. This includes verifying that the automatic positioning of the valves and the operation of each interlock and timer are correct, that the blowers start and develop the required flow rate and the necessary vacuum, and the upstream heaters meet current or wattage draw requirements (if not used to verify electrical continuity in SR 3.6.1.9.2). The 18 month

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.9.3 (continued)

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 [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [6.7].
 2. Regulatory Guide 1.96, Revision [1].
 3. FSAR, Section [15.6.5].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression pool is a concentric open container of water with a stainless steel liner that is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The amount of energy that the pool can absorb as it condenses steam is dependent upon the initial average suppression pool temperature. The lower the initial pool temperature, the more heat it can absorb without heating up excessively. Since it is an open pool, its temperature will affect both primary containment pressure and average air temperature. Using conservative inputs and methods, the maximum calculated primary containment pressure during and following a Design Basis Accident (DBA) must remain below the primary containment design pressure of [15] psig. In addition, the maximum primary containment average air temperature must remain < [185]°F.

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

- a. Complete steam condensation [—the original limit for the end of a LOCA blowdown was 170°F, based on the Bodega Bay and Humboldt Bay Tests];
- b. Primary containment peak pressure and temperature [—the design pressure is [15] psig and design temperature is [185]°F];
- c. Condensation oscillation (CO) loads [—a maximum allowable initial temperature of [100]°F ensures that CO loads do not exceed the Mark III CO load definition]; and
- d. Chugging loads [—a maximum allowable initial temperature of [100]°F ensures that expected LOCA

(continued)

BASES

BACKGROUND
(continued)

temperatures are within the range of Mark III tested conditions].

APPLICABLE
SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the suppression pool temperature analyses required by Reference 3). An initial pool temperature of [95]°F is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of [110]°F and vessel depressurization at a pool temperature of [120]°F are assumed for the Reference 2 analyses. The limit of [105]°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of the NRC Policy Statement.

LCO

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

- a. Average temperature \leq [95]°F when any OPERABLE intermediate range monitor (IRM) channel is $>$ [25/40] divisions of full scale on Range 7 and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.
- b. Average temperature \leq [105]°F when any OPERABLE IRM channel is $>$ [25/40] divisions of full scale on Range 7 and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was

(continued)

BASES

LCO (continued)

selected to provide margin below the $[110]^{\circ}\text{F}$ limit at which reactor shutdown is required. When testing ends, temperature must be restored to $\leq [95]^{\circ}\text{F}$ within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is $> [95]^{\circ}\text{F}$ is short enough not to cause a significant increase in plant risk.

- c. Average temperature $\leq [110]^{\circ}\text{F}$ when all OPERABLE IRM channels are $\leq [25/40]$ divisions of full scale on Range 7. This requirement ensures that the plant will be shut down at $> [110]^{\circ}\text{F}$. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

Note that $[25/40]$ divisions of full scale on IRM Range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP. At this power level, heat input is approximately equal to normal system heat losses.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1 and 3 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is $> [95]^{\circ}\text{F}$,

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

increased monitoring of the pool temperature is required to ensure it remains $\leq [110]^{\circ}\text{F}$. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to $\leq [25/40]$ divisions of full scale on Range 7 for all OPERABLE IRM channels within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be $> [95]^{\circ}\text{F}$ with any OPERABLE IRM channel $> [25/40]$ divisions of full scale on Range 7 when testing that adds heat to the suppression pool is being performed. However, if temperature is $> [105]^{\circ}\text{F}$, the testing must be immediately suspended to preserve the pool's heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature $> [110]^{\circ}\text{F}$ requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 is required at normal cooldown

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

rates (provided pool temperature remains $\leq [120]^{\circ}\text{F}$). Additionally, when pool temperature is $> [110]^{\circ}\text{F}$, increased monitoring of pool temperature is required to ensure that it remains $\leq [120]^{\circ}\text{F}$. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained $\leq [120]^{\circ}\text{F}$, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to $< [200]$ psig within 12 hours and the plant must be brought 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 without challenging plant systems.

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

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of the OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.1.1 (continued)

is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. FSAR, Section [6.2].
 2. FSAR, Section [15.2].
 3. NUREG-0783.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression pool is a concentric open container of water with a stainless steel liner, which is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling (RCIC) System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between [135,291] ft³ at the low water level limit of [18 ft 4.5 inches] and [138,701] ft³ at the high water level limit of [18 ft 9.75 inches].

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

If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive pool swell loads resulting from a Design Basis Accident (DBA) LOCA. An inadvertent upper pool dump could also overflow the weir wall into the drywell. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

within the limits specified so that the safety analysis of Reference 1 remains valid.

Suppression pool water level satisfies Criteria 2 and 3 of the NRC Policy Statement.

LCO

A limit that suppression pool water level be \geq [18 ft 4.5 inches] and \leq [18 ft 9.75 inches] is required to ensure that the primary containment conditions assumed for the safety analysis are met. Either the high or low water level limits were used in the safety analysis, depending upon which is conservative for a particular calculation.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced because of the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS-Shutdown."

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as main vents are covered, RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis or as long as the drywell sprays are OPERABLE. Prompt action to restore the suppression pool water level to within the normal range is prudent, however, to retain the margin to weir wall overflow from an inadvertent upper pool dump and reduce the risks of increased pool swell and dynamic loading. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within specified limits. Also, it takes

(continued)

BASES

ACTIONS

A.1 (continued)

into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency of this SR was developed considering operating experience related to trending variations in suppression pool water level and water level instrument drift during the applicable MODES and to assessing the proximity to the specified LCO level limits. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.

REFERENCES

1. FSAR, Section [6.2].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

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

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

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to [185]°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

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

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

suppression pool temperature is calculated to remain below the design limit.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of the NRC Policy Statement.

LCO

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

APPLICABILITY

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

ACTIONS

A.1

With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool

(continued)

BASES

ACTIONS

A.1 (continued)

cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the Required Action and required Completion Time of Condition A cannot be met or if two RHR suppression pool cooling subsystems 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 at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.3.1 (continued)

has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate \geq [7450] gpm, while operating in the suppression pool cooling mode with flow through the associated heat exchanger at least every 92 days, ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Section XI (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is [in accordance with the Inservice Testing Program or 92 days].

REFERENCES

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

B 3.6.2.4 Suppression Pool Makeup (SPMU) System

BASES

BACKGROUND

The function of the SPMU System is to transfer water from the upper containment pool to the suppression pool after a loss of coolant accident (LOCA). For a LOCA, with Emergency Core Cooling System injection from the suppression pool, a large volume of water can be held up in the drywell behind the weir wall. This holdup can significantly lower suppression pool water level. The water transfer from the SPMU System ensures a post LOCA suppression pool vent coverage of ≥ 2 ft above the top of the top row vents so that long term steam condensation is maintained. The additional makeup water is used as part of the long term suppression pool heat sink. The post LOCA delayed transfer of this water to the suppression pool provides an initially low vent submergence, which results in lower drywell pressure loading and lower pool dynamic loading during a Design Basis Accident (DBA) LOCA as compared to higher vent submergence. The sizing of the residual heat removal heat exchanger takes credit for the additional SPMU System water mass in the calculation of the post LOCA peak containment pressure and suppression pool temperature.

The required water dump volume from the upper containment pool is equal to the difference between the total post LOCA drawdown volume and the assumed volume loss from the suppression pool. The total drawdown volume is the volume of suppression pool water that can be entrapped outside of the suppression pool following a LOCA. The post LOCA entrapment volumes causing suppression pool level drawdown include:

- a. The free volume inside and below the top of the drywell weir wall;
- b. The added volume required to fill the reactor pressure vessel from a condition of normal power operation to a post accident complete fill of the vessel, including the top dome;
- c. The volume in the steam lines out to the inboard main steam isolation valve (MSIV) on three lines and out to the outboard MSIV on one line; and

(continued)

BASES

BACKGROUND (continued)

- d. Allowances for primary containment spray holdup on equipment and structural surfaces.

The SPMU System consists of two redundant subsystems, each capable of dumping the makeup volume from the upper containment pool to the suppression pool by gravity flow. Each dump line includes two normally closed valves in series. The upper pool is dumped automatically on a suppression pool water level Low-Low signal (with a LOCA signal permissive) or on the basis of a timer following a LOCA signal alone to ensure that the makeup volume is available as part of the long term energy sink for small breaks that might not cause dump on a suppression pool water level Low-Low signal. A 30 minute timer was chosen, since the initial suppression pool mass is adequate for any sequence of vessel blowdown energy and decay heat up to at least 30 minutes.

Although the minimum freeboard distance above the suppression pool high water level limit of LCO 3.6.2.2, "Suppression Pool Water Level," to the top of the weir wall is adequate to preclude flooding of the drywell, a LOCA permissive signal is used to prevent an erroneous suppression pool level signal from causing pool dump. In addition, the SPMU System mode switch may be keylocked in the "OFF" position to ensure that inadvertent dump will not occur. Inadvertent actuation of the SPMU System during MODE 4 or 5 could create a radiation hazard to plant personnel due to a loss of shield water from the upper pool if irradiated fuel were in an elevated position.

APPLICABLE SAFETY ANALYSES

Analyses used to predict suppression pool temperature following large and small break LOCAs, which are the applicable DBAs for the SPMU System, are contained in References 1 and 2. During these events, the SPMU System is relied upon to dump upper containment pool water to maintain drywell horizontal vent coverage and an adequate suppression pool heat sink volume to ensure that the primary containment internal pressure and temperature stay within design limits. The analysis assumes an SPMU System dump volume of [36,380] ft³ at a temperature of [125] F.

The SPMU System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO During a DBA, a minimum of one SPMU subsystem is required to maintain peak suppression pool water temperature below the design limits (Ref. 1). To ensure that these requirements are met, two SPMU subsystems must be OPERABLE with power from two independent safety related power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. The SPMU System is OPERABLE when the upper containment pool water temperature is $\leq [125]^{\circ}\text{F}$, the water level is $\geq [23 \text{ ft } 3 \text{ inches}]$, gates are in the stored condition, the piping is intact, and the system valves are OPERABLE. The above temperature and water level conditions correspond to an SPMU System available dump volume of $\geq [36,380] \text{ ft}^3$.

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

ACTIONS A.1

When upper containment pool water level is $< [23 \text{ ft } 3 \text{ inches}]$, the volume is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. A sufficient quantity of water is necessary to ensure long term energy sink capabilities of the suppression pool and maintain water coverage over the uppermost drywell vents. Loss of water volume has a relatively large impact on heat sink capability. Therefore, the upper containment pool water level must be restored to within limit within 4 hours. The 4 hour Completion Time is sufficient to provide makeup water to the upper containment pool to restore level within specified limit. Also, it takes into account the low probability of an event occurring that would require the SPMU System.

(continued)

BASES

ACTIONS
(continued)

B.1

When upper containment pool water temperature is $> [125]^{\circ}\text{F}$, the heat absorption capacity is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. Increased temperature has a relatively smaller impact on heat sink capability. Therefore, the upper containment pool water temperature must be restored to within limit within 24 hours. The 24 hour Completion Time is sufficient to restore the upper containment pool to within the specified temperature limit. It also takes into account the low probability of an event occurring that would require the SPMU System.

C.1

With one SPMU subsystem inoperable for reasons other than Condition A or B, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is acceptable in light of the redundant SPMU System capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

D.1 and D.2

If any Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.1

The upper containment pool water level is regularly monitored to ensure that the required limits are satisfied. The 24 hour Frequency of this SR was developed, considering operating experience related to upper containment pool water level variations and water level instrument drift during the applicable MODES and considering the low probability of a

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.1 (continued)

DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal upper containment pool water level condition.

SR 3.6.2.4.2

The upper containment pool water temperature is regularly monitored to ensure that the required limit is satisfied. The 24 hour Frequency was developed, based on operating experience related to upper containment pool temperature variations during the applicable MODES.

SR 3.6.2.4.3

Verifying the correct alignment for manual, power operated, and automatic valves in the SPMU System flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to being locked, sealed, or secured. 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 Frequency of 31 days is justified because the valves are operated under procedural control and because improper valve position would affect only a single subsystem. This Frequency has been shown to be acceptable through operating experience.

SR 3.6.2.4.4

The upper containment pool has two gates used to separate the pool into distinct sections to facilitate fuel transfer and maintenance during refueling operations and two additional gates in the separator pool weir wall extension,

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.4 (continued)

which, when installed, limit personnel exposure and ensure adequate water submergence of the separator when the separator is stored in the pool. The SPMU System dump line penetrations are located in the steam separator storage section of the pool. To provide the required SPMU System dump volume to the suppression pool, the gates must be removed (or placed in their stored position) to allow communication between the various pool sections. The 31 day Frequency is appropriate because the gates are moved under procedural control and only the infrequent movement of these gates is required in MODES 1, 2, and 3.

SR 3.6.2.4.5

This SR requires a verification that each SPMU subsystem automatic valve actuates to its correct position on receipt of an actual or simulated automatic initiation signal. This includes verification of the correct automatic positioning of the valves and of the operation of each interlock and timer. As noted, actual makeup to the suppression pool may be excluded. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.6 overlaps this SR to provide complete testing of the safety function. The [18] 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 [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [6.2].
 2. FSAR, Chapter [15].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombinder eliminates the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombinder is required to reduce the hydrogen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombinder accomplishes this by recombining hydrogen and oxygen to form water vapor. The vapor remains in the primary containment, thus eliminating any discharge to the environment. The primary containment hydrogen recombinder is manually initiated, since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent primary containment hydrogen recombinder subsystems are provided. Each consists of controls located in the control room, a power supply, and a recombinder located in primary containment. The recombiners have no moving parts. Recombination is accomplished by heating a hydrogen air mixture to $> [1150]^{\circ}\text{F}$. The resulting water vapor and discharge gases are cooled prior to discharge from the unit. Air flows through the unit at $[100]$ cfm, with natural circulation in the unit providing the motive force. A single recombinder is capable of maintaining the hydrogen concentration in primary containment below the 4.0 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombinder is powered from a separate Engineered Safety Feature bus and is provided with separate power panel and control panel.

Emergency operating procedures direct that the hydrogen concentration in primary containment be monitored following a DBA and that the primary containment hydrogen recombinder be manually activated to prevent the primary containment atmosphere from reaching a bulk hydrogen concentration of 4.0 v/o.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The primary containment hydrogen recombiner provides the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

- a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or
- b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with plant procedures, the peak hydrogen concentration in the primary containment remains < 4 v/o (Ref. 4).

The primary containment hydrogen recombiners satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner in the event of a worst case single active failure.

Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

(continued)

BASES (continued)

APPLICABILITY In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen concentration within primary containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure.

In MODE 3, both the hydrogen production rate and the total hydrogen production after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiner is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiner is not required in these MODES.

ACTIONS

A.1

With one primary containment hydrogen recombiner inoperable, the inoperable primary containment hydrogen recombiner must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE primary containment recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent hydrogen accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability

(continued)

BASES

ACTIONS

A.1 (continued)

limit, the low probability of the failure of the OPERABLE recombinder, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1 and B.2

Reviewer's Note: This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by [one division of the hydrogen ignitors]. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. [Reviewer's Note: The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability.] [Both] the [initial] verification [and all subsequent verifications] may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

BASES

ACTIONS
(continued)

C.1

If any Required Action and required 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. 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 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater sheath temperature increases to $\geq [1200]^{\circ}\text{F}$ in $\leq [5]$ hours and that it is maintained $> [1150]$ and $< [1300]^{\circ}\text{F}$ for $\geq [4]$ hours to check the capability of the recombiner to properly function (and that significant heater elements are not burned out).

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.2

This SR ensures that there are no physical problems that could affect primary containment hydrogen recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failures involve loss of power, blockage of the internal flow path, missile impact, etc. A visual inspection is sufficient to determine abnormal conditions that could cause such failures.

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.3.1.3

This SR requires performance of a resistance to ground test of each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is $\geq [10,000]$ ohms.

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50.44.
 2. 10 CFR 50, Appendix A, GDC 41.
 3. Regulatory Guide 1.7, Revision [1].
 4. FSAR, Section [6.2.5].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment and Drywell Hydrogen Ignitors

BASES

BACKGROUND

The primary containment and drywell hydrogen ignitors are a part of the combustible gas control required by 10 CFR 50.44 (Ref. 1) and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), to reduce the hydrogen concentration in the primary containment following a degraded core accident. The hydrogen ignitors ensure the combustion of hydrogen in a manner such that containment overpressure failure is prevented as a result of a postulated degraded core accident.

10 CFR 50.44 (Ref. 1) requires boiling water reactor units with Mark III containments to install suitable hydrogen control systems. The hydrogen ignitors are installed to accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water. This requirement was placed on reactor units with Mark III containments because they were not designed for inerting and because of their low design pressure. Calculations indicate that if hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water were to collect in primary containment, the resulting hydrogen concentration would be far above the lower flammability limit such that, without the hydrogen ignitors, if the hydrogen were ignited from a random ignition source, the resulting hydrogen burn would seriously challenge the primary containment.

The hydrogen ignitors are based on the concept of controlled ignition using thermal ignitors designed to be capable of functioning in a post accident environment, seismically supported and capable of actuation from the control room. Ignitors are distributed throughout the [32] regions of the drywell and primary containment in which hydrogen could be released or to which it could flow in significant quantities. The hydrogen ignitors are arranged in two independent divisions such that each containment region has two ignitors, one from each division, controlled and powered redundantly so that ignition would occur in each region even if one division failed to energize.

(continued)

BASES

BACKGROUND
(continued)

When the hydrogen ignitors are energized they heat up to a surface temperature $\geq [1700]^{\circ}\text{F}$. At this temperature, they ignite the hydrogen gas that is present in the airspace in the vicinity of the ignitor. The hydrogen ignitors depend on the dispersed location of the ignitors so that local pockets of hydrogen at increased concentrations would burn before reaching a hydrogen concentration significantly higher than the lower flammability limit. Hydrogen ignition in the vicinity of the ignitors is assumed to occur when the local hydrogen concentration reaches [8.0] volume percent (v/o) and results in [85]% of the hydrogen present being consumed.

APPLICABLE
SAFETY ANALYSES

The hydrogen ignitors cause hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 3). Burning occurs at the lower flammability concentration, where the resulting temperatures and pressures are relatively benign. Without the system, hydrogen could build up to higher concentrations that could result in a violent reaction if ignited by a random ignition source after such a buildup.

The hydrogen ignitors are not included for mitigation of a Design Basis Accident (DBA) because an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water is far in excess of the hydrogen calculated for the limiting DBA loss of coolant accident (LOCA). The hydrogen concentration resulting from a DBA can be maintained less than the flammability limit using the hydrogen recombiners. However, the hydrogen ignitors have been shown by probabilistic risk analysis to be a significant contributor to limiting the severity of accident sequences that are commonly found to dominate risk for units with Mark III containment.

The hydrogen ignitors are considered to be risk significant in accordance with the NRC Policy Statement.

LCO

Two divisions of primary containment and drywell hydrogen ignitors must be OPERABLE, each with more than 90% of the ignitors OPERABLE.

(continued)

BASES

LCO
(continued) This ensures operation of at least one ignitor division, with adequate coverage of the primary containment and drywell, in the event of a worst case single active failure. This will ensure that the hydrogen concentration remains near 4.0 v/o.

APPLICABILITY In MODES 1 and 2, the hydrogen ignitor is required to control hydrogen concentration to near the flammability limit of 4.0 v/o following a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding. The control of hydrogen concentration prevents overpressurization of the primary containment. The event that could generate hydrogen in quantities sufficiently high enough to exceed the flammability limit is limited to MODES 1 and 2.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a degraded core accident would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the hydrogen ignitor is low. Therefore, the hydrogen ignitor is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a degraded core accident are reduced due to the pressure and temperature limitations. Therefore, the hydrogen ignitors are not required to be OPERABLE in MODES 4 and 5 to control hydrogen.

ACTIONS

A.1

With one hydrogen ignitor division inoperable, the inoperable division must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE hydrogen ignitor division is adequate to perform the hydrogen burn function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of

(continued)

BASES

ACTIONS

A.1 (continued)

75% of the core cladding, the amount of time available after the event for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the low probability of failure of the OPERABLE hydrogen ignitor division.

Required Action A.1 has been modified by a Note indicating the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one hydrogen ignitor division is inoperable or when one or more areas with adjacent ignitors are inoperable. The allowance is provided because of the low probability of the occurrence of an event that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of both hydrogen ignitor divisions or adjacent ignitors, and the amount of time available after the event for operator action to prevent exceeding the flammability limit.

B.1 and B.2

With two primary containment and drywell ignitor divisions inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by one hydrogen recombiner and one drywell purge subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control capabilities. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control capabilities. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two ignitor divisions inoperable for up to 7 days. Seven days is a reasonable time to allow two ignitor divisions to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

BASES

ACTIONS
(continued)

C.1

If any Required Action and required 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. 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 3.6.3.2.1 and SR 3.6.3.2.2

These SRs verify that there are no physical problems that could affect the ignitor operation. Since the ignitors are mechanically passive, they are not subject to mechanical failure. The only credible failures are loss of power or burnout. The verification that each required ignitor is energized is performed by circuit current versus voltage measurement.

The Frequency of 184 days has been shown to be acceptable through operating experience because of the low failure occurrence, and provides assurance that hydrogen burn capability exists between the more rigorous 18 month Surveillances. Operating experience has shown these components usually pass the Surveillance when performed at a 184 day Frequency. Additionally, these surveillances must be performed every 92 days if four or more ignitors in any division are inoperable. The 92 day Frequency was chosen, recognizing that the failure occurrence is higher than normal. Thus, decreasing the Frequency from 184 days to 92 days is a prudent measure, since only two more inoperable ignitors (for a total of six) will result in an inoperable ignitor division. SR 3.6.3.2.2 is modified by a Note that indicates that the Surveillance is not required to be performed until 92 days after four or more ignitors in the division are discovered to be inoperable.

SR 3.6.3.2.3 and SR 3.6.3.2.4

These functional tests are performed every 18 months to verify system OPERABILITY. The current draw to develop a

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.3.2.3, and SR 3.6.3.2.4 (continued)

surface temperature of $\geq 1700^{\circ}\text{F}$ is verified for ignitors in inaccessible areas, e.g., in a high radiation area. Additionally, the surface temperature of each accessible ignitor is measured to be $\geq 1700^{\circ}\text{F}$ to demonstrate that a temperature sufficient for ignition is achieved. The 18 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 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50.44.
 2. 10 CFR 50, Appendix A, GDC 41.
 3. FSAR, Section [6.2.5].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 [Drywell Purge System]

BASES

BACKGROUND

The [Drywell Purge System] ensures a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The [Drywell Purge System] is an Engineered Safety Feature and is designed to operate following a loss of coolant accident (LOCA) in post accident environments without loss of function. The system has two independent subsystems, each consisting of a compressor and associated valves, controls, and piping. Each subsystem is sized to pump [500] scfm. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

Following a LOCA, the drywell is immediately pressurized due to the release of steam into the drywell environment. This pressure is relieved by the lowering of the water level within the weir wall, clearing the drywell vents and allowing the mixture of steam and noncondensibles to flow into the primary containment through the suppression pool, removing much of the heat from the steam. The remaining steam in the drywell begins to condense as steam flow from the reactor pressure vessel ceases, the drywell pressure falls rapidly. Both drywell purge compressors start automatically 30 seconds after a LOCA signal is received from the Emergency Core Cooling System instrumentation, but only when drywell pressure has decreased to within approximately [0.087] psi above primary containment pressure. This ensures the blowdown from the drywell to the primary containment is complete. The drywell purge compressors force air from the primary containment into the drywell. Drywell pressure increases until the water level between the weir wall and the drywell is forced down to the first row of suppression pool vents forcing drywell atmosphere back into containment and mixing with containment atmosphere to dilute the hydrogen. While drywell purge continues following the LOCA, hydrogen continues to be produced. Eventually, the 4.0 v/o limit is again approached

(continued)

BASES

BACKGROUND
(continued)

and the hydrogen recombiners are manually placed in operation.

APPLICABLE
SAFETY ANALYSES

The [Drywell Purge System] provides the capability for reducing the drywell hydrogen concentration to approximately the bulk average primary containment concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

- a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; and
- b. Radiolytic decomposition of water in the Reactor Coolant System and drywell sump.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.

Based on a conservative assumption used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach [3.5 v/o about 6 days] after the LOCA and [4.0 v/o about 2 days] later if no hydrogen mixing and recombiner were functioning (Ref. 2).

The [Drywell Purge System] satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two [drywell purge] subsystems must be OPERABLE to ensure operation of at least one primary containment [drywell purge] subsystem in the event of a worst case single active failure. Operation with at least one OPERABLE [drywell purge] subsystem provides the capability of controlling the hydrogen concentration in the drywell without exceeding the flammability limit.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the two [drywell purge] subsystems ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 v/o in the drywell, assuming a worst case single active failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the [Drywell Purge System] is low. Therefore, the [Drywell Purge System] is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the [Drywell Purge System] is not required in these MODES.

ACTIONS

A.1

With one [drywell purge] subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE subsystem is adequate to perform the drywell purge function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced drywell purge capability. The 30 day Completion Time is based on the availability of the second subsystem, the low probability of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, and the amount of time available after the event for operator action to prevent hydrogen accumulation from exceeding this limit.

Required Action A.1 has been modified by a Note indicating the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one subsystem is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE subsystem, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

(continued)

BASES

ACTIONS
(continued)

B.1 and B.2

Reviewer's Note: This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.

With two [drywell purge] subsystems inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by [one division of the hydrogen ignitors]. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. [Reviewer's Note: The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability.] [Both] the [initial] verification may [and all subsequent verifications] may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two [drywell purge] subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two [drywell purge] subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

If any Required Action and the required 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. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.3.3.1

Operating each [drywell purge] subsystem for ≥ 15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, compressor failure, or excessive vibration can be detected for corrective action. The 92 day Frequency is consistent with Inservice Testing Program Frequencies, operating experience, the known reliability of the compressor and controls, and the two redundant subsystems available.

SR 3.6.3.3.2

Verifying that each [drywell purge] subsystem flow rate is $\geq [500]$ scfm ensures that each subsystem is capable of maintaining drywell hydrogen concentrations below the flammability limit. The 18 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 [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.7, Revision [1].
 2. FSAR, Section [6.2.5].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 [Secondary Containment]

BASES

BACKGROUND

The function of the [secondary containment] is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the [secondary containment], the [secondary containment] is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The [secondary containment] is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump/motor heat load additions). To prevent ground level exfiltration while allowing the [secondary containment] to be designed as a conventional structure, the [secondary containment] requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSES

There are three principal accidents for which credit is taken for [secondary containment] OPERABILITY. These are a LOCA (Ref. 1), a fuel handling accident inside primary containment (Ref. 2), and a fuel handling accident in the auxiliary building (Ref. 3). The [secondary containment] performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

and that fission products entrapped within the [secondary containment] structure will be treated by the SGT System prior to discharge to the environment.

[Secondary containment] satisfies Criterion 3 of the NRC Policy Statement.

LCO

An OPERABLE [secondary containment] provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in [secondary containment], can be diluted and processed prior to release to the environment. For the [secondary containment] to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to [secondary containment]. Therefore, [secondary containment] OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining [secondary containment] OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the [primary or secondary containment].

ACTIONS

A.1

If [secondary containment] is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of

(continued)

BASES

ACTIONS

A.1 (continued)

maintaining [secondary containment] during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring [secondary containment] OPERABILITY) occurring during periods where [secondary containment] is inoperable is minimal.

B.1 and B.2

If the [secondary containment] cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

Movement of irradiated fuel assemblies in the [primary or secondary containment], CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the [secondary containment]. In such cases, the [secondary containment] is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the [secondary containment] is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

BASES

ACTIONS

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

movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the [secondary containment] boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to [secondary containment] vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal [secondary containment] vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that [secondary containment] equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the [secondary containment] will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining [secondary containment] OPERABILITY requires verifying each door in the access opening is closed, except when the access opening is being used for entry and exit; then, at least one door must remain closed. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

[SR 3.6.4.1.4 and] SR 3.6.4.1.5

The SGT System exhausts the [secondary containment] atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.4 verifies that the SGT System will rapidly establish and maintain a pressure in the [secondary containment] that is less than the lowest postulated pressure external to the [secondary containment] boundary. This is confirmed by demonstrating that one SGT subsystem will draw down the [secondary containment] to $\geq [0.25]$ inches of vacuum water gauge in $\leq [120]$ seconds. This cannot be accomplished if the [secondary containment] boundary is not intact. SR 3.6.4.1.5 demonstrates that each SGT subsystem can maintain $\geq [0.266]$ inches of vacuum water gauge for 1 hour at a flow rate $\leq [4000]$ cfm. The 1 hour test period allows [secondary containment] to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure [secondary containment] boundary integrity. Since these SRs are [secondary containment] tests, they need not be performed with each SGT subsystem. The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [15.6.5].
 2. FSAR, Section [15.7.6].
 3. FSAR, Section [15.7.4].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, that are released during certain operations when primary containment is not required to be OPERABLE, or that take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices 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), and blind flanges are considered passive devices. Check valves or other automatic valves designed to close without operator action following an accident are considered active devices. Isolation barrier(s) for the penetration are discussed in Reference 2.

Automatic SCIVs close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1), a fuel handling accident inside

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

primary containment (Ref. 3), and a fuel handling accident in the auxiliary building (Ref. 4). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The automatic power operated isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 5.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 5.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other

(continued)

BASES

APPLICABILITY
(continued)

situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies. Moving irradiated fuel assemblies in the [primary or secondary containment] may also occur in MODES 1, 2, and 3.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when the need for [secondary containment] isolation is indicated.

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

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criteria are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths

(continued)

BASES

ACTIONS

B.1 (continued)

with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the [primary and secondary containment] must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the [secondary containment] boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in [secondary containment] that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

SR 3.6.4.2.2

Verifying the isolation time of each power operated and each automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are [in accordance with the Inservice Testing Program or 92 days].

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a [secondary containment] isolation signal is required to prevent leakage of radioactive material from [secondary containment] following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a [secondary containment] isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The [18] 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 [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [15.6.5].
 2. FSAR, Section [6.2.3].
 3. FSAR, Section [15.7.6].
 4. FSAR, Section [15.7.4].
 5. FSAR, Section [].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

- a. A moisture separator;
- b. An electric heater;
- c. A prefilter;
- d. A high efficiency particulate air (HEPA) filter;
- e. A charcoal adsorber;
- f. A second HEPA filter; and
- g. A centrifugal fan with inlet flow control vanes.

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the auxiliary and enclosure building structures. The internal pressure of the SGT System boundary region is maintained at a negative pressure of [0.25] inch water gauge when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building when exposed to a [10] mph wind blowing at an angle of [45]° to the building.

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative

(continued)

BASES

BACKGROUND (continued)

humidity of the airstream to less than [70]% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter is provided to collect any carbon fines exhausted from the charcoal adsorber.

The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both enclosure building recirculation fans and both charcoal filter train fans start. SGT System flows are controlled by modulating inlet vanes installed on the charcoal filter train exhaust fans and two position volume control dampers installed in branch ducts to individual regions of the secondary containment.

APPLICABLE SAFETY ANALYSES

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Ref. 3). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.

The SGT System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two operable subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the [primary or secondary containment].

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE SGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2.1, C.2.2, and C.2.3

During movement of irradiated fuel assemblies in the [primary or secondary containment], during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 cannot be

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

completed within the required Completion Time, the OPERABLE SGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the unit in a Condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

The Required Actions of Condition C have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

D.1

If both SGT subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1, E.2, and E.3

When two SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the [primary and secondary containment] must be immediately

(continued)

BASES

ACTIONS

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

suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem for $\geq [10]$ continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation [with the heaters on (automatic heater cycling to maintain temperature)] for $\geq [10]$ continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies

(continued)

BASES

SURVEILLANCE SR 3.6.4.3.2 (continued)

and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT subsystem starts upon receipt of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR requires verification that the SGT filter cooler bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
 2. FSAR, Section [6.2.3].
 3. FSAR, Section [15.6.5].
 4. Regulatory Guide 1.52, Rev. [2].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.1 Drywell

BASES

BACKGROUND

The drywell houses the reactor pressure vessel (RPV), the reactor coolant recirculating loops, and branch connections of the Reactor Coolant System (RCS), which have isolation valves at the primary containment boundary. The function of the drywell is to maintain a pressure boundary that channels steam from a loss of coolant accident (LOCA) to the suppression pool, where it is condensed. Air forced from the drywell is released into the primary containment. The pressure suppression capability assures that peak LOCA temperature and pressure in the primary containment are within design limits. The drywell also protects accessible areas of the containment from radiation originating in the reactor core and RCS.

To ensure the drywell pressure suppression capability, the drywell bypass leakage must be minimized to prevent overpressurization of the primary containment during the drywell pressurization phase of a LOCA. This requires periodic testing of the drywell bypass leakage, confirmation that the drywell air lock is leak tight, OPERABILITY of the drywell isolation valves (DIVs), and confirmation that the drywell vacuum relief valves are closed.

The isolation devices for the drywell penetrations are a part of the drywell barrier. To maintain this barrier:

- a. The drywell air lock is OPERABLE except as provided in LCO 3.6.5.2, "Drywell Air Lock";
- b. The drywell penetrations required to be closed during accident conditions are either:
 1. capable of being closed by an OPERABLE automatic DIV, or
 2. closed by manual valves, blind flanges, or de-activated automatic valves secured in closed positions except as provided in LCO 3.6.5.3, "Drywell Isolation Valves (DIVs)"; and

(continued)

BASES

BACKGROUND
(continued)

- c. The Drywell Vacuum Relief System is OPERABLE except as provided in LCO 3.6.5.6, "Drywell Vacuum Relief System."

This Specification is intended to ensure that the performance of the drywell in the event of a DBA meets the assumptions used in the safety analyses (Ref. 1).

APPLICABLE
SAFETY ANALYSES

Analytical methods and assumptions involving the drywell are presented in Reference 1. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Maintaining the pressure suppression capability assures that safety analyses remain valid and that the peak LOCA temperature and pressure in the primary containment are within design limits.

The drywell satisfies Criteria 2 and 3 of the NRC Policy Statement.

LCO

Maintaining the drywell OPERABLE is required to ensure that the pressure suppression design functions assumed in the safety analyses are met. The drywell is OPERABLE if the drywell structural integrity is intact and the bypass leakage is within limits, except prior to the first startup after performing a required drywell bypass leakage test. At this time, the drywell bypass leakage must be \leq [10%] of the drywell bypass leakage limit.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the 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 drywell is not required to be OPERABLE in MODES 4 and 5.

(continued)

BASES (continued)

ACTIONS

A.1

In the event the drywell is inoperable, it 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 the drywell OPERABLE during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring drywell OPERABILITY) occurring during periods when the drywell is inoperable is minimal. Also, the Completion Time is the same as that applied to inoperability of the primary containment in LCO 3.6.1.1, "Primary Containment."

B.1 and B.2

If the drywell 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 3.6.5.1.1

The analyses in Reference 2 are based on a maximum drywell bypass leakage. This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable A/\sqrt{k} design value of $[1.0] \text{ ft}^2$ assumed in the safety analysis. As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be $\leq [10\%]$ of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design A/\sqrt{k} . At the design A/\sqrt{k} the containment temperature and pressurization response are bounded by the assumptions of the safety analysis. The leakage test is performed every $[18]$ months, consistent with the difficulty of performing the test, risk of high radiation exposure, and the remote possibility that a component failure that is not identified by some other drywell or primary containment SR

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.1.1 (continued)

might occur. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.5.1.2

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from performing its intended function. This SR ensures that drywell structural integrity is maintained. The [40] month Frequency was chosen so that the interior and exterior surfaces of the drywell can be inspected at every other refueling outage. Due to the passive nature of the drywell structure, the [40] month Frequency is sufficient to identify component degradation that may affect drywell structural integrity.

REFERENCES

1. FSAR, Chapter [6] and Chapter [15].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.2 Drywell Air Lock

BASES

BACKGROUND

The drywell air lock forms part of the drywell boundary and provides a means for personnel access during MODES 2 and 3 during low power phase of unit startup. For this purpose, one double door drywell air lock has been provided, which maintains drywell isolation during personnel entry and exit from the drywell. Under the normal unit operation, the drywell air lock is kept sealed. The air pressure in the seals is maintained > [60] psig by the seal air flask and pneumatic system, which is maintained at a pressure > [90] psig.

The drywell air lock is designed to the same standards as the drywell boundary. Thus, the drywell air lock must withstand the pressure and temperature transients associated with the rupture of any primary system line inside the drywell and also the rapid reversal in pressure when the steam in the drywell is condensed by the Emergency Core Cooling System flow following loss of coolant accident flooding of the reactor pressure vessel (RPV). It is also designed to withstand the high temperature associated with the break of a small steam line in the drywell that does not result in rapid depressurization of the RPV.

The air lock is nominally a right circular cylinder, [10] ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. During periods when the drywell is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent drywell entry is necessary. 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 Design Basis Accident (DBA).

The air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock interlock mechanism is defeated.

(continued)

BASES

BACKGROUND
(continued)

The drywell air lock forms part of the drywell pressure boundary. Not maintaining air lock OPERABILITY may result in degradation of the pressure suppression capability, which is assumed to be functional in the unit safety analyses. The drywell air lock does not need to meet the requirements of 10 CFR 50, Appendix J (Ref. 1), since it is not part of the primary containment leakage boundary. However, it is prudent to specify a leakage rate requirement for the drywell air lock. A seal leakage rate limit of ≤ 200 scfh and an air lock overall leakage rate limit of ≤ 200 scfh, at pressure $\geq P_a$ (11.5 psig), have been established to assure the integrity of the seals.

APPLICABLE
SAFETY ANALYSES

Analytical methods and assumptions involving the drywell are presented in Reference 2. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Since the drywell air lock is part of the drywell pressure boundary, its design and maintenance are essential to support drywell OPERABILITY, which assures that the safety analyses are met.

The drywell air lock satisfies Criterion 3 of the NRC Policy Statement.

LCO

The drywell air lock forms part of the drywell pressure boundary. The air lock safety function assures that steam resulting from a DBA is directed to the suppression pool. Thus, the air lock's structural integrity is essential to the successful mitigation of such an event.

The air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, air lock leakage must be within limits, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of the drywell does not exist when the drywell is required to be OPERABLE.

Closure of a single door in the air lock is necessary to support drywell OPERABILITY following postulated events.

(continued)

BASES

LCO
(continued) Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.

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

ACTIONS The ACTIONS are modified by Note 1 that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is inoperable, however, then there is a short time during which the drywell boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the drywell boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the drywell during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if the drywell is exceeding its bypass leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.5.1 to be taken in this event.

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

With one drywell air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1). This ensures that a leak tight drywell 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 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.

(continued)

BASES

ACTIONS

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

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

Required Action A.3 verifies that the air lock has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable drywell boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls that ensure that the OPERABLE air lock door remains closed.

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. The exception of the Note does not affect tracking the Completion Times from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. Drywell entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside the drywell that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the drywell was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the drywell during the short time that the OPERABLE door is expected to be open.

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

With the drywell air lock interlock mechanism inoperable, the Required Actions and associated Completion Times consistent with Condition A are applicable.

(continued)

BASES

ACTIONS

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

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. Note 2 allows entry and exit into the drywell 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).

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

With the air lock inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate drywell bypass leakage using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the drywell inoperable if both doors in an air lock have failed a seal test or the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), drywell remains OPERABLE, yet only 1 hour (per LCO 3.6.5.1) 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 drywell leakage rate can still be within limits.

Required Action C.2 requires that one door in the drywell air lock must be verified to be closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.5.1, which requires that the drywell be restored to OPERABLE status within 1 hour.

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

(continued)

BASES

ACTIONS
(continued)

D.1 and D.2

If the inoperable drywell air lock 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 3.6.5.2.1

This SR requires a test be performed to verify seal leakage of the drywell air lock doors at pressures \geq [11.5] psig. A seal leakage rate limit of \leq [200] scfh has been established to ensure the integrity of the seals. The Surveillance is only required to be performed once after each closing. The Frequency of 72 hours is based on operating experience and is considered adequate in view of the other indications available to plant operations personnel that the seal is intact.

SR 3.6.5.2.2

Every 7 days the drywell air lock seal air flask pressure is verified to be \geq [90] psig to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable, based on operating experience, and is considered adequate in view of the other indications to the plant operations personnel that the seal air flask pressure is low.

SR 3.6.5.2.3

The air lock door interlock is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the air lock are designed to withstand the maximum expected post accident drywell

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.2.3 (continued)

pressure, closure of either door will support drywell OPERABILITY. Thus, the door interlock feature supports drywell OPERABILITY while the air lock is being used for personnel transit in and out of the drywell. 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 only challenged when drywell is entered, this test is only required to be performed once every [18] months. The [18] 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 [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The Surveillance is modified by a Note requiring the Surveillance to be performed only upon entry into the drywell.

SR 3.6.5.2.4

This SR requires a test to be performed to verify overall air lock leakage of the drywell air lock at pressures \geq [11.5] psig. The [18] 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 [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR has been modified by a Note indicating that an inoperable air lock door does not invalidate the previous successful performance of an overall air lock leakage test. This is considered reasonable, since either air lock door is

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.2.4 (continued)

capable of providing a fission product barrier in the event of a DBA.

SR 3.6.5.2.5

This SR ensures that the drywell air lock seal pneumatic system pressure does not decay at an unacceptable rate. The air lock seal will support drywell OPERABILITY down to a pneumatic pressure of [90] psig. Since the air lock seal air flask pressure is verified in SR 3.6.5.2.2 to be \geq [90] psig, a decay rate \leq [30] psig over [10] days is acceptable. The [10] day interval is based on engineering judgment, considering that there is no postulated DBA where the drywell is still pressurized [10] days after the event.

The [18] 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 [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix J.
 2. FSAR, Chapters [6 and 15].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.3 Drywell Isolation Valve[s]

BASES

BACKGROUND

The drywell isolation valves, in combination with other accident mitigation systems, function to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

The OPERABILITY requirements for drywell isolation valves help ensure that valves are closed, when required, and isolation occurs within the time limits specified for those isolation valves designed to close automatically. Therefore, the OPERABILITY requirements support minimizing drywell bypass leakage assumed in the safety analysis (Ref. 1) for a DBA. 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, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no credible single failure or malfunction of an active component can result in a loss of isolation.

The Drywell Vacuum Relief System valves serve a dual function, one of which is drywell isolation. However, since the other safety function of vacuum relief would not be available if the normal drywell isolation valve actions were taken, the drywell isolation valve OPERABILITY requirements are not applicable to the Drywell Vacuum Relief System isolation valves. Similar surveillance requirements in the LCO for Drywell Vacuum Relief System provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The Drywell Vent and Purge System is a high capacity system with a [20] inch line, which has isolation valves covered by this LCO. The system supplies filtered outside air directly to the drywell through two lines, each containing two primary containment isolation valves (PCIVs) and two drywell isolation valves called drywell purge isolation valves. The

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BASES

BACKGROUND (continued)

drywell air is exhausted through a line also containing two drywell purge isolation valves by means of two fan units, which are part of the Containment Cooling System charcoal filter trains located inside primary containment. After the air is conditioned and filtered, it is exhausted through two PCIVs. The system is used to remove trace radioactive airborne products prior to personnel entry. The Drywell Vent and Purge System is seldom used in MODE 1, 2, or 3; therefore, the drywell purge isolation valves are seldom open during power operation.

The drywell purge isolation valves fail closed on loss of instrument air or power. The drywell purge isolation valves are fast closing valves (approximately [4] seconds). These valves are qualified to close against the differential pressure induced by a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

This LCO is intended to ensure that releases from the core do not bypass the suppression pool so that the pressure suppression capability of the drywell is maintained. Therefore, as part of the drywell boundary, drywell isolation valve OPERABILITY minimizes drywell bypass leakage. Therefore, the safety analysis of any event requiring isolation of the drywell is applicable to this LCO.

The DBA resulting in a release of steam, water, or radioactive material within the drywell is a LOCA. In the analysis for these accidents, it is assumed that drywell isolation valves either are closed or function to close within the required isolation time following event initiation. Analyses (Ref. 1) also assumed a 4 second drywell purge isolation valve closure time following a 1 second delay prior to closure.

The drywell isolation valves and drywell purge isolation valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

The drywell isolation valve safety function is to form a part of the drywell boundary.

(continued)

BASES

LCO
(continued)

The drywell isolation valves are required to have isolation times of automatic drywell isolation valves within limits, automatic drywell isolation valves actuate on an automatic isolation signal, drywell isolation manual valves closed, purge valves closed, and 20 inch purge valves blocked to restrict maximum valve opening. While the Drywell Vacuum Relief System valves isolate drywell penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.5.6, "Drywell Vacuum Relief System." The valves covered by this LCO are included (with their associated stroke time for automatic valves) in Reference 2.

The normally closed isolation valves or blind flanges 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 (including check valves with flow through the valve secured), and blind flanges are in place. These passive isolation valves and devices are those listed in Reference 2.

APPLICABILITY

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

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated when a need for drywell isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path.

(continued)

BASES

ACTIONS
(continued)

The third Note requires the OPERABILITY of affected systems to be evaluated when a drywell isolation valve is inoperable. This ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable drywell isolation valve.

The fourth Note ensures appropriate remedial actions are taken when the drywell bypass leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Note 4 is added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one drywell isolation valve inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic drywell isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. In this Condition, the remaining OPERABLE drywell isolation valve is adequate to perform the isolation function. However, the overall reliability is reduced because a single failure in the OPERABLE drywell isolation valve could result in a loss of drywell isolation. The 8 hour Completion Time is acceptable, since the drywell design bypass leakage A/\sqrt{K} of $[1.0]$ ft^2 would be maintained even with a single failure due to application of ACTIONS Note 4. In addition, the Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting drywell OPERABILITY during MODES 1, 2, and 3.

For affected penetration flow paths that have been isolated in accordance with Required Action A.1, the affected penetrations must be verified to be isolated on a periodic basis. This is necessary to ensure that drywell penetrations that are required to be isolated following an accident, and are 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 device manipulation; rather, it involves verification that those devices outside drywell and capable of potentially

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

being mispositioned are in the correct position. Since these devices are inside primary containment, the time period specified as "prior to entering MODE 2 or 3 from 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 that will ensure that device misalignment is an unlikely possibility. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)."

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. 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 drywell isolation valves inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage A/\sqrt{K} of $[1.0] \text{ ft}^2$ is maintained due to application of ACTIONS Note 4. The Completion Time is reasonable, considering the time required to isolate the penetration, and the probability of a DBA, which requires the drywell isolation valves to close, occurring during this short time is very low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two isolation valves. For penetration flow paths with one

(continued)

BASES

ACTIONS

B.1 (continued)

drywell isolation valve, Condition A provides the appropriate Required Actions.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in 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 3.6.5.3.1

Each [] inch drywell purge isolation valve is required to be verified sealed closed at 31 day intervals. This Surveillance is intended to be used for drywell purge isolation valves that are not qualified to open under accident conditions. This SR is designed to ensure that a gross breach of drywell is not caused by an inadvertent or spurious drywell purge isolation valve opening. Detailed analysis of these [] inch drywell purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to support drywell OPERABILITY. Therefore, these valves are required to be in sealed closed position during MODES 1, 2, and 3. These [] inch drywell purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leakage within limits. The Frequency is a result of the NRC resolution of Generic Issue B-24 (Ref. 3) related to purge valve use during unit operations.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.5.3.2

This SR ensures that the [20] inch drywell purge isolation valves are closed as required or, if open, open for an allowable reason. This SR is intended to be used for drywell purge isolation valves that are fully qualified to close under accident conditions; therefore, these valves are allowed to be open for limited periods of time. This SR has been modified by a Note indicating the SR is not required to be met when the drywell purge supply or exhaust valves are open for pressure control, ALARA or air quality considerations for personnel entry, or surveillances that require the valve to be open [provided the [20] inch containment [purge system supply and exhaust] lines are isolated]. The 31 day Frequency is consistent with the valve requirements discussed under SR 3.6.5.3.1.

SR 3.6.5.3.3

This SR requires verification that each drywell isolation manual valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that drywell bypass leakage is maintained to a minimum. Since these valves are inside primary containment, the Frequency specified as "prior to entering MODE 2 or 3 from MODE 4, if not performed in the previous 92 days," is appropriate because of the inaccessibility of the drywell isolation valves and because these drywell isolation valves are operated under administrative controls and the probability of their misalignment is low.

A Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open.

SR 3.6.5.3.4

Verifying that the isolation time of each power operated and each automatic drywell isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation time and Frequency of this SR are [in accordance with the Inservice Testing Program or 92 days].

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.5.3.5

Verifying that each automatic drywell isolation valve closes on a drywell isolation signal is required to prevent bypass leakage from the drywell following a DBA. This SR ensures each automatic drywell isolation valve will actuate to its isolation position on a drywell isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The [18] 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, since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown these components usually pass this Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.5.3.6

Verifying that each [] inch drywell purge valve is blocked to restrict opening to > [50]% is required to ensure that the valves can be closed under DBA conditions within the time limits assumed in the safety analyses.

The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

REFERENCES

1. FSAR, Section [6.2.4].
 2. FSAR, Table [6.2-44].
 3. Generic Issue B-24.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.4 Drywell Pressure

BASES

BACKGROUND

Drywell-to-primary containment differential pressure is an assumed initial condition in the analyses that determine the primary containment thermal hydraulic and dynamic loads during a postulated loss of coolant accident (LOCA).

If drywell pressure is less than the primary containment airspace pressure, the water level in the weir annulus will increase and, consequently, the liquid inertia above the top vent will increase. This will cause top vent clearing during a postulated LOCA to be delayed, and that would increase the peak drywell pressure. In addition, an inadvertent upper pool dump occurring with a negative drywell-to-primary containment differential pressure could result in overflow over the weir wall.

The limitation on negative drywell-to-primary containment differential pressure ensures that changes in calculated peak LOCA drywell pressures due to differences in water level of the suppression pool and the drywell weir annulus are negligible. It also ensures that the possibility of weir wall overflow after an inadvertent pool dump is minimized. The limitation on positive drywell-to-primary containment differential pressure helps ensure that the horizontal vents are not cleared with normal weir annulus water level.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. Among the inputs to the design basis analysis is the initial drywell internal pressure (Ref. 1). The initial drywell internal pressure affects the drywell pressure response to a LOCA (Ref. 1) and the suppression pool swell load definition (Ref. 2).

Additional analyses (Refs. 3 and 4) have been performed to show that if initial drywell pressure does not exceed the negative pressure limit, the suppression pool swell and vent clearing loads will not be significantly increased and the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

probability of weir wall overflow is minimized after an inadvertent upper pool dump.

Drywell pressure satisfies Criterion 2 of the NRC Policy Statement.

LCO

A limitation on the drywell-to-primary containment differential pressure of [≥ -0.26 psid and ≤ 2.0 psid] is required to ensure that suppression pool water is not forced over the weir wall, vent clearing does not occur during normal operation, containment conditions are consistent with the safety analyses, and LOCA drywell pressures and pool swell loads are within design values.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the 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 the drywell-to-primary containment differential pressure limitation is not required in MODE 4 or 5.

ACTIONS

A.1

With drywell-to-primary containment differential pressure not within the limits of the LCO, it must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell-to-primary containment differential pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 3.6.5.4.1

This SR provides assurance that the limitations on drywell-to-primary containment differential pressure stated in the LCO are met. The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES and to assessing proximity to the specified LCO pressure limits. 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. FSAR, Section [6.2.1].
 2. FSAR, Section [3.8].
 3. FSAR, Section [6.2.1.1.6].
 4. FSAR, Section [6.2.7].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.5 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 drywell average air temperature affects equipment OPERABILITY, personnel access, and the calculated response to postulated Design Basis Accidents (DBAs). The limitation on drywell average air temperature ensures that the peak drywell temperature during a design basis loss of coolant accident (LOCA) does not exceed the design temperature of [330]°F. The limiting DBA for drywell atmosphere temperature is a small steam line break, assuming no heat transfer to the passive steel and concrete heat sinks in the drywell.

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Increasing the initial drywell average air temperature could change the calculated results of the design bases analysis. The safety analyses (Ref. 1) assume an initial average drywell air temperature of [135]°F. This limitation ensures that the safety analyses remain valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of [330]°F. The consequence of exceeding this design temperature may result in the degradation of the drywell structure under accident loads. Equipment inside the drywell that is required to mitigate the effects of a DBA is designed and qualified to operate under environmental conditions expected for the accident.

Drywell average air temperature satisfies Criterion 2 of the NRC Policy Statement.

LCO

If the initial drywell average air temperature is less than or equal to the LCO temperature limit, the peak accident temperature can be maintained below the drywell design

(continued)

BASES

LCO
(continued) temperature during a DBA. This ensures the ability of the drywell to perform its design function.

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

When the drywell average air temperature is not within the limit of the LCO, it must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 8 hour Completion Time is acceptable, considering the sensitivity of the analyses to variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

If drywell average air temperature cannot be restored to within limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours 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 3.6.5.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the drywell analysis. Drywell air temperature is monitored in all quadrants and at various elevations. Since the measurements are uniformly

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.5.1 (continued)

distributed, an arithmetic average is an accurate representation of actual drywell average temperature.

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

REFERENCES

1. FSAR, Section [6.2].
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.6 Drywell Vacuum Relief System

BASES

BACKGROUND

The Mark III pressure suppression containment is designed to condense, in the suppression pool, the steam released into the drywell in the event of a loss of coolant accident (LOCA). The steam discharging to the pool carries the noncondensibles from the drywell. Therefore, the drywell atmosphere changes from low humidity air to nearly 100% steam (no air) as the event progresses. When the drywell subsequently cools and depressurizes, noncondensibles in the drywell must be replaced to avoid excessive weir wall overflow into the drywell. Rapid weir wall overflow must be controlled in a large break LOCA, so that essential equipment and systems located above the weir wall in the drywell are not subjected to excessive drag and impact loads. The drywell post-LOCA and the drywell purge vacuum relief subsystems are the means by which noncondensibles are transferred from the primary containment back to the drywell.

The vacuum relief systems are a potential source of bypass leakage (i.e., some of the steam released into the drywell from a LOCA bypasses the suppression pool and leaks directly to the primary containment airspace). Since excessive bypass leakage could degrade the pressure suppression function, the Drywell Vacuum Relief System has been designed with at least two valves in series in each vacuum breaker line. This minimizes the potential for a stuck open valve to threaten drywell OPERABILITY. The [two] drywell purge vacuum relief subsystems use separate [10] inch lines penetrating the drywell, and each subsystem consists of a series arrangement of a motor operated isolation valve and two check valves. The [two] drywell post-LOCA vacuum relief subsystems use a common [10] inch line penetrating the drywell, and each subsystem consists of a motor operated valve in series with a check valve. At least two [10] inch lines must be available to provide adequate relief to control rapid weir wall overflow.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The Drywell Vacuum Relief System must function in the event of a large break LOCA to control rapid weir wall overflow that could cause drag and impact loadings on essential equipment and systems in the drywell above the weir wall. The Drywell Vacuum Relief System is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA. Furthermore, their passive operation (remaining closed and not leaking during drywell pressurization) is implicit in all of the LOCA analyses (Ref. 1).

The Drywell Vacuum Relief System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO ensures that in the event of a LOCA, [two] drywell post-LOCA and [two] drywell purge vacuum relief subsystems are available to mitigate the potential subsequent drywell depressurization. Each vacuum relief subsystem is OPERABLE when capable of opening at the required setpoint but is maintained in the closed position during normal operation.

APPLICABILITY

In MODES 1, 2, and 3, a Design Basis Accident could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief System OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Drywell Vacuum Relief System OPERABLE is not required in MODE 4 or 5.

ACTIONS

The ACTIONS Note ensures appropriate remedial actions are taken when the drywell bypass leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, the Note is added to require the proper actions be taken.

(continued)

BASES

ACTIONS
(continued)

A.1

With one or more vacuum relief subsystems open, the subsystem must be closed within 4 hours. This assures that drywell leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage (A/\sqrt{K}) of $[1.0]$ ft² is maintained, and is considered a reasonable length of time needed to complete the Required Action.

A Note has been added to provide clarification that separate Condition entry is allowed for vacuum relief subsystems not closed.

B.1 and C.1

With one [or two] drywell post-LOCA vacuum relief subsystems inoperable or one drywell purge vacuum relief subsystem inoperable, for reasons other than being not closed, the inoperable subsystem(s) must be restored to OPERABLE status within 30 days. In these Conditions, the remaining OPERABLE vacuum relief subsystems are adequate to perform the depressurization mitigation function since two [10] inch lines remain available. The 30 day Completion Time takes into account the redundant capability afforded by the remaining subsystems, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

D.1 and E.1

With [two] drywell purge vacuum relief subsystems inoperable or with [two] drywell post-LOCA and one drywell purge vacuum relief subsystems inoperable, for reasons other than being not closed, at least one inoperable subsystem must be restored to OPERABLE status within 72 hours. In these Conditions, only one [10] inch line remains available. The 72 hour Completion Time takes into account at least one vacuum relief subsystem is still OPERABLE, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

(continued)

BASES

ACTIONS
(continued)

F.1, F.2, G.1, and G.2

If the inoperable drywell vacuum relief subsystem(s) cannot be closed or restored to OPERABLE status within the required Completion Time, or if two drywell purge vacuum relief subsystems are inoperable, for reasons other than being not closed, and one or two drywell post-LOCA vacuum relief subsystem(s) are inoperable, for reasons other than being not closed, 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 3.6.5.6.1

Each vacuum breaker and its associated isolation valve is verified to be closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker or associated isolation valve position indication or by verifying that the vacuum breakers are closed when a differential pressure of [1.0] psid between the drywell and primary containment is maintained for 1 hour without makeup. The 7 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker or isolation valve status available to the plant personnel, and has been shown to be acceptable through operating experience.

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

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.5.6.2

Each vacuum breaker and its associated isolation valve must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This provides assurance that the safety analysis assumptions are valid. A 31 day Frequency was chosen to provide additional assurance that the vacuum breakers and their associated isolation valves are OPERABLE.

SR 3.6.5.6.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption that the vacuum breaker will open fully at a differential pressure of [1.0] psid is valid. The [18] 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 [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [6.2].
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B 3.7 PLANT SYSTEMS

B 3.7.1 [Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)]

BASES

BACKGROUND

The [SSW] System is designed to provide cooling water for the removal of heat from unit auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, standby diesel generators (DGs), and room coolers for Emergency Core Cooling System equipment required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The [SSW] System also provides cooling to unit components, as required, during normal shutdown and reactor isolation modes. During a DBA, the equipment required for normal operation only is isolated from the [SSW] System, and cooling is directed only to safety related equipment.

The [SSW] System consists of the [UHS], two independent cooling water headers (subsystems A and B), and their associated pumps, piping, valves, and instrumentation. The two [SSW] pumps, or one [SSW] pump and the high pressure core spray service water pump, are sized to provide sufficient cooling capacity to support the required safety related systems during safe shutdown of the unit following a loss of coolant accident (LOCA). Subsystems A and B are redundant and service equipment in [SSW] Divisions 1 and 2, respectively.

The [UHS] consists of two concrete makeup water basins, each containing one cooling tower with two fan cells per basin. The combined basin volume is sized such that sufficient water inventory is available for all [SSW] System post LOCA cooling requirements for a 30 day period with no external makeup water source available (Regulatory Guide 1.27, Ref. 1). Normal makeup for each basin is provided automatically by the Plant Service Water System.

Cooling water is pumped from the cooling tower basins by the two [SSW] pumps to the essential components through the two main redundant supply headers (subsystems A and B). After removing heat from the components, the water is discharged to the cooling towers where the heat is rejected through direct contact with ambient air.

Subsystems A and B supply cooling water to redundant equipment required for a safe reactor shutdown. Additional

(continued)

BASES

BACKGROUND (continued)

information on the design and operation of the [SSW] System and [UHS] along with the specific equipment for which the [SSW] System supplies cooling water is provided in the FSAR, Section [9.2.1] and the FSAR, Table [9.2-3] (Refs. 2 and 3, respectively). The [SSW] System is designed to withstand a single active or passive failure, coincident with a loss of offsite power, without losing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

Following a DBA or transient, the [SSW] System will operate automatically without operator action. Manual initiation of supported systems (e.g., suppression pool cooling) is, however, performed for long term cooling operations.

APPLICABLE SAFETY ANALYSES

The volume of each water source incorporated in a [UHS] complex is sized so that sufficient water inventory is available for all [SSW] System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the [SSW] System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the FSAR, Sections [9.2.1], [6.2.1.1.3.3.1.6] and Chapter [15], (Refs. 2, 4, and 5, respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA. The [SSW] System provides cooling water for the RHR suppression pool cooling mode to limit suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its intended function of limiting the release of radioactive materials to the environment following a LOCA. The [SSW] System also provides cooling to other components assumed to function during a LOCA (e.g., RHR and Low Pressure Core Spray systems). Also, the ability to provide onsite emergency AC power is dependent on the ability of the [SSW] System to cool the DGs.

The safety analyses for long term containment cooling were performed, as discussed in the FSAR, Sections [6.2.1.1.3.3.1.6] and [6.2.2.3] (Refs. 4 and 6, respectively), for a LOCA, concurrent with a loss of offsite power, and minimum available DG power. The worst case single failure affecting the performance of the [SSW] System

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

is the failure of one of the two standby DGs, which would in turn affect one [SSW] subsystem. The [SSW] flow assumed in the analyses is [7900] gpm per pump to the heat exchanger (FSAR, Table [6.2-2], Ref. 7). Reference 2 discusses [SSW] System performance during these conditions.

The [SSW] System, together with the [UHS], satisfy Criterion 3 of the NRC Policy Statement.

LCO

The OPERABILITY of subsystem A (Division 1) and subsystem B (Division 2) of the [SSW] System is required to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring both subsystems to be OPERABLE ensures that either subsystem A or B will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure.

A subsystem is considered OPERABLE when:

- a. The associated pump is OPERABLE;
- b. The associated [UHS] is OPERABLE; and
- c. The associated piping, valves, instrumentation, and controls required to perform the safety related function are OPERABLE.

OPERABILITY of the [UHS] is based on a maximum water temperature of [95]°F with OPERABILITY of each subsystem requiring a minimum basin water level at or above elevation [130 ft 3 inches] mean sea level (equivalent to an indicated level of \geq [7 ft 3 inches]) and four OPERABLE cooling tower fans.

The isolation of the [SSW] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [SSW] System.

OPERABILITY of the High Pressure Core Spray (HPCS) Service Water System (SWS) is addressed by LCO 3.7.2, "HPCS SWS."

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, the [SSW] System and [UHS] are required to be OPERABLE to support OPERABILITY of the equipment serviced by the [SSW] System and [UHS], and are required to be OPERABLE in these MODES.

 In MODES 4 and 5, the OPERABILITY requirements of the [SSW] System and [UHS] are determined by the systems they support.

ACTIONS

A.1

If one or more cooling towers have one fan inoperable (i.e., up to one fan per cooling tower inoperable), action must be taken to restore the inoperable cooling tower fan(s) to OPERABLE status within 7 days.

The 7 day Completion Time is reasonable, based on the low probability of an accident occurring during the 7 days that one cooling tower fan is inoperable in one or more cooling towers, the number of available systems, and the time required to complete the Required Action.

B.1

If one [SSW] subsystem is inoperable [for reasons other than Condition A], it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE [SSW] subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE [SSW] subsystem could result in loss of [SSW] function. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable [SSW] subsystem results in an inoperable DG or RHR shutdown cooling, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS
(continued)

C.1 and C.2

If the [SSW] subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both [SSW] subsystems are inoperable [for reasons other than Condition A], or the [[UHS] is determined inoperable for reasons other than Condition A], the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE
REQUIREMENTS

SR 3.7.1.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the [UHS] water source below the minimum level, the affected [SSW] subsystem must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

This SR verifies the water level [in each [SSW] pump well of the intake structure] to be sufficient for the proper operation of the [SSW] pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.3

Verification of the [UHS] temperature ensures that the heat removal capability of the [SSW] System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.7.1.4

Operating each cooling tower fan for ≥ 15 minutes ensures that all fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency is based on operating experience, the known reliability of the fan units, the redundancy available, and the low probability of significant degradation of the cooling tower fans occurring between Surveillances.

SR 3.7.1.5

Verifying the correct alignment for each manual, power operated, and automatic valve in each [SSW] subsystem flow path provides assurance that the proper flow paths will exist for [SSW] operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position. 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.

This SR is modified by a Note indicating that isolation of the [SSW] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [SSW] System. As such, when all [SSW] pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the [SSW] System is still OPERABLE.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.7.1.6

This SR verifies that the automatic isolation valves of the [SSW] System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the [SSW] pump and cooling tower fans in each subsystem. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed on the [18] month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
 2. FSAR, Section [9.2.1].
 3. FSAR, Table [9.2-3].
 4. FSAR, Section [6.2.1.1.3.3.1.6].
 5. FSAR, Chapter [15].
 6. FSAR, Section [6.2.2.3].
 7. FSAR, Table [6.2-2].
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B 3.7 PLANT SYSTEMS

B 3.7.2 High Pressure Core Spray (HPCS) Service Water System (SWS)

BASES

BACKGROUND

The HPCS SWS is designed to provide cooling water for the removal of heat from components of the Division 3 HPCS System.

The HPCS SWS consists of the Ultimate Heat Sink (UHS) Basin A, one cooling water header (subsystem C of the Standby Service Water (SSW) System), and the associated pumps, piping, and valves. The UHS is also considered part of the SSW System (LCO 3.7.1, "[Standby Service Water (SSW) System and [Ultimate Heat Sink (UHS)]").

Cooling water is pumped from a UHS water source by the HPCS service water pump to the essential components through the HPCS service water supply header. After removing heat from the components, the water is discharged to the cooling towers, where the heat is rejected through direct contact with ambient air.

The HPCS SWS specifically supplies cooling water to the Division 3 HPCS diesel generator jacket water coolers and HPCS pump room cooler. The HPCS SWS pump is sized such that it will provide adequate cooling water to the equipment required for safe shutdown. Following a Design Basis Accident or transient, the HPCS SWS will operate automatically and without operator action as described in the FSAR, Section [9.2.1] (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the HPCS SWS to provide adequate cooling to the HPCS System is an implicit assumption for safety analyses evaluated in the FSAR, Chapters [6] and [15] (Refs. 2 and 3, respectively).

The HPCS SWS satisfies Criterion 3 of the NRC Policy Statement.

LCO

The HPCS SWS is required to be OPERABLE to ensure that the HPCS System will operate as required. An OPERABLE HPCS SWS

(continued)

BASES

LCO (continued)

consists of an OPERABLE UHS; an OPERABLE pump; and an OPERABLE UHS flow path, capable of taking suction from the associated SSW source and transferring the water to the appropriate unit equipment.

The OPERABILITY of the UHS is specified in LCO 3.7.1. However, the OPERABILITY of the basin cooling tower fans does not affect the OPERABILITY of the HPCS SWS, due to the limited heat removal during its operation.

APPLICABILITY

In MODES 1, 2, and 3, the HPCS SWS is required to be OPERABLE to support OPERABILITY of the HPCS System since it is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the HPCS SWS and the UHS are determined by the HPCS System.

ACTIONS

A.1

When the HPCS SWS is inoperable, the capability of the HPCS System to perform its intended function cannot be ensured. Therefore, if the HPCS SWS is inoperable, the HPCS System must be declared inoperable immediately and Condition C of LCO 3.5.1, "ECCS—Operating," entered.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR ensures that adequate cooling can be maintained. With the UHS water source below the minimum level, the HPCS SWS must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.2

Verifying the correct alignment for each manual, power operated, and automatic valve in the HPCS service water flow path provides assurance that the proper flow paths will exist for HPCS service water operation. This SR does not

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.7.2.2 (continued)

apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in correct position prior to locking, sealing, or securing.

A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required 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.

This SR is modified by a Note indicating that isolation of the [HPCS SWS] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [HPCS SWS] System. As such, when all [HPCS SWS] pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the [HPCS SWS] System is still OPERABLE.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.2.3

This SR verifies that the automatic valves of the HPCS SWS will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.5 overlaps this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed at the [18] month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section [9.2.1].
 2. FSAR, Chapter [6].
 3. FSAR, Chapter [15].
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B 3.7 PLANT SYSTEMS

B 3.7.3 [Control Room Fresh Air (CRFA)] System

BASES

BACKGROUND

The [CRFA] System provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA).

The safety related function of the [CRFA] System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air or outside supply air. Each subsystem consists of a demister, an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork and dampers. Demisters remove water droplets from the airstream. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

In addition to the safety related standby emergency filtration function, parts of the [CRFA] System are operated to maintain the control room environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room personnel), the [CRFA] System automatically switches to the isolation mode of operation to prevent infiltration of contaminated air into the control room. A system of dampers isolates the control room, and control room air flow is recirculated and processed through either of the two filter subsystems.

The [CRFA] System is designed to maintain the control room environment for a 30 day continuous occupancy after a DBA, without exceeding a 5 rem whole body dose or its equivalent to any part of the body. [CRFA] System operation in maintaining the control room habitability is discussed in the FSAR, Sections [6.5.1] and [9.4.1] (Refs. 1 and 2, respectively).

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The ability of the [CRFA] System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in the FSAR, Chapters [6] and [15] (Refs. 3 and 4, respectively). The isolation mode of the [CRFA] System is assumed to operate following a loss of coolant accident, main steam line break fuel handling accident, and control rod drop accident. The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 4. No single active or passive failure will cause the loss of outside or recirculated air from the control room.

The [CRFA] System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two redundant subsystems of the [CRFA] System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The [CRFA] System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both subsystems. A subsystem is considered OPERABLE when its associated:

- a. Fan is OPERABLE;
- b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and
- c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

APPLICABILITY

In MODES 1, 2, and 3, the [CRFA] System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission product release.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the [CRFA] System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

- a. During operations with a potential for draining the reactor vessel (OPDRVs);
- b. During CORE ALTERATIONS; and
- c. During movement of irradiated fuel assemblies in the [primary or secondary containment].

ACTIONS

A.1

With one [CRFA] subsystem inoperable, the inoperable [CRFA] subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE [CRFA] subsystem is adequate to perform control room radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of [CRFA] System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable [CRFA] subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS
(continued)

C.1, C.2.1, C.2.2, and C.2.3

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the [primary or secondary containment], during CORE ALTERATIONS, or during OPDRVs, if the inoperable [CRFA] subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE [CRFA] subsystem may be placed in the isolation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

Required Action C.1 is modified by a Note alerting the operator to [place the system in the toxic gas protection mode if the toxic gas, automatic transfer capability is inoperable].

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the [primary and secondary containment] must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

(continued)

BASES

ACTIONS
(continued)

D.1

If both [CRFA] subsystems are inoperable in MODE 1, 2, or 3, the [CRFA] System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

The Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the [primary or secondary containment], during CORE ALTERATIONS, or during OPDRVs, with two [CRFA] subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the [primary and secondary containment] must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE
REQUIREMENTS

SR 3.7.3.1

This SR verifies that a subsystem in a standby mode starts on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.7.3.1 (continued)

each subsystem once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. [Systems with heaters must be operated for ≥ 10 continuous hours with the heaters energized. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system.] Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

SR 3.7.3.2

This SR verifies that the required CRFA testing is performed in accordance with the [Ventilation Filter Testing Program (VFTP)]. The CRFA filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The [VFTP] includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the [VFTP].

SR 3.7.3.3

This SR verifies that each [CRFA] subsystem starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.5 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is specified in Reference 5.

SR 3.7.3.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the [CRFA] System. During the emergency mode of operation, the [CRFA] System is designed to slightly pressurize the control room to [0.1] inches water gauge positive pressure with respect to adjacent areas to prevent unfiltered inleakage. The [CRFA]

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.7.3.4 (continued)

System is designed to maintain this positive pressure at a flow rate of [500] cfm to the control room in the isolation mode. The Frequency of [18] months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs.

REFERENCES

1. FSAR, Section [6.5.1].
 2. FSAR, Section [9.4.1].
 3. FSAR, Chapter [6].
 4. FSAR, Chapter [15].
 5. Regulatory Guide 1.52, Revision 2, March 1978.
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B 3.7 PLANT SYSTEMS

B 3.7.4 [Control Room Air Conditioning (AC)] System

BASES

BACKGROUND

The [Control Room AC] System provides temperature control for the control room following isolation of the control room.

The [Control Room AC] System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room air. Each subsystem consists of heating coils, cooling coils, fans, chillers, compressors, ductwork, dampers, and instrumentation and controls to provide for control room temperature control.

The [Control Room AC] System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room environment for a sustained occupancy of 12 persons. The design conditions for the control room environment are 72°F and 50% relative humidity. The [Control Room AC] System operation in maintaining the control room temperature is discussed in the FSAR, Sections [6.4] and [9.4.1] (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the [Control Room AC] System is to maintain the control room temperature for a 30 day continuous occupancy.

The [Control Room AC] System components are arranged in redundant safety related subsystems. During emergency operation, the [Control Room AC] System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active failure of a component of the [Control Room AC] System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The [Control Room AC] System is designed in accordance with Seismic Category I requirements. The [Control Room AC] System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

The [Control Room AC] System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two independent and redundant subsystems of the [Control Room AC] System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The [Control Room AC] System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls.

APPLICABILITY

In MODE 1, 2, or 3, the [Control Room AC] System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the [Control Room AC] System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

- a. During operations with a potential for draining the reactor vessel (OPDRVs);
 - b. During CORE ALTERATIONS; and
 - c. During movement of irradiated fuel assemblies in the [primary or secondary containment].
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(continued)

BASES (continued)

ACTIONS

A.1

With one [control room AC] subsystem inoperable, the inoperable [control room AC] subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE [control room AC] subsystem is adequate to perform the control room air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control room air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room isolation, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable [control room AC] subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the [primary or secondary containment], during CORE ALTERATIONS, or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE [control room AC] subsystem may be placed immediately in operation.

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the [primary and secondary containment] must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

D.1

If both [control room AC] subsystems are inoperable in MODE 1, 2, or 3, the [Control Room AC] System may not be capable of performing the intended function. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

The Required Actions of Condition E.1 are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the [primary or secondary containment], during CORE ALTERATIONS, or during OPDRVs with two [control room AC] subsystems inoperable, action must be taken to immediately suspend activities that present a potential for releasing

(continued)

BASES

ACTIONS

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

radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the [primary or secondary containment] must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the [safety analyses]. The SR consists of a combination of testing and calculation. The [18] month Frequency is appropriate since significant degradation of the [Control Room AC] System is not expected over this time period.

REFERENCES

1. FSAR, Section [6.4].
 2. FSAR, Section [9.4.1].
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B 3.7 PLANT SYSTEMS

B 3.7.5 Main Condenser Offgas

BASES

BACKGROUND

During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensable gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases.

The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser Offgas System failure event as discussed in the FSAR, Section [15.7.1] (Ref. 1). The analysis assumes a gross failure in the Main Condenser Offgas System that results in the rupture of the Main Condenser Offgas System pressure boundary. The gross gamma activity rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits (NUREG-0800, Ref. 2) of 10 CFR 100 (Ref. 3), or the NRC staff approved licensing basis.

The main condenser offgas limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 100 $\mu\text{Ci/Mwt-second}$ after decay of 30 minutes. The LCO is established consistent with

(continued)

BASES

LCO
(continued) this requirement $([3833] \text{ Mwt} \times 100 \mu\text{Ci/Mwt-second} = [380] \text{ mCi/second})$.

APPLICABILITY The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits within the associated Completion Time, [all main steam lines] or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The

(continued)

BASES

ACTIONS

B.1, B.2, B.3.1, and B.3.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by $\geq 50\%$ after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any [main steam line is not isolated] and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. FSAR, Section [15.7.1].
 2. NUREG-0800.
 3. 10 CFR 100.
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B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is [35]% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a two valve chest connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the FSAR, Section [7.7.1.5] (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in the FSAR, Section [15.1.2] (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in an MCPR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded. [With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow continued operation.]

An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2). The MCPR limit for the inoperable Main Turbine Bypass System is specified in the COLR.

APPLICABILITY The Main Turbine Bypass System is required to be OPERABLE at $\geq 25\%$ RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, sufficient margin to these limits exists $< 25\%$ RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), or the MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

(continued)

BASES

ACTIONS
(continued)

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the MCPR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE
REQUIREMENTS

SR 3.7.6.1

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the [18] month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.7.6.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in [unit specific documentation]. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the [18] month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section [7.7.1.5].
 2. FSAR, Section [15.1.2].
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B 3.7 PLANT SYSTEMS

B 3.7.7 Fuel Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel storage pool and upper containment fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident.

A general description of the spent fuel storage pool and upper containment fuel storage pool design is found in the FSAR, Section [9.1.2] (Ref. 1). The assumptions of the fuel handling accident are found in the FSAR, Sections [15.7.4] and [15.7.6] (Refs. 2 and 3, respectively).

APPLICABLE SAFETY ANALYSES

The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are $\leq 25\%$ (NUREG-0800, Section 15.7.4, Ref. 4) of the 10 CFR 100 (Ref. 5) exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 6).

The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto stored fuel bundles. The consequences of a fuel handling accident inside the auxiliary building and inside containment are documented in References 2 and 3, respectively. The water levels in the spent fuel storage pool and upper containment fuel storage pool provide for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident.

The fuel pool water level satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO The specified water level preserves the assumption of the fuel handling accident analysis (Refs. 2 and 3). As such, it is the minimum required for fuel movement within the spent fuel storage pool and upper containment fuel storage pool.

APPLICABILITY This LCO applies whenever movement of irradiated fuel assemblies occurs in the associated fuel storage racks since the potential for a release of fission products exists.

ACTIONS A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With either fuel pool level less than required, the movement of irradiated fuel assemblies in the associated storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE SR 3.7.7.1
REQUIREMENTS

This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool and upper containment fuel storage racks must be checked periodically. The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable and water level changes are controlled by unit procedures.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section [9.1.2].
 2. FSAR, Section [15.7.4].
 3. FSAR, Section [15.7.6].
 4. NUREG-0800, Section 15.7.4, Revision 1, July 1981.
 5. 10 CFR 100.
 6. Regulatory Guide 1.25, March 1972.
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (diesel generators (DGs) 2A, 2C, and 1B). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems—Operating"). Each ESF bus has three separate and independent offsite sources of power. Each ESF bus has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the transmission network. From the switchyard two electrically and physically separated circuits provide AC power to each 4.16 kV ESF bus. A 115 kV power source provides a third completely independent circuit. The offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and circuits to the onsite Class 1E [ESF buses] is found in FSAR, Chapter [8] (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the [onsite Class 1E ESF bus(es)].

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within [1 minute] after the initiating signal is received, all automatic and permanently connected

(continued)

BASES

BACKGROUND
(continued)

loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation").

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the DG. For Divisions 1 and 2, the automatic diesel start and the power from normal to emergency power supplies is controlled by the Load Shedding and Sequencing (LSS) System. The LSS circuits actuate on loss of offsite power or LOCA signal. The system starts the DGs and, if an undervoltage exists on a Division 1 or 2 bus, it sheds nonvital loads from the affected bus and then sequentially starts the vital loads. The Division 3 bus has no shedding or sequencing.

Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating is 7000 kW for Divisions 1 and 2 and is 3300 kW for Division 3, with 10% overload permissible for up to 2 hours in any 24 hour period.

APPLICABLE
SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter [6] (Ref. 4) and Chapter [15] (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits;

(continued)

BASES

- a. An assumed loss of all offsite power or all onsite AC power; and
- b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of the NRC Policy Statement.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs (11, 12, and 13), ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE. In general, Division 3 does not have a load sequencer since it has only one large load (i.e., the high pressure core spray (HPCS) pump). In such cases the LCO should refer to the Division 1 and 2 sequencers only.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. Each offsite circuit consists of incoming breaker and disconnect to the respective service transformers 11 and 21, the 11 and 21 service transformers, the ESF transformers 11 and 21, and the respective circuit path including feeder breakers to the 4.16 kV ESF buses.

LCO
(continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and

(continued)

BASES

LCO
(continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical.

APPLICABILITY

The AC sources and sequencers are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

- a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of A00s or abnormal transients; and
- b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS

(continued)

BASES

APPLICABILITY
(continued)

entered, the Division 3 AC sources provide no additional assurance of meeting the above criteria.

AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 Emergency Core Cooling Systems (ECCS)). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has no offsite power.

The Completion Time for Required Action A.2 is intended to allow time for the operator 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." In this Required Action, the Completion Time only begins on discovery that both:

- a. The division has no offsite power supplying its loads;
and

(continued)

BASES

ACTIONS

A.2 (continued)

- b. A required feature on the other division is inoperable.

If, at any time during the existence of this Condition (one offsite circuit inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one division of the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other division that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours.

This Completion Time assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. In the event more than one division is without offsite power, this assumption is not met. Therefore, the optional Completion Time is specified. Should two or more divisions be affected, the 24 hour Completion Time is conservative with respect to the

(continued)

BASES

ACTIONS

A.3 (continued)

Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the on-site Class 1E distribution system.

The Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

(continued)

BASES

ACTIONS
(continued)

B.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 Emergency Core Cooling Systems (ECCS)). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

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." In this Required Action, the Completion Time only begins on discovery that both:

- a. An inoperable DG exists; and
- b. A required feature on another division is inoperable.

If, at any time during the existence of this Condition (one DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more required support or supported features, or both, that are associated with the OPERABLE DG(s), results in starting the Completion Time for the Required Action. Four

(continued)

BASES

ACTIONS

B.2 (continued)

hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the [plant corrective action program] will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), [24] hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

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BASES

ACTIONS
(continued)

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of

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BASES

ACTIONS

C.1 and C.2 (continued)

function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 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." In this Required Action, the Completion Time only begins on discovery that both:

- a. All required offsite circuits are inoperable; and
- b. A required feature is inoperable.

If, at any time during the existence of this Condition (two offsite circuits inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

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BASES

ACTIONS

C.1 and C.2 (continued)

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

- a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and
- b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

division, Actions for LCO 3.8.9, "Distribution Systems—Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

E.1

With two DGs inoperable, there is one remaining standby AC source. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

(continued)

BASES

ACTIONS

E.1 (continued)

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with Division 1 or 2 remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent—an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, Division 3 systems could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1

The sequencer(s) is an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer(s) is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus.] Therefore, loss of an [ESF bus's sequencer] affects every major ESF system in the [division]. The [12] hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident requiring sequencer OPERABILITY occurring during periods when the sequencer is inoperable is minimal.

This Condition is preceded by a Note that allows the Condition to be deleted if the plant design is such that any sequencer failure mode only affects the ability of the associated DG to power its respective safety loads under any conditions. Implicit in this Note is the concept that the Condition must be retained if any sequencer failure mode results in the inability to start all or part of the safety

(continued)

BASES

ACTIONS

F.1 (continued)

loads when required, regardless of power availability, or results in overloading the offsite power circuit to a safety bus during an event thereby causing its failure. Also implicit in the Note is the concept that the Condition is not applicable to any Division that does not have a sequencer [Division 3 does not normally have a sequencer in the circuitry].

G.1 and G.2

If the inoperable AC electrical power sources [and sequencers] cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit 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 systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10).

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of [3740] V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of [9756] V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to $\pm 2\%$ of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note 2 for SR 3.8.1.2) to indicate that all DG starts for these

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, some manufacturers recommend that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 10). The 10 second start requirement may not be applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. Since SR 3.8.1.7 does require a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule") is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the

(continued)

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SURVEILLANCE
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SR 3.8.1.3 (continued)

equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between [0.8 lagging] and [1.0]. The [0.8] value is the design rating of the machine, while [1.0] is an operational limitation [to ensure circulating currents are minimized]. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The normal 31 day Frequency for this Surveillance (see Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 3).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance must be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank [and engine mounted tank] is at or above the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.1.4 (continued)

level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day [and engine mounted] tanks once every [31] days eliminates the necessary environment for bacterial survival. This is most effective means in controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support the continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping

(continued)

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SR 3.8.1.6 (continued)

system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is variable, depending on individual system design, with up to a 92 day interval. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 12); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day [and engine mounted] tanks during or following DG testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The [18 month] Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant

(continued)

BASES

SURVEILLANCE
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SR 3.8.1.8 (continued)

safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The load referenced for DG 11 is the 1200 kW low pressure core spray pump; for DG 12, the 550 kW residual heat removal (RHR) pump; and for DG 13 the 2180 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. This Surveillance may be accomplished by:

- a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or
- b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For the Grand Gulf Nuclear Station these values are the same.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of the 5 second load

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SR 3.8.1.9 (continued)

sequence interval associated with sequencing of this largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The [18 month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed using a power factor $\leq [0.9]$. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable;
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

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SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor $\leq [0.9]$. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The [18 month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable;

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SR 3.8.1.10 (continued)

- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform

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SR 3.8.1.11 (continued)

these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. [For the [Division 3] DG, standby conditions mean that the lube oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by natural circulation.] The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time ([10] seconds) from the design basis actuation signal (LOCA signal) and operates for \geq [5] minutes. The [5] minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the

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SR 3.8.1.12 (continued)

loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of [18 months] takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for the Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed, generator differential current,

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SR 3.8.1.13 (continued)

and low lube oil pressure) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The [18 month] Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance removes a required DG from service. Credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable;
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

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SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours—22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor $\leq [0.9]$. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

The [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

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SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

The [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(5).

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9),

(continued)

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SR 3.8.1.16 (continued)

paragraph 2.1.(6), and takes into consideration plant conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(8); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the

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SR 3.8.1.17 (continued)

electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.18

Under accident conditions [and loss of offsite power] loads are sequentially connected to the bus by the load sequencing panel. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The [10]% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable;

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SR 3.8.1.18 (continued)

- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of [18 months] takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of [18 months].

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

Diesel Generator Test Schedule

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.

According to Regulatory Guide 1.9 (Ref. 3), Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.

The Frequency for accelerated testing is 7 days, but no less than 24 hours. Tests conducted at intervals of less than 24

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

Diesel Generator Test Schedule (continued)

hours may be credited for compliance with Required Actions. However, for the purpose of re-establishing the normal 31-day Frequency, a successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts, and the consecutive test count is not reset.

A test interval in excess of 7 days (or 31 days, as appropriate) constitutes a failure to meet SRs and results in the associated DG being declared inoperable. It does not, however, constitute a valid test or failure of the DG, and any consecutive test count is not reset.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
 2. FSAR, Chapter [8].
 3. Regulatory Guide 1.9.
 4. FSAR, Chapter [6].
 5. FSAR, Chapter [15].
 6. Regulatory Guide 1.93.
 7. Generic Letter 84-15, July 2, 1984.
 8. 10 CFR 50, Appendix A, GDC 18.
 9. Regulatory Guide 1.108.
 10. Regulatory Guide 1.137.
 11. ANSI C84.1, 1982.
 12. ASME, Boiler and Pressure Vessel Code, Section XI.
 13. IEEE Standard 308.
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources—Shutdown

BASES

BACKGROUND	A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources—Operating."
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APPLICABLE SAFETY ANALYSES	<p>The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies ensures that:</p> <ul style="list-style-type: none">a. The unit can be maintained in the shutdown or refueling condition for extended periods;b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; andc. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.
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In general, when the unit is shut down the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

- a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.
- b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.
- c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.
- d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One offsite circuit capable of supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems—Shutdown," ensures that all required Division 1 loads, Division 2 loads, or both, are powered from offsite power. An OPERABLE DG, associated with a Division 1 or Division 2 Distribution System Engineered Safety Feature

(continued)

BASES

LCO
(continued)

(ESF) bus required OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) is required to be OPERABLE, a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensures an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a., or a circuit required to meet LCO Item c. may be connected, with the second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensure the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel draindown).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective ESF bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant. [The offsite circuit consists of incoming breaker and disconnect to the respective service transformers 11 and 21, the 11 and 21 service transformers, the ESF transformers 11 and 21, and the respective circuit path including feeder breakers to all 4.16 kV ESF buses required by LCO 3.8.10.]

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within [10] seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO
(continued)

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. [In addition, proper sequencer operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts on the ability to start and maintain energized loads required OPERABLE by LCO 3.8.10.]

It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions. [No fast transfer capability is required for offsite circuits to be considered OPERABLE.]

As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that, even with a single failure, the plant will not be in immediate difficulty.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the [primary or secondary] containment provide assurance that:

- a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;
- b. Systems needed to mitigate a fuel handling accident are available;
- c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and
- d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

(continued)

BASES (continued)

ACTIONS

A.1

An offsite circuit is considered inoperable if it is not available to one required ESF division. If two or more ESF 4.16 kV buses are required per LCO 3.8.10, division(s) with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable with no offsite power available, appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the [primary or secondary containment], and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4
(continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized division.

C.1

When the HPCS is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS is not available. Since these sources only affect the HPCS, the HPCS is declared inoperable and the Required Actions of the affected Emergency Core Cooling Systems LCO entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.10 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering HPCS will still perform its function, absent an additional single failure.

SURVEILLANCE
REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.2.1 (continued)

with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from each storage tank to its respective day tank by a transfer pump associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated in the control room.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of [7] days of operation. [The onsite storage in addition to the engine oil sump is sufficient to ensure 7 days continuous operation.] This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s).

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in FSAR, Chapter [6] (Ref. 4) and Chapter [15] (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown."

The starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources, LCO 3.8.1 and LCO 3.8.2, are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and

(continued)

BASES

APPLICABILITY (continued) starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

- a. Full load operation required after an inadvertent start while at minimum required level; or
- b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < 500 gal, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is

(continued)

BASES

ACTIONS

B.1 (continued)

restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil

(continued)

BASES

ACTIONS

D.1 (continued)

properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < [225] psig, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is > [125] psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.1 (continued)

provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The 500 gal requirement is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

- a. Sample the new fuel oil in accordance with ASTM D4057-[] (Ref. 6);
- b. Verify in accordance with the tests specified in ASTM D975-[] (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 (or an API gravity at 60°F of $\geq 27^\circ$ and $\leq 39^\circ$), a

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.3 (continued)

kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of $\geq 125^{\circ}\text{F}$; and

- c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[] (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-[] (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-[] (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1522-[] (Ref. 6) or ASTM D2622-[] (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-[], Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. [For those designs in which the total volume of stored fuel oil is contained in two or more interconnected tanks, each tank must be considered and tested separately.]

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.3 (continued)

concentration is unlikely to change between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. [A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed.] The pressure specified in this SR is intended to reflect the lowest value at which the [five] starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of the Surveillance.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.8.3.6

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7), examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance.

REFERENCES

1. FSAR, Section [9.5.4].
 2. Regulatory Guide 1.137.
 3. ANSI N195, Appendix B, 1976.
 4. FSAR, Chapter [6].
 5. FSAR, Chapter [15].
 6. ASTM Standards: D4057-[]; D975-[]; D4176-[]; D975-[]; D1552-[]; D2622-[]; D2276-[].
 7. ASME, Boiler and Pressure Vessel Code, Section XI.
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources—Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of three independent Class 1E DC electrical power subsystems, Divisions 1, 2, and 3. Each subsystem consists of a battery, associated battery charger(s), and all the associated control equipment and interconnecting cabling.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the Engineered Safety Feature (ESF) batteries.

Each of the Division 1 and 2 electrical power subsystems provides the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. Also, these DC subsystems provide DC electrical power to the inverters, which in turn power the AC vital buses. The Division 3 DC electrical power subsystem provides DC motive and control power as required for the High Pressure Core Spray (HPCS) System diesel generator (DG) set control and protection.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems—Operating," and LCO 3.8.10, "Distribution Systems—Shutdown."

Each Division 1 and 2 battery has adequate storage capacity to carry the required load continuously for at least 4 hours and to perform three complete cycles of intermittent loads as discussed in the FSAR, Section [8.3.2] (Ref. 4).

(continued)

BASES

BACKGROUND (continued)

The Division 3 battery has adequate storage to carry the required load continuously for at least 2 hours (Ref. 4).

Each DC battery subsystem is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

The batteries for a DC electrical power subsystem are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The voltage design limit is 1.75 V per cell (Ref. 4).

Each battery charger of Division 1 and 2 DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state within 12 hours while supplying normal steady state loads (Ref. 4).

The battery charger of Division 3 DC electrical power subsystem has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state in 8 hours while supplying normal steady state loads (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter [6] (Ref. 5) and Chapter [15] (Ref. 6), assume that ESF systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

maintaining DC sources OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite AC power or of all onsite AC power; and
- b. A worst case single failure.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The DC electrical power subsystems, each subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the divisions, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

- a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
- b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 4 and 5 are addressed in the Bases for LCO 3.8.5, "DC Sources—Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

Condition A represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system division.

If one of the required [Division 1 or 2] DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger, or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1

With the Division 3 DC electrical power subsystem inoperable, the HPCS and 2C Standby Service Water System may be incapable of performing their intended functions and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, "ECCS—Operating," [and LCO 3.7.1, "Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)"]].

C.1 and C.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The limits established for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The 12 month Frequency of this SR is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

Reviewer's Note: The requirement to verify that terminal connections are clean and tight applies only to nickel cadmium batteries as per IEEE Standard P1106, "IEEE Recommended Practice for Installation, Maintenance, Testing and Replacement of Vented Nickel - Cadmium Batteries for Stationary Applications." This requirement may be removed for lead acid batteries.

The connection resistance limits for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test once per 60 months.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.4.7 (continued)

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.4.8 (continued)

acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 8) and IEEE-485 (Ref. 11). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity \geq 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is \geq 10% below the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. FSAR, Section [8.3.2].

(continued)

BASES

REFERENCES
(continued)

5. FSAR, Chapter [6].
 6. FSAR, Chapter [15].
 7. Regulatory Guide 1.93, December 1974.
 8. IEEE Standard 450, 1987.
 9. Regulatory Guide 1.32, February 1977.
 10. Regulatory Guide 1.129, December 1974.
 11. IEEE Standard 485.
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources—Shutdown

BASES

BACKGROUND A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources—Operating."

APPLICABLE SAFETY ANALYSES The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of irradiated fuel assemblies ensures that:

- a. The facility can be maintained in the shutdown or refueling condition for extended periods;
- b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and
- c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO The DC electrical power subsystems, each consisting of [two] battery banks, [one or two] battery charger[s], and

(continued)

BASES

LCO
(continued)

the corresponding control equipment and interconnecting cabling within the division, are required to be OPERABLE to support required divisions of Distribution System divisions required OPERABLE by LCO 3.8.10, "Distribution Systems—Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the [primary or secondary containment] provide assurance that:

- a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;
- b. Required features needed to mitigate a fuel handling accident are available;
- c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and
- d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If more than one DC distribution subsystem is required according to LCO 3.8.10, the DC subsystems remaining OPERABLE with one or more DC power sources inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel.

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

By allowing the option to declare required features inoperable with associated DC power source(s) inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

(continued)

BASES (continued)

- REFERENCES
1. FSAR, Chapter [6].
 2. FSAR, Chapter [15].
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources—Operating," and LCO 3.8.5, "DC Sources—Shutdown."

APPLICABLE SAFETY ANALYSES The initial conditions of Design Basis Accident (DBA) and transient analyses in FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one division of DC sources OPERABLE during accident conditions, in the event of:

- a. An assumed loss of all offsite AC power or all onsite AC power; and
- b. A worst case single failure.

Since battery cell parameters support the operation of the DC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with limits not met.

(continued)

BASES (continued)

APPLICABILITY The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, battery electrolyte is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met, and continued operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A and B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

(continued)

BASES

ACTIONS

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

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable for operation prior to declaring the DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 60°F, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE
REQUIREMENTS

SR 3.8.6.1

The SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). In addition, within 24 hours of a battery discharge < [110] V or a battery overcharge > [150] V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ [110] V, do not constitute a battery discharge provided the battery terminal voltage and float current

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.6.2 (continued)

return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is $\geq 60^{\circ}\text{F}$ is consistent with a recommendation of IEEE-450 (Ref. 3), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer's recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra $\frac{1}{4}$ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron

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BASES

SURVEILLANCE
REQUIREMENTS

Table 3.8.6-1 (continued)

transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 3), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.195 (0.015 below the manufacturer's fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.190 (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells > 1.200 (0.010 below the manufacturer's fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not mask overall degradation of the battery.

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BASES

SURVEILLANCE
REQUIREMENTS

Table 3.8.6-1 (continued)

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable:

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C Allowable Value for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ($\geq [1.190]$), is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote (b) in Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

Table 3.8.6-1 (continued)

current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within [7] days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than [7] days.

Reviewer's Note: The value of [2] amps used in footnote (b) and (c) is the nominal value for float current established by the battery vendor as representing a fully charged battery with an allowance for overall battery condition.

REFERENCES

1. FSAR, Chapter [6].
 2. FSAR, Chapter [15].
 3. IEEE Standard 450, 1987.
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters—Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. There is one inverter per AC vital bus, making a total of four inverters. The function of the inverter is to provide AC electrical power to the vital buses. The inverter can be powered from an internal AC source/rectifier or from the station battery. The station battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Emergency Core Cooling Systems (ECCS) initiation.

Specific details on inverters, such as type, capacity, operating limits, and number and status of spares, can be found in the FSAR, Chapter [8] (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter [6] (Ref. 2) and Chapter [15] (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ECCS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining electrical power sources OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite AC or all onsite AC electrical power; and
- b. A worst case single failure.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of the NRC Policy Statement.

LCO

The inverters ensure the availability of AC electrical power for the instrumentation for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ECCS instrumentation and controls is maintained. The four battery powered inverters ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized.

OPERABLE inverters require the associated vital bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a [125 VDC] station battery. Alternatively, power supply may be from an internal AC source via rectifier as long as the station battery is available as the uninterruptible power supply.

This LCO is modified by a Note allowing [one or two] inverters to be disconnected from an [associated common] battery for ≤ 24 hours. This allowance is provided to allow the performance of an equalizing charge on one battery. If the inverters were not disconnected, the resulting voltage condition might damage the inverters. Disconnecting the inverters is allowed provided the associated AC vital buses are energized from their [Class 1E constant voltage source transformer or inverter using internal AC source] and that the AC vital buses for the other batteries are energized from the associated inverters. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while it takes into consideration the time required to perform an equalizing charge on the battery bank.

(continued)

BASES

LCO (continued)

The intent of this Note is to limit the number of inverters that may be disconnected. Only those inverters associated with the single battery undergoing an equalizing charge may be disconnected. All other inverters must be aligned to their associated batteries, regardless of the number of inverters or plant design.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

- a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
- b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Inverters—Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is manually re-energized from its [Class 1E constant voltage source transformer or inverter using internal AC source]. LCO 3.8.9 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the AC vital bus were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately. This ensures the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might

(continued)

BASES

ACTIONS

A.1 (continued)

entail. When the AC vital bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

B.1

With the Division 3 inverter inoperable, the associated Division 3 ECCS subsystem may be incapable of performing intended function and must be immediately declared inoperable. This also requires entry into applicable Conditions and Required Actions for LCO 3.5.1, "ECCS—Operating."

C.1 and C.2

If the inoperable devices or components 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 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Chapter [8].
 2. FSAR, Chapter [6].
 3. FSAR, Chapter [15].
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters—Shutdown

BASES

BACKGROUND A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters—Operating."

APPLICABLE SAFETY ANALYSES The initial conditions of Design Basis Accident (DBA) and transient accident analyses in the FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protection System and Emergency Core Cooling Systems instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each AC vital bus during MODES 4 and 5 ensures that:

- a. The facility can be maintained in the shutdown or refueling condition for extended periods;
- b. Sufficient instrumentation and control capability are available for monitoring and maintaining the unit status; and
- c. Adequate power is available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The inverters were previously identified as part of the Distribution System and, as such, satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or postulated DBA. The battery powered inverters provide uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized. OPERABLE inverters require the AC vital bus be powered by the inverter through inverted DC voltage. This ensures the availability of sufficient inverter power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY The inverters required to be OPERABLE in MODES 4 and 5 and also any time during movement of irradiated fuel assemblies in the [primary or secondary] containment provide assurance that:

- a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;
- b. Systems needed to mitigate a fuel handling accident are available;
- c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and
- d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If two divisions are required by LCO 3.8.10, "Distribution Systems—Shutdown," the remaining OPERABLE inverters may be

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

capable of supporting sufficient required feature(s) to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required feature(s) inoperable with the associated inverter(s) inoperable, appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the [primary or secondary] containment, and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power or powered from a constant voltage source transformer.

SURVEILLANCE
REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

(continued)

BASES (continued)

- REFERENCES
1. FSAR, Chapter [6].
 2. FSAR, Chapter [15].
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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems—Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided by division into three independent AC, DC, and AC vital bus electrical power distribution subsystems.

The primary AC distribution system consists of each 4.16 kV Engineered Safety Feature (ESF) bus that has at least one separate and independent offsite source of power, as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a preferred source. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources—Operating," and the Bases for LCO 3.8.4, "DC Sources—Operating."

The secondary plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers.

The 120 VAC vital buses 2YV1, 2YV2, 2YV3, and 2YV4 are arranged in four load groups and are normally powered from DC. The alternate power supply for the vital buses is a Class 1E constant voltage source transformer powered from the same division as the associated inverter; its use is governed by LCO 3.8.7, "Inverters—Operating." Each constant voltage source transformer is powered from AC.

There are three independent 125 VDC electrical power distribution subsystems. The list of all distribution buses is located in Table [8.1.X.X].

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite or onsite AC electrical power; and
- b. A worst case single failure.

The AC, DC, and AC vital bus electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required AC, DC, and AC vital bus power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1, 2, and 3 AC, DC, and AC vital bus electrical power primary distribution subsystems are required to be OPERABLE.

Maintaining the Division 1, 2, and 3 AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

OPERABLE AC, electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution

(continued)

BASES

LCO (continued)

subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated [inverter via inverted DC voltage, inverter using internal AC source, or Class 1E constant voltage transformer].

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

- a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
- b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.10, "Distribution Systems—Shutdown."

ACTIONS

A.1

With one or more Division 1 or 2 required AC buses, load centers, motor control centers, or distribution panels (except AC vital buses), in one division inoperable, the

(continued)

BASES

ACTIONS

A.1 (continued)

remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit, and on restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

- a. There is potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.
- b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.12, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to

(continued)

BASES

ACTIONS

A.1 (continued)

restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

B.1

With one Division 1 or 2 AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down and maintain the unit in the safe shutdown condition. Overall reliability is reduced, however, because an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated [inverter via inverted DC, inverter using internal AC source, or Class 1E constant voltage transformer].

Condition B represents one AC vital bus without power; potentially both the DC source and the associated AC source nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining vital buses, and restoring power to the affected vital bus.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate AC vital power, that would have Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

(continued)

BASES

ACTIONS

B.1 (continued)

- a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;
- b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without adequate vital AC power, while not providing sufficient time for the operators to perform the necessary evaluations and actions to restore power to the affected division;
- c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, for restoring the vital bus distribution system. At this time, an AC division could again become inoperable, and vital bus distribution could be restored to OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

(continued)

BASES

ACTIONS
(continued)

C.1

With Division 1 or 2 DC buses in one [division] inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that could be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, that would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

- a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;
- b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and
- c. The potential for an event in conjunction with a single failure of a redundant component.

(continued)

BASES

ACTIONS

C.1 (continued)

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC division could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

D.1 and D.2

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, 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.

E.1

With the Division 3 electrical power distribution system inoperable, the Division 3 powered systems are not capable of performing their intended functions. Immediately

(continued)

BASES

ACTIONS

E.1 (continued)

declaring the high pressure core spray inoperable allows the ACTIONS of LCO 3.5.1, "ECCS—Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE
REQUIREMENTS

SR 3.8.9.1

Meeting this Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter [6].
 2. FSAR, Chapter [15].
 3. Regulatory Guide 1.93, December 1974.
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Table B 3.8.9-1 (page 1 of 1)
AC, DC, and AC Vital Bus Electrical Power Distribution Systems

TYPE	VOLTAGE	[DIVISION 1]*	[DIVISION 2]*	[DIVISION 3]*
AC safety buses	[4160 V] [480 V] [480 V] [120 V]	[ESF Bus] [NB01] Load Centers [NG01, NG03] Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D] Distribution Panels [NP01, NP03]	[ESF Bus] [NB02] Load Centers [NG02, NG04] Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D] Distribution Panels [NP02, NP04]	[ESF Bus] [NB03] Motor Control Centers [NG05A, NG05C] Distribution Panels [NP05, NP06]
DC buses	[125 V]	Bus [NK01] Bus [NK03] Distribution Panels [NK41, NK43, NK51]	Bus [NK02] Bus [NK04] Distribution Panels [NK42, NK44, NK52]	Bus [NK05] Distribution Panel [NK45]
AC vital buses	[120 V]	Bus [NN01] Bus [NN03]	Bus [NN02] Bus [NN04]	Bus [NN05]

* Each [division] of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems—Shutdown

BASES

BACKGROUND A description of the AC, DC, and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems—Operating."

APPLICABLE SAFETY ANALYSES The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of irradiated fuel assemblies in the primary or secondary containment ensures that:

- a. The facility can be maintained in the shutdown or refueling condition for extended periods;
- b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and
- c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications' required systems, equipment, and components—both specifically addressed by their own LCOs, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the [secondary] containment provide assurance that:

- a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;
- b. Systems needed to mitigate a fuel handling accident are available;
- c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and
- d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.9.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the [primary or secondary] containment and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal—shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution subsystem is functioning properly, with the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter [6].
 2. FSAR, Chapter [15].
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B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce unit procedures in preventing the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the position of the refueling platform, the loading of the refueling platform main hoist, and the full insertion of all control rods. With the reactor mode switch in the shutdown or refueling position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block in the Control Rod Drive System to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform and the fuel grapple are physically located over the reactor vessel. The main hoist has two switches that open when the hoist is loaded with fuel. The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over

(continued)

BASES

BACKGROUND
(continued)

the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

The hoist switches open at a load lighter than the weight of a single fuel assembly in water.

APPLICABLE
SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the FSAR analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core, such that, considering switch hysteresis and maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of the NRC Policy Statement.

LCO

To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling platform position, and the refueling platform main hoist fuel loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod

(continued)

BASES

LCO
(continued) blocks to prevent operations that could result in
criticality during refueling operations.

APPLICABILITY In MODE 5, a prompt reactivity excursion could cause fuel
damage and subsequent release of radioactive material to the
environment. The refueling equipment interlocks protect
against prompt reactivity excursions during MODE 5. The
interlocks are only required to be OPERABLE during in-vessel
fuel movement with refueling equipment associated with the
interlocks.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is
on, and no fuel loading activities are possible. Therefore,
the refueling interlocks are not required to be OPERABLE in
these MODES.

ACTIONS

A.1

With one or more of the required refueling equipment
interlocks inoperable, the unit must be placed in a
condition in which the LCO does not apply. In-vessel fuel
movement with the affected refueling equipment must be
immediately suspended. This action ensures that operations
are not performed with equipment that would potentially not
be blocked from unacceptable operations (e.g., loading fuel
into a cell with a control rod withdrawn). Suspension of
in-vessel fuel movement shall not preclude completion of
movement of a component to a safe position.

SURVEILLANCE
REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each
required refueling equipment interlock will function
properly when a simulated or actual signal indicative of a
required condition is injected into the logic. The CHANNEL
FUNCTIONAL TEST may be performed by any series of
sequential, overlapping, or total channel steps so that the
entire channel is tested.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.9.1.1 (continued)

The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR, Section [7.6.1.1].
 3. FSAR, Section [15.4.1.1].
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B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Rod Control and Information System).

This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refuel position one-rod-out interlock is explicitly assumed in the FSAR analysis of the control rod withdrawal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

The refuel position one-rod-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") prevent criticality by preventing withdrawal of more than one control rod. With

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

one control rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

The refuel position one-rod-out interlock satisfies Criterion 3 of the NRC Policy Statement.

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. At least one channel of the refuel position one-rod-out interlock is required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of these channels.

APPLICABILITY

In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1) and the control rods (LCO 3.1.3) provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A.1 and A.2

With the refuel position one-rod-out interlock inoperable, the refueling interlocks are not capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE
REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refueling position one-rod-out interlock requires the reactor mode switch to be in Refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refueling position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Frequency of 12 hours is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The 7 day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator of control rods not fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.1 has been modified by a Note that states the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.9.2.2 (continued)

CHANNEL FUNCTIONAL TEST is not required to be performed
until 1 hour after any control rod is withdrawn.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR, Section [7.6.1.1].
 3. FSAR, Section [15.4.1.1].
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B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND

Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2) or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1).

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the intermediate range monitor neutron flux scram (LCO 3.3.1.1), the average power range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis of the control rod withdrawal error during refueling in the FSAR (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. Additionally, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

Control rod position satisfies Criterion 3 of the NRC Policy Statement.

LCO

All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.

APPLICABILITY

During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.

ACTIONS

A.1

With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the FSAR. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE
REQUIREMENTS

SR 3.9.3.1

During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

The 12 hour Frequency takes into consideration the procedural controls on control rod movement during refueling

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.9.3.1 (continued)

as well as the redundant functions of the refueling
interlocks.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR Section [15.4.1.1].
-
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B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel for each control rod provides information necessary to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1 and LCO 3.9.2) use the full-in position indication channel to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position indication channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the withdrawal of any other control rod.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the intermediate range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time.

Control rod position indication satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO One control rod full-in position indication channel for each control rod must be OPERABLE to provide the required inputs to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling equipment interlock all-rods-in logic (LCO 3.9.1), and correct position indication to at least one channel of the refuel position one-rod-out interlock logic (LCO 3.9.2). For the refueling equipment interlock all-rods-in logic the required full-in position indication channel for each control rod is Channel B. At all other times (when the refueling equipment interlocks are not required to be OPERABLE) either Channel A or Channel B OPERABILITY for each control rod satisfies the LCO.

APPLICABILITY During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

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

(continued)

BASES

ACTIONS
(continued)

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more required full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions may be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicators(s) and to disarm the drive(s) to ensure that the control rod is not withdrawn. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE
REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are activated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. The full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.9.4.1 (continued)

visual and audible indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR, Section [15.4.1.1].
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B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY—Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the intermediate range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur.

Control rod OPERABILITY during refueling satisfies Criterion 3 of the NRC Policy Statement.

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator

(continued)

BASES

LCO
(continued) pressure is \geq [1520] psig and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore, are not required to be OPERABLE.

APPLICABILITY During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS A.1

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures that the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

SURVEILLANCE
REQUIREMENTS SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure that a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is \geq [1520] psig.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

The 7 day Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.3 and SR 3.0.4.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
 2. FSAR, Section [15.4.1.1].
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B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level[—Irradiated Fuel]

BASES

BACKGROUND

The movement of [irradiated] fuel assemblies [or handling of control rods] within the RPV requires a minimum water level of [22 ft 8 inches] above the top of the RPV flange. During refueling, this maintains a sufficient water level in the upper containment pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During movement of [irradiated] fuel assemblies [or handling of control rods] the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 100 (Ref. 4) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 5).

While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped assembly, dropping an assembly on the RPV flange will result in reduced releases of fission gases. [Based on this judgement, and the physical dimensions which preclude normal operation with water level 23 feet above the flange, a slight reduction in this water level is acceptable (Ref. 4).]

RPV water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

A minimum water level of [22 ft 8 inches] above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 3.

APPLICABILITY

LCO 3.9.6 is applicable when moving [irradiated] fuel assemblies [or handling control rods (i.e., movement with other than the normal control rod drive)] within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. [If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident.] [Requirements for handling of new fuel assemblies or control rods (where water depth to the RPV flange is not of concern) are covered by LCO 3.9.7, "RPV Water Level - New Fuel or Control Rods."] Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.7, "Fuel Pool Water Level."

Reviewer's Note: LCO 3.9.6 is written to cover new fuel and control rods as well as irradiated fuel. If a plant adopts LCO 3.9.7, however, the second bracketed portion of this Applicability is adopted in lieu of the first bracketed portion. Additional modifications would also be made to the title and Required Action A.1.

(continued)

BASES (continued)

ACTIONS

A.1

If the water level is < [22 ft 8 inches] above the top of the RPV flange, all operations involving movement of [irradiated] fuel assemblies [and handling of control rods] within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of [irradiated] fuel movement [and control rod handling] shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE
REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of [22 ft 8 inches] above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
 2. FSAR, Section [15.7.6].
 3. NUREG-0800, Section [15.7.4].
 4. NUREG-0831, Supplement 6, Section [16.4.2].
 5. 10 CFR 100.11.
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B 3.9 REFUELING OPERATIONS

B 3.9.7 Reactor Pressure Vessel (RPV) Water Level—New Fuel or Control Rods

BASES

BACKGROUND

The movement of new fuel assemblies or handling of control rods within the RPV when fuel assemblies seated within the reactor vessel are irradiated requires a minimum water level of [23 ft] above the top of irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level above the irradiated fuel. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During movement of new fuel assemblies or handling of control rods over irradiated fuel assemblies, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of [23 ft] allows a decontamination factor of 100 (Ref. 4) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of [23 ft] and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 5).

The related assumptions include the worst case dropping of an irradiated fuel assembly onto the reactor core loaded with irradiated fuel assemblies.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

RPV water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

A minimum water level of [23 ft] above the top of irradiated fuel assemblies seated within the RPV is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 3.

APPLICABILITY

LCO 3.9.7 is applicable when moving new fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) over irradiated fuel assemblies seated within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.7, "Fuel Pool Water Level." Requirements for handling irradiated fuel over the RPV are covered by LCO 3.9.6, "[Reactor Pressure Vessel (RPV)] Water Level[—Irradiated Fuel]."

ACTIONS

A.1

If the water level is < [23 ft] above the top of irradiated fuel assemblies seated within the RPV, all operations involving movement of new fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.9.7.1

Verification of a minimum water level of [23 ft] above the top of the irradiated fuel assemblies seated within the RPV ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
 2. FSAR, Section [15.7.6].
 3. NUREG-0800, Section [15.7.4].
 4. NUREG-0831, Supplement 6, Section [16.4.2].
 5. 10 CFR 100.11.
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B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR)—High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines or to the upper containment pool via a common single flow distribution sparger or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Standby Service Water System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and the water level \geq [22 ft 8 inches] above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

(continued)

BASES

LCO
(continued) An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and 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. A Note is provided to allow a 2 hour exception to shut down the operating subsystem every 8 hours.

APPLICABILITY One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with irradiated fuel in the RPV and with the water level \geq [22 ft 8 inches] above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems. RHR Shutdown Cooling System requirements in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level $<$ [22 ft 8 inches] above the RPV flange, are given in LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be established within 1 hour. In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. 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

(continued)

BASES

ACTIONS

A.1 (continued)

reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit's Operating Procedures. For example, this may include the use of the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed. The method used to remove the decay heat should be the most prudent choice based on unit conditions.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend operations involving an increase in reactor decay heat load by suspending the loading of irradiated fuel assemblies into the RPV.

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 (i.e., one secondary containment isolation valve and associated instrumentation are operable or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, 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, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

(continued)

BASES

ACTIONS
(continued)

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE
REQUIREMENTS

SR 3.9.8.1

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

REFERENCES

None.

B 3.9 REFUELING OPERATIONS

B 3.9.9 Residual Heat Removal (RHR)—Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines, to the upper containment pool via a common single flow distribution sparger, or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Standby Service Water System. The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level < 22 ft 8 inches above the RPV flange both RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

(continued)

BASES

LCO
(continued)

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and 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. A Note is provided to allow a 2 hour exception to shut down the operating subsystem every 8 hours.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE in MODE 5, with irradiated fuel in the RVP and with the water level < [22 ft 8 inches] above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems. RHR Shutdown Cooling System requirements in MODE 5, and with the water level \geq [22 ft 8 inches] above the RPV flange, are given in LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level."

ACTIONS

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, 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

(continued)

BASES

ACTIONS

A.1 (continued)

thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit's Operating Procedures. For example, this may include the use of the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed. The method used to remove decay heat should be the most prudent choice based on unit conditions.

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

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, 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 (i.e., one secondary containment isolation valve and associated instrumentation are operable or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, 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, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

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

SURVEILLANCE
REQUIREMENTS

SR 3.9.9.1

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

REFERENCES

None.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3).

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing will eventually be required with minimum reactor coolant temperatures > 200°F.

The hydrostatic test requires increasing pressure to []% of design pressure (1250 psig) or [] psig, and because of the expected increase in reactor vessel fluence, the minimum allowable vessel temperature according to LCO 3.4.11 is increased to []°F. This increase to []% of design pressure does not exceed the Safety Limit of 1375 psig.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is $> 200^{\circ}\text{F}$, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the hydrostatic or leak tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.8, "Reactor Coolant System (RCS) Specific Activity," are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure coolant injection and low pressure core spray subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS—Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures $> 200^{\circ}\text{F}$, can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures $> 200^{\circ}\text{F}$, while the ASME inservice test itself requires the safety/relief valves to be gagged, preventing their OPERABILITY.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures $> 200^{\circ}\text{F}$ for the purposes of performing either an inservice leak or hydrostatic test.

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation.

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is $> 200^{\circ}\text{F}$. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements shall be entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to $\leq 200^{\circ}\text{F}$.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operations LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to $\leq 200^{\circ}\text{F}$ with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 for reaching MODE 4 from MODE 3.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

REFERENCES

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.
 2. FSAR, Section [15.1.40].
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B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

- a. Shutdown—Initiates a reactor scram; bypasses main steam line isolation and reactor high water level scrams;
- b. Refuel—Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation and reactor high water level scrams;
- c. Startup/Hot Standby—Selects NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation and reactor high water level scrams; and
- d. Run—Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, suppression pool makeup, and main steam isolation valve isolations.

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality.

The interlock functions of the shutdown and refuel positions of the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, or startup/hot standby) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," and LCO 3.10.8, "SDM Test—Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires

(continued)

BASES

LCO
(continued)

repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5 with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

In MODE 5, with the reactor mode switch in the refuel position, only one control rod can be withdrawn under the refuel position one rod out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed without this allowance. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent

(continued)

BASES

APPLICABILITY (continued)	criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.
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ACTIONS	<u>A.1, A.2, A.3.1, and A.3.2</u>
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These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS, except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control rods remain inserted and result in operation in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS	<u>SR 3.10.2.1 and SR 3.10.2.2</u>
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Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2 (continued)

effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. The Surveillances performed at the 12 hour and 24 hour Frequencies are intended to provide appropriate assurance that each operating shift is aware of and verify compliance with these Special Operations LCO requirements.

REFERENCES

1. FSAR, Section [7.6.1.1].
 2. FSAR, Section [15.4.1.1].
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B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal—Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of an accident. Explicit safety analyses in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing" without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn.

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the

(continued)

BASES

LCO
(continued) withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication") full insertion requirements for all other control rods, and scram functions (LCO 3.3.1.1, "Reaction Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative control in Item d.2 of this Special Operations LCO, minimizes potential reactivity excursions.

ACTIONS A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. This Required Action has been modified by a Note that clarifies the intent

(continued)

BASES

ACTIONS

A.1 (continued)

of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 and are alternative Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE
REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The 24 hour Frequency is acceptable because of the administrative

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued)

controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks that preclude additional control rod withdrawals.

REFERENCES

1. FSAR, Section [15.4.1.1].
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B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal—Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of an accident. Explicit safety analyses in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing the CRD because this removal renders the withdrawn control rod incapable of being scrammed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram

(continued)

BASES

LCO (continued)

function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. 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 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 each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS
(continued)

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies that the intent of any other LCO is Required Action to insert all control rods. This Required Action includes exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the shutdown position. Action must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

B.1, B.2.1, and B.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must immediately be suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or restore compliance with this Special Operations LCO.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. FSAR, Section [15.4.1.1].
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B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY—Refueling").

(continued)

BASES (continued)

APPLICABLE
SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of accidents. Explicit safety analyses in the FSAR (Ref. 1) demonstrate that the proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn (by insertion of a control rod block).

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES (continued)

LCO As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs—LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5—not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduces the potential for reactivity excursions.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE
REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and
SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods other than the control rod withdrawn for the removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied.

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative

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BASES

SURVEILLANCE SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and
REQUIREMENTS SR 3.10.5.5 (continued)

controls on control rod removal and hardware interlocks to
block an additional control rod withdrawal.

REFERENCES 1. FSAR, Section [15.4.1.1].

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rods may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the FSAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

the cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY—Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

When loading fuel into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Spiral reloading encompasses reloading a cell (four fuel locations immediately adjacent to a control rod) on the edge of a continuous fueled region (the cell can be loaded in any sequence). Otherwise, all control rods must be fully inserted before loading fuel.

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BASES (continued)

APPLICABILITY Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.

ACTIONS A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

**SURVEILLANCE
REQUIREMENTS** SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.

REFERENCES 1. FSAR, Section [15.4.1.1].

B 3.10 Special Operations

B 3.10.7 Control Rod Testing—Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod pattern controller (RPC) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RPC. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a control rod drop accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests may include SDM demonstrations, control rod scram time testing, control rod friction testing, and testing performed during the Startup Test Program. This Special Operations LCO provides the necessary exceptions to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RPC provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analyses of References 1, 2, 3, and 4 may not be preserved. Therefore, special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

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BASES

APPLICABLE
SAFETY ANALYSES
(continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence remain valid. When deviating from the prescribed sequences of LCO 3.1.6, individual control rods must be bypassed in the Rod Action Control System (RACS). Assurance that the test sequence is followed can be provided by a second licensed operator or other qualified member of the technical staff verifying conformance to the approved test sequence. These controls are consistent with those normally applied to operation in the startup range as defined in SR 3.3.2.1.8, when it is necessary to deviate from the prescribed sequence (e.g., an inoperable control rod that must be fully inserted).

APPLICABILITY

Control rod testing, while in MODES 1 and 2 with THERMAL POWER greater than the LPSP of the RPC, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to the LPSP of the RPC, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed control rod sequences of

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BASES

APPLICABILITY
(continued)

LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal—Hot Shutdown" or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal—Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 1 and 2 are satisfied. During these Special Operations and while in MODE 5, the one rod out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock) and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, minimize potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern not in compliance with the special test sequence), the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken either to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE
REQUIREMENTS

SR 3.10.7.1

During performance of the special test, a second licensed operator or other qualified member of the technical staff is required to verify conformance with the approved sequence for the test. [Note: A member of the technical staff is considered to be qualified if he possesses skills equal to a licensed operator [in the following areas:]] This verification must be performed during control rod movement to prevent deviations from the specified sequence. This Surveillance provides adequate assurance that the specified test sequence is being followed and is also supplemented by SR 3.3.2.1.8, which requires verification of the bypassing of control rods in RACS and subsequent movement of these control rods.

(continued)

BASES (continued)

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).
 2. Letter from T. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.
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B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup/hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup/hot standby position while in MODE 5, is provided by the Intermediate Range Monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the Rod Pattern Controller (RPC), APRM, and control rod coupling, the single notch withdrawal mode is specified for out of sequence withdrawals. Requiring the single notch withdrawal mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2.a and 2.d) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, RPS

(continued)

BASES

LCO
(continued)

MODE 2 requirements for Functions 2.a and 2.d of Table 3.3.1.1-1 must be enforced and the approved control rod withdrawal sequence must be enforced by the RPC (LCO 3.3.2.1, Function 1.b, MODE 2), or must be verified by a second licensed operator or other qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in LCO 3.1.6, "Rod Pattern Control" (i.e., out of sequence control rod withdrawals) must be made in the notched withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since, if the control rod

(continued)

BASES

ACTIONS

A.1 (continued)

fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows control rods to be bypassed in the Rod Action Control System (RACS) if required to allow insertion of the inoperable control rods and continued operation. SR 3.3.2.1.9 provides additional requirements when the control rods are bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

With one or more of the requirements of this LCO not met, for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES

ACTIONS
(continued)

B.1

With the requirements of this LCO not met, the affected control rod shall be declared inoperable. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE
REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a and 2.d, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. However, the control rod withdrawal sequences during the SDM tests may be enforced by the RPC (LCO 3.3.2.1, Function 1.b, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RPC (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.10.8.5 (continued)

verification is required to be performed any time a control rod is withdrawn to the "full out" notch position or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 1520 psig is well below the expected pressure of 1750 psig to 2000 psig. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement For United States (as amended).
 2. Letter, T.A. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.
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B 3.10 SPECIAL OPERATIONS

B 3.10.9 Recirculation Loops—Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO in MODES 1 and 2 is to allow either the PHYSICS TESTS or the Startup Test Program to be performed with less than two recirculation loops in operation. Testing performed as part of the Startup Test Program (Ref. 1), or PHYSICS TESTS authorized under the provisions of 10 CFR 50.59 (Ref. 2) or otherwise approved by the NRC, may be required to be performed under natural circulation conditions with the reactor critical. LCO 3.4.1, "Recirculation Loops Operating," requires that one or both recirculation loops be in operation during MODES 1 and 2. This Special Operations LCO provides the appropriate additional restrictions to allow testing at natural circulation conditions or in single loop operation with the reactor critical.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Coolant Recirculation System is an initial condition assumed in the design basis loss of coolant accident (Ref. 3). 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 postulated accident. During PHYSICS TESTS $\leq 5\%$ RTP, or limited testing during the Startup Test Program for the initial cycle, the decay heat in the reactor coolant is sufficiently low, such that the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important. In addition, the probability of a Design Basis Accident (DBA) or other accidents occurring during the limited time allowed at natural circulation or in single loop operation is low.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES (continued)

LCO As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. However, to perform testing at natural circulation conditions or with a single operating loop, operations must be limited to those tests defined in the Startup Test Program or approved PHYSICS TESTS performed at $\leq [5\%]$ RTP. To minimize the probability of an accident, while operating at natural circulation conditions or with one operating loop, the duration of these tests is limited to ≤ 24 hours. This Special Operations LCO then allows suspension of the requirements of LCO 3.4.1 during such testing. In addition to the requirements of this LCO, the normally required MODE 1 or MODE 2 applicable LCOs must be met.

APPLICABILITY This Special Operations LCO may only be used while performing testing at natural circulation conditions or while operating with a single loop, as may be required as part of the Startup Test Program or during low power PHYSICS TESTS. Additional requirements during these tests to limit the operating time at natural circulation conditions reduce the probability that a DBA may occur with both recirculation loops not in operation. Operations in all other MODES are unaffected by this LCO.

ACTIONS A.1

With the testing performed at natural circulation conditions or with a single operating loop, and the duration of the test exceeding the 24 hour time limit, actions should be taken to promptly shut down. Inserting all insertable control rods will result in a condition that does not require both recirculation loops to be in operation. The allowed Completion Time of [1] hour provides sufficient time to insert the withdrawn control rods.

B.1

With the requirements of this LCO not met for reasons other than those specified in Condition A (e.g., low power PHYSICS TESTS exceeding [5]% RTP, or unapproved testing at natural circulation), the reactor mode switch should immediately be

(continued)

BASES

ACTIONS

B.1 (continued)

placed in the shutdown position. This results in a condition that does not require both recirculation loops to be in operation. The action to immediately place the reactor mode switch in the shutdown position prevents unacceptable consequences from an accident initiated from outside the analysis bounds. Also, operation beyond authorized bounds should be terminated upon discovery.

SURVEILLANCE
REQUIREMENTS

SR 3.10.9.1 and SR 3.10.9.2

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of this LCO. Because the 1 hour Frequency provides frequent checks of the LCO requirements during the allowed 24 hour testing interval, the probability of operation outside the limits concurrent with a postulated accident is reduced even further.

REFERENCES

1. FSAR, Chapter [14].
 2. 10 CFR 50.59.
 3. FSAR, Section [6.3.3.4].
 4. FSAR, Section [].
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B 3.10 SPECIAL OPERATIONS

B 3.10.10 Training Startups

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit training startups to be performed while in MODE 2 to provide plant startup experience for reactor operators. This training involves withdrawal of control rods to achieve criticality and then further withdrawal of control rods, as would be experienced during an actual plant startup. During these training startups, if the reactor coolant is allowed to heat up, maintenance of a constant reactor vessel water level requires the passage of reactor coolant through the Reactor Water Cleanup System, as the reactor coolant specific volume increases. Since this results in reactor water discharge to the radioactive waste disposal system, the amount of this discharge should be minimized. This Special Operations LCO provides the appropriate additional controls to allow one residual heat removal (RHR) subsystem to be aligned in the shutdown cooling mode, so that the reactor coolant temperature can be controlled during the training startups, thereby minimizing the discharge of reactor water to the radioactive waste disposal system.

APPLICABLE SAFETY ANALYSES

The Emergency Core Cooling System (ECCS) is designed to provide core cooling following a loss of coolant accident (LOCA). The low pressure coolant injection (LPCI) mode of the RHR System is one of the ECCS subsystems assumed to function during a LOCA. With reactor power $\leq 1\%$ RTP (equivalent to all OPERABLE intermediate range monitor (IRM) channels $\leq 25/40$ divisions of full scale on Range 7) and average reactor coolant temperature $< 200^\circ\text{F}$, the stored energy in the reactor core and coolant system is very low, and a reduced complement of ECCS can provide the required core cooling, thereby allowing operation with one RHR subsystem in the shutdown cooling mode (Ref. 1).

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Training startups may be performed while in MODE 2 with no RHR subsystems aligned in the shutdown cooling mode and, therefore, without meeting this Special Operations LCO or its ACTIONS. However, to minimize the discharge of reactor coolant to the radioactive waste disposal system, performance of the training startups may be performed with one RHR subsystem aligned in the shutdown cooling mode to maintain reactor coolant temperature $< 200^{\circ}\text{F}$. Under these conditions, the THERMAL POWER must be maintained $\leq 1\%$ RTP (equivalent to all OPERABLE IRM channels $\leq 25/40$ divisions of full scale on Range 7) and the reactor coolant temperature must be $\leq 200^{\circ}\text{F}$. This Special Operations LCO then allows changing the LPCI OPERABILITY requirements. In addition to the requirements of this LCO, the normally required MODE 2 applicable LCOs must also be met.

APPLICABILITY

Training startups while in MODE 2 may be performed with one RHR subsystem aligned in the shutdown cooling mode to control the reactor coolant temperature. Additional requirements during these tests to restrict the reactor power and reactor coolant temperature provide protection against potential conditions that could require operation of both RHR subsystems in the LPCI mode of operation. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more of the requirements of this LCO not met, (i.e., any OPERABLE IRM channel $> 25/40$ division of full scale on Range 7, or average reactor coolant temperature $\geq 200^{\circ}\text{F}$) the reactor may be in a condition that requires the full complement of ECCS subsystems, and the reactor mode switch must be immediately placed in the shutdown position. This results in a condition that does not require all RHR

(continued)

BASES

ACTIONS

A.1 (continued)

subsystems to be OPERABLE in the LPCI mode of operation. This action may restore compliance with the requirements of this Special Operations LCO or may result in placing the plant in either MODE 3 or MODE 4.

SURVEILLANCE
REQUIREMENTS

SR 3.10.10.1 and SR 3.10.10.2

Periodic verification that the THERMAL POWER and reactor coolant temperature limits of this Special Operations LCO are satisfied will ensure that the stored energy in the reactor core and reactor coolant are sufficiently low to preclude the need for all RHR subsystems to be aligned in the LPCI mode of operation. The 1 hour Frequency provides frequent checks of these LCO requirements during the training startup.

REFERENCES

1. FSAR, Section [6.3.3.4].
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11. ABSTRACT (200 words or less)

This report documents the results of the combined effort of the NRC and the industry to produce improved Standard Technical Specifications (STS), Revision 1 for General Electric BWR/6 Plants. The changes reflected in Revision 1 resulted from the experience gained from license amendment applications to convert to these improved STS or to adopt partial improvements to existing technical specifications. This NUREG is the result of extensive public technical meetings and discussions between the Nuclear Regulatory Commission (NRC) staff and various nuclear power plant licensees, Nuclear Steam Supply System (NSSS) Owners Groups, NSSS vendors, and the Nuclear Energy Institute (NEI). The improved STS were developed based on the criteria in the Final Commission Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors, dated July 22, 1993. The improved STS will be used as the basis for individual nuclear power plant licensees to develop improved plant-specific technical specifications. This report contains three volumes. Volume 1 contains the Specifications for all chapters and sections of the improved STS. Volume 2 contains the Bases for Chapters 2.0 and 3.0, and Sections 3.1 - 3.3 of the improved STS. Volume 3 contains the Bases for Sections 3.4 - 3.10 of the improved STS.

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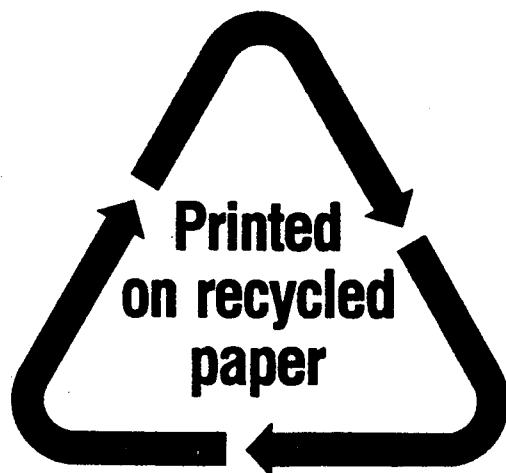
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